BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1146

In the Matter of:	)
Application of Duke Energy Carolinas,	)
LLC for Adjustment of Rates and	)
Charges Applicable to Electric Utility	)
Service in North Carolina	)

DIRECT TESTIMONY OF JUSTIN R. BARNES ON BEHALF OF NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

OFFICIAL COPY

Jan 23 2018

OFFICIAL COPY

Jan 23 2018

OFFICIAL COPY

Jan 23 2018

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A. Justin R. Barnes, 401 Harrison Oaks Blvd., Suite 100, Cary, North Carolina, 27513. My current position is Director of Research with EQ Research LLC ("EQ Research").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND OCCUPATIONAL BACKGROUND.

A. I obtained a Bachelor of Science in Geography from the University of Oklahoma in Norman in 2003 and a Master of Science in Environmental Policy from Michigan Technological University in 2006. I was employed at the North Carolina Solar Center at North Carolina State University for more than five years, where I worked on the *Database of State Incentives for Renewables and Efficiency ("DSIRE")* project, and several other projects related to state renewable energy and efficiency policy.

In my current position I coordinate EQ Research's various research projects for clients, assist in the oversight of EQ Research's electric industry regulatory and general rate case tracking services and perform customized research and analysis to fulfill client requests. I have testified before the Public Service Commission of South Carolina, the Oklahoma Corporation Commission, the Colorado Public Utilities Commission, the Utah Public Service Commission, and the Public Utility Commission of Texas as an expert in distributed generation

OFFICIAL COPY

Jan 23 2018

("DG") policy, rate design, and cost of service. My *curriculum vitae* is attached as Exhibit JRB-1.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION ("COMMISSION")?

A. Yes. I submitted direct testimony in Docket No. E-2, Sub 1142 addressing Duke Energy Progress, LLC's ("DEP") request for a general rate increase.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the North Carolina Sustainable Energy Association ("NCSEA").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses four issues with the rates application put forth by Duke Energy Carolinas, LLC ("DEC" or "the Company"), all of which relate to rate design and cost of service. My central focus is on the first two issues I list below, related to residential fixed charges. These topics are heavily interrelated and give rise to common concerns in both the near- and long-term. My testimony is broken into the following topic areas:

1. The Company's proposed increases in residential fixed basic facilities charges ("BFCs"), from a perspective of ratemaking principles and the proper determination and allocation of customer-related costs.[1]
2. The Company's proposed Grid Reliability and Resiliency Rider ("GRR Rider"), with a focus on the distribution of costs and benefits among

[1] In my testimony I use the term "basic facilities charge" to refer to DEC's fixed monthly base rate charge because that is how it is defined in the Company's tariff. The term should be considered equivalent to the terms "fixed charge" or "customer charge", as used elsewhere in my testimony.

OFFICIAL COPY

Jan 23 2018

customer classes and the determination of the proposed fixed and volumetric rates associated with the GRR Rider.

3. The Company's classification of past and anticipated coal ash remediation costs as related to production demand rather than energy.
4. Certain misleading and inaccurate statements made by the Company regarding DG.

Q. PLEASE SUMMARIZE AND EXPLAIN YOUR RECOMMENDATIONS TO THE COMMISSION ON THE COMPANY'S PROPOSED CUSTOMER CHARGES.

A. I recommend that the Commission reject the dramatic increases to residential BFCs that DEC has proposed and retain DEC's current charges. If the Commission does find that any changes to the level of the residential BFCs are justified, those increases should be capped at the overall percentage increase in revenue by rate class. My recommendation is based on demonstration that the Company's proposed charges are:

1. Extreme by numerous objective measures in comparison to national ratemaking trends and trends among other utility companies that DEC has identified as comparable for the purpose of determining an appropriate return on equity ("ROE");
2. Based on a distribution cost classification methodology, the Minimum System Method, that is logically flawed, and even assuming it is valid, has been improperly executed by the Company; and

OFFICIAL COPY

Jan 23 2018

3. Damaging to customer incentives to pursue energy efficiency and DG, which has the effect of increasing future risks to ratepayers at the precise time when the consequences of those risks could not be more apparent.

I further recommend that the Commission establish a methodology for determining customer-related costs that reflects cost causation and results in consistency between the state's utilities.

Q. PLEASE SUMMARIZE AND EXPLAIN YOUR RECOMMENDATIONS TO THE COMMISSION ON THE COMPANY'S PROPOSED CLASSIFICATION AND ALLOCATION OF COAL ASH REMEDIATION COSTS.

A. I recommend that the Commission direct the Company to classify all costs associated with coal ash remediation as energy-related, and that this change be reflected in revised class revenue allocations. My recommendation is based on the fact that coal ash is a by-product of energy production, and its creation bears little or no relationship to system peak demand. Because it is directly tied to the use and consumption of coal as a fuel, energy use is the primary cost causation factor.

Q. PLEASE SUMMARIZE AND EXPLAIN YOUR RECOMMENDATIONS TO THE COMMISSION ON THE COMPANY'S GRR RIDER.

A. I recommend that the Commission deny DEC's proposal to establish the GRR Rider and adopt NCSEA Witness Caroline Golin's recommendation to establish a new proceeding to further investigate the contents, costs and benefits, cost allocation, and rate design of the Company's proposed grid modernization

OFFICIAL COPY

Jan 23 2018

investments. The GRR Rider, as proposed, places further upward pressure on residential customer rates with roughly 72% of the total costs borne by the residential class, of which roughly 57% would be recovered via a fixed charge. The impacts on fixed residential charges in particular are highly concerning given that the GRR Rider represents only a small portion of the Company's expected grid modernization investments and the Company is separately seeking large increases in residential BFCs under its base rate proposal. I believe there is a critical need for the Commission to take a closer look at the Company's grid modernization plans in order to consider the long-term rate effects, including but not limited to what available information suggests will be further, large increases in fixed monthly charges on residential customers.

II. DEC'S RESIDENTIAL BFC PROPOSAL AND ANALYSIS OF CUSTOMER-RELATED COSTS.

Q. PLEASE DESCRIBE THE COMPANY'S RATE PROPOSAL WITH RESPECT TO FIXED MONTHLY BFCS.

A. DEC is seeking dramatic increases in BFCs for the residential service class, from a 39.99% increase in the BFC for the residential time-of-use rate schedule (Schedule RT) to a 50.76% increase for the other residential rate schedules. Table 1 below sourced from Exhibit No. 8 of the Direct Testimony of Michael Pirro depicts the proposed increases.[2]

---

[2] Direct Testimony of Michael J. Pirro for Duke Energy Carolinas, LLC, Exhibit 8 (August 25, 2017) (hereinafter "Pirro Direct"). The source contains additional columns, rate details for non-residential rate classes, and notes that have been omitted from Table 1.

OFFICIAL COPY

Jan 23 2018

Table 1: Proposed Residential BFCs

Rate Class	Current BFC	DEC Unit Costs	Proposed BFC	Rate Change	Percent Change
Residential Standard (RS)	$11.80	$23.78	$17.79	$5.99	50.76%
Residential Electric Space & Water Hearing (RE)	$11.80	$24.98	$17.79	$5.99	50.76%
Residential Energy Star (ES)	$11.80	$23.78	$17.79	$5.99	50.76%
Residential Time-of-Use (RT)	$13.38	$24.08	$18.73	$5.35	39.99%

It is important to note that these charges do not reflect the Company's current GRR Rider proposal or any future increases in the fixed monthly charges that would be established in the GRR Rider.

Q. DO YOU AGREE THAT THE COMPANY'S PROPOSAL FOR RESIDENTIAL BFCS IS REASONABLE?

A. No. I object to the Company's proposal for several reasons. First, the proposed charges and proposed increases are extreme by multiple measures, and violate the principle of gradualism in utility ratemaking. Second, the Company's derivation of the customer-specific costs used to derive the charges, which uses the Minimum System Method for classifying distribution costs, is flawed. Third, if adopted they will substantially dilute consumers' ability to control their energy costs and their incentive to save energy through behavioral changes or investments in energy efficiency and DG. I discuss each of these criticisms in more detail in the following subsections.

OFFICIAL COPY

Jan 23 2018

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION WITH RESPECT TO RESIDENTIAL BFCS?

A. I recommend that the Company's current BFCs be maintained. In the alternative, should the Commission believe it is necessary to increase them, they should only be increased by the percentage increase in the overall revenue requirements adopted for each residential sub-class. I strongly recommend that the Commission take the former approach and maintain the charges at their present levels.

I also recommend that the Commission consider how the Company's capital investment plans, including both its transmission and distribution investment plan and its Power/Forward proposal, would affect so-called customer-related costs. As I discuss in the following subsections, the Company's methods of establishing customer-related costs tend to assign a large portion of shared distribution costs to the residential sector. Taken together, the Company's capital investment plans and current cost allocation and classification methods are indicative of a pattern of escalating residential rates and residential BFCs that would go well beyond the Company's current, highly aggressive, proposal for increases.

A. DEC's Proposed Increases to Residential BFCs are Extreme.

Q. IN WHAT WAYS ARE THE COMPANY'S PROPOSED RESIDENTIAL BFCS EXTREME?

A. The proposed customer charges for the residential class are extreme insofar as they would result in:

OFFICIAL COPY

Jan 23 2018

1. BFCs far in excess of the national average, other Duke Energy Corporation affiliates, and those of corporations deemed comparable to the Duke Energy Corporation in the Direct Testimony of Robert Hevert;[3] and
2. Increases far in excess, both in monetary and percentage terms, of increases approved by regulators in other states during rate cases filed during the last three years, including those approved for comparable companies.

Q. HOW DID YOU ARRIVE AT THE CONCLUSIONS ABOVE AND WHAT EVIDENCE DO YOU PRESENT TO SUPPORT THESE CLAIMS.

A. I conducted a review of current residential customer charges for 165 investor-owned utilities ("IOUs") in 49 states and the District of Columbia.[4] The utilities in this survey encompass all major IOUs and nearly all smaller IOUs in each state, thus it presents a comprehensive national picture of residential fixed charges. I also conducted a review of adopted increases in residential customer charges for IOU general rate case applications filed since July 2014. A total of 106 general rate cases are represented in this sample, though the total number of utilities is lower because several utilities had multiple rate cases during this time frame. Consequently, the sample of adopted increases reflects these utilities more than once. Both datasets were current as of October 2, 2017. Exhibit JRB-2 contains the full results of both of these surveys.

[3] For a full list *see* Direct Testimony of Robert B. Hevert for Duke Energy Carolinas, LLC, Table 1 (August 25, 2017) (hereinafter "Hevert Direct").
[4] Nebraska is the only state not represented in this survey. Nebraska is unique in that it is the only state served entirely by consumer-owned utilities not subject to external rate regulation.

OFFICIAL COPY

Jan 23 2018

As I note above, the "comparable" utilities are based on the proxy companies included that DEC Witness Hevert selected for his ROE analysis. To generate these averages, I selected all of the local distribution utilities affiliated with these companies from my larger dataset of fixed charges and approved increases.

Q. PLEASE SUMMARIZE THE RESULTS OF THE RESEARCH YOU DESCRIBE ABOVE.

A. Table 2 below presents comparisons between current fixed monthly charge averages and DEC's current ($11.80/month) and proposed rates ($17.79/month). Table 3 presents averages of *increases* approved in rate cases filed during the last three years relative to the Company's proposed increase of $5.99/month, or 50.76%.

Table 2: Fixed Charge Comparisons

Basis of Comparison (Averages)	Fixed Charge ($)	DEC Current Diff. ($)	DEC Current Diff. (%)	DEC Proposed Diff. ($)	DEC Proposed Diff. (%)
National	$10.59	$1.21	11.43%	$7.20	67.99%
Duke Affiliate	$8.16	$3.64	44.61%	$9.63	118.01%
Duke Comparables	$10.24	$1.56	15.23%	$7.55	73.73%
DEC Current	$11.80				
DEC Proposed	$17.79				

Table 3: Fixed Charge Increase Comparisons

Basis of Comparison (Averages)	Increase ($)	Increase (%)	DEC Above ($)	DEC Above (%)
National	$1.11	14.09%	$4.88	36.67%
Duke Affiliates	$2.56	39.40%	$3.43	11.36%
Duke Comparables	$1.14	14.65%	$4.85	36.11%
DEC Proposed	$5.99	50.76%		

OFFICIAL COPY

Jan 23 2018

Tables 2 and 3 clearly show that DEC's current BFC is already substantially above average, the increase it proposes would greatly increase these differences, and the proposed increase goes far beyond average increases approved by other regulators in recent years.

Q. PLEASE EXPLAIN WHY YOU INCLUDED A COMPARISON TO COMPANIES "COMPARABLE" TO THE DUKE ENERGY CORPORATION IN YOU ANALYSIS.

A. DEC Witness Hevert describes his selection of proxy companies as intended to consist of those with "risk profiles comparable to the subject company".[5] To be clear, none of his selection criteria involve an assessment of a company's risk profile based on revenue generated via fixed charges. However, it is inescapable that fixed charges do have the effect of providing a high degree of certainty for a portion of a utility's revenue during a given month or year (i.e., little or no risk of under-recovery), making it less vulnerable to sales fluctuations. I make no claims as to how specifically fixed charge revenue affects a utility's risk profile. Nevertheless, I do believe that the list of proxy companies is illustrative insofar as it represents an additional basis for comparing different utilities, and shows results similar to the national and Duke affiliate comparisons I have done.

Q. DO YOU HAVE ANY OTHER OBSERVATIONS REGARDING THE RESULTS OF YOUR RESIDENTIAL FIXED CHARGE ANALYSIS?

[5] Hevert Direct, p. 13, lines 12-13.

OFFICIAL COPY

Jan 23 2018

A. Yes. First, the statistics in these tables and the source data in Exhibit JRB-2 exclude the Company's GRR Rider, which would establish a further increase of $0.72/month residential monthly fixed charges.[6] Beyond this detail applicable to the Company's rate proposals, it is also important to note that with respect to other utilities represented in the sample:

- In Table 3, the Company Affiliate average increase refers to a single increase for the Company's Duke Energy Progress division in South Carolina. The dollar amount ($2.56/month) and percentage increase (39.4%) for this increase reflect an increase in the fixed charge from $6.50/month to $9.06/month. Both the monetary increase and the percentage increase appear relatively high compared to national averages, but this is largely attributable to the lower starting point for the increase.
- Eversource Connecticut, whose fixed monthly charge of $19.25 ranks as the 11th highest fixed charge, is in the midst of a general rate case where the utility has proposed reducing the charge to no more than $11.88/month (the "maximum residential customer charge").[7]
- Three of the utilities with fixed charges higher than what DEC has proposed are located in New York. The New York Public Service

[6] Pirro Direct, Exhibit No. 9.

[7] Testimony of the Rates Panel on Behalf of the Connecticut Light and Power Company dba Eversource Energy, Connecticut Public Utility Regulatory Authority Docket No. 17-10-46 (January 12, 2018).

OFFICIAL COPY

Jan 23 2018

Commission ("NYPSC") is in the process of broadly reconsidering utility rates for residential customers, including the role of fixed charges.[8]

- Three utilities with current charges higher than DEC's proposal, Public Service Oklahoma, Rocky Mountain Power Wyoming, and Montana-Dakota Utilities Wyoming have extremely rural service territories where fixed infrastructure serves a relatively small number of customers. Consequently, their systems are not necessarily comparable to DEC's. Given these facts, DEC's proposal is actually even more extreme than the information in Exhibit JRB-2 suggests.

Q. ARE THE COMPANY'S PROPOSED INCREASES TO THE RESIDENTIAL AND OTHER CLASS CUSTOMER CHARGES CONSISTENT WITH THE PRINCIPLE OF GRADUALISM?

A. Absolutely not. Company Witness Pirro states that gradualism is an important consideration in ratemaking.[9] I certainly agree with this statement. However, the Company's proposal with respect to customer charges is inconsistent with this ratemaking principle. As evidenced by both the amount and percentage of the proposed increase in the residential fixed charge, the Company's proposal clearly does not represent "gradualism" as practiced by regulators in other states. It is only "gradual" with respect to the Company's calculated customer unit costs, which I disagree with and will discuss later in my testimony.

---

[8] *See*, *e.g.*, *Staff Scope of Study to Examine Bill Impacts of a Range of Mass Market Rate Reform Scenarios*, New York Public Service Commission Matter No. 17-01277 (October 3, 2017).
[9] Pirro Direct. p. 11, lines 5-7.

OFFICIAL COPY

Jan 23 2018

B. DEC's Proposed Customer Charge Increases Would Dilute Customers' Motivations to Pursue Energy Efficiency and DG.

Q. HOW DO FIXED CHARGES AFFECT CUSTOMER BEHAVIOR WITH RESPECT TO ENERGY EFFICIENCY?

A. Higher fixed customer charges result in more revenue being collected under fixed fees, which in turn reduces the energy and demand rates necessary to raise the remaining portion of the revenue requirement. Lower variable charges provide less of an incentive for customers to reduce their demand or overall energy use. In effect, customers see less savings as a result of conservation, so they are less motivated to reduce their overall energy usage or demand.

The Company's estimate that the proposed rate increases associated with its current application will result in 1.3% reduction in retail sales and peak demand during 2018 agrees with this generalized effect.[10] Higher rates, to the extent that they are not structured as fixed rates, prompt customers to purchase less energy.

Q. HOW WOULD THE COMPANY'S PROPOSAL FOR INCREASING CUSTOMER CHARGES AFFECT ENERGY USAGE RATES?

A. For the RS and RE rates combined, the fixed charge increase translates to roughly 0.577 ¢/kWh based on the test year number of residential customers and energy sales used in the Company's cost of service study. This figure is derived by multiplying the proposed monthly increase of $5.99 by the number of 2016

---

[10] Pirro Direct, Exhibit No. 6.

OFFICIAL COPY

Jan 23 2018

residential customer bills, resulting in a residential customer charge revenue increase of roughly \$122.6 million. Dividing this revenue increase by test year sales of roughly 21.2 million MWh results in the 0.577 ¢/kWh figure.[11]

Q. HOW WOULD SUCH A CHANGE AFFECT CUSTOMER SAVINGS FROM DG INSTALLATION OR ENERGY EFFICIENCY?

A. The effect would be meaningful. The National Renewable Energy Laboratory ("NREL") PVWatts calculator estimates that a well-sited 4 kilowatt ("kW") PV system in the Charlotte, North Carolina area will produce roughly 5,800 kWh during the first year.[12] If degradation of 0.5% annually is considered, the 20-year annual average system production would amount to 5,220 kWh. Based on this estimate, over 20 years the customer would save \$600 less under DEC's residential customer charge proposal relative to the current fixed charge rate. This assumes that DEC does not seek further increases in the fixed customer charge.

The savings reduction impacts for energy efficiency would be smaller on a per customer basis because energy efficiency investments do not typically result in the same level of annual energy savings as DG. Nevertheless, if the fixed charge increase reduced overall residential class energy efficiency savings by only 1%, the level of forgone savings for the residential class as a whole would exceed \$1.2 million annually. The diluted conservation incentive as reflected in utility

[11] Values sourced from Application to Adjust Retail Rates, Request for an Accounting Order, and to Consolidate Dockets, Form E-1, (hereinafter "DEC Form E-1") Item 45E (1CP 2016 Adj. Prop. Unit Costs).

[12] Estimate uses default PVWatts values. PVWatts is available at http://pvwatts.nrel.gov/pvwatts.php.

OFFICIAL COPY

Jan 23 2018

rates would have to be made up through incentives via energy efficiency or DG incentive programs in order to achieve the same outcomes.

Q. WHAT ARE THE LONG-TERM EFFECTS OF DILUTING INCENTIVES FOR ENERGY CONSERVATION AND DG?

A. The long-term effects with respect to utility rates are difficult to ascertain. Logically, less conservation and less DG leads to higher amounts of utility investment in generation, transmission, and distribution, which in turn places upward pressure on rates.

