BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-34, SUB 54
DOCKET NO. E-34, SUB 55

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| In the Matter of Application for | ) |
| General Rate Case | ) |
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| DOCKET NO. E-34, SUB 55 | ) |
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| In the Matter of Petition of | ) |
| Appalachian State University d/b/a | ) |
| New River Light and Power for an | ) |
| Accounting Order to Defer Certain | ) |
| Capital Costs and New Tax | ) |
| Expenses | ) |

**DIRECT TESTIMONY OF**

**JUSTIN R. BARNES**

**ON BEHALF OF**

**APPALACHIAN VOICES**

**JUNE 6, 2023**

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# I. Introduction

**Q. Please state your name, business address, and current position.**

A. My name is Justin R. Barnes. My business address is 1155 Kildaire Farm Rd., Suite 202, Cary, North Carolina, 27511. My current position is President of EQ Research LLC.

**Q. On whose behalf are you submitting testimony?**

A. I am submitting testimony on behalf of Appalachian Voices (AV).

**Q. Have you previously submitted testimony before the North Carolina Utilities Commission (NCUC or the Commission)?**

A. Yes. I have submitted testimony in Commission Docket Nos. E-2 Sub 1219 and E-7 Sub 1214 addressing the respective Duke Energy Progress (DEP) and Duke Energy Carolinas (DEC) 2019 rate cases, and in Commission Docket Nos. E-2 Sub 1142 and E-7 Sub 1146 addressing the Duke Energy affiliates' 2017 rate cases.

**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 roughly five years as a Policy Analyst and Senior Policy Analyst.[1] During

[1] The North Carolina Solar Center is now known as the North Carolina Clean Energy Technology Center.

that time I worked on the Database of State Incentives for Renewables and Efficiency (DSIRE) project, and several other projects related to state renewable energy and energy efficiency policy. I joined EQ Research in 2013 as a Senior Analyst, became the Director of Research in 2015, and became the President of EQ Research in May 2023. In my current position, I coordinate and contribute to EQ Research's various research projects for clients, provide oversight of EQ Research's electric industry tracking services and consulting projects, and perform customized research and analyses to fulfill client requests.

Outside of North Carolina, I have submitted testimony before public utility commissions in Colorado, Georgia, Hawaii, Kentucky, Michigan, New Hampshire, New Jersey, New York, Oklahoma, South Carolina, Texas, Utah, Virginia, Wisconsin, and the City Council of New Orleans[2] on various issues related to distributed generation (DG) and distributed energy resource (DER) policy, net metering, general rate design and DG customer rate design, cost of service and cost allocation, utility ownership of DERs, avoided cost rates for qualifying facilities (QFs), and customer-sited battery storage program design. These individual regulatory proceedings have involved a mix of general rate cases and other types of contested cases. My curriculum vitae is attached as Exhibit JRB-1. It contains summaries of the subject matter I have addressed in each of these proceedings.

[2] The City Council of New Orleans regulates the rates and operations of Entergy New Orleans in a manner equivalent to state public utility commissions.

**Q. Please describe the purpose of your testimony and how it is organized.**

A. My testimony addresses three topics, which I have separated into the following sections:

- Section II addresses: (a) the establishment of a net energy metering (NEM) tariff by Appalachian State University d/b/a New River Light and Power (NRLP) in the form of a proposed, new Schedule NBR, including the Standby Supplemental Charge (SSC) proposed as part of this tariff, and (b) a buy-all, sell all DG tariff option in the form of Schedule PPR.
- Section III addresses NRLP's proposal to increase the residential basic facilities charge (BFC) from $12.58/month to $14.50/month.
- Section IV contains my concluding remarks and summarized recommendations.

**Q. Please summarize your recommendations to the Commission regarding NRLP's Schedule NBR proposal and the reasons for those recommendations.**

A. The Commission should approve the establishment of Schedule NBR, but with several modifications to the design NRLP proposed. My primary recommended modification is the elimination of the SSC component, which is supported by my analysis of the costs avoided by NRLP by residential customer-sited solar generation. My analysis, which corrects for certain errors in NRLP's own analysis, indicates that the value of such generation is approximately equal to the residential retail rate. As a consequence, the SSC is unnecessary as a means of protecting non-participants from a cross-subsidy and would overcharge Schedule NBR participants.

Specifically, I have calculated that <u>exclusive of NRLP's marginal distribution costs</u>, the value of residential customer-sited generation is in the range of 11.8 – 13.7 cents/kWh compared to a proposed residential retail rate of roughly 14.8 cents/kWh. I state this as a range because the specific value depends on assumptions used for solar system orientation, which impacts the contribution to the various peak demands that cause NRLP to incur costs. Based on available information about NRLP's distribution costs, layering an avoided distribution capacity benefit on top of the amounts for non-distribution avoided costs would likely eliminate the remaining cost/benefit deficit (1.1 – 3.0 cents/kWh) due to the relatively good alignment between solar production and NRLP's distribution system peaks.

I also recommend that the proposed Schedule NBR be modified to eliminate the provision requiring the annual forfeiture of accrued net excess credits on January 1 of each year. Instead, Schedule NBR should be modified to allow indefinite carryover of accrued credits, or in the alternative, allow a customer to choose their annual period. This change is justified because: (a) it is necessary to allow customers to size a system to fully offset their annual on-site energy consumption; (b) indefinite rollover provides a simple and effective deterrent against oversizing; and (c) given the results of my evaluation of solar benefits, no such “haircut” to customer compensation for customer-sited PV installations is justified.

**Q. Please summarize your observations and recommendations regarding NRLP’s proposed Schedule PPR.**

A. The proposed Schedule PPR is a buy all, sell all tariff which would prohibit customers with qualifying behind the meter solar systems from using their system output to offset their energy consumption, and require those customers to sell all their output to NRLP at an avoided cost rate and buy all their power from NRLP at the retail rate that would apply to their customer class. I recommend that the Commission decline to approve Schedule PPR because it:

- Bars qualifying customers from enjoying the full benefit of their solar systems by prohibiting them from consuming the energy they generate on-site;
- Bases the compensation rate on a solar valuation methodology that I demonstrate is inaccurate; and
- Could be confusing to prospective DG customers given that its eligibility requirements significantly overlap those of Schedule NBR.

To the extent that NRLP might intend for Schedule PPR to deter retail rate customers who might otherwise be inclined to “oversize” their solar systems above the system cap Schedule NBR imposes, there are more effective ways of accomplishing that objective, such as imposing a cost-based charge on over-sized solar systems if those larger systems impose additional, unnecessary costs on NRLP.

**Q. Please summarize your recommendations to the Commission on the proposed increase in the residential BFC.**

A. The Commission should deny NRLP's proposal to increase the residential BFC to $14.50/month, and direct NRLP to reduce the residential BFC to no more than $10.61/month. My recommendation is based on my separate calculations of residential customer-related unit costs using three different methods. One calculation is based largely on NRLP's methodology for determining the BFC, with certain modifications to improve its accuracy, as explained later in my testimony. This calculation produces a residential BFC of $11.49/month. The second is an alternative calculation that I conducted using what is often termed the Basic Customer Method, which is a common method of setting BFCs throughout the country. This calculation produces a residential BFC of $10.61/month.

Finally, I have calculated alternative BFCs of $10.81/month for residential customers and $14.86/month for commercial general customers based on AV Witness Hoyle's calculations of an appropriate cost of capital and applying the resulting class revenue requirements reductions to reduce the BFCs for these customer classes. In sum, these three methodologies, when applied properly, result in a BFC ranging from $11.49/month down to $10.61, representing a reduction of $3.01 to $3.89 from NRLP's requested

BFC. On the balance, a maximum charge of $10.61/month most appropriately captures the multitude of competing factors involved.

# II. Proposed Schedule NBR and Schedule PPR

## A. Summary of the Schedule NBR Proposal & Summarized Response

**Q. Please briefly summarize NRLP's proposed Schedule NBR.**

A. Schedule NBR, as proposed by NRLP in its initial filing, has the following key elements:[3]

1. Available to residential and non-residential customers that install behind-the-meter ("BTM") photovoltaic ("PV") systems, with the system size capped at the lesser of the customer's anticipated annual peak demand, or 20 kW for residential customers and 1,000 kW for non-residential customers.
2. An energy netting regime that could be referred to as "Retail NEM" because it allows for the netting of imports and exports over the course of a monthly billing period (i.e., NEM) and the carryover of net monthly excess generation at the retail rate to the following month (i.e., the Retail in Retail NEM).[4]
3. An annual reconciliation mechanism where any accrued credits for excess generation are zeroed out on January 1 of each year.

[3] NRLP Application, Exhibit B – Proposed Tariffs.
[4] NRLP response to AV 2-3(a).

4. An additional charge on participant customers referred to as the SSC, which is set at $6.17/kW of AC nameplate capacity of the PV system, which NRLP proposes to base on the AC capacity of the inverter.[5]

**Q. How does NRLP explain its proposed design for Schedule NBR?**

A. NRLP witness Halley states that Schedule NBR was designed to meet the criteria provided in N.C.G.S. § 62-126.4.[6] As relevant to the design of Schedule NBR, the principal criterion that Witness Halley refers to appears to be N.C.G.S. § 62-126.4(b), which provides as follows:

> The rates shall be nondiscriminatory and established only after an investigation of the costs and benefits of customer-sited generation. The Commission shall establish net metering rates under all tariff designs that ensure that the net metering retail customer pays its full fixed cost of service. Such rates may include fixed monthly energy and demand charges.

**Q. Does the proposed Schedule NBR provide nondiscriminatory treatment of customer generators that is based on the costs and benefits of customer-sited generation?**

A. No. Most significantly, the SSC component of proposed Schedule NBR conflicts with the statutory directive that rates be "nondiscriminatory" because it is based on an erroneous analysis of the "costs and benefits" of customer-sited PV generation. I describe the errors in NRLP's calculation of the SSC in Section II(B) of my testimony. As a consequence, the SSC would cause customer-generators to pay more than their net "fixed cost of

[5] NRLP response to AV 5-2(a).
[6] Direct Testimony of Randall E. Halley ("Halley Direct") at p. 47.

service" given the relative costs and benefits associated with customer generation.