Beyond this, it creates unknown and likely unknowable risks for current and future ratepayers. This proceeding is illustrative of the fact that such long-term risks are not easy to assess. The Company is presently seeking recovery of significant costs associated with coal ash remediation, which comprise a large part of the revenue increase request. These costs were not priced into the rates that existed during the time period when coal ash accumulated at storage sites. Regardless of the reasons for this, or what was deemed reasonable and prudent at the time, this amounts to a market failure in hindsight. In other words, had rates reflected these future costs, customers would have purchased less electricity and in theory the result would have been more economically efficient.

Instead, assuming that the Commission approves some form of recovery for coal ash remediation costs, current customers will be saddled with costs that they had no opportunity to avoid. Ultimately, diluting incentives for energy efficiency and DG runs against a policy of avoiding future costs or the risk of

OFFICIAL COPY

Jan 23 2018

future costs. Especially under the current circumstances, I do not believe that this would be a wise course of action.

C. The Minimum System Method is Not an Appropriate Methodology for Classifying Distribution Costs.

Q. PLEASE DEFINE CUSTOMER-RELATED COSTS.

A. Company Witness Hager defines customer-related costs as "costs incurred primarily as a result of the number of customers being served."[13] I do not wholly agree with this definition, specifically the use of the word "primarily". A more appropriate definition of customer-related costs would be the definition used by the Regulatory Assistance Project ("RAP"), which defines customer-related costs as "[c]osts that vary *directly* with the number of customers."[14] (Emphasis added)

Q. HOW DOES THE COMPANY ARRIVE AT ITS CALCULATION OF CUSTOMER-RELATED COSTS?

A. There are several elements. The Company's COSS classifies as all costs related to meters and services, in Federal Energy Regulatory Commission ("FERC") Accounts 369-370 (services and meters, respectively) as customer-related. It also classifies a "portion" of the costs associated with FERC Accounts 364, 365, and 368, relating to poles, towers and fixtures (Account 364), overhead conductors and devices (Account 365), and line transformers (Account 368) as customer-related. These Accounts are classified based on what is often referred to as the Minimum System Method. Underground conductors (Account 367) are not

---

[13] Direct Testimony of Janice Hager for Duke Energy Carolinas, LLC, p. 7, lines 15-16 (August 25, 2017).
[14] J. Lazar and W. Gonzalez, *Smart Rate Design for a Smart Future*, p. 36, REGULATORY ASSISTANCE PROJECT (2015), *available at* http://www raponline.org/document/download/id/7680.

OFFICIAL COPY

Jan 23 2018

assessed separately under the Company's COSS study, but underground line miles are incorporated into the analysis as though they were overhead conductors.[15]

The calculated customer costs also include a large portion of distributed system operations and maintenance ("O&M") costs. Some O&M expense categories are split between energy and demand classifications (e.g., supervision) while others are applied exclusively to one category or another (e.g., overhead and underground lines). Overall, for the RS class, 75% of distribution O&M is classified as customer-related, largely because overhead line maintenance (64.7% of all distribution O&M costs for the RS class) is classified exclusively as customer-related.[16] Finally, the customer category includes a portion of administration and general plant in-service and associated O&M expenses, and customer service, accounting, and sales expenses are assigned exclusively to the customer category.[17]

Q. PLEASE DESCRIBE THE MINIMUM SYSTEM METHOD AND HOW IT AFFECTS RATEMAKING.

A. The theory behind the Minimum System Method is that the distribution system is designed to not only serve customer demand, but also to connect customers regardless of their need for electricity. That is, it assumes that some costs of the shared distribution system are effectively incurred solely for the purpose of

---

[15] Duke Energy Carolinas, LLC's Response to NCSEA Data Request No. 5-7 (hereinafter "DEC Response to NCSEA DR5-7").
[16] *See*, DEC Form E-1, Item 45D. p. 12 (detailing distribution O&M).
[17] *Id*., pp. 11-12.

OFFICIAL COPY

Jan 23 2018

connecting each customer and that these costs should therefore be classified as customer-related. The analysis typically relies on an examination of the book costs associated with each cost category (e.g., poles and conductors) to establish the costs associated with a hypothetical "minimum" distribution system.

One variant on the Minimum System Method is the Zero- or Minimum-Intercept Method. This method is intended to respond to the frequent criticism that the Minimum System Method double counts demand-related costs because a minimum system is still capable of serving some level of demand. The Company's use of the Minimum System Method does not attempt to eliminate the demand-related component of the minimum system as the Zero- or Minimum-Intercept Method would do.

In ratemaking, the results of a minimum system analysis influence how distribution costs are allocated to different rate classes. This is because the allocators based on the number of customers in a class differ from those based on demand or energy. Generally speaking, the result of more costs being classified as customer-related is a larger revenue requirement for classes with the largest number of customers (e.g., the residential class). In practice, it also has a cascading effect because other cost allocators rely in part on the distribution-related allocators. For instance, the RS class has roughly 78% of total general and administrative expenses assigned to the customer category. In contrast, the Large

OFFICIAL COPY

Jan 23 2018

General Service (LGS) class has only roughly 21% of total general and administrative expenses assigned to the customer category.[18]

Finally, the results of the minimum system analysis may also influence how revenue is collected in the form of customer, demand, or energy charges to the extent that charges are based on the classification of costs (i.e., customer costs collected via customer charges). This is the case with DEC's proposal, which uses the calculated customer unit costs as a benchmark for devising proposed BFCs.

Q. WHAT EFFECT DOES THE USE OF THE MINIMUM SYSTEM METHOD HAVE ON THE COMPANY'S RESIDENTIAL REVENUE REQUIREMENTS AND CALCULATED UNIT COSTS?

A. According to the Company's analysis, which I have attached as Exhibit JRB-3, if the Minimum System Method is removed from the cost of service study, the calculated customer unit cost for the RS class decreases from $23.59/month to $11.08/month.[19] The proposed revenue for the residential class as a whole is reduced by roughly $31.3 million.[20] The adjustment prompts corresponding shifts in revenue requirements for other classes as well as changes to demand-related unit costs.

Q. IS THE MINIMUM SYSTEM METHOD GENERALLY ACCEPTED AS AN APPROPRIATE METHOD FOR CLASSIFYING DISTRIBUTION SYSTEM COSTS?

---

[18] *Id*. p. 13 and p. 77.

[19] Duke Energy Carolinas, LLC's Response NCSEA Data Request No. 5-1, Attachment 2. (hereinafter "DEC Response to NCSEA DR5-1, Attachment 2").

[20] Calculated based on data from DEC Form E-1, Item 45E and DEC Response to NCSEA DR5-1, Attachment 2.

OFFICIAL COPY

Jan 23 2018

A. No. The Minimum System Method is based on the dubious premise that customers will pay to connect to the distribution grid even if they do not intend to use any electricity. In reality, a customer that has no demand for electricity would have no need to be connected to the distribution system. Distribution costs are caused by that demand and the customer density of a service territory, not by the presence of the customer. A zero or minimum demand customer of the type represented by the Minimum System Study or the Zero-Intercept variant simply does not exist.

Even if one stipulates that items such as poles themselves have no load-carrying or demand-serving capability, they are still an integral part of a system designed to serve customer demand. Thus their cost remains tied to the need to serve customer demand. Taken to its furthest extent, the flawed premise underlying the Minimum System Method effectively assumes that any distribution cost not proven to fall into another category must be customer-related. Dr. James Bonbright discusses this line of thinking in his seminal work *Principles in Public Utility Rates*. In his treatise, Dr. Bonbright acknowledges that one could devise a so-called minimum system, but dismisses the notion that the costs of that system are customer-related, referring to them as “unallocable”.

> What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Indeed, if the company’s entire service area stays fixed, an increase in the number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system. . .

OFFICIAL COPY

Jan 23 2018

> But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs . . . while it is also denied a place among the customer costs . . . to which cost function does it then belong? The only defensible answer, in my opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs...But fully-distributed cost analyst dare not avail himself of this solution, since he is the prisoner of his own assumption that "the sum of the parts is equal to the whole." He is therefore under impelling pressure to fudge his cost apportionments by using the category of customer costs as a dumping ground for costs that he cannot plausibly impute to any of his other cost categories.[21]

Q. DO OTHER STATES USE THE MINIMUM DISTRIBUTION SYSTEM METHOD FOR ALLOCATING DISTRIBUTION COSTS AND SETTING CUSTOMER CHARGES?

A. Many states confine the definition of "customer" costs to those costs that are directly attributable to a customer, such as metering and billing, excluding portions of the distribution system shared by multiple customers. A report commissioned by the National Association of Regulatory Utility Commissioners ("NARUC") found that this "basic customer method" (100% demand for shared distribution facilities and 100% customer for meters and services) was the most common approach at the time of the report:

> There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. The most common method used is the basic customer method, which classifies all poles, wires, and transformers as demand-related and meters, meter-reading, and billing as customer-related. This general approach is used in more than thirty states.[22]

---

[21] Dr. James Bonbright, *Principles of Public Utility Rates*, p. 348-349, Columbia University Press (1961).
[22] F. Weston, et al., *Charges for Distribution Service: Issues in Rate Design*, p. 19, REGULATORY ASSISTANCE PROJECT (2000), *available at* http://pubs.naruc.org/pub/536F0210-2354-D714-51CF-037E9E00A724.

OFFICIAL COPY

Jan 23 2018

In other states, some portion of the shared distribution system may be considered customer-related and allocated on that basis, but the methodology used can vary from state to state.

Rate design practices are likewise variable because rate design involves a balance of numerous competing objectives, such as fairness, stability, effectiveness at meeting revenue requirements, cost causation and customer acceptance. The balancing reflects the fact that these objectives are frequently in conflict with one another. Regardless, as evidenced by the data presented in Exhibit JRB-2, it is clear that regulators have only rarely adopted residential fixed charges at the level proposed by the Company, or monetary increases as large as what the Company proposes.

Q. ARE YOU AWARE OF ANY RECENT REGULATORY DEVLOPMENTS THAT SPEAK TO CONSIDERATION OF THE MINIMUM SYSTEM METHOD OR THE BALANCING OF COMPETING RATEMAKING OBJECTIVES?

A. Yes. Exhibit JRB-2 provides some indication of such an balancing act on the part of regulators, showing numerous examples of instances where fixed residential customer charges have been held constant or increased by only very small amounts. In addition, there are two very recent examples of fixed charge *decreases* that deserve mention in this context, from Nevada and Connecticut.

In Connecticut, as I previously mentioned, Eversource Connecticut's residential fixed charges are poised to decrease significantly, from $19.25/month

OFFICIAL COPY

Jan 23 2018

to a proposed maximum of $11.88/month.[23] The origin of this proposed decrease was customer dissatisfaction with large residential fixed charge increases adopted in 2013 and 2014, which gave rise to 2015 legislation restricting fixed charges to costs directly related to metering, billing, service connections, and customer service.[24] Incidentally, such a decrease is already reflected in a reduction of United Illuminating Connecticut's (the other IOU operating in the state) residential fixed charge from $17.25/month to $9.67/month, which was adopted in December 2016.

In Nevada, in the Nevada Power Company's 2017 general rate case, the Public Utilities Commission of Nevada ("PUCN") found it reasonable to reduce basic service charges for the residential, multi-family residential, large single-family residential, and small commercial classes by $0.25/month. This corresponds to a reduction of the residential fixed monthly charge from $12.75 to $12.50/month. In doing so, the PUCN stated:

> The basic service charge is an important mechanism for a utility to recover fixed costs. Rate design should balance the need for recovery of these fixed costs with the principles of sending proper price signals and creating stability in rates. Decreasing the basic service charge . . . achieves this balance between public interests and Nevada Power stability. This reduction also sends a price signal that encourages residential ratepayers to conserve energy and promotes stability by allowing customers to exercise greater control over their total bills.[25]

---

[23] Testimony of the Rates Panel on Behalf of the Connecticut Light and Power Company dba Eversource Energy, Connecticut Public Utility Regulatory Authority Docket No. 17-10-46 (January 12, 2018).
[24] 2015 Conn. Acts 15-5 (Spec. Sess.).
[25] Order Granting in Part and Denying in Part General Rate Application by the Nevada Power Company, p. 120, Public Utilities Commission of Nevada Docket Nos. 17-06003 and 17-06004 (December 29, 2017).

OFFICIAL COPY

Jan 23 2018

In the Connecticut example, the assignment of costs of the shared distribution system to the customer category is being discarded. In Nevada, the PUCN recognized the value of rate stability and customers' ability to control their energy costs and concluded that the modest reduction would not unreasonably undermine the Nevada Power Company's recovery of fixed costs.

Q. IS THE MINIMUM SYSTEM METHOD USED IN DEC'S SOUTH CAROLINA SERVICE TERRITORY?

A. No. In 1991 on the recommendation of staff, the South Carolina Public Service Commission eliminated the use of the Minimum System Method from the Company's South Carolina Cost of Service Study ("COSS"), in favor of using a "more appropriate allocation factor."[26]

Q. HAS THE MINIMUM SYSTEM METHOD BEEN APPROVED FOR USE IN NORTH CAROLINA?

A. I am aware that all three IOUs in North Carolina have used the Minimum System Method in their cost of service studies in recent rate cases and that in 1988 the Commission declined to eliminate the use of the method for cost allocation purposes "at this time." At the same time the Commission refrained from using the results of the analysis for the purpose of setting residential customer charges.[27]

It is not clear to me that the Commission has recently delved into the details of the different methodologies used by North Carolina utilities in

---

[26] Order No. 91-1022, p. 7, South Carolina Public Service Commission Docket No. 91-216-E (November 18, 1991).

[27] Order Granting Partial Increase in Rates and Charges, p. 130, North Carolina Utilities Commission Docket No. E-2, Sub 537 (August 5, 1988).

OFFICIAL COPY

Jan 23 2018

conducting their minimum system studies. In fact, significant differences in methodology are apparent to me based on my review of the studies performed by DEP, DEC, and Dominion Energy North Carolina ("Dominion"). For instance, in its 2016 general rate case, Dominion classified only 31.08% of secondary poles in FERC Account 364 as customer related.[28] DEP classified 95.9% of secondary poles in FERC Account 364 as customer related in its most recent rate case.[29]

DEC effectively classifies all shared secondary and primary poles in FERC Account 364 (as well as conductors in FERC Account 365) as customer-related. This is visible in the Company's COSS in the form of negative values for demand-related plant in service for FERC Accounts 364 and 365.[30] The negative values arise because the Company's calculated minimum system is larger than the actual FERC Account balance after removing direct assignments, which necessitates an adjustment. The true-up adjustment effectively results in a demand-related component of zero and a customer-related component of 100%. Similar differences are evident for other distribution Accounts, contributing to a wide range of estimates of residential customer unit costs, as follows:

- Dominion: $12.07/month[31]
- DEP: $27.82/month[32]

---

[28] Application of Virginia Electric and Power Company, d/b/a Dominion North Carolina Power, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, Docket No. E-22, Sub 532 (March 31, 2016). DEC Form E-1, Item 45F, p. 121.
[29] Duke Energy Progress, LLC's Response to NCSEA Data Request No. 10-20, Attachment B, Docket No. E-2, Sub 1142 (detailing customer and demand percentages by FERC Account).
[30] DEC Form E-1, Item 45D, p. 5.
[31] Direct Testimony of Glenn A. Pierce on Behalf of Dominion North Carolina Power, Exhibit GAP-1, Schedule 6, p. 1, Docket No. E-22, Sub 534 (March 31, 2016).

OFFICIAL COPY

Jan 23 2018

- DEC: $23.78/month[33]

Q. IS THE MINIMUM SYSTEM METHOD ENDORSED BY NARUC?

A. No. The NARUC Electric Utility Cost Allocation Manual ("NARUC Manual") refers to the Minimum System Method as *one* method of classifying distribution costs, but it does not endorse any method in particular. In fact, the preface expressly states, in the context of the objectives:

> The writing style should be non-judgmental, not advocating any one particular method, but trying to include all currently used methods with pros and cons.[34]

The section on distribution cost allocation protocols goes on to note that the results are directly related to the assumptions used, such as how the minimum size distribution equipment is selected. Furthermore, the NARUC Manual includes cautionary statements regarding the use of the minimum system, among them that the "minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost."[35]

Finally, it is also worth noting that the NARUC Manual dates from 1991, while the NARUC-commissioned report on state distribution system classification mentioned previously is more recent, having been published in 2000. All of this serves to demonstrate that the Minimum System Method should not be regarded

---

[32] Direct Testimony of Steven Wheeler, Exhibit 1, Docket No. E-2, Sub 1142 (June 1, 2017).
[33] Pirro Direct, Exhibit No. 8.
[34] Electric Utility Cost Allocation Manual, p. ii, National Association of Regulatory Utility Commissioners, (1991).
[35] *Id*. p. 95.

OFFICIAL COPY

Jan 23 2018

as the commonly accepted or prevailing method of distribution system cost classification.

Q. DOES BASING BFCS ON THE UNIT COSTS IMPLIED BY THE MINIMUM SYSTEM METHOD RESULT IN RATES THAT ARE ECONOMICALLY EFFICIENT?

A. No, for several reasons. First, as Dr. Bonbright observed, a hypothetical minimum system does not necessarily change if the system area stays constant while the number of customers changes. That is, in a fixed system, the marginal cost of a new customer can be zero, which might occur where a large apartment building with many customers replaces a commercial or industrial establishment. Therefore the minimum system unit costs do not represent an accurate signal of marginal customer-related costs that would be consistent with economically efficient rates.

Second, one underlying principle of rate regulation is that regulated rates should attempt to approximate the result that would be achieved in a competitive market. If one acknowledges that the minimum system incorporates some level of load carrying (i.e., demand-related) capability, the method translates what should be a demand-based price signal into a fixed price signal.

Third, if on the other hand the study is modified in an attempt to reflect a zero-load system (i.e., Zero- or Minimum-Intercept Method), the result implies that customers would be willing to pay the associated unit costs for the ability to connect to the system and be able to serve a zero or minimal load (e.g., a 60-watt

OFFICIAL COPY

Jan 23 2018

light bulb). In other words, in the present case, it suggests that residential customers would be willing to pay $285 per year ($23.78 per month for 12 months) to be able to power a single light bulb. Moreover, it presumes that they would do so indefinitely for years on end as opposed to pursuing other options for supplying such a minimum load. This presumption stretches the boundaries of credibility. A far more reasonable presumption is that customers connect to the grid to serve their entire load, and the grid is designed to meet those needs.

D. DEC's Minimum System Study Contains Numerous Errors

Q. PLEASE DESCRIBE HOW THE COMPANY PERFORMS ITS MINIMUM SYSTEM STUDY.

A. At a high level, it defines costs for specified minimum-sized components in FERC Accounts 364, 365, and 368, and extrapolates those results across the entire Company system. For instance, it defines a cost per mile of a minimum size conductor (age adjusted) then multiplies that amount by the miles of conductor line on the system. Similar methods are used for poles and line transformers, utilizing an estimate of the number of poles and line transformers per mile of conductor. According to the Company, the minimum-sized system equates to a 100-watt lighting load per customer as the "smallest measureable load".[36]

The Commission should also be aware that while underground lines and conduit are not directly part of DEC's minimum system study currently, it intends

[36] Duke Energy Carolinas, LLC's Response to NCSEA Data Request No. 11-8(a).

OFFICIAL COPY

Jan 23 2018

to include them in future studies as "standard" equipment.[37] This is significant given the significant investments in undergrounding that the Company expects to make in future years. NCSEA Witness Golin discusses the Company's anticipated undergrounding investments in more detail.

Q. WHAT PROBLEMS HAVE YOU IDENTIFIED WITH THE WAY THE COMPANY HAS CONDUCTED ITS MINIMUM SYSTEM STUDY?

A. First, I will reiterate that I disagree with the use of the Minimum System Method for classifying distribution costs altogether for the reasons I have previously described. That said, if the Commission were to accept its use on a conceptual level, I see several problems with the Company's methodology that all serve to distort the results and increase the portion of the distribution system classified as customer-related.