**Q. Please discuss the specific problems that you have identified with the proposed Schedule NBR.**

A. There are numerous problems with the proposed SSC and how NRLP calculated it based on its assessment of solar costs and benefits, the conceptual design of the proposed SSC and its applicability, and one structural issue with Schedule NBR. The deficiencies that I have identified are listed and described below, with identifiers to the more specific sub-issue(s) to which they relate.

1. SSC Issue #1 (Cost-Benefit Evaluation): NRLP's evaluation of the costs and benefits of customer-sited solar makes a basic methodological error by basing the calculation of avoided cost benefits on the volumetric residential retail rate, rather than the unit costs associated with the demand-based cost elements that produce the retail rate. This is erroneous because retail rates for these components represent the costs of peak demand as averaged over overall class usage, not the value of a given kilowatt ("kW") of demand reduction. The conflation of averaged costs with unit costs of peak demands causes NRLP to understate the costs avoided by customer-sited PV generation even if one accepts all of the other elements of its methodology.

2. SSC Issue #2 (Cost-Benefit Evaluation): NRLP's evaluation of the costs and benefits of customer-sited solar production relies on solar production data of highly questionable reliability in order to determine the effective solar capacity contribution towards peak demand hours. Specifically, there is an extreme amount of missing hourly data (roughly 30% of total daylight hours), which NRLP attempted to "fill in" using a methodology that is inconsistent with the shape of a solar production profile.
3. SSC Issue #3 (Cost-Benefit Evaluation): NRLP fails to include reduced distribution system loading and accompanying avoided distribution capacity benefits in its evaluation based on a simple blanket and unsupported assertion that its distribution costs are fixed.
4. SSC Issue #4 (Charge Applicability & Calculation): NRLP proposes to apply the SSC to all Schedule NBR customers, including non-residential Commercial General and Commercial Demand customers, but its determination of costs and benefits is based on, and specific to, residential rates and the residential rate structure (i.e., the volumetric retail rates are a basic input). Therefore, even if one agrees with the conceptual design of the SSC and NRLP had correctly calculated the costs and benefits of customer-sited solar, the proposed SSC rate would be incorrect if applied to non-residential rate classes.

5. SSC Issue #5 (Charge Applicability & Calculation): NRLP proposes to levy the charge based on the AC nameplate capacity of the customer's inverter rather than the system design capacity.[7] Leaving aside the other issues with the SSC that I have described, this charge determinant is mis-aligned with NRLP's methodology for determining the amount of the proposed SSC, which at its core is based on PV system energy production. Energy production is determined by the design capacity of a system, which for customer-sited PV is often lower than the inverter rating due to the fact that inverters come in standardized sizes that do not precisely line up with the production capability of the system.

6. Dual Schedule NBR & SSC Issue (Annual Reset and Charge Calculation): NRLP's proposal to zero out accrued excess generation on January 1 of each year is misaligned with NRLP's SSC calculation, which implicitly assumes that customers would be able to fully utilize all system production to offset retail purchases from NRLP as part of the "cost" side of its evaluation of customer-sited PV costs and benefits. In NRLP's SSC calculation, it made no adjustment to reflect the fact that its "costs" (i.e., customer savings) would be reduced by credits that are forfeited due to the reset. Furthermore, this provision would limit

[7] On a similar note, I would also add that NRLP Witness Halley mistakenly calculates system AC nameplate rating based on the maximum hourly *coincident* production of NRLP's customer solar generation sample. In practice, the AC nameplate rating of an individual PV generation system is reflected by its maximum generation in *isolation* from any other PV system. However, this inaccuracy does not appear to impact the resulting calculation of the proposed SSC as applied to AC system capacity because he makes a symmetrical error by using this measure of AC nameplate capacity as the denominator in the calculation of PV capacity contributions during peak hours.

customers' ability to size their PV systems to fully offset annual on-site energy needs, because it would result in forfeited credits for a typical 100% offset PV system.

**Q. Has NRLP provided any further information on its proposal subsequent to the initial filing that relates to the problems that you have identified?**

A. Yes. In response to data requests, NRLP indicated that it intended to make supplemental filings addressing items (4) and (6) listed above. Specifically, as it relates to item (4), NRLP stated that it intended to make a supplemental filing proposing separate SSCs for the Commercial General and Commercial Demand rate classes.[8] Regarding item (6), NRLP indicated that it intended to make a supplemental filing eliminating the annual reset of customer excess credit balances.[9] However, thus far, NRLP has made no such supplemental filings.

### B. NRLP's Methodology for Analyzing Customer-Sited PV Benefits is Erroneous and Underestimates PV Benefits

**Q. Please briefly describe NRLP's evaluation of the costs and benefits of customer-sited PV that underpins the proposed SSC.**

A. NRLP performs a calculation using residential rates under which the costs of customer-sited PV are determined by applying estimated system production to the volumetric retail rate, which is the rate at which customer

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[8] NRLP response to AV 2-3(b).

[9] NRLP response to AV 2-3(d).

savings accrue. For example, the calculated annual cost of a system that produces 5,000 kWh annually for a customer with a retail rate of $0.10/kWh would be $500.

The benefits are derived by applying a percentage contribution to those same retail rates based on how solar production aligns with how those costs are incurred. For the wholesale energy component of rates, this percentage is set at 100%, which reflects the fact that customer-sited PV generation reduces wholesale energy purchases at a 1:1 ratio. For the cost components that are determined based on monthly peak demands, NRLP calculated a solar capacity contribution using production meter data from existing residential PV installations for the hours during the test year in which those peaks occurred. I discuss the reliability of these calculated solar capacity contributions in Section II(C). In any case though, NRLP applies these solar contribution percentages to the following cost items as reflected in its cost-of-service study ("COSS"):[10]

- DEC Transmission (29.12%)
- Blue Ridge Electric Membership Corporation ("BREMCO") Transmission (29.12%)
- Carolina Power Partners ("CPP") Production Demand Related (26.03%)
- CPP Production Energy Related (100%)

[10] Exhibit REH-19A.

Applying these percentages to each individual cost component of residential retail rates and summing the results produces NRLP's calculated solar avoided cost rate (i.e., the solar benefit) of roughly 8.9 cents/kWh. This compares to a total residential retail rate of roughly 14.8 cents/kWh (i.e., the solar cost).[11] The proposed SSC is calculated by first multiplying the supposed benefit "deficit" by expected annual PV production to produce a revenue deficit amount ($/year). Next, NRLP translates that amount to the proposed SSC by dividing it by NRLP's estimate of PV AC nameplate capacity (kW) to produce a $/kW-month SSC. Specifically, the total net benefits deficit (after accounting for solar capacity contributions) is roughly $3,000/year, which is divided by a calculated, existing residential PV systems' nameplate capacity of 40.485 kW, and then divided by 12 months to produce the proposed SSC of $6.17/kW-month.[12]

**Q. Does NRLP assign any benefit component to avoided distribution costs?**

A. No. NRLP's calculations of solar benefits are confined to its wholesale energy supply and transmission costs.

**Q. Do you agree with any aspects of this calculation of NRLP's solar costs and benefits evaluation?**

A. Yes. Some aspects of the calculation are entirely appropriate. For instance, in general, assuming that customer-sited solar customers are able fully to

[11] Exhibit REH-19B.
[12] Exhibit REH-19A.

benefit at the retail rate from all production from their systems, the retail rate multiplied by solar production is appropriate for establishing the "cost" side of the cost-benefit equation. I also agree that it is appropriate to apply solar contribution percentages to individual cost sources in order to properly attribute cost avoidance driven by solar. Along these lines, the 100% factor applied to energy-related costs is reasonable, and in concept, it is also reasonable to apply capacity contribution percentages to those costs that are incurred based on different measures of monthly coincident peak demand.

**Q. What aspects of NRLP's methodology are erroneous?**

A. There are two primary deficiencies. First, it is not appropriate to use the volumetric retail rate as the "value" rate for demand-related costs. The retail rate is the rate at which a customer saves money, but it cannot be used to calculate a solar value rate because the volumetric retail rate is an <u>averaged cost</u> derived by dividing total costs ($) by total class usage (kWh). As a consequence, it does not reflect the actual cost of demand during the specific peak hours that cause NRLP to incur costs. Using it as NRLP does in the solar value calculation greatly understates the quantifiable benefits of customer-sited generation.

The solar value rate must instead be calculated by first dividing those same total costs ($) by the units of demand from which they are incurred to produce a demand unit cost ($/kW), adjusting that cost as necessary to reflect solar coincidence (%), and then dividing that amount by <u>total solar production</u> rather than class retail sales. Stated another way, the $/kWh retail rate is determined by class load factor, whereas the $/kWh solar value rate is determined by solar capacity factor. Those factors are invariably two different numbers. The relevant equations that produce both rates are specified in Table 1 below.

**Table 1: Components of Rate Calculations**

| **Class Retail Rate Components & Calculation** | |
|---|---|
| **Class Retail Rate ($/kWh)** | **Class Demand Cost ($) / Total Class Energy Sales (kWh)** |
| Total Demand Cost ($) | Wholesale Demand Cost ($/kW) X Total Peak Demand (kW). |
| Class Demand Cost ($) | Total Demand Cost ($) X (Class Peak Demand / Total Peak Demand). |
| **Solar Value Rate Components and Calculation** | |
| **Solar Value Rate ($/kWh)** | Class Demand Unit Cost ($/kW) / Solar Production (kWh) X Solar Coincidence Factor (%) |
| Class Demand Unit Cost ($/kW) | Class Demand Cost ($) / Class Peak Demand (kW). |
| Solar Coincidence Factor (%) | Derived by alignment of solar production with peak hours |

To be perfectly clear, this is an error in NRLP's calculation that is unrelated to any subjective judgment on how to conduct a value of solar evaluation. In that respect, it is the equivalent of a math error.