My first concern relates back to fundamental issues with the framework of the Minimum System Method generally, applied to the results of DEC's study. As I previously observed, the Company's calculated minimum system exceeds the total FERC Account balance for primary and secondary poles and conductors, resulting in a "negative" demand assignment for those Accounts.[38]

Q. CAN YOU EXPLAIN WHY THE COMPANY'S MINIMUM SYSTEM STUDY RESULTS IN THESE NEGATIVE DEMAND ASSIGNMENTS?

A. It appears that a large portion of the overage in FERC Account 364 (Poles) is attributable to the way the Company treats underground lines, which are

[37] Duke Energy Carolinas, LLC's Response to NCSEA Data Request No. 11-10.
[38] DEC Form E-1, Item 45C, p. 15.

OFFICIAL COPY
Jan 23 2018

incorporated as though they are overhead lines by adding the miles of underground lines to the miles for overhead lines.[39] The minimum system study produces an outsized assignment to FERC Account 364 because the poles in the minimum system associated with the miles of underground line do not actually exist. The same issue applies to FERC Account 365, which has non-existent overhead line miles. A portion of the overages is also likely attributable to the assumptions used by the Company in developing the components and costs for its minimum system.

Q. IS THE COMPANY'S APPROACH TO TRANSLATING UNDERGROUND FACILITIES TO OVERHEAD FACILITIES IN ITS MINIMUM SYSTEM STUDY REASONABLE IN YOUR OPINION?

A. I will acknowledge that the Company's approach has some intuitive appeal, i.e., if there were not underground facilities, more overhead facilities would be needed. However, in my opinion there are considerable drawbacks to this approach. First, it obscures the effects that other assumptions in the minimum system study have on the results, creating a situation where the customer-related percentage of the distribution system is effectively driven by the non-existent facilities. That makes it more difficult to ascertain how other assumptions impact the results.

Second, there is no way to determine whether this fictional overhead system accurately represents how the system would look if all electric distribution was accomplished using overhead facilities. For instance, would there actually be

[39] Duke Energy Carolinas, LLC's Response to NCSEA Data Request No. 5-7.

OFFICIAL COPY

Jan 23 2018

the same number of total line miles? Would the amount of direct assignments be the same? Would the minimum size facilities on the system be the same? As I have observed, the minimum system is itself only a hypothetical scenario that is driven by the assumptions used in its creation. The Company's method of translating underground facilities to overhead facilities takes this a step further into speculation.

Finally, this approach has consequences for other aspects of the COSS that are tied to the percentage of distribution system classified as customer-related. While the Company incorporates a negative demand adjustor into the plant in service calculations, equivalent adjustments are not apparent in other aspects of the COSS, like distribution O&M. If one were to suppose that the customer-related portion of distribution O&M should be aligned with the customer-related percentage of distribution plant, the addition of underground lines to the overhead accounts distorts the allocation of O&M by artificially raising the customer-related percentage of distribution plant to 100%.

Q. WHAT OTHER ASSUMPTIONS IN THE COMPANY'S MINIMUM SYSTEM STUDY ARE INCORRECT IN YOUR OPINION?

A. There are several issues that contribute to the oversized minimum system proposed by the Company, across all applicable FERC Accounts. I will describe each individually.

OFFICIAL COPY

Jan 23 2018

Q. WHAT ERRORS ARE PRESENT IN THE COMPANY'S MINIMUM SYSTEM CALCULATION FOR FERC ACCOUNT 364, RELATING TO POLES AND STRUCTURES?

A. First, the Company has failed to separately estimate costs for primary and secondary poles in FERC Account 364. The Company's cost estimate is based on poles used to support primary conductors.[40] Primary poles are larger and more expensive because they must support larger wires. Secondary poles cost from to 61% to 66% of cost used in the Company's study depending on whether the minimum size is based on the smallest pole currently on the system, or the standard secondary pole the Company currently installs.[41] In my opinion, the smallest pole currently on the system is more appropriate to use than the current standard pole.

Second, the manner in which the Company applies underground line mileage to overhead line costs all but ensures that FERC Account 364 will be classified as 100% customer-related. As I previously described, the minimum system study produces an overage in FERC Account 364 in part because it includes poles that do not actually exist. When underground line miles are simply added to overhead line miles, an excess in the Account is guaranteed, leading to a 100% customer classification.

---

[40] Duke Energy Carolinas, LLC's Response to NCSEA Data Request No. 5-2.
[41] Duke Energy Carolinas, LLC's Response to NCSEA Data Request No. 11-16.

OFFICIAL COPY

Jan 23 2018

Q. WHAT ERRORS ARE PRESENT IN THE COMPANY'S MINIMUM SYSTEM CALCULATION FOR FERC ACCOUNT 365, RELATING TO OVERHEAD CONDUCTORS?

A. Again, the Company failed to differentiate between primary and secondary conductor costs. I am unable to quantify the difference in cost associated with addressing secondary conductors separately because the Company did not provide cost information for secondary conductors using the same format that it used for primary conductors.[42] Likewise, the minimum system calculation for overhead lines contains "phantom" underground line miles that do not exist, leading to the Account excess and a 100% customer classification.

Q. WHAT ERRORS ARE PRESENT IN THE COMPANY'S MINIMUM SYSTEM CALCULATION FOR FERC ACCOUNT 368, RELATING LINE TRANSFORMERS?

A. There are several inconsistencies with the minimum system for this Account, as follows:

- The minimum transformer size used in the study is 15 kVa, which represents the smallest transformer *currently* used by the Company.[43] However, the smallest overhead transformer on the Company's system currently is rated at 1 kVa and roughly 10% of the Company's transformers are rated at 10 kVA or

[42] Duke Energy Carolinas LLC's Response to NCSEA Data Request No. 11-17.
[43] *Id*.

OFFICIAL COPY

Jan 23 2018

less.[44] A 15 kVA transformer is clearly not the minimum size transformer on the Company's system.

- In addressing line transformers, the Company fails to recognize that the number of customers per transformer differs by class. A single transformer typically serves multiple residential customers, while a larger commercial customer may have a dedicated transformer. The Company's study effectively assumes each class is served by the system average number of transformers per customer, which overstates costs for classes above that average (e.g., residential) and understates costs for classes below the average.
- The Company uses an estimate of 11 transformers per mile of line to develop its minimum system for line transformers.[45] However, based on the number of line miles in the Company's study, this would result in a total of 858,040 transformers on the system. The actual number of overhead line transformers on the system is 692,233, a difference of 24%.[46] It is not clear to me whether this seeming "excess" amount of line transformers is associated with how the minimum system study addresses underground lines. I will also note that DEC provided conflicting information on the number of transformers per mile used in the minimum system calculation, specifying the number as eight transformers per mile in response to one data request.[47] As noted above, DEC used 11 transformers per mile in its study.

[44] Duke Energy Carolinas, LLC's Response to NCSEA Data Request No. 11-11, Attachment.
[45] Duke Energy Carolinas, LLC's Response to NCSEA Data Request No. 5-7.
[46] Duke Energy Carolinas, LLC's Response to NCSEA Data Request No. 11-11, Attachment.
[47] Duke Energy Carolinas, LLC's Response to NCSEA Data Request No. 5-2.

OFFICIAL COPY

Jan 23 2018

Q. ARE THERE ANY OTHER ISSUES WITH THE COMPANY'S MINIMUM SYSTEM STUDY THAT YOU WISH TO RAISE?

A. Yes. If the Minimum System Method is used, it should also be used for FERC Account 369 (Service Drops). The Company assigns service drops as 100% customer-related. In my opinion it is only reasonable to consider service drops as entirely customer-related if the Minimum System Method is not employed. If the Minimum System Method is used it should be applied to FERC Account 369 as well in recognition that service drop size is influenced by customer load.

Q. DOES THE COMPANY'S MINIMUM SYSTEM STUDY DOUBLE-COUNT DEMAND-RELATED COSTS?

A. Yes. For line transformers specifically, the Company has not attempted to remove the load carrying capacity of a system composed entirely of 15 kVa transformers. Consequently, the customer category of costs contains demand-related costs that are allocated based on customer numbers, while each class also receives an allocation of the remaining costs based on demand.

For conductors, demand is being double counted because underground conductors are allocated entirely based on demand, but also incorporated into the minimum system as though they were overhead lines. The negative demand adjustor for conductors totals only roughly $24 million in terms of gross electric plant in service.[48] This amount is insufficient to balance out the roughly $549 million in gross plant in service that underground conductors add to FERC

[48] DEC Form E-1, Item 45C, p. 15

OFFICIAL COPY

Jan 23 2018

Account 365 in the minimum system.[49] This corresponds to a net double-count of $525 million in terms of gross plant in service.

The same effect is present for poles in FERC Account 365, but is much smaller as poles add $585.3 million to the minimum system, while the negative demand allocation is $567.9 million.[50] This equates to a net double-count of roughly $17.3 million.

These estimates are apart from the effects of the Company's failure to differentiate between primary and secondary poles and conductors in its minimum system costing estimates.

Q. BASED ON YOUR REVIEW OF DEC'S MINIMUM SYSTEM STUDY, WHAT ARE YOUR CONCLUSIONS?

A. I have serious concerns about whether the study is accurate for several reasons. The results would force one to conclude that all primary and secondary pole and conductor costs are incurred on the basis of the number of customers being served. In fact, the results show a minimum system that results in a negative demand component, which simply is not plausible or logical, and utilize numerous assumptions that inflate the size and cost of the minimum system beyond what it should be.

Furthermore, the differences between the results of DEC's study and Dominion's equivalent study are obvious and meaningful. This difference in

---

[49] Based on Duke Energy Carolinas, LLC's Response to NCSEA Data Request No. 5-7. The $549 million figure corresponds to 28,992.86 underground conductor miles times the $18,927.10/mile minimum system conductor cost.

[50] DEC Form E-1, Item 45C, p. 15. Duke Energy Carolinas, LLC's Response to NCSEA Data Request No. 5-7.

OFFICIAL COPY

Jan 23 2018

itself, apart from the specific issues that I have identified, is sufficient reason for the Commission to question the validity of the Company's study, and the Minimum System Method in general as an accurate portrayal of cost causation.

Finally, the fact is that the Company's Minimum System Study is being used to justify dramatic increases in BFCs, which benefit the Company by fixing a larger portion of its revenue. At the same time, it is seeking approval of a GRR Rider that would recover additional costs via fixed monthly charges, and beyond that is contemplating much larger distribution system investments that would result in an escalating cycle of large fixed charge increases for the foreseeable future. Those investments include undergrounding investments that the Company intends to include in its minimum system study in future iterations. I find this pattern and its implications to be highly disturbing and I think the Commission should be equally concerned.

Q. WHAT ARE YOUR RECOMMENDATIONS WITH RESPECT TO DEC'S MINIMUM SYSTEM STUDY?

A. The Commission should reconsider its past acceptance of this method for the allocation for distribution costs, and disregard the results as a consideration in rate design. If the Commission does not choose to categorically reject the Minimum System Method on a conceptual level for the purpose of cost allocation, it should nevertheless decline to rely on the results for the purpose of rate design.

III. DEC'S PROPOSED GRR RIDER

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED GRR RIDER.

OFFICIAL COPY
Jan 23 2018

A. The proposed GRR Rider is intended to recover anticipated capital investments its transmission and distribution system through 2021. These investments are part of the Company's Power/Forward proposal. The specific proposed rates are confined to investments during the period from July 1, 2017 to December 31, 2018, as well as associated O&M expenses.

For costs through 2018 the Company requests revenue of $30.9 million for the distribution-related aspects of the plan and $4.8 million for transmission-related aspects, totaling $35.7 million for the 2018 calendar year. The total amount of investment reflected in this revenue figure is $309.3 million, of which $245 million is distribution-related and $63.6 million is transmission-related. To that is added $18.6 million in distribution O&M and $1.5 million in transmission O&M.[51] NCSEA Witness Golin discusses the components of these proposed investments in greater detail in her testimony.

As proposed, the GRR Rider would recover these costs through a combination of monthly fixed charges and energy charges. Table 4 below details the proposed revenues and charges based on Exhibit No. 9 of the Direct Testimony of DEC Witness Michael Pirro.

[51] Direct Testimony of Jane L. McManeus for Duke Energy Carolinas, LLC, Exhibit No. 4 (August 25, 2017).

OFFICIAL COPY

Jan 23 2018

Table 4: GRR Rider Revenues and Costs by Class

Rate Class	Customer Revenue	Monthly Charge	Non-Customer Revenue	Energy Charge ($/kWh)	Total Revenue	Class % Revenue
Residential	$14,653,999	$0.72	$10,918,736	$0.000511	$25,572,735	71.7%
General Service - Small	$1,891,089	$0.65	$1,648,154	$0.000380	$3,539,243	9.9%
General Service - Large	$72,689	$0.67	$1,358,542	$0.000281	$1,431,231	4.0%
Lighting	$0	N/A	$182,342	$0.000252	$182,342	0.5%
Traffic Signal Service	$42,467	$0.59	$1,393	$0.000134	$43,860	0.1%
Industrial Service	$30,857	$0.73	$613,354	$0.000309	$644,211	1.8%
OPTV-Secondary	$138,238	$0.69	$2,707,802	$0.000201	$2,846,040	8.0%
OPTV-Primary	$2,108	$0.56	$1,333,341	$0.000137	$1,335,449	3.7%
OPTV-Transmission	$0	$0.00	$70,709	$0.000079	$70,709	0.2%
TOTAL	$16,831,447		$18,834,375		$35,665,822	100.0%

Q. WHAT ARE YOUR OBSERVATIONS ON THE STRUCTURE OF THE PROPOSED GRR RIDER?

A. The most prominent characteristic is that under the 2018 cost structure, the residential class would bear by far the greatest burden under the proposal, 71.7% of the total revenue requirement. Furthermore, the rate structure is weighted towards the residential customer-related category. The customer-related category contains 57% of the total residential class obligation, and 41% of the total GRR Rider revenues for all classes. The plan relies on the residential sector to shoulder most of the cost burden, of which more than 57% would be unavoidable as a fixed charge.

Q. HOW WAS THE BREAKDOWN BETWEEN CUSTOMER AND NON-CUSTOMER COSTS ESTABLISHED BY THE COMPANY?

A. The Company utilized a methodology based broadly on its Minimum System Method to establish the customer component for distribution-related investments.

OFFICIAL COPY

Jan 23 2018

However, unlike its actual minimum system study, the individual projects and improvements encompassed by the GRR Rider were not segregated by FERC Account. Instead, the customer portion corresponds to the overall percentage of the distribution system classified as customer-related, 62.6% for the total residential class.[52]

Q. DO YOU AGREE THAT THE COMPANY'S DERIVATION OF CUSTOMER-RELATED COSTS PRODUCES AN ACCURATE RESULT?

A. No. At a minimum this approach suffers from the same deficiencies I have previously identified with the Minimum System Method. Of greatest significance is the question of whether *any* of these investments could reasonably classified as customer-related. The overall program is intended to support increased reliability, incremental to routine investment, which would suggest that none of the distribution upgrades are representative of a minimum system. Furthermore, if demand is isolated and separated out in order to represent a zero-load system, the concept of reliability is meaningless because there is no load that can be disrupted.

Beyond that overarching issue, the specific way in which the Company performed the customer-related calculation for the GRR Rider is also unreliable for several reasons:

1. The Company includes both services and meters in the numerator and denominator of its percentage calculation, which are classified as 100%

---

[52] Duke Energy Carolinas, LLC's Response to Public Staff Data Request No. 87-28b, Attachment.

OFFICIAL COPY

Jan 23 2018

customer-related. The addition has the effect of increasing the overall customer-related percentage. This makes no sense because none of the GRR Rider investments appear to involve these categories of equipment. If those costs are removed from both the numerator and denominator the residential customer-related allocation declines to 54.5%.

2. The Company does not relate GRR Rider investments to individual FERC Accounts and as a result, it is impossible to align the GRR Rider allocations with minimum system study, even at the FERC Account level. The lack of detail also prevents an evaluation of whether the characteristics of individual investments are outside the scope of a minimum size system.
3. Some GRR Rider costs are defined as customer-related when they would not be under Company's current minimum system study. For instance, underground lines and conduit are *not* part the Company's minimum system, but the Company's GRR Rider method indirectly classifies 62.6% of these costs as customer-related by using the overall distribution plant average to create the customer-related assignment.

Q. DO THE CLASS REVENUE REQUIREMENTS AND CHARGES SHOWN IN TABLE 4 REPRESENT THE TOTAL REVENUES AND CHARGES UNDER THE GRR RIDER?

A. No. Through 2021, the total cost of DEC's portion of the Power/Forward proposal has been estimated by the Company at $2.9 billion in capital expenditures and

OFFICIAL COPY

Jan 23 2018

$130 million in O&M.[53] These are the costs that the GRR Rider is intended to recover, though the DEC portion of the Power/Forward proposal is estimated at $7.8 billion over the next 10 years. Thus the specified rates in Table 4 above represent 10.6% of the expected capital investment and 15.5% of expected O&M through 2021, which in turn is only a portion of the Power/Forward proposal.

Q. CAN YOU ESTIMATE WHAT THE LONG-TERM RATE IMPACTS OF THE COMPANY'S PLANS WOULD BE ON THE RESIDENTIAL FIXED RATE CONTAINED IN THE RIDER?

A. The GRR Rider rates proposed in this docket are just the tip of the iceberg because they only reflect a small percentage of expected spending through 2021, and an even smaller portion of the overall Power/Forward proposal. While it is not possible for me to precisely predict the residential rate impacts that would accompany the full initiative, if one takes the percentage of total investment and O&M embodied in the proposed GRR Rider rates and applies them forward to the total forecast investment and forecast O&M through only 2021, the residential fixed charge portion of the GRR Rider rises to roughly $5.30/month or $63.60/year. Even if one assumes that customer growth will dilute the monthly GRR Rider rate, the rate would remain around $5/month or $60/year if the Company added 100,000 residential customers between now and 2021.

This is a rough number insofar as the available information does not permit the isolation of distribution investments and O&M over this timeframe,

[53] Direct Testimony of Robert M. Simpson, III for Duke Energy Carolinas, LLC, p. 23, lines 18-19 (August 25, 2017).

OFFICIAL COPY

Jan 23 2018

and it rests on the allocation to the residential class and the customer portion of that allocation remaining at the current levels. However, it is worth noting that it could in fact understate the rate because as I previously observed, the Company has stated that it intends to apply the Minimum System Method to underground distribution in the future. That would tend to increase the allocation of costs to the residential class and increase the portion of those costs that are identified as customer-related, both of which would increase the fixed portion of the charge.

Q. WOULD THIS OVERALL LEVEL OF INCREASE BE LOWER IF THE COMPANY MADE THE SAME INVESTMENTS AND RECOVERED THE COSTS IN BASE RATES RATHER THROUGH A RIDER?

A. I would not expect it to be lower. The rate is driven by the level of distribution investment and the Company's use of its minimum system study to assign customer-related costs. If these assumptions remain the same, the results should be similar. In fact, there is reason to believe that if translated to unit costs in base rates, the monthly cost would be higher. For instance, the GRR Rider effectively assigns 62.6% of distribution O&M for the residential class to the customer category. In contrast, the Company's COSS assigns roughly 75% of total distribution O&M as customer-related for the RS portion of the overall residential class.[54]

---

[54] DEC Form E-1, Item 45D. p. 12 (detailing distribution O&M).

OFFICIAL COPY

Jan 23 2018

Q. HOW DO YOU THINK THE COMMISSION SHOULD EVALUATE WHETHER THE GRR RIDER IS "FAIR" TO RESIDENTIAL CUSTOMERS?

A. In the present context, I would define fairness as the equitable distribution of costs and benefits. At a minimum, this definition gives rise to the following questions:

1. Will the benefits of the program expected be shared in a manner that is consistent with the cost breakdown?
2. How are the cost responsibility and class benefits broken down by individual investment category?
3. In a competitive environment, would customers actually be willing to pay these costs based on the incremental benefits they receive?