**Q. Please describe the second error in NRLP's analysis.**

A. NRLP fails to ascribe any avoided distribution capacity value to customer-sited PV generation. This is erroneous because all utilities have marginal distribution costs, and by definition, any marginal cost has the potential to be avoided because it has not yet been incurred. The simple fact that some costs have already been incurred, and as such are "embedded," does not change the fact that marginal costs invariably exist, and those future costs are avoidable. The full exclusion of this benefit component (i.e., assumed to be zero) artificially lowers the calculated benefit amount.

**Q. Can you further illustrate why NRLP's use of volumetric retail rates in its calculation of solar value is in error?**

A. Yes. One obvious implication of NRLP's methodology is that it caps the solar value rate at the class retail rate. For instance, under NRLP's method, the CPP Demand Related Component has an effective retail volumetric rate of $0.025459/kWh, which is derived by dividing the total revenue requirement for that cost ($1,578,131) by total class energy sales (61,988,218 kWh), and effectively spreads out the costs incurred by demand during peak periods across all customer usage. NRLP then calculates a solar value rate by multiplying that rate by a solar coincidence factor (26%) to produce its stated solar value rate of $0.006628/kWh for CPP Production Demand Costs. NRLP's algebraic calculations cannot produce a solar value rate that is higher than the class retail rate.

This is misaligned with how NRLP incurs CPP Production Demand Related costs and how a portion of those costs are assigned to a given class, which are both based on demand during 12 monthly peak hours. Critically, total annual class energy sales have nothing to do with either the incurrence of these costs, or their allocation to individual classes. In practice, the cost of a kWh used during one of the 12 monthly peak hours (the unit cost) based on the proposed residential class revenue requirement is $15.97, not $0.025459.[13] When applied across 12 months, the total demand unit cost ($/peak kW-year) is $191.66. That is, if a hypothetical 1 kW customer-sited resource was 100% effective at reducing demand during a monthly peak hour, the monetary value of that demand reduction is $15.97, and if it did so during every monthly peak hour, the value would be $191.66. NRLP's methodology dictates that the maximum value that a 1 kW customer-sited resource could produce over a year is $33.16.

**Q. Does NRLP employ a proper methodology for calculating the value of reductions in peak demand elsewhere in its general rate case application?**

A. Yes. NRLP did employ the correct unit cost-based methodology for assessing the value of demand reductions during peak hours in its design of a proposed Interruptible Rate. In that proposed rate, the compensation due to a participant customer that curtails load during a monthly peak hour is set at the $/kW unit cost rate plus an adder for line losses. This same methodology is appropriate to use in the context of calculating a customer-sited solar value rate for demand-related rate components.

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[13] Calculated based on REH-19A and REH-14. The wholesale cost is stated in terms of $/kW peak demand, but since it is based on an hourly measurement, it can also effectively be stated as a volumetric kWh rate. The annual demand unit cost in this case is $191.66/kW of average demand during the 12 monthly peak hours.

**Q. To be clear, is NRLP's miscalculation of the value solar provides reducing peak demand related to how one calculates the *effectiveness* of customer-sited solar at mitigating costs caused by peak demand?**

A. No. I used a "100% effective" assumption in the previous example for the purpose of simplicity. If a different solar effective capacity amount is used, the analysis in the previous example still applies, only it would result in lower dollar amounts.

**Q. Please elaborate on why NRLP's decision to exclude any solar value contribution for avoided distribution costs is in error.**

A. NRLP contends that its distribution costs are fixed in nature and uses that assertion as the basis for failing to include an avoided distribution capacity component in its solar value calculation.[14] While it is true that embedded costs that have already been incurred are fixed, that does not mean that no avoidable costs exist presently and into the future. All utilities have marginal distribution costs since the distribution grid is not static and new investments are continually being made. This is true regardless of whether a utility has conducted a marginal cost study, which NRLP has not.[15]

[14] Halley Direct at p. 48.
[15] NRLP response to AV 2-4.

**Q. Are avoided distribution capacity costs commonly considered as a benefit category in solar cost-benefit analyses?**

A. Yes. The resulting values often differ considerably from study to study depending on the characteristics of the individual utility system but their inclusion as a category of potentially avoidable costs is nearly universal.

**Q. Is there reason to believe that avoided distribution capacity could constitute a meaningful benefit attributable to customer-sited PV systems in NRLP's service territory?**

A. Yes, for two reasons. First, a solar production shape is fairly well-aligned with the timing of the NRLP monthly system peaks that are used to allocate distribution costs according to NRLP's attribution of distribution cost causation. I conducted two separate calculations of solar capacity contribution to distribution peaks, one based on the timing of the 12 monthly peaks NRLP used for its 2021 COSS, and one based on the AMI updated 2016 COSS that NRLP submitted to the Commission after the conclusion of its last rate case. For a rooftop-sited South-facing solar profile sourced from the National Renewable Energy Laboratory's (NREL) PVWatts Calculator,[16] the 2016 peaks produce an effective solar capacity contribution of 27.9% using an equal hour weighting, and 26.9% using a load-weighted average. For the 2021 COSS, the same system produces an

[16] *Solar Resource Data*, NREL, https://pvwatts.nrel.gov/pvwatts.php (last visited June 6, 2023).

effective solar capacity contribution of 32.7% using an equal hour weighting.[17]

Second, even though NRLP has not conducted a marginal distribution cost study, its embedded distribution costs can be known and are quite high. Based on NRLP's proposed residential revenue requirement, the embedded distribution unit costs are $227.37 per average peak kW-year. At an average distribution peak contribution of 30% and average solar production of roughly 1,300 kWh/kW, the solar benefit rate would be roughly 5.2 cents/kWh vs. a residential retail distribution rate of roughly 3.3 cents/kWh. I discuss the specific quantification of avoided costs using a corrected valuation methodology in Section II(D) of my testimony.

### C. NRLP's Study of Customer-Sited PV Capacity Contributions Relies on Incomplete Data and Inaccurate Assumptions

**Q. Please restate the problems that you have identified in NRLP's evaluation of customer-sited PV capacity contributions to different measures of coincident demand.**

A. The most significant problems are: (a) the sheer amount of missing production metering data in the sample that NRLP relies on, and (b) the method NRLP used to fill in missing hourly data, which is inconsistent with a solar production shape. There are also other oddities within certain other

[17] I did not conduct a load-weighted evaluation for the 2021 COSS because system load amounts were not provided in NRLP's COSS. The difference is almost certainly de minimis given the 2018 results.

aspects of NRLP's sample (e.g., monthly solar production shapes that are highly inconsistent with typical solar production shapes). The sources of those strange characteristics may be attributable at least in part to missing data.

**Q. How much data is missing from NRLP's solar production metering sample?**

A. In total, the sample shows zero values for 29.3% of total hours during the prime 9AM – 5PM solar production period, and 30.5% for the period from 8AM – 7PM. It is possible that some of the zero readings are valid zero production readings, especially for the hours around dawn and dusk. However, in many cases the zero readings exist between other non-zero readings when some level of solar production would be expected (even if minimal) during hours not on the solar production margin. Table 2 shows the zero reading amounts for each of the 15 customers in the dataset for the 9AM – 5 PM window.[18]

**Table 2: NRLP Solar Production Missing Hours (9AM - 5PM)**

| Customer | Missing # | Missing % |
|---|---|---|
| 1 | 1,459 | 50% |
| 2 | 900 | 31% |
| 3 | 244 | 8% |
| 4 | 1,543 | 53% |
| 5 | 1,125 | 39% |
| 6 | 260 | 9% |
| 7 | 1,145 | 39% |
| 8 | 252 | 9% |

[18] Developed using NRLP's response to AV 2-2, Attachment.

| | | |
|---|---|---|
| 9 | 2,252 | 77% |
| 10 | 1,329 | 46% |
| 11 | 327 | 11% |
| 12 | 232 | 8% |
| 13 | 393 | 13% |
| 14 | 281 | 10% |
| 15 | 1,103 | 38% |
| Total | 12,845 | 29% |

As shown in Table 2, the number of missing hours differ considerably by customer, with a few customers that have missing percentages of greater than 50% and a larger number with missing data well in excess of the average 29% threshold.

**Q. How are these missing hours distributed from the standpoint of how they affect NRLP's calculation of effective solar capacity according to different measures of monthly coincident peak demand?**

A. NRLP filled in estimated hourly solar production for roughly 18% of the monthly peaks associated with calculating the solar capacity percentage for DEC transmission peak hours and roughly 15% of the readings used to calculate the CPP production demand capacity contribution.[19] Given this, the missing data has the potential to meaningfully affect the results, to say nothing of the fact that the total amount of missing data raises reasonable questions about the basic reliability of the dataset.

[19] *Id.*

**Q. How did NRLP estimate solar production for the missing hours in its coincident peak contribution dataset?**

A. It averaged the difference between the last valid data reading before the interruption and first valid reading after the interruption over the intervening hours.[20] In effect, it assumed that the solar production profile was flat, or constant, during the missing hours.

**Q. Is this an accurate method for estimating solar system production for missing data?**

A. No. The level of accuracy progressively diminishes as the duration of missing readings lengthens because average hourly solar production varies along an upside down U-shaped curve centered on a peak at solar noon. On average, the average duration of missing data for the solar production amounts that NRLP estimated was 7 hours.[21] Over this duration, the accuracy of NRLP's estimation methodology could be exceedingly low as applied to individual hours.

**Q. What are your conclusions regarding the validity of NRLP's solar capacity contribution evaluation?**

A. The amount of missing data and the potential impacts that this missing data could have on the results raise serious questions about its validity. As a result, the proposed SSC for Schedule NBR, which relies in large part on

[20] NRLP response to AV 5-3, Attachment.
[21] *Id.*

the solar capacity contribution evaluation, rests on insufficient evidence and should not be adopted.

### D. A Corrected Evaluation of Customer-Sited PV Benefits Produces a Value Approximately Equal to the Retail Rate

**Q. Please explain your analysis of solar benefits, including the corrections that you have made to NRLP's methodology.**

A. There are two primary elements to my evaluation. First, in all of my calculations, I corrected the error that I previously discussed in NRLP's solar value equation to use residential class unit costs rather than residential class volumetric retail rates as inputs for calculating demand-related benefits of customer-sited PV.