While I focus on the residential class here, the same questions are reasonable to pose when evaluating the effects of the proposal on other customer classes.

Q. SINCE DISTRIBUTION SERVICE IS A MONOPOLY SERVICE, WHY DO YOU MENTION "WILLINGNESS TO PAY" IN A COMPETITIVE MARKET AS AN IMPORTANT QUESTION?

A. This question addresses whether in fact a net benefit exists. One idea inherent in utility regulation is that regulation should function as a substitute for competition. In other words, since customers cannot select their electric distribution provider based on service characteristics or prices, regulation is critical for protecting them from being sold goods that they do not want or need at the price being imposed.

OFFICIAL COPY

Jan 23 2018

As a corollary, regulation should provide customers with the services they do desire at a cost less than or equal to the value of the good. This concept has been referred to as using regulation to impose the "disciplines of competitive markets".[55] One aspect of this, in my opinion, is avoiding investments that would not be made in a competitive market because customers do not desire the service or product at a given price point.

NCSEA Witness Golin dissects the cost-benefit analysis that the Company has done on its overall grid modernization plan, how those costs and benefits are distributed among customer classes, and the implications for potential willingness to pay. Her analysis casts strong doubt on the suppositions that residential customers will accrue benefits similar to the cost burden that they face, and have a willingness to pay for the services being provided.

Q. PLEASE SUMMARIZE YOUR CRITICISMS OF THE COMPANY'S GRR RIDER PROPOSAL.

A. I have concerns about the GRR Rider proposal itself, and the long-term signal it sends. With respect to the first, the GRR Rider clearly places the bulk of costs on the residential class, the majority of which would be recovered by a fixed monthly charge. As discussed by NCSEA Witness Golin, the Company has not provided evidence that the benefits would be shared equitably in line with that cost burden. Furthermore, the Company's proposed rate structure relies on an assessment of customer-related costs that lacks consideration of critical details and in some

[55] F. Weston, et al., *Charges for Distribution Service: Issues in Rate Design*, p. 17, REGULATORY ASSISTANCE PROJECT (2000), *available at* http://pubs.naruc.org/pub/536F0210-2354-D714-51CF-037E9E00A724.

OFFICIAL COPY

Jan 23 2018

ways directly conflicts with its COSS. At best it is superficial and cannot be considered reliable.

In the longer term, I find the GRR Rider proposal to be a first step in the direction of dramatic increases in residential rates and BFCs. The Company's current proposal for large residential BFC increases coupled with its reliance on the Minimum System Method and expectations for large distribution system investments under the Power/Forward proposal all point to future requests for large escalations in residential rates and monthly charges. Extrapolating to the future, the investments associated with the GRR Rider alone would likely result in a residential fixed charge of more than $5/month under the proposed structure. It is hard to see how this would be a desirable outcome.

Q. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION ON THE COMPANY'S GRR RIDER?

A. I recommend that the Commission decline to approve the Company's proposal. Instead, the topic of grid modernization, including the levels and types of investments, the allocation of costs and benefits, and rate recovery should be investigated as part of the dedicated proceeding recommended by NCSEA Witness Golin.

IV. DEC'S CLASSIFICATION OF COAL ASH REMEDIATION COSTS

Q. HOW DOES THE COMPANY'S COST OF SERVICE STUDY ALLOCATE COAL ASH REMEDIATION COSTS?

OFFICIAL COPY

Jan 23 2018

A. The Company allocates coal ash remediation expenses according to the production demand allocator, which utilizes the summer coincident peak ("Summer CP") method to determine class cost responsibility.[56] This results in coal ash remediation costs being assigned on the basis of a class's demand at the time of summer peak hour during the test year.

Q. IS PRODUCTION DEMAND THE CORRECT ALLOCATOR TO USE FOR COAL ASH REMEDIATION COSTS IN YOUR OPINION?

A. No. As I discussed in my testimony in DEP's 2017 general rate case,[57] I believe an energy-related allocator is more appropriate because coal ash is a by-product of fuel, namely coal. The volume of coal ash is directly associated with the amount of electricity produced and the volume of coal used to product this electricity, and remediation costs are directly related to the volume of accumulated coal ash that requires remediation activities. In contrast, production demand as measured over a single summer peak hour has little if any explanatory power with respect to the "cause" of coal ash remediation costs. An energy-related allocator, such as production energy at the source, provides a far better measure of cost causation.

Q. WHAT EFFECTS DOES THE COMPANY'S PROPOSED ALLOCATION METHOD HAVE?

A. For one, it distorts class allocations of coal ash remediation costs, among other things resulting in the residential class being allocated a larger percentage of the revenue requirement than would be the case under an energy-based allocation

---

[56] DEC Form E-1, Item 45C (COSS, line 513).

[57] Direct Testimony of Justin R. Barnes on Behalf of North Carolina Sustainable Energy Association, Docket No. E-2, Sub 1142 (October 20, 2017).

OFFICIAL COPY

Jan 23 2018

method, and lighting classes receiving a zero allocation.[58] It also distorts the calculation of unit costs that are used to some degree in rate design. Ultimately, both effects contrive to send inaccurate price signals to customers.

Q. WHAT ACTION SHOULD THE COMMISSION TAKE WITH RESPECT TO THE CLASSIFICATION OF COAL ASH REMEDIATION COST CLASSIFICATION AND ALLOCATION?

A. As I stated in the DEP rate case, I recommend that the Commission direct DEC to classify all coal ash remediation costs as energy-related now and in the future. To this I would add that even if the Commission declines adopt my recommendation for the purpose of class cost allocation, it should nevertheless direct the Company to adjust its rate designs as necessary to confine *recovery* of coal ash remediation costs to energy charges. That would least partially correct the price signal sent to customers.

V. DEC'S STATEMENTS REGARDING DG

Q. WHAT STATEMENTS DOES THE COMPANY MAKE IN ITS APPLICATION REGARDING DG?

A. There are references to DG in different contexts throughout the Company's application and direct testimony. I focus here on statements and references made by Company Witness Robert Hevert which dramatically overstate the supposed risk DG poses to utilities.

[58] DEC Form E-1, Item 45C (COSS, line 513).

OFFICIAL COPY

Jan 23 2018

Q. HOW DOES COMPANY WITNESS HEVERT OVERSTATE THE RISK DG POSES TO UTILITIES?

A. Mr. Hevert refers to a discussion on the state of distributed energy from the California Public Utilities Commission ("CPUC") to paint a dire picture of the "significant risks to incumbent electric utilities such as DE Carolinas" face from DG. In doing so, he discusses the impacts of community choice aggregators ("CCAs") on utilities based on statements from CPUC Commissioner Michael Picker, pointing specifically to potentially dramatic reductions in the customer base as a result of CCA formation. He then attributes those comments as referring to the risks posed by DG.[59]

This implied equivalency is absurd, conflating CCA formation with DG. CCAs are a form of electric choice that allow customers to depart from utility generation service en masse to take service from a provider organized via local governments. His discussion might prove accurate if, for instance, the entire City of Charlotte and all of its ratepayers could install DG and depart from DEC service virtually overnight. However, such an event is clearly impossible, and moreover, ignores tangible benefits that DG can provide which are not present in a simple "departure" of customers to a CCA.

Q. DO YOU OBJECT TO ANY OTHER PORTIONS OF COMPANY WITNESS HEVERT'S DISCUSSION OF DG?

[59] Hevert Direct. p. 55, lines 1-15.

OFFICIAL COPY

Jan 23 2018

A. Mr. Hevert describes a cycle under which a utility has difficulty recovering fixed costs as DG customers "leave the system", leaving a remaining pool of customers to cover those fixed costs.[60] This is inaccurate in part because DG customers do not typically "leave" the system. They generally remain connected and pay the same rates and charges that other customers pay, albeit on reduced consumption from the grid. That reduced consumption affects their cost of service (e.g., lower peak demand) and has the potential to create long-term savings in the form of reduced or deferred grid and generation investments. True, reduced investment opportunities can be characterized as a risk to utilities, but this does not necessarily mean that it should be seen as a risk to other ratepayers, who would benefit from a reduced need for utility investments.

Q. PLEASE SUMMARIZE YOUR THOUGHTS ON MR. HEVERT'S TESTIMONY AND THE RELATIONSHIP OF DG TO UTILITIES AND THE GRID.

A. I read Mr. Hevert's testimony as suggesting that the Commission must "do something" about retail net metering and DG, lest DEC become subject to a cycle of increasing inability to recover fixed costs that results in disastrous credit downgrades. I do not doubt that DEC sees DG as a potential competitor and future business risk. However, I would argue that competition is in fact good, and that the risk of future DEC profits is not equivalent to a risk to ratepayers. I trust that the Commission will appreciate this distinction in future proceedings

[60] *Id*. p. 53, lines 8-10.

OFFICIAL COPY

Jan 23 2018

involving more direct discussions of DG and give full consideration to the benefits that DG can provide to the grid and ratepayers.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR CONCERNS ABOUT THE COMPANY'S APPLICATION.

A. My overarching concern is that there are multiple elements of the Company's application that individually and collectively could result in extraordinary increases in residential rates and fixed charges. There are a confluence of factors at play here. One is the Company's clear intent to aggressively seek higher residential customer charges. Another is the manner in which it has used its minimum system study to disproportionately assign costs as customer-related, allocating the bulk of those costs to the residential sector. The final element is the Company's capital investment plans, most specifically the Power/Forward proposal and Rider GRR, for which it is already seeking additional fixed charges that are likely to grow substantially over time if approved.

The misclassification of coal ash costs as related to production demand rather than energy adds insult to injury, placing additional costs on the residential class in a manner that is contrary to cost causation. This is all at the same time as the Company makes dire warnings about the risks DG holds for DEC and its ability to recover fixed costs in a manner that greatly exaggerates this risk.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

OFFICIAL COPY

Jan 23 2018

A. I recommend that the Commission:

1. Maintain the residential BFC at its current level, or in the alternative, allow it to increase by no more than the adopted class average rate increase.
2. Decline to use the Company's minimum system study as basis for cost allocation and rate design in this proceeding, and instead rely on the Company's "no minimum system" COSS results. I further recommend that the Commission reconsider its past decision to allow the Minimum System Method to be used for cost allocation in light of the problems I have identified with the method and its execution, the disparity in practices between the state's utilities, and the foreseeable, negative impacts that its continued use would have on residential rates and residential BFCs.
3. Decline to adopt the Company's GRR Rider proposal, and instead pursue a further investigation of grid modernization that addresses appropriate investments, cost allocation, the relative distribution of costs and benefits, and rate design, as recommended by NCSEA Witness Golin.
4. Direct the Company to classify coal ash remediation costs as energy-related now and in the future in order to accurately reflect cost causation, or in the alternative direct that coal ash costs be treated as energy-related for rate design purposes so as provide a more accurate price signal to customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

OFFICIAL COPY
Jan 23 2018

JUSTIN R. BARNES

(919) 825-3342, jbarnes@eq-research.com

EDUCATION

Michigan Technological University Houghton, Michigan
Master of Science, Environmental Policy, August 2006
Graduate-level work in Energy Policy.

University of Oklahoma Norman, Oklahoma
Bachelor of Science, Geography, December 2003
Area of concentration in Physical Geography.

RELEVANT EXPERIENCE

Director of Research, July 2015 – present
Senior Analyst & Research Manager, March 2013 – July 2015
EQ Research, LLC and Keyes, Fox & Wiedman, LLP Cary, North Carolina

- Oversee state legislative, regulatory policy, and general rate case tracking service that covers policies such as net metering, interconnection standards, rate design, renewables portfolio standards, state energy planning, state and utility incentives, tax incentives, and permitting.
- Responsible for service design, formulating improvements based on client needs, and ultimate delivery of reports to clients. Expanded service to cover energy storage.
- Oversee and perform policy research and quantitative or qualitative analysis to fulfill client requests, and for internal and published reports, focused primarily on state solar market drivers such as net metering, rate design, incentives, and renewable portfolio standards.
- Provide expert witness testimony on issues related to overall DG policy, rate design, cost of service, and DG costs and benefits.

Senior Policy Analyst, January 2012 – May 2013;
Policy Analyst*,* September 2007 – December 2011
North Carolina Solar Center, N.C. State University Raleigh, North Carolina

- Responsible for researching and maintaining information for the Database of State Incentives for Renewables and Efficiency (DSIRE), the most comprehensive public source of renewables and energy efficiency incentives and policy data in the United States.
- Managed state-level regulatory tracking for private wind and solar companies.
- Coordinated the organization's participation in the SunShot Solar Outreach Partnership, a U.S. Department of Energy project to provide outreach and technical assistance for local governments to develop and transform local solar markets.
- Developed and presented educational workshops, reports, administered grant contracts and associated deliverables, provided support for the SunShot Initiative, and worked with diverse group of project partners on this effort.
- Responsible for maintaining the renewable portfolio standard dataset for the National Renewable Energy Laboratory for use in its electricity modeling and forecasting analysis.
- Authored the *DSIRE RPS Data Updates*, a monthly newsletter providing up-to-date data and historic compliance information on state RPS policies.
- Responded to information requests and provided technical assistance to the general public, government officials, media, and the energy industry on a wide range of subjects, including federal tax incentives, state property taxes, net metering, state renewable portfolios standard policies, and renewable energy credits.

OFFICIAL COPY

Jan 23 2018

- Extensive experience researching, understanding, and disseminating information on complex issues associated with utility regulation, policy best practices, and emerging issues.

SELECTED ARTICLES and PUBLICATIONS

- EQ Research and Synapse Energy Economics for Delaware Riverkeeper Network. *Envisioning Pennsylvania's Energy Future*. 2016.
- Barnes, J., R. Haynes. *The Great Guessing Game: How Much Net Metering Capacity is Left?*. September 2015. Published by EQ Research, LLC.
- Barnes, J., Kapla, K. *Solar Power Purchase Agreements (PPAs): A Toolkit for Local Governments*. July 2015. For the Interstate Renewable Energy Council, Inc. under the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *2013 RPS Legislation: Gauging the Impacts*. December 2013. Article in Solar Today.
- Barnes, J., C. Laurent, J. Uppal, C. Barnes, A. Heinemann. *Property Taxes and Solar PV: Policy, Practices, and Issues*. July 2013. For the U.S. DOE SunShot Solar Outreach Partnership.
- Kooles, K, J. Barnes. *Austin, Texas: What is the Value of Solar; Solar in Small Communities: Gaston County, North Carolina*; and *Solar in Small Communities: Columbia, Missouri*. 2013. Case Studies for the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *The Report of My Death Was An Exaggeration: Renewables Portfolio Standards Live On*. 2013. For Keyes, Fox & Wiedman.
- Barnes, J. *Why Tradable SRECs are Ruining Distributed Solar*. 2012. Guest Post in Greentech Media Solar.
- Barnes, J., multiple co-authors. *State Solar Incentives and Policy Trends*. Annually for five years, 2008-2012. For the Interstate Renewable Energy Council, Inc.
- Barnes, J. *Solar for Everyone?* 2012. Article in Solar Power World On-line.
- Barnes, J., L. Varnado. *Why Bother? Capturing the Value of Net Metering in Competitive Choice Markets*. 2011. American Solar Energy Society Conference Proceedings.
- Barnes, J. *SREC Markets: The Murky Side of Solar*. 2011. Article in State and Local Energy Report.
- Barnes, J., L. Varnado. *The Intersection of Net Metering and Retail Choice: an overview of policy, practice, and issues*. 2010. For the Interstate Renewable Energy Council, Inc.

TESTIMONY

- North Carolina Utilities Commission, Docket No. E-2 Sub 1142. October 2017
- Public Utility Commission of Texas, Control No. 46831. June 2017
- Utah Public Service Commission, Docket No. 14-035-114. June 2017.
- Colorado Public Utilities Commission, Proceeding No. 16A-0055E. May 2016.
- Public Utility Commission of Texas, Control No. 44941. December 2015.
- Oklahoma Corporation Commission, Cause No. PUD 201500271. November 2015.
- South Carolina Public Service Commission, Docket No. 2015-54-E. May 2015.
- South Carolina Public Service Commission, Docket No. 2015-53-E. April 2015.
- South Carolina Public Service Commission, Docket No. 2015-55-E. April 2015.
- South Carolina Public Service Commission, Docket No. 2014-246-E. December 2014.

AWARDS, HONORS & AFFILIATIONS

- Solar Power World Magazine, Editorial Advisory Board Member (October 2011 – March 2013)
- Michigan Tech Finalist for the Midwest Association of Graduate Schools Distinguished Master's Thesis Awards (2007)
- Sustainable Futures Institute Graduate Scholar Michigan Tech University (2005-2006)

OFFICIAL COPY

Jan 23 2018

Table 1: National Residential Fixed Charge Comparison (Current Rates)[1]

State	Utility	Existing Fixed Charge	Rank
Wyoming	Montana-Dakota Utilities[2]	$25.00	1
New York	Central Hudson Gas & Electric [3]	$24.00	2
Mississippi	Mississippi Power[4]	$23.71	3
New York	RG&E[5]	$21.38	4
Wisconsin	Wisconsin Public Service[6]	$21.00	5
Hawaii	Hawaii Electric Light (HELCO)[7]	$20.50	6
New York	Orange & Rockland Utilities[8]	$20.00	7
Oklahoma	PSO[9]	$20.00	8
Wyoming	Rocky Mountain Power[10]	$20.00	9
Florida	Gulf Power[11]	$19.76	10
Connecticut	Eversource[12]	$19.25	11
Wisconsin	MGE[13]	$19.00	12
Hawaii	Maui Electric (MECO)[14]	$18.00	13
North Carolina	**Duke Energy Carolinas (PROPOSED)**	**$17.79**	**14**
Hawaii	Hawaiian Electric (HECO)[15]	$17.00	14
Indiana	IP&L[16]	$17.00	15
New York	National Grid[17]	$17.00	16
Illinois	Ameren Illinois[18]	$16.97	17
Florida	Tampa Electric[19]	$16.62	18
Colorado	Black Hills Energy[20]	$16.50	19
Wisconsin	We Energies[21]	$15.99	20
New York	Con Edison[22]	$15.76	21
Wyoming	Black Hills Power[23]	$15.50	22
Illinois	Commonwealth Edison[24]	$15.27	23
Nevada	Sierra Pacific Power Company[25]	$15.25	24
New Hampshire	Unitil[26]	$15.24	25
New York	NYSEG[27]	$15.11	26
District of Columbia	Pepco[28]	$15.09	27
Arizona	UniSource Energy Services[29]	$15.00	28
Michigan	Upper Peninsula Power Company[30]	$15.00	29
Wisconsin	Alliant Energy[31]	$15.00	30
Alabama	Alabama Power[32]	$14.50	31
Kansas	Westar Energy[33]	$14.50	32
New Hampshire	Liberty Utilities[34]	$14.50	33
North Dakota	Xcel Energy[35]	$14.50	34
Pennsylvania	PPL Electric Utilities[36]	$14.09	35
Florida	Florida Public Utilities[37]	$14.00	36
Indiana	NIPSCO[38]	$14.00	37
Kansas	Empire District Electric[39]	$14.00	38
Kansas	KCP&L[40]	$14.00	39
Wisconsin	Xcel Energy[41]	$14.00	40
North Dakota	Montana-Dakota Utilities[42]	$13.98	41
Alaska	Alaska Power Company[43]	$13.85	42
Vermont	Green Mountain Power[44]	$13.16	43

OFFICIAL COPY

Jan 23 2018

Arizona	Tucson Electric Power[45]	$13.00	47
Missouri	Empire District Electric[46]	$13.00	44
Oklahoma	OG&E[47]	$13.00	45
Wyoming	Black Hills Energy[48]	$13.00	46
Nevada	Nevada Power Company[49]	$12.75	48
New Hampshire	Eversource[50]	$12.64	49
Tennessee	Kingsport Power (AEP AppCo)[51]	$12.63	50
Missouri	KCP&L[52]	$12.62	51
Oklahoma	Empire District Electric[53]	$12.50	52
Kentucky	Kentucky Utilities[54]	$12.25	53
Kentucky	LG&E[55]	$12.25	54
Michigan	Wisconsin Public Service[56]	$12.00	55
Virginia	Kentucky Utilities[57]	$12.00	56
Iowa	Alliant Energy[58]	$11.95	57
North Carolina	**Duke Energy Carolinas[59] (CURRENT)**	**$11.80**	**58**
Delaware	Delmarva Power[60]	$11.70	59
Pennsylvania	Citizens' Electric Company[61]	$11.50	60
Pennsylvania	Met-Ed[62]	$11.25	61
Pennsylvania	Penelec[63]	$11.25	62
North Carolina	Duke Energy Progress[64]	$11.13	63
Arkansas	Empire District Electric[65]	$11.04	64
Indiana	Vectren Indiana[66]	$11.00	65
Kentucky	Kentucky Power[67]	$11.00	66
Pennsylvania	Penn Power[68]	$11.00	67
Wisconsin	Northwestern Wisconsin Electric[69]	$11.00	68
North Carolina	Dominion North Carolina Power[70]	$10.96	69
Pennsylvania	Wellsboro Electric Company[71]	$10.95	70
Maine	Central Maine Power[72]	$10.68	71
Oregon	Portland General Electric[73]	$10.50	72
Missouri	KCP&L Greater Missouri Operations[74]	$10.43	73
Arizona	Arizona Public Service[75]	$10.00	94
California	SCE[76]	$10.00	78
California	PG&E[77]	$10.00	79
California	SDG&E[78]	$10.00	80
Georgia	Georgia Power Company[79]	$10.00	75
South Carolina	South Carolina Electric & Gas[80]	$10.00	76
Texas	Sharyland Utilities[81]	$10.00	74
Texas	Xcel Energy[82]	$10.00	77
Arkansas	Oklahoma Gas & Electric[83]	$9.75	81
Minnesota	Otter Tail Power Company[84]	$9.75	82
Connecticut	United Illuminating[85]	$9.67	83
Oregon	Pacific Power[86]	$9.50	84
Indiana	Duke Energy Indiana[87]	$9.40	85
South Dakota	Black Hills Power[88]	$9.25	86
Alaska	Alaska Electric Light & Power[89]	$9.22	87
South Carolina	Duke Energy Progress[90]	$9.06	88
Missouri	Ameren Missouri[91]	$9.00	89
Wisconsin	Superior Water Light & Power[92]	$9.00	90
Illinois	MidAmerican Energy[93]	$8.97	91

OFFICIAL COPY
Jan 23 2018

Florida	Duke Energy Florida[94]	$8.76	92
Michigan	Xcel Energy[95]	$8.75	93
Iowa	MidAmerican Energy[96]	$8.50	95
New Mexico	Xcel Energy (SPS)[97]	$8.50	96
Washington	Avista Utilities[98]	$8.50	97
Pennsylvania	PECO[99]	$8.45	98
Arkansas	Entergy Arkansas[100]	$8.40	99
Ohio	Ohio Power Company[101]	$8.40	100
Virginia	Appalachian Power Company[102]	$8.35	101
South Carolina	Duke Energy Carolinas[103]	$8.29	102
South Dakota	Xcel Energy[104]	$8.25	103
Texas	AEP Texas North[105]	$8.18	104
Maryland	Delmarva Power[106]	$8.17	105
Minnesota	Minnesota Power[107]	$8.00	106
Minnesota	Xcel Energy[108]	$8.00	107
North Dakota	Otter Tail Power Company[109]	$8.00	111
Oregon	Idaho Power Company[110]	$8.00	108
South Dakota	MidAmerican Energy[111]	$8.00	109
South Dakota	Otter Tail Power Company[112]	$8.00	110
Texas	SWEPCO[113]	$8.00	112
Utah	Rocky Mountain Power[114]	$8.00	114
West Virginia	Appalachian Power Company[115]	$8.00	113
Maryland	BGE[116]	$7.90	115
Florida	Florida Power & Light[117]	$7.87	116
Arkansas	SWEPCO[118]	$7.75	117
Washington	Pacific Power[119]	$7.75	118
Maryland	Pepco[120]	$7.60	119
Maine	Emera Maine[121]	$7.54	120
Michigan	DTE[122]	$7.50	121
South Dakota	Montana-Dakota Utilities[123]	$7.50	122
Washington	Puget Sound Energy[124]	$7.49	123
Pennsylvania	West Penn Power[125]	$7.44	124
Indiana	Indiana Michigan Power[126]	$7.30	125
Michigan	Indiana Michigan Power[127]	$7.25	126
California	Pacific Power[128]	$7.20	127
Louisiana	Entergy Louisiana[129]	$7.04	128
Massachusetts	Unitil[130]	$7.00	129
Michigan	Consumers Energy[131]	$7.00	130
New Mexico	El Paso Electric[132]	$7.00	131
New Mexico	PNM[133]	$7.00	132
Texas	Entergy Texas[134]	$7.00	133
Virginia	Dominion Virginia[135]	$7.00	134
Texas	El Paso Electric[136]	$6.90	135
Mississippi	Entergy Mississippi[137]	$6.75	136
Texas	AEP Texas Central[138]	$6.74	137
California	Liberty Utilities[139]	$6.56	138
Massachusetts	Eversource Eastern[140]	$6.43	139
California	Bear Valley Electric Service[141]	$6.39	140
Massachusetts	Eversource Western[142]	$6.00	141

OFFICIAL COPY
Jan 23 2018

Ohio	Duke Energy Ohio[143]	$6.00	142
South Dakota	NorthWestern Energy[144]	$6.00	143
Idaho	Avista Utilities[145]	$5.75	144
Massachusetts	National Grid[146]	$5.50	145
Louisiana	SWEPCO[147]	$5.49	146
Montana	Montana-Dakota Utilities[148]	$5.47	147
Texas	Centerpoint Energy[149]	$5.47	148
Colorado	Xcel Energy[150]	$5.39	149
Idaho	Rocky Mountain Power[151]	$5.00	150
Idaho	Idaho Power Company[152]	$5.00	151
Maryland	Potomac Edison[153]	$5.00	152
Michigan	Alpena Power Company[154]	$5.00	153
New Jersey	Atlantic City Electric[155]	$5.00	156
Rhode Island	National Grid[156]	$5.00	155
West Virginia	First Energy Utilities[157]	$5.00	154
New Jersey	Rockland Electric[158]	$4.54	157
Kentucky	Duke Energy Kentucky[159]	$4.50	158
Louisiana	Entergy Louisiana (Legacy EGSL)[160]	$4.46	159
Ohio	Dayton Power & Light[161]	$4.25	160
Montana	NorthWestern Energy[162]	$4.10	161
Ohio	First Energy Utilities[163]	$4.00	162
Texas	Oncor[164]	$3.06	163
New Jersey	JCP&L[165]	$2.98	164
New Jersey	PSEG[166]	$2.27	165
	Average	**$10.59**	
	Average (Excluding DEC NC)	**$10.59**	

OFFICIAL COPY

Jan 23 2018

Table 2: Recent Fixed Charge Approvals[167]

State	Utility	Existing Fixed Charge	Approved Fixed Charge	$ Increase Approved	Approved % Increase
Arizona	Tucson Electric Power[168]	$10.00	$13.00	$3.00	30.0%
Arizona	UniSource Energy[169]	$10.00	$15.00	$5.00	50.0%
Arizona	Arizona Public Service[170]	$8.66	$10.00	$1.34	15.5%
Arkansas	Entergy Arkansas[171]	$6.96	$8.40	$1.44	20.7%
Arkansas	Oklahoma Gas & Electric[172]	$7.94	$9.75	$1.81	22.8%
California	Liberty Utilities[173]	$7.10	$6.56	-$0.54	-7.6%
California	SDG&E[174]	$10.00	$10.00	$0.00	0.0%
Colorado	Black Hills Energy[175]	$16.50	$16.50	$0.00	0.0%
Colorado	Xcel Energy[176]	$6.75	$5.39	-$1.36	-20.1%
Connecticut	Eversource[177]	$16.00	$19.25	$3.25	20.3%
Connecticut	United Illuminating[178]	$17.25	$9.67	-$7.58	-43.9%
Delaware	Delmarva Power[179]	$11.70	$11.70	$0.00	0.0%
D.C.	Pepco[180]	$13.00	$15.09	$2.09	16.1%
Florida	Florida Power & Light[181]	$7.87	$7.87	$0.00	0.0%
Florida	Gulf Power[182]	$18.85	$19.76	$0.65	3.4%
Idaho	Avista Utilities[183]	$5.25	$5.75	$0.50	9.5%
Idaho	Avista Utilities[184]	$5.25	$5.25	$0.00	0.0%
Indiana	IP&L[185]	$11.00	$17.00	$6.00	54.5%
Indiana	NIPSCO[186]	$11.00	$14.00	$3.00	27.3%
Kansas	KCP&L[187]	$10.71	$14.00	$3.29	30.7%
Kansas	Westar Energy[188]	$12.00	$14.50	$2.50	20.8%
Kentucky	Kentucky Power[189]	$8.00	$11.00	$3.00	37.5%
Kentucky	Kentucky Utilities[190]	$10.75	$12.25	$1.50	14.0%
Kentucky	Kentucky Utilities[191]	$10.75	$10.75	$0.00	0.0%
Kentucky	LG&E[192]	$10.75	$10.75	$0.00	0.0%
Maine	Emera Maine[193]	$5.82	$7.54	$1.72	29.6%
Maryland	BGE[194]	$7.50	$7.90	$0.40	5.3%
Maryland	BGE[195]	$7.50	$7.50	$0.00	0.0%
Maryland	Delmarva Power[196]	$7.94	$8.17	$0.23	2.9%
Maryland	Pepco[197]	$7.39	$7.60	$0.21	2.8%
Massachusetts	National Grid[198]	$4.00	$5.50	$1.50	37.5%
Massachusetts	Unitil[199]	$7.00	$7.00	$0.00	0.0%
Michigan	Consumers Energy[200]	$7.00	$7.00	$0.00	0.0%
Michigan	Consumers Energy[201]	$7.00	$7.00	$0.00	0.0%
Michigan	DTE[202]	$6.00	$7.50	$1.50	25.0%
Michigan	DTE[203]	$6.00	$6.00	$0.00	0.0%
Michigan	Indiana Michigan Power[204]	$7.25	$7.25	$0.00	0.0%
Michigan	Upper Peninsula Power[205]	$12.00	$15.00	$3.00	25.0%
Michigan	Wisconsin Public Service[206]	$9.00	$12.00	$3.00	33.3%
Michigan	Xcel Energy[207]	$8.65	$8.75	$0.10	1.2%
Minnesota	Otter Tail Power[208]	$8.50	$9.75	$1.25	14.7%
Minnesota	Xcel Energy[209]	$8.00	$8.00	$0.00	0.0%
Mississippi	Mississippi Power[210]	$23.71	$23.71	$0.00	0.0%

OFFICIAL COPY
Jan 23 2018

Missouri	Ameren Missouri[211]	$8.00	$9.00	$1.00	12.5%
Missouri	Ameren Missouri[212]	$8.00	$8.00	$0.00	0.0%
Missouri	Empire District Electric[213]	$12.52	$13.00	$0.48	3.8%
Missouri	Empire District Electric[214]	$12.52	$12.52	$0.00	0.0%
Missouri	KCP&L[215]	$11.88	$12.62	$0.74	6.2%
Missouri	KCP&L[216]	$9.00	$11.88	$2.88	32.0%
Missouri	KCP&L Greater Missouri[217]	$9.54	$10.43	$0.89	9.3%
Montana	Montana-Dakota Utilities[218]	$5.47	$5.47	$0.00	0.0%
Nevada	Sierra Pacific Power[219]	$15.25	$15.25	$0.00	0.0%
New Hampshire	Liberty Utilities[220]	$11.79	$14.50	$2.71	23.0%
New Hampshire	Unitil[221]	$10.27	$15.24	$4.97	48.4%
New Jersey	Atlantic City Electric[222]	$4.00	$4.44	$0.44	11.0%
New Jersey	Atlantic City Electric[223]	$4.44	$5.00	$0.56	12.6%
New Jersey	JCP&L[224]	$1.92	$2.98	$1.06	55.2%
New Jersey	Rockland Electric[225]	$4.44	$4.54	$0.10	2.3%
New Mexico	El Paso Electric[226]	$7.00	$7.00	$0.00	0.0%
New Mexico	PNM[227]	$5.00	$7.00	$2.00	40.0%
New Mexico	Xcel Energy[228]	$7.90	$8.50	$0.60	7.6%
New York	Central Hudson [229]	$24.00	$24.00	$0.00	0.0%
New York	Con Edison[230]	$15.76	$15.76	$0.00	0.0%
New York	Con Edison[231]	$15.76	$15.76	$0.00	0.0%
New York	NYSEG[232]	$15.11	$15.11	$0.00	0.0%
New York	Orange & Rockland[233]	$20.00	$20.00	$0.00	0.0%
New York	RG&E[234]	$21.38	$21.38	$0.00	0.0%
North Carolina	Dominion North Carolina[235]	$10.96	$10.96	$0.00	0.0%
North Dakota	Montana-Dakota Utilities[236]	$10.65	$13.98	$3.33	31.3%
Oklahoma	OG&E[237]	$13.00	$13.00	$0.00	0.0%
Oklahoma	PSO[238]	$20.00	$20.00	$0.00	0.0%
Oregon	Portland General Electric[239]	$10.00	$10.50	$0.50	5.0%
Pennsylvania	Citizens' Electric[240]	$8.00	$11.50	$3.50	43.8%
Pennsylvania	Met-Ed[241]	$10.25	$11.25	$1.00	9.8%
Pennsylvania	Met-Ed[242]	$8.11	$10.25	$2.14	26.4%
Pennsylvania	PECO[243]	$7.12	$8.45	$1.33	18.7%
Pennsylvania	Penelec[244]	$9.99	$11.25	$1.26	12.6%
Pennsylvania	Penelec[245]	$7.98	$9.99	$2.01	25.2%
Pennsylvania	Penn Power[246]	$10.85	$11.00	$0.15	1.4%
Pennsylvania	Penn Power[247]	$8.89	$10.85	$1.96	22.0%
Pennsylvania	PPL Electric Utilities[248]	$14.09	$14.09	$0.00	0.0%
Pennsylvania	Wellsboro Electric[249]	$9.75	$10.95	$1.20	12.3%
Pennsylvania	West Penn Power[250]	$5.81	$7.44	$1.63	28.1%
Pennsylvania	West Penn Power[251]	$5.00	$5.81	$0.81	16.2%
South Carolina	Duke Energy Progress[252]	$6.50	$9.06	$2.56	39.4%
South Dakota	MidAmerican Energy[253]	$7.00	$8.00	$1.00	14.3%
South Dakota	Montana-Dakota Utilities[254]	$6.00	$7.50	$1.50	25.0%
South Dakota	NorthWestern Energy[255]	$5.00	$6.00	$1.00	20.0%
South Dakota	Xcel Energy[256]	$8.25	$8.25	$0.00	0.0%
Tennessee	Kingsport Power[257]	$7.30	$12.63	$5.33	73.0%
Texas	El Paso Electric[258]	$5.00	$6.90	$1.90	38.0%
Texas	Xcel Energy[259]	$9.50	$10.00	$0.50	5.3%

OFFICIAL COPY

Jan 23 2018

Texas	Xcel Energy[260]	$7.60	$9.50	$1.90	25.0%
Virginia	Kentucky Utilities[261]	$12.00	$12.00	$0.00	0.0%
Washington	Avista Utilities[262]	$8.50	$8.50	$0.00	0.0%
Washington	Avista Utilities[263]	$8.50	$8.50	$0.00	0.0%
Wisconsin	Alliant Energy[264]	$7.67	$15.00	$7.33	95.6%
Wisconsin	MGE[265]	$19.00	$19.00	$0.00	0.0%
Wisconsin	NW Wisconsin Electric[266]	$7.50	$11.00	$3.50	46.7%
Wisconsin	SWL&P[267]	$7.00	$9.00	$2.00	28.6%
Wisconsin	Wisconsin Public Service[268]	$19.00	$21.00	$2.00	10.5%
Wisconsin	Xcel Energy[269]	$14.00	$14.00	$0.00	0.0%
Wisconsin	Xcel Energy[270]	$8.00	$14.00	$6.00	75.0%
Wyoming	Montana-Dakota Utilities[271]	$25.00	$25.00	$0.00	0.0%
Wyoming	Rocky Mountain Power[272]	$20.00	$20.00	$0.00	0.0%
AVERAGES		**$10.16**	**$11.27**	**$1.11**	**14.09%**

---

[1] Table 1 and Table 2 characterize the minimum bills in California, Hawaii, and Utah as fixed charges, though they are not strictly speaking fixed charges. This affects the rankings and averages to a small degree, inflating the average fixed charge and placing Duke Energy utilities slightly lower on the ranking scale than they would otherwise be because minimum bills for Hawaii utilities are substantially higher than the fixed monthly customer charge.

[2] WY PSC. Docket No. 14409. Order No. 23958. Appendix A, p. 11. April 6, 2017. Charge is stated as $0.822/day, translating to a monthly charge of $25.00/month.

[3] NY PSC. Case No. 14-E-0318. Order Approving Rate Plan. p. 57. June 17, 2016. Order rejected settlement providing for an increase in the fixed charge, retaining it at $24.00/month. See current SC-1 rate, available at: https://www.cenhud.com/rates/index

[4] MS PSC. Docket No. 2015-UN-80. PSC Order. December 3, 2015. Base charge of $0.78 per day, translating to a monthly charge of $23.79. See current Rate R-55, available at: http://www mississippipower.com/my-home/my-bill/pricing-and-rates

[5] NY PSC. Case No. 15-E-0285. Order Approving Electric and Gas Rate Plans. p. 21. June 15, 2016. See current RGE Rate SC-1, available at: https://www.rge.com/SuppliersAndPartners/pricingandtariffs/tariffratesummaries/psc19 html

[6] WI PSC. Docket No. 6690-UR-124. Final Decision. p. 63. December 17, 2015.

[7] Hawaii Electric Light (HELCO). Schedule R, available at: https://www hawaiianelectric.com/my-account/rates-and-regulations/hawaii-electric-light-rates

[8] NY PSC. Case No. 14-E-0493. Order Establishing Rate Plan. Appendix 18, Schedule 1. October 16, 2015.

[9] OK Corporation Commission. Cause No. PUD 201500208. Order No. 657877. November 10, 2016. See current Schedule RS, available at: https://www.psoklahoma.com/account/bills/rates/

[10] WY PSC. Docket No. 14076. Order No. 23208. December 30, 2015. See current Schedule 2 available at: https://www.rockymountainpower net/about/rar/wri.html

[11] FL PSC. Docket No. 160186-EI. Order No. PSC-17-0178-S-EI. p. 3. June 16, 2017. Order retains the existing residential rate structure. See Schedule RS, stating the charge as $0.65/day, translating to a monthly charge of $19.76, available at: https://www.gulfpower.com/residential/savings-and-energy/rates-and-billing/rates-rules-and-regulations

[12] CT PURA. Docket No. 14-05-06. Decision dated December 17, 2014. p. 190.

[13] WI PSC. Docket No. 3270-UR-121. Final Decision. Appendix B, p. 2. December 15, 2016.

[14] Maui Electric (MECO). Maui Schedule R, available at: https://www.hawaiianelectric.com/my-account/rates-and-regulations/maui-electric-rates---maui

[15] Hawaii Electric (HECO). Schedule R, available at: https://www.hawaiianelectric.com/my-account/rates-and-regulations/hawaiian-electric-rates

[16] IN URC. Cause No. 44576. Final Order. p. 72. March 16, 2016.