Second, I analyzed the solar contribution to peak under five different scenarios in order to present a complete picture representative of the likely range of capacity contributions based on typical customer-sited solar orientation. To correct for the missing data underlying NRLP's analysis, I developed three analyses based on projected solar production data, for rooftop-sited systems oriented on a South, Southwest, and Southeast azimuth, respectively. I used these three system orientations to reflect the fact that site limitations sometimes preclude the "due South orientation" that is optimal for customers (i.e., maximizes energy production) and the fact that the capacity contribution amounts rely on hypothetical average production shapes rather than metered production data from actual installations.

I also conducted two analyses that rely on NRLP's solar peak analysis despite the insufficiency of NRLP's solar production data, in order to provide an apples-to-apples comparison to NRLP's analysis that should help the Commission assess the results of the three more accurate scenarios just discussed. In one, I simply applied the same solar capacity contribution methodology that NRLP used, arriving at a different result solely as a result of the solar value calculation methodology correction described above. In the second, I also corrected how nameplate AC capacity is calculated in NRLP's analysis, by relying on the sum of maximum single hour production from sampled systems, rather than the maximum coincident production of the system sample.

The results of each of these five analyses support the same conclusion: solar value is approximately equal to the retail rate.

**Q. Please explain how you estimated the avoided distribution capacity benefits of customer-sited solar, given that NRLP did not address this benefit component.**

A. As with other system costs, I used NRLP's proposed residential revenue requirement for NRLP Distribution and the monthly average residential class peak demand used to allocate those costs to calculate $/kW unit costs. That is, the cost of distribution capacity is based on NRLP's embedded distribution costs rather than marginal distribution costs because NRLP's marginal distribution costs are not known.

I then calculated the solar capacity contribution percentage based on the relevant solar production profiles and the monthly peak hours identified in NRLP's 2021 COSS and its AMI updated 2016 COSS. This is conceptually the same as NRLP's methodology for calculating solar capacity contributions for demand-related costs. The specific capacity contribution multiplier I used is the average of the values based on the two COSSs. The solar value rate was calculated using the annual energy production from each solar production profile.

**Q. What are the results of the analysis that you have conducted on the value of customer-sited PV in NRLP's service territory?**

A. The resulting customer-sited solar values, as stated in terms of $/kWh of solar production, are considerably higher than NRLP's estimates. The principal reason for these differences is the correction of the solar value equation that I have previously described. With the exception of one scenario, my analysis actually uses lower solar capacity contributions than those used by NRLP in its evaluation in order to correct an error in NRLP's analysis related to its calculation of aggregate existing solar nameplate capacity. Nevertheless, the resulting solar values are higher due to the correction I made to the basic solar value equation. Table 3 shows the ultimate results of my analysis for each of the five scenarios. Further details of the calculation for each scenario are contained in Exhibit JRB-2 and my attached workpapers.

**Table 3: Customer-Sited PV Value by Capacity Contribution Scenario**

| Metric | South Facing | Southwest Facing | Southeast Facing | NRLP | Corrected NRLP |
|---|---|---|---|---|---|
| Solar Value Rate ($/kWh) | $0.12269 | $0.12821 | $0.11760 | $0.13707 | $0.11922 |
| Solar Value % of Retail Rate | 82.6% | 86.3% | 79.2% | 92.3% | 80.2% |
| Deficit From Retail Rate ($/kWh) | ($0.02580) | ($0.02028) | ($0.03090) | ($0.01142) | ($0.02928) |
| **Values above assign a zero value for avoided distribution costs** | | | | | |
| Estimated Avoided Distribution Cost Rate ($/kWh) | $0.05201 | $0.04941 | $0.05352 | $0.05201 | $0.05201 |
| Solar Value Including Distribution ($/kWh)[22] | $0.17470 | $0.17763 | $0.17111 | $0.18908 | $0.17122 |
| Solar Value % of Retail Rate | 117.6% | 119.6% | 115.2% | 127.3% | 115.3% |

**Q. Based on your analysis, what can the Commission conclude about the value of customer-sited PV generation in NRLP's service territory?**

A. According to my analyses, the value of customer-sited PV generation exceeds the residential retail rate by 15% or more when avoided distribution costs based on embedded costs are used in the calculation. Furthermore, the relative value stated in terms of the percentage of retail rate would reach 100% even if marginal distribution costs are steeply discounted relative to

[22] For the purpose of calculating avoided distribution capacity costs included in the two furthest right columns, I used the value from the South-facing production profile due to my concerns about the reliability of NRLP's production meter data.

embedded distribution costs. Retail NEM without NRLP's proposed SSC is justified from the standpoint of cost causation.

## E. Schedule NBR Should Offer Retail NEM With Indefinite Carryover and No Standby Charge

**Q. What are your recommendations to the Commission regarding NRLP's proposed Schedule NBR?**

A. The Commission should approve the establishment of Schedule NBR with the following changes. First, Schedule NBR should not include the proposed SSC component. As I have demonstrated, after correcting for NRLP's solar value methodological errors, the value of customer-sited PV generation is greater than the residential retail rate, and therefore adopting Retail NEM would not result in any cross-subsidization from non-participant customers or NRLP.