OFFICIAL COPY

Jan 23 2018

---

[17] National Grid. Schedule SC-1, available at: https://www9.nationalgridus.com/niagaramohawk/home/rates/4_standard.asp

[18] Ameren Illinois. Schedule DS-1, Historic Delivery Charges Informational Sheets. Calculated as the sum of the customer charge, meter charge, and uncollectables monthly fee. Available at: https://www.ameren.com/illinois/rates/historical-map-p

[19] Tampa Electric Company. Schedule RS (Sheet No. 6.030), available at: http://www.tampaelectric.com/company/ourpowersystem/tariff/

[20] CO PUC. Docket No. 16AL-0326E. Decision No. C16-1140. p. 36. December 19, 2016. See current schedule RS-1, available at: https://www.blackhillsenergy.com/node/19559

[21] We Energies. Schedule Rg-1. Stated as a charge of $0.52602/day, translating to a monthly charge of $15.99. Available at: http://www.we-energies.com/residential/rates_policies/index htm

[22] NY PSC. Case No. 16-E-0060. Order Approving Electric Rate Plan. January 25, 2017. Order adopted a joint party proposal maintaining the existing rate. See Schedule SC-1, available at: https://www2.dps ny.gov/ETS/jobs/display/download/6090846.pdf

[23] Black Hills Power Wyoming. Schedule R. Available at: https://www.blackhillsenergy.com/rates. Note that a different rate applies for Black Hills Energy (dba Cheyenne Light & Power), also included in Table 1.

[24] Commonwealth Edison. Rate DSPP, Delivery Service Charges. Available at: https://www.comed.com/MyAccount/MyBillUsage/Pages/CurrentRatesTariffs.aspx. Stated rate is the sum of customer, metering and uncollectables factor charges.

[25] PUCN. Docket No. 16-06006. Order Granting in Part and Denying Part General Rate Application by Sierra Pacific Power. December 22, 2016. See tariff compliance filing dated December 30, 2016 (Sheet 63G) showing no change in the residential customer charge, available at: http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2016-6/17802.pdf

[26] NH PUC. Docket No. DE 16-384. Order No. 26,007. p. 10-11. April 20, 2017. Order adopts a customer charge of $15/month, with a step adjustment effective May 1, 2017 to the current $15.24/month rate. See Schedule D, available at: http://unitil.com/energy-for-residents/electric-information/tariffs

[27] NY PSC. Case No. 15-E-0283. Order Approving Electric and Gas Rate Plans. p. 21. June 15, 2016. See current NYSEG Rate SC-1, available at: http://www nyseg.com/SuppliersAndPartners/pricingandtariffs/electricitytariffs/PSC120TableOfContents.html

[28] DC PSC. Docket No. FC 1139. Order No. 18846. p. 145. July 24, 2017.

[29] AZ Corporation Commission. Docket No. E-4204A-15-0142. Decision No. 75697. p. 66. August 18, 2016.

[30] MI PSC. Docket No. U-17895. Final Order. p. 55. September 8, 2016

[31] WI PSC. Docket No. 660-UR-120. Final Decision. p. 7. December 22, 2016.

[32] Alabama Power. Rate FD (Family Dwelling). Available at: https://www.alabamapower.com/residential/residential-pricing-and-rates/standard-family-dwelling-rate.html

[33] KS Corporation Commission. Docket No. 15-WSEE-115-RTS. Order Approving Stipulation .p. 22. September 24, 2015. Order adopted the settlement proposing a $14.50/month customer charge.

[34] NH PUC. Docket No. DE 16-383. Order No. 26,005. p. 8. April 12, 2017.

[35] Xcel Energy North Dakota. Residential Service, Section 5, Sheet 1. Available at: https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/rates/ND/Ne_Section_05.pdf

[36] PA PUC. Docket No. R-2015-2469275. Opinion and Order. p. 8. November 19, 2015.

[37] Florida Public Utilities. Schedule RS, available at: http://www.fpuc.com/electric/rates-tariffs/

[38] IN URC. Cause No. 44688. Final Order. p. 68. July 18, 2016.

[39] Empire District Electric Kansas. Schedule RG (Residential General Service). Available at: https://www.empiredistrict.com/CustomerService/Rates/Electric/KS

[40] KS Corporation Commission. Docket No, 15-KCPE-116-RTS. Final Order. Attachment B, p. 4. September 10, 2015. Order adopted the settlement specifying the $14/month customer charge.

[41] WI PSC. Docket No. 4220-UR-122. Final Decision. Appendix B, p. 2. December 1, 2016.

OFFICIAL COPY

Jan 23 2018

---

[42] ND PSC. Case No. PU-16-666. Findings of Fact, Conclusions of Law and Order. p. 6. June 16, 2017. Charge is stated as $0.46/day, translating to a monthly charge of $13.98.
[43] Alaska Light and Power Company. Schedule A-1. Available at: https://www.aptalaska.com/regulatory/
[44] Green Mountain Power. Rate 1 Residential Service. Available at: http://www.greenmountainpower.com/rates/. Charge is stated as $0.433/day, translating to a monthly charge of $13.16.
[45] AZ Corporation Commission. Docket No. E-01933A-15-0322. p. 186. Decision No. 75795. February 24, 2017.
[46] MO PSC. Docket No. ER-2016-0023. Order Approving Stipulation and Agreement. p. 2. August 10, 2016.
[47] OK Corporation Commission. Cause No. PUD 201500273. Order No. 662059. p. 4. March 20, 2017. Order adopts the ALJ recommendation, retaining the existing customer charge at $13. See Schedule R-1, available at: https://oge.com/wps/wcm/connect/81687ef5-a4b0-4b0f-b8a0-1cfaa22b1045/3.00+R-1.pdf?MOD=AJPERES&CACHEID=81687ef5-a4b0-4b0f-b8a0-1cfaa22b1045
[48] Black Hills Energy (dba Cheyenne Light, Fuel & Power). Schedule R. Available at: https://www.blackhillsenergy.com/sites/blackhillsenergy.com/files/clfp_electricity.pdf
[49] Nevada Power Company. Schedule RS. Available at: https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/about-nvenergy/rates-regulatory/np_res_rate.pdf
[50] Eversource New Hampshire. Rate R. Available at: https://www.eversource.com/Content/nh/business/my-account/billing-rates/rates-tariffs/electric-tariffs-rules
[51] TN Regulatory Authority. Docket No. 1600001. Order Approving Stipulation. Attachment C, Schedule 1. October 19, 2016.
[52] MO PSC. Docket No. ER-2016-0285. Report and Order. p. 57. May 3, 2017.
[53] Empire District Electric Oklahoma. Schedule RG (Residential General Service). Available at: https://www.empiredistrict.com/CustomerService/Rates/Electric/OK
[54] KY PSC. Docket No. 2016-00370. Final Order. p. 19. May 22, 2017.
[55] KY PSC. Docket No. 2016-00371. Final Order. p. 22. May 22, 2017.
[56] MI PSC. Docket No. U-17669. Order Approving Settlement Agreement. Attachment A, p. 33. April 23, 2015.
[57] VA Corporation Commission. Docket No. PUC-2015-00063. Final Order. p. 5. February 2, 2016
[58] Alliant Energy Iowa. Electric Residential Usage Service. Available at: https://www.alliantenergy.com/CustomerService/AlliantEnergyService/RatesandTariffs/ElectricRatesIOWA. Current rate reflects an interim rate during the pending rate increase request in IUB Docket No RPU-2017-001. Prior to the interim rate, the rate was $10.50/month.
[59] Duke Energy Carolinas NC. Schedule RS. Available at: https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-nc/ncschedulers.pdf?la=en
[60] DE PSC. Docket No. 16-0649. Order No. 9048. Exhibit 2, p. 3. May 23, 2017.
[61] PA PUC. Docket No. R-2016-2531550. Final Order. April 6, 2017. The Order approved a party settlement, resulting in the current rates. See Schedule RS, available at: https://www.citizenselectric.com/TariffStart.asp
[62] PA PUC. Docket No. R-2016-2537349. Opinion and Order. p. 10. January 19, 2017. Order approved a party settlement resulting in the current rates. See Rate RS, available at: https://www.firstenergycorp.com/content/customer/customer_choice/pennsylvania/pennsylvania_tariffs.html#gsc.tab=0
[63] PA PUC. Docket No. R-2016-2537352. Opinion and Order. p. 11. January 19, 2017. Order approved a party settlement resulting in the current rates. See Rate RS, available at: https://www.firstenergycorp.com/content/customer/customer_choice/pennsylvania/pennsylvania_tariffs.html#gsc.tab=0
[64] Duke Energy Progress NC. Schedule RES, available at: https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-nc/r1ncscheduleresdep.pdf?la=en

OFFICIAL COPY

Jan 23 2018

---

65 Empire District Electric Arkansas. Schedule RG. Available at: https://www.empiredistrict.com/CustomerService/Rates/Electric/AR
66 Vectren Indiana. Rate RS. Available at: https://www.vectren.com/information/rates
67 KY PSC. Docket No. 2014-00396. Final Order. p. 57. June 22, 2015.
68 PA PUC. Docket No. R-2016-2537355. Opinion and Order. p. 13. January 19, 2017. Order approved a party settlement resulting in the current rates. See Rate RS, available at: https://www.firstenergycorp.com/content/customer/customer_choice/pennsylvania/pennsylvania_tariffs.html#gsc.tab=0
69 WI PSC. Docket No. 4280-ER-106. Final Decision. Appendix D, p. 1. June 20, 2017.
70 NCUC. Docket No. E-22, Sub 532. Order Approving Rate Increase. p. 16. December 22, 2016. Adopted settlement provides for no customer charge increase, retaining the existing rate. See Schedule 1, available at: https://www.dominionenergy.com/library/domcom/pdfs/north-carolina-power/rates/shared/entire-filing.pdf?la=en
71 PA PUC. Docket No. R-2016-2531551. Final Order. April 6, 2017. The Order approved a party settlement, resulting in the current rates. See Schedule No. 1, available at: https://wellsboroelectric.com/wp-content/uploads/2014/03/Distribution-Tariff-Supp-106-Apr-11-2017.pdf
72 Central Maine Power. Rate A. Available at: http://www.cmpco.com/YourHome/pricing/pricingSchedules/default html
73 OR PUC. Docket No. UE 294. Order No. 15-356. p. 11. November 3, 2015.
74 MO PSC. Docket No. ER-2016-0156. Order Approving Stipulation. September 28, 2016. Order adopted a settlement resulting in the current rates. See the non-unanimous settlement, available at: https://www.efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=936033685
75 AZ Corporation Commission. Docket No. E-01345A-16-0036. Decision No. 76364. September 19, 2017. Settlement Agreement. p. 17. Refers to the daily rate of $0.329 for Schedule R-XS applicable to customers with monthly use averaging 600 kWh or less. This replaces the former daily rate of $0.285 under Schedule E-12 as it existed prior to this proceeding.
76 Southern California Edison. Schedule D. Available at: https://www.sce.com/NR/sc3/tm2/pdf/ce12-12.pdf. Listed rate refers to $0.329/day minimum bill, translating to $10/month.
77 Pacific Gas and Electric. Schedule E-1. Available at: https://www.pge.com/tariffs/index.page. Listed rate refers to $0.32854/day minimum bill, translating to $10/month.
78 San Diego Gas and Electric. Schedule DR. Available at: http://regarchive.sdge.com/tm2/ssi/inc_elec_rates_res.html. Listed rate refers to $0.329/day minimum bill, translating to $10/month.
79 Georgia Power. Schedule R-22. Available at: https://georgiapower.com/docs/rates-schedules/residential-rates/2.10_R.pdf
80 South Carolina Electric & Gas. Rate 8. Available at: https://www.sceg.com/paying-my-bill/rates
81 Sharyland Utilities. Residential Service. Available at: http://1op2ep3s2jsaoeg8a36pkogmht.wpengine.netdna-cdn.com/wp-content/uploads/2017/04/03-23-17-sharyland-tariff-manual.pdf. Rate refers to SBC portion of territory excluding the McAllen division, calculated as the sum of the customer charge and metering charge.
82 PUCT. Control No. 45524. Order Adopting Settlement. January 26, 2017. See current Residential Service schedule, available at: https://www.xcelenergy.com/company/rates_and_regulations/rates/texas_rates,_rights,_&_service_rules
83 AR PSC. Docket No. 16-052-U. Order No. 8 Adopting Settlement. p. 9. May 18, 2017.
84 MN PUC. Docket No. E-017/GR-15-1033. Findings of Fact, Conclusions and Order. p. 84. May 1, 2017.
85 CT PURA. Docket No. 16-06-04. Final Decision. p. 96. December 14, 2016. Order sets "maximum" test year customer charge of $8.50, but requires an adjustment for the overall rate increase. See current Rate R, available at: https://uinet.custhelp.com/cgi-bin/uinet.cfg/php/enduser/std_adp.php?p_faqid=3418
86 Pacific Power OR. Schedule 4. Available at: https://www.pacificpower net/about/rr/ori html
87 Duke Energy Indiana. Rate RS. Available at: https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-in/raters.pdf?la=en

OFFICIAL COPY
Jan 23 2018

[88] Black Hills Power SD. Rate Designation R. Available at: https://www.blackhillsenergy.com/sites/blackhillsenergy.com/files/bhp-sd-rates.pdf
[89] Alaska Electric Light & Power. Rate 10. Available at: https://www.aelp.com/Customer-Service/Rates-Billing/Current-Rates
[90] SC PSC. Docket No. 2016-227-E. Order Approving Settlement. December 21, 2016. See current rate Schedule RES, available at: https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-sc/r1scscheduleres.pdf?la=en
[91] MO PSC. Docket No. ER-2016-0179. Decision Approving Settlement. p. 12. March 8, 2017. Decision approved a $1/month increase, reflected in current rate SC-1, available at: https://www.ameren.com/missouri/rates/electric-full-service-bundle
[92] WI PSC. Docket No. 5820-UR-114. Final Decision. Appendix B, page 2 of 6. August 10, 2017.
[93] MidAmerican Energy. Rate RS. Available at: https://www.midamericanenergy.com/content/pdf/rates/elecrates/ilelectric/il-elec.pdf. Calculated as the sum of the customer and metering charge.
[94] Duke Energy FL. Rate RS-1. Available at: https://www.duke-energy.com/home/billing/rates#tab-22bdf686-d7d1-46c4-92d5-053d18b95e49
[95] MI PSC. Docket U-17710. Order Approving Settlement Agreement. Attachment A, Residential Service Schedule MR-1. March 23, 2015.
[96] MidAmerican Energy IA. Rate RS. Available at: https://www.midamericanenergy.com/content/pdf/rates/elecrates/iaelectric/ia-elec.pdf
[97] NM PRC. Docket No. 16-00296-UT. Final Order Adopting Stipulation. August 10, 2016. See current Rate No. 1, available at: https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/rates/NM/nm_sps_e_entire.pdf
[98] WA UTC. Docket No. UE-160228. p. 57. Final Order Rejecting Tariff Filing. December 15, 2016. Commission determined that the existing rates were just and reasonable and therefore retained them. See Rate Schedule No. 1, available at: https://myavista.com/about-us/our-rates-and-tariffs/washington-electric-resources
[99] PA PUC. Docket No. R-2015-2468981. Opinion and Order. p. 11. December 17, 2015.
[100] AR PSC. Docket No. 15-015-U. Final Order. February 23, 2016. Settlement resulted in the current rates under Schedule RS, available at: http://www.entergy-arkansas.com/your_home/tariffs.aspx
[101] Ohio Power Company. Schedule RS. Available at: https://www.aepohio.com/account/bills/rates/AEPOhioRatesTariffsOH.aspx
[102] Appalachian Power Company. Schedule RS. Available at: https://appalachianpower.com/account/bills/rates/APCORatesTariffsVA.aspx
[103] Duke Energy Carolinas SC. Schedule RS. Available at: https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-sc/scschedulers.pdf?la=en
[104] SD PUC Docket No. EL14-058. Order Adopting Settlement. June 16, 2015. See Settlement Exhibit PJS-2, Schedule 2-1 for prior and adopted rates, available at: http://puc.sd.gov/commission/dockets/electric/2014/EL14-058/settlement/pjs2-1-1.pdf
[105] AEP Texas North Division. Residential Service Schedule. Available at: https://www.aeptexas.com/account/bills/rates/AEPTexasRatesTariffsTX.aspx. Rate refers to the sum of the customer charge and metering charge.
[106] MD PSC. Case No. 9424. Order No. 88033. p. 27. February 15, 2017.
[107] Minnesota Power. Schedule Pg-1. Available at: https://www mnpower.com/CustomerService/Rates
[108] MN PUC. Docket No. E002/GR-15-826. Findings of Fact, Conclusions and Order. p. 61. May 11, 2017. The Order left the existing charged unchanged, resulting in the current rate, available at: https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/rates/MN/Me_Section_5.pdf
[109] Otter Tail Power Company ND. Residential Service Schedule. Available at: https://www.otpco.com/pricing/north-dakota/residential-rate-summary-nd/
[110] Idaho Power Company. Rate Schedule 1. Available at: https://www.idahopower.com/AboutUs/RatesRegulatory/Tariffs/default.cfm?state=or

OFFICIAL COPY

Jan 23 2018

[111] SD PUC. Docket No. EL14-072. Order Adopting Settlement. June 17, 2015. See current Rate RS, available at: https://www midamericanenergy.com/content/pdf/rates/elecrates/sdelectric/sd-elec.pdf

[112] Otter Tail Power Company. Residential Service. Available at: https://www.otpco.com/pricing/south-dakota/residential-rate-summary-sd/

[113] SWEPCO TX. Rate RS. Available at: https://swepco.com/account/bills/rates/SWEPCORatesTariffsTX.aspx

[114] Rocky Mountain Power UT. Residential Service. Available at: https://www.rockymountainpower net/about/rar/uri.html. Rate refers to the monthly minimum bill, while the monthly fixed charge is slightly lower ($6.00).

[115] Appalachian Power Company. Schedule RS. Available at: https://appalachianpower.com/account/bills/rates/APCORatesTariffsWV.aspx

[116] MD PSC. Case No. 9406. Order No. 87591. p. 195. June 3, 2016.

[117] FL PSC. Docket No. 160021-EI. Order No. PSC-0560-AS-EI. Exhibit A, p. 50. December 15, 2016.

[118] SWEPCO AR. Rate Schedule No. 2. Available at: https://swepco.com/account/bills/rates/SWEPCORatesTariffsAR.aspx

[119] Pacific Power WA. Rate Schedule 16. Available at: https://www.pacificpower net/about/rr/wri html

[120] MD PSC. Case No. 9418. Order No. 87884. p. 110. November 15, 2016.

[121] ME PUC. Docket No. 2015-00360. Final Order Part II. December 22, 2016. Order does not address rate design. See current Rate A (applicable to Bangor Hydro), available at: http://www.emeramaine.com/residential/rates/. Listed rate is the sum of the distribution service and stranded cost monthly charges.

[122] MI PSC. Case No. U-18014. Final Decision. p. 110. January 31, 2017.

[123] SD PUC. Docket EL15-024. Order Granting Joint Motion for Approval of Settlement Stipulation. June 15, 2016. See current Rate 10, available at https://www.montana-dakota.com/docs/default-source/rates-tariffs/sdElectric10. Stated charge is $0.247 per day, translating to a charge of $7.51/month.

[124] Puget Sound Energy. Schedule 7. Available at: https://pse.com/aboutpse/Rates/Documents/elec_sch_007.pdf.

[125] PA PUC. Docket R-2016-2537359. Order and Opinion. January 19, 2017. Order approved a party settlement resulting in the current rates. See current Schedule 10, available at: https://www.firstenergycorp.com/content/dam/customer/Customer%20Choice/Files/PA/tariffs/WPP-Tariff-40-with-Supp-29.pdf.

[126] Indiana Michigan Power Company. Tariff RS. Available at: https://www.indianamichiganpower.com/global/utilities/lib/docs/ratesandtariffs/Indiana/IMINTB16-08-07-2017.pdf.

[127] MI PSC. Case No. U-17698. Order Approving Settlement Agreement. August 14, 2015. See current Tariff RS, available at https://www.indianamichiganpower.com/global/utilities/lib/docs/ratesandtariffs/Michigan/IMMITB04-28-2017.pdf.

[128] Pacific Power & Light Company. Schedule No. D. Available at https://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/California/Approved_Tariffs/Rate_Schedules/Residential_Service.pdf.

[129] Entergy Louisiana. Schedule RS-L. Available at: http://www.entergy-louisiana.com/content/price/tariffs/LA/ell_elec_rs-l.pdf.

[130] MA DPU. Docket 15-80. Final Decision. p. 319. April 29, 2016.

[131] MI PSC. Case No. U-17990. Final Decision. p. 137. February 28, 2017.

[132] NM PRC. Case No. 15-00127-UT. Final Order Partially Adopting Recommended Decision. p. 58. June 8, 2016.

[133] NM PRC. Case No. 15-00261-UT. Final Order Partially Adopting Corrected Recommended Decision. September 28, 2016. See Rate No. 1A, available at https://www.pnm.com/documents/396023/396197/schedule_1_a.pdf/d9cfda9e-61a1-4008-ba3c-4152c9dbe7f1.

[134] Entergy Texas. Schedule RS. Available at: http://www.entergy-texas.com/content/price/tariffs/eti_rs.pdf.

OFFICIAL COPY
Jan 23 2018

[135] Dominion Energy (Virginia Electric and Power Company). Schedule 1. Available at: https://www.dominionenergy.com/library/domcom/pdfs/virginia-power/rates/shared/entire-filed-tariff.pdf.
[136] PUCT. Docket No. 44941. Final Decision. p. 11. August 25, 2016.
[137] Entergy Mississippi. Schedule RS-37C. Available at http://www.entergy-mississippi.com/content/price/tariffs/emi_rs-c.pdf.
[138] AEP Texas - Central Division. Residential Service. Available at: https://www.aeptexas.com/global/utilities/lib/docs/ratesandtariffs/Texas/CentralDivTariffMar2017.pdf. The charge indicated is sum of "Customer Charge" and "Metering Charge."
[139] CA PUC. Docket A.15-05-008. D.16-12-024. Decision Adopting a Modified All-Party Settlement. Exhibit F. December 1, 2016. See Schedule No. D-1, available at https://california.libertyutilities.com/uploads/August%202017%20Tariff%20Updates/D-1%20Aug%201%202017.pdf. The current version of Schedule No. D-1 reflects a charge of $8.17, but the CA PUC has not formally approved that charge. The associated tariff advice letter (E-72) is listed as suspended though the charge has been allowed to take effect.
[140] Eversource Energy (Eastern Massachusetts — Greater Boston). Rate R-1. Available at https://www.eversource.com/Content/docs/default-source/rates-tariffs/120.pdf?sfvrsn=2 and https://www.eversource.com/Content/docs/default-source/rates-tariffs/190.pdf?sfvrsn=28.
[141] Bear Valley Electric Service. Schedule No. D. Available at: https://www.bves.com/media/managed/ratechange032217/D.pdf. Stated charge is $0.210 per day, translating to a monthly charge of $6.39.
[142] Eversource Energy (Western Massachusetts Electric Company). Schedule R-1. Available at https://www.eversource.com/Content/docs/default-source/rates-tariffs/1000.pdf?sfvrsn=2 and https://www.eversource.com/Content/docs/default-source/rates-tariffs/1052.pdf?sfvrsn=36.
[143] Duke Energy Ohio. Rate RS. Available at: https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-oh/sheet-no-30-rate-rs-oh-e.pdf.
[144] SD PUC. Docket EL14-106. Order Approving Revised Settlement Stipulation. November 4, 2015. See current Rate No. 10, available at: http://www.northwesternenergy.com/docs/default-source/documents/sd_ne_rates/sd_elec/SouthDakotaElectricRateSchedule.
[145] ID PUC. Case No. AVU-E-16-03. Order No. 33682. December 28, 2016. See current Schedule 1, available at: https://www myavista.com/-/media/myavista/content-documents/our-rates-and-tariffs/id/id_001.pdf.
[146] MA DPU. Docket 15-155. Final Decision. p. 475. September 30, 2016.
[147] Southwestern Electric Power Company (SWEPCO). Residential Service (Schedule RS). Available at https://www.swepco.com/global/utilities/lib/docs/ratesandtariffs/Louisiana/LouisianaA_06_06_2013.pdf.
[148] MT PSC. Docket No. D2015.6.51. Final Order. March 25, 2016. See current Rate 10, available at: https://www.montana-dakota.com/docs/default-source/rates-tariffs/mTelectric10. Stated charge is $0.17 per day, translating to a monthly charge of $5.17
[149] CenterPoint Energy Houston Electric. Residential Service. Available at: http://www.centerpointenergy.com/en-us/Documents/RatesandTariffs/HoustonElectric/CNP-Retail-Del-Tariff-Book-HOU.pdf. The charge indicated is sum of "Customer Charge" and "Metering Charge."
[150] CO PUC. Docket 16AL-0048E. Decision Granting Motion to Approve Settlement. November 9, 2016. See current Schedule R, available at: https://www.xcelenergy.com/staticfiles/xe/PDF/Regulatory/CO-Rates-&-Regulations-Entire-Electric-Book.pdf.
[151] Rocky Mountain Power. Residential Service (Schedule No. 1). Available at https://www.rockymountainpower net/content/dam/rocky_mountain_power/doc/About_Us/Rates_and_Regulation/Idaho/Approved_Tariffs/Rate_Schedules/Residential_Service.pdf.
[152] Idaho Power Company. Schedule 1. Available at https://www.idahopower.com/AboutUs/RatesRegulatory/Tariffs/tariffPDF.cfm?id=156.
[153] The Potomac Edison Company. Schedule R. Available at https://www.firstenergycorp.com/content/dam/customer/Customer%20Choice/Files/maryland/tariffs/PotomacEdisonRetailTariff.pdf.

OFFICIAL COPY
Jan 23 2018

[154] Alpena Power. Residential Service. Available at: http://www.alpenapower.com/wp-content/uploads/2014/09/Complete-Rate-Book-MPSC-9.pdf.
[155] NJ BPU. Docket ER17030308. Decision and Order Adopting Initial Decision and Stipulation of Settlement. p. 3. September 22, 2017.
[156] National Grid. Basic Residential Rate (A-16). Available at: https://www9.nationalgridus.com/narragansett/home/rates/4_a16.asp
[157] WV PSC. Case No. 14-0702-E-42T. Commission Order. February 3, 2015. See Monongahela Power Company Schedule A, available at: https://www.firstenergycorp.com/customer_choice/west_virginia/west_virginia_tariffs html#gsc.tab=0
[158] NJ BPU. Docket ER16050428. Order Approving Stipulation. See Schedule E, Attachment 1, p. 7 of 28. February 22, 2017.
[159] Duke Energy Kentucky. Rate RS. Available at: https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-ky/sheet-no-30-rate-rs-ky-e.pdf.
[160] Entergy Louisiana (Legacy EGSL Service Area). Schedule RS-G. Available at: http://www.entergy-louisiana.com/content/price/tariffs/GS/ell_elec_rs-g.pdf.
[161] Dayton Power & Light. Electric Distribution Service Residential (Tariff No. D17). Available at: https://www.dpandl.com/images/uploads/D17-Residential_3-24-15.pdf.
[162] NorthWestern Energy. Schedule No. REDS-1. Available at: http://www northwesternenergy.com/docs/default-source/documents/mt_rates/Electric/REDS-1.
[163] Ohio Edison, Toledo Edison and The Illuminating Company. Rate RS. Available at: https://www.firstenergycorp.com/content/customer/customer_choice/ohio_/ohio_tariffs.html#gsc.tab=0
[164] Oncor Electric Delivery Company. Residential Service. Available at: http://www.oncor.com/EN/Documents/About%20Oncor/Billing%20Rate%20Schedules/Tariff%20for%20Retail%20Delivery%20Service.pdf. The charge indicated is sum of "Customer Charge" and "Metering Charge."
[165] NJ BPU. Docket ER16040383. Order Adopting Stipulation. December 12, 2016. See current Service Classification RS, available at: https://www.firstenergycorp.com/content/dam/customer/Customer%20Choice/Files/New%20Jersey/tariffs/BPU-12-Part-III-Effective-9-1-2017.pdf.
[166] Public Service Electric and Gas Company (PSEG). Rate Schedule RS. Available at: https://www.pseg.com/family/pseandg/tariffs/electric/pdf/electric_tariff.pdf.
[167] From IOU rate cases for which applications were submitted from July 2014 onward. The table does not include interim rate increases allowed to take effect while the application officially remains pending. Instances where an application was dismissed or withdrawn have been removed. Where multiple rate cases involving the same utility were completed during the timeframe, all changes are included, resulting in some utilities being listed more than once. A total of 86 utilities are represented. Consequently, the averages do not reflect the average of current fixed charges both because some rates below have been superseded and because Tables 1 and 2 include a larger sample of utilities.
[168] AZ Corporation Commission. Docket No. E-01933A-15-0322. p. 186. Decision No. 75795. February 24, 2017.
[169] AZ Corporation Commission. Docket No. E-4204A-15-0142. Decision No. 75697. p. 66. August 18, 2016.
[170] AZ Corporation Commission. Docket No. E-01345A-16-0036. Decision No. 76364. September 19, 2017. Settlement Agreement. p. 17. Refers to the daily rate of $0.329 for Schedule R-XS applicable to customers with monthly use averaging 600 kWh or less. This replaces the former daily rate of $0.285 under Schedule E-12 as it existed prior to this proceeding.
[171] AR PSC. Docket No. 15-015-U. Final Order. February 23, 2016. See red-lined compliance tariffs resulting from final order at p. 437, available at: http://www.apscservices.info/pdf/15/15-015-U_376_1.pdf
[172] AR PSC. Docket No. 16-052-U. Order No. 8 Adopting Settlement. p. 9. May 18, 2017. See red-lined initially proposed tariffs for former fixed charge, available at: http://www.apscservices.info/pdf/16/16-052-U_43_7.pdf

OFFICIAL COPY

Jan 23 2018

---

[173] CA PUC. Docket A.15-05-008. D.16-12-024. Decision Adopting a Modified All-Party Settlement. Exhibit F. December 1, 2016. See Schedule No. D-1, available at https://california.libertyutilities.com/uploads/August%202017%20Tariff%20Updates/D-1%20Aug%201%202017.pdf. The current version of Schedule No. D-1 reflects a charge of $8.17, but the CA PUC has not formally approved that charge. The associated tariff advice letter (E-72) is listed as suspended though the charge has been allowed to take effect.
[174] CA PUC. Docket A.15-04-012. D.17-08-030. Decision Adopting Revenue Allocation and Rate Design for San Diego Gas & Electric Company. p. 31. August 24, 2017.
[175] CO PUC. Docket No. 16AL-0326E. Decision No. C16-1140. p. 36. December 19, 2016.
[176] CO PUC. Docket 16AL-0048E. Decision Granting Motion to Approve Settlement. November 9, 2016. See current Schedule R, available at: https://www.xcelenergy.com/staticfiles/xe/PDF/Regulatory/CO-Rates-&-Regulations-Entire-Electric-Book.pdf and red-lined tariffs filed with the initial proposal, available at: https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=664443&p_session_id=
[177] CT PURA. Docket No. 14-05-06. Decision dated December 17, 2014. p. 184 (adopted rate) and 190 (prior rate).
[178] CT PURA. Docket No. 16-06-04. Final Decision. p. 96. December 14, 2016. Order sets "maximum" test year customer charge of $8.50, but requires an adjustment for the overall rate increase. See current Rate R, available at: https://uinet.custhelp.com/cgi-bin/uinet.cfg/php/enduser/std_adp.php?p_faqid=3418 and initial proposed red-lined tariffs, available at: http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/e422d52b1f01024185257fe300647cce?OpenDocument
[179] DE PSC. Docket No. 16-0649. Order No. 9048. Exhibit 2, p. 3. May 23, 2017.
[180] DC PSC. Docket No. FC 1139. Order No. 18846. p. 145. July 24, 2017.
[181] FL PSC. Docket No. 160021-EI. Order No. PSC-0560-AS-EI. Exhibit A, p. 50. December 15, 2016.
[182] FL PSC. Docket No. 160186-EI. Order No. PSC-17-0178-S-EI. p. 3. June 16, 2017. Order retains the existing residential rate structure. See Schedule RS, stating the charge as $0.65/day, translating to a monthly charge of $19.76, available at: https://www.gulfpower.com/residential/savings-and-energy/rates-and-billing/rates-rules-and-regulations and initially proposed red-lined tariffs, available at: http://www.psc.state.fl.us/library/filings/16/08160-16/08160-16.pdf
[183] ID PUC. Case No. AVU-E-16-03. Order No. 33682. p. 2. December 28, 2016. See also current Schedule 1, available at: https://www.myavista.com/-/media/myavista/content-documents/our-rates-and-tariffs/id/id_001.pdf
[184] ID PUC. Case No. AVU-E-15-05. Order No. 33437. p. 2 (existing charge) and p. 6 (providing for no increase in the charge). December 18, 2015.
[185] IN URC. Cause No. 44576. Final Order. p. 72. March 16, 2016.
[186] IN URC. Cause No. 44688. Final Order. p. 68 and 88. July 18, 2016.
[187] KS Corporation Commission. Docket No, 15-KCPE-116-RTS. Final Order. Attachment B, p. 4. September 10, 2015. Order adopted the settlement specifying the $14/month customer charge. See initially proposed red-lined tariffs for prior rate, available at: http://estar.kcc.ks.gov/estar/ViewFile.aspx/S20150102153029.pdf?Id=60a892a4-dca3-4c7a-b7c0-e27329605c63
[188] KS Corporation Commission. Docket No. 15-WSEE-115-RTS. Order Approving Stipulation .p. 22. September 24, 2015. Order adopted the settlement proposing a $14.50/month customer charge. See initially proposed red-lined tariffs for prior rate, available at: http://estar.kcc.ks.gov/estar/ViewFile.aspx/S20150302143551.pdf?Id=74e4c4cf-8c4d-4f30-95cc-59ce1417777b
[189] KY PSC. Docket No. 2014-00396. Final Order. p. 57-58. June 22, 2015.
[190] KY PSC. Docket No. 2016-00370. Final Order. p. 19. May 22, 2017.
[191] KY PSC. Docket No. 2014-00371. Final Order. p. 3. June 30, 2015.
[192] KY PSC. Docket No. 2014-00372. Final Order. p. 4. June 30, 2015.
[193] ME PUC. Docket No. 2015-00360. Final Order Part II. December 22, 2016. Order does not address rate design. See current Rate A (applicable to Bangor Hydro), available at:

OFFICIAL COPY

Jan 23 2018

http://www.emeramaine.com/residential/rates/. Listed rate is the sum of the distribution service and stranded cost monthly charges. See also prior tariff, located at: https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=89421&CaseNumber=2015-00360

[194] MD PSC. Case No. 9406. Order No. 87591. p. 195. June 3, 2016.

[195] MD PSC. Case No. 9355. Order No. 86757. p. 28 (providing for no increase in the customer charge). December 12, 2014.

[196] MD PSC. Case No. 9424. Order No. 88033. p. 27. February 15, 2017.

[197] MD PSC. Case No. 9418. Order No. 87884. p. 110. November 15, 2016.

[198] MA DPU. Docket 15-155. Final Decision. p. 473-475. September 30, 2016.

[199] MA DPU. Docket 15-80. Final Decision. p. 318-319. April 29, 2016.

[200] MI PSC. Case No. U-17990. Final Decision. p. 137. February 28, 2017.

[201] MI PSC. Case No. U-17735. Final Decision. p. 101-102. November 19, 2015.

[202] MI PSC. Case No. U-18014. Final Decision. p. 109-110. January 31, 2017.

[203] MI PSC. Case No. U-17767. Final Decision. p. 120. December 11, 2015.

[204] MI PSC. Case No. U-17698. Order Approving Settlement Agreement. p. 2. August 14, 2015. See current Tariff RS, available at https://www.indianamichiganpower.com/global/utilities/lib/docs/ratesandtariffs/Michigan/IMMITB04-28-2017.pdf.

[205] MI PSC. Docket No. U-17895. Final Order. p. 55. September 8, 2016.

[206] MI PSC. Docket No. U-17669. Order Approving Settlement Agreement. Attachment A, p. 33. April 23, 2015. See initial rate design testimony (Beyer, p. 13) for prior rate, available at: http://efile mpsc.state.mi.us/efile/docs/17669/0002.pdf

[207] MI PSC. Docket U-17710. Order Approving Settlement Agreement. Attachment A, Residential Service Schedule MR-1. March 23, 2015. See initial rate design testimony (Dahl, p. 12) for prior rate, available at: http://efile mpsc.state.mi.us/efile/docs/17710/0001.pdf

[208] MN PUC. Docket No. E-017/GR-15-1033. Findings of Fact, Conclusions and Order. p. 75 (prior) and 84 (adopted). May 1, 2017.

[209] MN PUC. Docket No. E002/GR-15-826. Findings of Fact, Conclusions and Order. p. 61. May 11, 2017. The Order left the existing charged unchanged, resulting in the current rate, available at: https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/rates/MN/Me_Section_5.pdf

[210] MS PSC. Docket No. 2015-UN-80. PSC Order. December 3, 2015. Base charge of $0.78 per day, translating to a monthly charge of $23.71. See current Rate R-55, available at: http://www mississippipower.com/my-home/my-bill/pricing-and-rates

[211] MO PSC. Docket No. ER-2016-0179. Decision Approving Settlement. p. 12. March 8, 2017. Decision approved a $1/month increase, reflected in current rate SC-1, available at: https://www.ameren.com/missouri/rates/electric-full-service-bundle

[212] MO PSC. Docket No. ER-2014-0258. Report and Order. p. 76-77. April 29, 2015.

[213] MO PSC. Docket No. ER-2016-0023. Order Approving Stipulation and Agreement. p. 2. August 10, 2016. See initial rate design testimony (p. 9) for prior charge, available at: https://www.efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=935963958

[214] MO PSC. Docket No. ER-2014-0351. Report and Order. p. 11. June 24, 2015.

[215] MO PSC. Docket No. ER-2016-0285. Report and Order. p. 57. May 3, 2017. See initial rate design testimony (Schedule MEM-3, p. 6) for prior customer charge, available at: https://www.efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=936015684

[216] MO PSC. Docket No. ER-2014-0370. Report and Order. p. 88-89. September 2, 2015.

[217] MO PSC. Docket No. ER-2016-0156. Order Approving Stipulation. September 28, 2016. Order adopted a settlement resulting in the current rates. See the non-unanimous settlement, available at: https://www.efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=936033685. See initial rate design testimony (p. 19) for prior rate, available at: https://www.efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=935985987

OFFICIAL COPY

Jan 23 2018

[218] MT PSC. Docket No. D2015.6.51. Final Order. p. 9. March 25, 2016. See current Rate 10, available at: https://www.montana-dakota.com/docs/default-source/rates-tariffs/mTelectric10. Stated charge is $0.17 per day, translating to a monthly charge of $5.17

[219] PUCN. Docket No. 16-06006. Order Granting in Part and Denying Part General Rate Application by Sierra Pacific Power. December 22, 2016. See tariff compliance filing dated December 30, 2016 (Sheet 63G) showing no change in the residential customer charge, available at: http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2016-6/17802.pdf

[220] NH PUC. Docket No. DE 16-383. Order No. 26,005. p. 8. April 12, 2017. See initial filing of red-lined proposed permanent tariffs for prior rate, available at: http://puc.nh.gov/Regulatory/Docketbk/2016/16-383/INITIAL%20FILING%20-%20PETITION/16-383_2016-04-29_GSEC_DBA_LIBERTY_TARIFF_PERM_RATES.PDF

[221] NH PUC. Docket No. DE 16-384. Order No. 26,007. p. 10-11. April 20, 2017. Order adopts a customer charge of $15/month, with a step adjustment effective May 1, 2017 to the current $15.24/month rate. See current Schedule D, available at: http://unitil.com/energy-for-residents/electric-information/tariffs and initial rate design testimony (p. 64) for prior rate, available at: http://puc.nh.gov/Regulatory/Docketbk/2016/16-384/INITIAL%20FILING%20-%20PETITION/16-384_2016-04-29_UES_DTESTIMONY_H_OVERCAST.PDF

[222] NJ BPU. Docket ER16030252. Order Adopting Stipulation of Settlement for the Base Rate Case and Establishing a Phase II to Review the PowerAhead Program at the BPU. p. 5. August 24, 2016.

[223] NJ BPU. Docket ER17030308. Decision and Order Adopting Initial Decision and Stipulation of Settlement. p. 3. September 22, 2017.

[224] NJ BPU. Docket ER16040383. Order Adopting Stipulation. Attachment 2, p. 2. December 12, 2016. See current Service Classification RS, available at: https://www.firstenergycorp.com/content/dam/customer/Customer%20Choice/Files/New%20Jersey/tariffs/BPU-12-Part-III-Effective-9-1-2017.pdf.

[225] NJ BPU. Docket ER16050428. Order Approving Stipulation. See Schedule E, Attachment 1, p. 7 of 28. February 22, 2017.

[226] NM PRC. Case No. 15-00127-UT. Final Order Partially Adopting Recommended Decision. p. 58. June 8, 2016.

[227] NM PRC. Case No. 15-00261-UT. Final Order Partially Adopting Corrected Recommended Decision. p. 80 (referring to amount of current charge and requested increase). September 28, 2016. See Rate No. 1A, available at https://www.pnm.com/documents/396023/396197/schedule_1_a.pdf/d9cfda9e-61a1-4008-ba3c-4152c9dbe7f1.

[228] NM PRC. Docket No. 16-00296-UT. Final Order Adopting Stipulation. August 10, 2016. See current Rate No. 1, available at: https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/rates/NM/nm_sps_e_entire.pdf and initial rate design testimony (Attachment RML-7, p. 1) for prior rates, available at: http://164.64.85.108/infodocs/2015/10/PRS20215104DOC.PDF

[229] NY PSC. Case No. 14-E-0318. Order Approving Rate Plan. p. 57. June 17, 2016. Order rejected settlement providing for an increase in the fixed charge, retaining it at $24.00/month. See current SC-1 rate, available at: https://www.cenhud.com/rates/index

[230] NY PSC. Case No. 16-E-0060. Order Approving Electric Rate Plan. January 25, 2017. Order adopted a joint party proposal maintaining the existing rate. See Schedule SC-1, available at: https://www2.dps.ny.gov/ETS/jobs/display/download/6090846.pdf

[231] NY PSC. Case No. 15-E-0050. Order Adopting Proposal to Extend Rate Plan. June 19, 2015. Proposal extended existing SC-1 rates for one year, unchanged.

[232] NY PSC. Case No. 15-E-0283. Order Approving Electric and Gas Rate Plans. p. 21. June 15, 2016. See current NYSEG Rate SC-1, available at: http://www.nyseg.com/SuppliersAndPartners/pricingandtariffs/electricitytariffs/PSC120TableOfContents.html

[233] NY PSC. Case No. 14-E-0493. Order Establishing Rate Plan. Appendix 18, Schedule 1. October 16, 2015. See also p. 11 describing the rate plan, which does not include any customer charge increases.

OFFICIAL COPY

Jan 23 2018

234 NY PSC. Case No. 15-E-0285. Order Approving Electric and Gas Rate Plans. p. 21. June 15, 2016. See current RGE Rate SC-1, available at: https://www.rge.com/SuppliersAndPartners/pricingandtariffs/tariffratesummaries/psc19 html

235 NCUC. Docket No. E-22, Sub 532. Order Approving Rate Increase. p. 16. December 22, 2016. Adopted settlement provides for no customer charge increase, retaining the existing rate. See Schedule 1, available at: https://www.dominionenergy.com/library/domcom/pdfs/north-carolina-power/rates/shared/entire-filing.pdf?la=en

236 ND PSC. Case No. PU-16-666. Findings of Fact, Conclusions of Law and Order. p. 6. June 16, 2017. Charge is stated as $0.46/day, translating to a monthly charge of $13.98. See initially proposed red-lined tariffs for prior rate, available at: http://www.psc.nd.gov/database/documents/16-0666/003-020.pdf

237 OK Corporation Commission. Cause No. PUD 201500273. Order No. 662059. p. 4. March 20, 2017. Order adopts the ALJ recommendation, retaining the existing customer charge at $13. See Schedule R-1, available at: https://oge.com/wps/wcm/connect/81687ef5-a4b0-4b0f-b8a0-1cfaa22b1045/3.00+R-1.pdf?MOD=AJPERES&CACHEID=81687ef5-a4b0-4b0f-b8a0-1cfaa22b1045

238 OK Corporation Commission. Cause No. PUD 201500208. Order No. 657877. p. 143 (discussing existing customer charge). November 10, 2016. See current Schedule RS, available at: https://www.psoklahoma.com/account/bills/rates/.

239 OR PUC. Docket No. UE 294. Order No. 15-356. p. 11. November 3, 2015.

240 PA PUC. Docket No. R-2016-2531550. Final Order. April 6, 2017. The Order approved a party settlement, resulting in the current rates. See current Schedule RS, available at: https://www.citizenselectric.com/TariffStart.asp and initial filing detailing prior charges (p. 7) available at: http://www.puc.pa.gov/pcdocs/1471660.pdf

241 PA PUC. Docket No. R-2016-2537352. Opinion and Order. p. 11. January 19, 2017. Order approved a party settlement resulting in the current rates. See current Rate RS, available at: https://www.firstenergycorp.com/content/customer/customer_choice/pennsylvania/pennsylvania_tariffs.html#gsc.tab=0n and the initial filing with red-lined tariff proposals, available at: http://www.puc.state.pa.us/pcdocs/1436865.pdf

242 PA PUC. Docket No. R-2014-2428745. Final Order. p. 3. April 9, 2015. Order adopts settlement but does not discuss rate design. See Settlement Exhibit 4, p. 1 detailing current and proposed rates, available at: http://www.puc.state.pa.us/pcdocs/1341067.pdf

243 PA PUC. Docket No. R-2015-2468981. Opinion and Order. p. 11. December 17, 2015. See Settlement Exhibit A with red-line settlement tariffs for prior charge (tariff p. 45), available at: http://www.puc.state.pa.us/pcdocs/1381271.pdf

244 PA PUC. Docket No. R-2016-2537352. Opinion and Order. p. 11. January 19, 2017. Order approved a party settlement resulting in the current rates. See current Rate RS, available at: https://www.firstenergycorp.com/content/customer/customer_choice/pennsylvania/pennsylvania_tariffs.html#gsc.tab=0 and the initial filing with red-lined tariff proposals, available at: http://www.puc.state.pa.us/pcdocs/1436873.pdf

245 PA PUC. Docket No. R-2014-2428743. Final Order. p. 3. April 9, 2015. Order adopts settlement but does not discuss rate design. See Settlement Exhibit 4, p. 1 detailing current and proposed rates, available at: http://www.puc.state.pa.us/pcdocs/1341079.pdf

246 PA PUC. Docket No. R-2016-2537355. Opinion and Order. p. 13. January 19, 2017. Order approved a party settlement resulting in the current rates. See current Rate RS, available at: https://www.firstenergycorp.com/content/customer/customer_choice/pennsylvania/pennsylvania_tariffs.html#gsc.tab=0 and initial filing with red-lined tariff proposals, available at: http://www.puc.state.pa.us/pcdocs/1436874.pdf

247 PA PUC. Docket No. R-2014-2428744. Final Order. p. 3. April 9, 2015. Order adopts settlement but does not discuss rate design. See Settlement Exhibit 4, p. 1 detailing current and proposed rates, available at: http://www.puc.state.pa.us/pcdocs/1341065.pdf

248 PA PUC. Docket No. R-2015-2469275. Opinion and Order. p. 8. November 19, 2015.

249 PA PUC. Docket No. R-2016-2531551. Final Order. April 6, 2017. The Order approved a party settlement, resulting in the current rates. See Schedule No. 1, available at:

OFFICIAL COPY

Jan 23 2018

https://wellsboroelectric.com/wp-content/uploads/2014/03/Distribution-Tariff-Supp-106-Apr-11-2017.pdf and initial filing detailing prior charges (p. 6) available at: http://www.puc.pa.gov/pcdocs/1471646.pdf

[250] PA PUC. Docket R-2016-2537359. Order and Opinion. January 19, 2017. Order approved a party settlement resulting in the current rates. See current Schedule 10, available at: https://www.firstenergycorp.com/content/dam/customer/Customer%20Choice/Files/PA/tariffs/WPP-Tariff-40-with-Supp-29.pdf and initial filing with red-lined tariff proposals, available at: http://www.puc.state.pa.us/pcdocs/1436870.pdf

[251] PA PUC. Docket No. R-2014-02428742. Final Order. p. 3. April 9, 2015. Order adopts settlement but does not discuss rate design. See Settlement Exhibit 4, p. 1 detailing current and proposed rates, available at: http://www.puc.state.pa.us/pcdocs/1341050.pdf

[252] SC PSC. Docket No. 2016-227-E. Order Approving Settlement. December 21, 2016. See current rate Schedule RES, available at: https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-sc/r1scscheduleres.pdf?la=en and initially proposed red-lined tariffs detailing the prior rate, available at: https://dms.psc.sc.gov/Attachments/Matter/6ee58943-f5e3-4b43-b35d-1f6294305b39

[253] SD PUC. Docket No. EL14-072. Order Adopting Settlement. June 17, 2015. See current Rate RS, available at: https://www.midamericanenergy.com/content/pdf/rates/elecrates/sdelectric/sd-elec.pdf and Settlement Exhibit PJS-4, Schedule 2-1 showing prior and adopted rates, available at: http://www.puc.sd.gov/commission/dockets/electric/2014/el14-072/pjs4-2-1.pdf

[254] SD PUC. Docket EL15-024. Order Granting Joint Motion for Approval of Settlement Stipulation. June 15, 2016. See current Rate 10, available at https://www.montana-dakota.com/docs/default-source/rates-tariffs/sdElectric10. Stated charge is $0.247 per day, translating to a charge of $7.51/month. For prior rates, see Settlement Exhibit EJP-2, Schedule 2-1, available at: https://puc.sd.gov/commission/dockets/electric/2015/EL15-024/memo/EJP-2-2-1.pdf

[255] SD PUC. Docket EL14-106. Order Approving Revised Settlement Stipulation. November 4, 2015. See current Rate No. 10, available at: http://www.northwesternenergy.com/docs/default-source/documents/sd_ne_rates/sd_elec/SouthDakotaElectricRateSchedule and Settlement Exhibit EJP-2, Schedule 2-1 for prior rates, available at: https://puc.sd.gov/commission/dockets/electric/2014/EL14-106/memo/EJP-2-2-1.pdf

[256] SD PUC Docket No. EL14-058. Order Adopting Settlement. June 16, 2015. See Settlement Exhibit PJS-2, Schedule 2-1 for prior and adopted rates, available at: http://puc.sd.gov/commission/dockets/electric/2014/EL14-058/settlement/pjs2-1-1.pdf

[257] TN Regulatory Authority. Docket No. 1600001. Order Approving Stipulation. Attachment C, Schedule 1. October 19, 2016.

[258] PUCT. Docket No. 44941. Final Decision. p. 11. August 25, 2016. See initial rate design testimony (Schichtl, p. 23) for prior rates, available at: http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/44941_2_861552.PDF

[259] PUCT. Control No. 45524. Order Adopting Settlement. January 26, 2017. See current Residential Service schedule, available at: https://www.xcelenergy.com/company/rates_and_regulations/rates/texas_rates,_rights,_&_service_rules and initial rate design testimony (Luth, p. 45) for prior rate, available at: http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/45524_2_882623.PDF

[260] PUCT. Control No. 43965. Final Order. p. 54. December 18, 2015.

[261] VA Corporation Commission. Docket No. PUC-2015-00063. Final Order. p. 5. February 2, 2016

[262] WA UTC. Docket No. UE-160228. p. 57. Final Order Rejecting Tariff Filing. December 15, 2016. Commission determined that the existing rates were just and reasonable and therefore retained them. See Rate Schedule No. 1, available at: https://myavista.com/about-us/our-rates-and-tariffs/washington-electric-resources

[263] WA UTC. Docket No. UE-150204. Final Order. p. 10. January 6, 2016.

[264] WI PSC. Docket No. 660-UR-120. Final Decision. p. 7 (adopted rate) and 35 (prior rate). December 22, 2016.

[265] WI PSC. Docket No. 3270-UR-121. Final Decision. Appendix B, p. 2. December 15, 2016.

[266] WI PSC. Docket No. 4280-ER-106. Final Decision. Appendix D, p. 1. June 20, 2017.

---

267 WI PSC. Docket No. 5820-UR-114. Final Decision. Appendix B, page 2 of 6. August 10, 2017.
268 WI PSC. Docket No. 6690-UR-124. Final Decision. p. 63. December 17, 2015.
269 WI PSC. Docket No. 4220-UR-122. Final Decision. Appendix B, p. 2. December 1, 2016.
270 WI PSC. Docket No. 4220-UR-121. Final Decision. Appendix B, p. 2. December 23, 2015.
271 WY PSC. Docket No. 14409. Order No. 23958. Appendix A, p. 11. April 6, 2017. Charge is stated as $0.822/day, translating to a monthly charge of $25.00/month.
272 WY PSC. Docket No. 14076. Order No. 23208. December 30, 2015. See current Schedule 2 available at: https://www.rockymountainpower.net/about/rar/wri html. See initially proposed red-line tariffs for reference to prior rate, available at: https://www.rockymountainpower net/content/dam/rocky_mountain_power/doc/About_Us/Rates_and_Regulation/Wyoming/Regulatory_Filings/Docket_20000_469_ER_15/03-02-15_Direct_Testimony_and_Exhibits/Joelle_R_Steward/exhibits/Exhibit_RMP_JRS_8.pdf

OFFICIAL COPY

Jan 23 2018

OFFICIAL COPY

Jan 23 2018

DUKE ENERGY CAROLINAS LLC
Docket No. E-7, Sub 1146
DEMAND, ENERGY AND CUSTOMER COS STUDY
FOR THE TEST PERIOD ENDED December 31, 2016
NORTH CAROLINA PROPOSED REVENUE - SUMMER CP
PROPOSED REVENUE
Without Minimum System

	DEMAND	UNIT	COSTS	ENERGY	UNIT	COSTS	DEMAND & ENERGY	UNIT	COSTS	CUSTOMER	UNIT	COSTS
	Revenue	KW*	$/KW/Mo	Revenue	Annual KWH **	Cents/KWH	Revenue	Annual KWH **	Cents/KWH	Revenue	Avg Bills ***	$/Cust/Mo
RS 1	$ 1 020 741 000	3 488 271	24 39	$ 265 390 000	12 249 369 000	2 166561	$ 1 286 131 000	12 249 369 000	10 499569	$ 133 276 000	1 002 832	11 08
R	3 384 000	11 794	23 91	1 074 000	49 461 000	2 171408	4 458 000	49 461 000	9 013162	254 000	1 939	10 92
RE 1	682 558 000	2 045 719	27 80	196 027 000	8 993 422 000	2 179671	878 585 000	8 993 422 000	9 769196	95 730 000	702 734	11 35
TOTAL RS	**1,706,683,000**	**5,545,784**	**25.65**	**462,491,000**	**21,292,252,000**	**2.172109**	**2,169,174,000**	**21,292,252,000**	**10.187621**	**229,260,000**	**1,707,505**	**11.19**
SGS	373 227 000	1 182 245	26 31	102 841 000	4 381 606 000	2 347107	476 068 000	4 381 606 000	10 865149	29 768 000	237 219	10 46
LGS	301 210 000	1 122 802	22 36	113 653 000	4 877 751 000	2 330029	414 863 000	4 877 751 000	8 505211	1 110 000	8 844	10 46
TOTAL GS	**674,437,000**	**2,305,047**	**24.38**	**216,494,000**	**9,259,357,000**	**2.338111**	**890,931,000**	**9,259,357,000**	**9.621953**	**30,878,000**	**246,063**	**10.46**
OL	74 358 000	-	0 00	11 168 000	476 973 000	2 341432	85 526 000	476 973 000	17 930994	14 272 000	277 924	4 28
NL	91 000	-	0 00	10 000	280 000	3 571429	101 000	280 000	36 071429	-	7	0 00
GL	4 165 000	-	0 00	479 000	18 546 000	2 582767	4 644 000	18 546 000	25 040440	62 000	1 052	4 91
PL	27 601 000	-	0 00	5 513 000	229 174 000	2 405596	33 114 000	229 174 000	14 449283	260 000	4 738	4 57
OL GL PL	**106,215,000**	**-**	**0.00**	**17,170,000**	**724,973,000**	**2.368364**	**123,385,000**	**724,973,000**	**17.019255**	**14,594,000**	**283,721**	**4.29**
S	902 000	1 254	59 94	244 000	10 469 000	2 330691	1 146 000	10 469 000	10 946604	540 000	5 920	7 60
TOTAL LIGHTING	**107,117,000**	**1,254**	-	**17,414,000**	**735,442,000**	**2.367828**	**124,531,000**	**735,442,000**	**16.932810**	**15,134,000**	**289,641**	**4.35**
I	121 374 000	401 815	25 17	48 435 000	1 984 592 000	2 440552	169 809 000	1 984 592 000	8 556368	476 000	3 762	10 54
OP V Sec Small	390 856 000	1 476 212	22 06	188 311 000	7 995 048 000	2 355345	579 167 000	7 995 048 000	7 244072	2 063 000	16 385	10 49
OP V Sec Med	112 018 000	431 598	21 63	60 943 000	2 552 367 000	2 387705	172 961 000	2 552 367 000	6 776494	29 000	294	8 22
OP V Sec Lg	114 958 000	445 841	21 49	72 541 000	3 017 429 000	2 404067	187 499 000	3 017 429 000	6 213866	7 000	84	6 94
OP V Pri Small	10 585 000	35 543	24 82	7 413 000	310 184 000	2 389872	17 998 000	310 184 000	5 802362	9 000	103	7 28
OP V Pri Med	28 171 000	97 858	23 99	16 566 000	692 435 000	2 392427	44 737 000	692 435 000	6 460823	7 000	72	8 10
OP V Pri Lg	316 915 000	1 264 675	20 88	210 263 000	8 806 795 000	2 387509	527 178 000	8 806 795 000	5 986037	10 000	140	5 95
OP V rans	27 247 000	114 011	19 92	21 324 000	896 459 000	2 378692	48 571 000	896 459 000	5 418095	-	4	0 00
TOTAL OPT	**1,000,750,000**	**3,865,738**	**21.57**	**577,361,000**	**24,270,717,000**	**2.378838**	**1,578,111,000**	**24,270,717,000**	**6.502119**	**2,125,000**	**17,082**	**10.37**
TOTAL RETAIL	**$ 3,610,361,000**	**12,119,638**	**24.82**	**$ 1,322,195,000**	**57,542,360,000**	**2.297777**	**$ 4,932,556,000**	**57,542,360,000**	**8.572043**	**$ 277,873,000**	**2,264,053**	**10.23**

*System Peak Demand at Generation Level COSS allocator KW
**KWH at Customer Meter rom COSS allocator SMWH
***Average Bills rom COSS allocator AVGB LL