Second, Schedule NBR should include a provision allowing for indefinite rollover of monthly energy credits for excess generation, rather than the proposed annual calendar year account reset. This change is sound policy because it is necessary to allow customers to fully offset their annual on-site consumption with customer-sited PV and benefit from that on-site energy production, which is consistent with state policy favoring the entire spectrum of demand-side options. The purpose of self-generation is to offset a customer's on-site energy needs and any limitations on that objective should be reasoned and justified rather than arbitrary.

It is justified from a ratemaking and cost-causation standpoint because my solar value analysis indicates that such a compensation "haircut" is neither necessary nor justified as a measure to mitigate cross-subsidies. It also retains and sends an implicit signal to customers that discourages oversizing by preventing a customer from benefitting from consistent excess production beyond their annual energy needs, since those credits would become "stranded" and could never redeemed by the customer.

**Q. Is there any risk of cost-shifting associated with the application of Schedule NBR to non-residential rate classes?**

A. Not really. Using the Commercial General rate class inputs, the solar value is 102% of the sum of non-distribution cost components and 79% of the total retail rate, without consideration of any avoided distribution costs. Adjusting both of those values to include avoided distribution capacity would produce results similar to my residential evaluation, since the solar contribution to system-wide distribution peaks would not change. Since the Commercial Demand rate class features demand rate components that solar customers would not be able to avoid, and correspondingly lower volumetric rates (i.e., a lower cost of customer-sited generation in terms of solar customer savings), the potential risk of subsidization of customer-generators within that rate class is even lower.

**Q. Is it necessary that a DG tariff design for NRLP customers entirely eliminate the potential for cross-subsidization?**

A. No. As a practical matter doing so is impossible because there are unavoidable uncertainties involved, and cost attribution is inherently an exercise in approximation. Therefore, an approximate solution is sufficient and reasonable.

### F. Schedule PPR Is Punitive and Suboptimal

**Q. Please describe proposed Schedule PPR.**

A. Proposed Schedule PPR, or "Purchased Power from Renewable Energy Facilities (a.k.a. Buy All/ Sell All)," is a separate NRLP tariff available to all customers who operate qualifying, behind the meter solar generation. In contrast to Schedule NBR, customers participating in Schedule PPR would effectively be prohibited from using their solar systems' output to offset their energy bills. Instead, participating customers would be required to buy all their power from NRLP at the relevant retail rate[23] and sell all their solar output to NRLP, for which they would receive $0.089039 per kWh per month in energy credits as compensation.[24] The AC capacity for qualifying systems could not be designed to exceed 1,000 kW and would need to operate parallel with NRLP's distribution system.[25] In addition, qualifying

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[23] ASU, along with other participating customers, would pay the retail rate that applied to its customer class. *See generally* NRLP responses to AV DR 6-1, 6-3 (summarizing the current buy all, sell all riders and describing differences in the proposed buy all, sell all rider established under schedule PPR).
[24] Application, Ex. B at 27.
[25] NRLP response to AV DR 6-6.

systems must be "manufactured, installed, and operated in accordance with all applicable government regulatory and industry standards and must fully conform with . . . NRLP's applicable interconnection standards."[26]

**Q. Who may enroll in Schedule PPR?**

A. Witness Halley states that although NRLP has proposed its net billing rate schedule, Schedule NBR, NRLP will "continue to offer the existing buy all / sell all option to purchase renewable energy at its avoided cost rate from its customers."[27] According to Exhibit B to NRLP's Application, Schedule PPR is available to "Sellers who operate a photovoltaic (PV) generation energy source in parallel with New River Light and Power Company's (NRLP) system."[28] According to NRLP's responses to discovery requests, Schedule PPR would replace existing schedules SPP Demand, SPP No Demand and SPP Fixed (existing buy all/sell all).[29] NRLP has four rate schedules, R (Residential Service), G (Commercial General Service), GL (Commercial Demand Service), and A (for ASU).[30] Accordingly, Schedule

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[26] Application, Ex. B at 27.
[27] Halley Direct at p.3.
[28] Application, Ex. B at 27.
[29] NRLP response to AV DR 6-3. However, NRLP's filings in the most recent avoided cost proceeding suggest that these rate schedules would continue to be offered to Public Utility Regulatory Policies Act ("PURPA") qualifying facilities ("QFs") that are not eligible for Schedule NBR or Schedule PPR; if that is not the case, it is not clear what rate schedule NRLP would use for a QF. New River Light & Power's Compliance Filing of Rates and Contracts, *Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2021*, Docket No. E-100, Sub 175 (N.C.U.C. Dec. 5, 2022).
[30] NRLP response to AV DR 6-5. NRLP has proposed to close schedule GLH, which currently has no existing customers. NRLP response to AV DR 6-6.

PPR would be available to customers on each of these rate schedules, in place of the existing buy-all-sell-all schedules.

I will also mention that there could be some customers for whom Schedule PPR would appear to be the only option. Schedule NBR is available to customers on Rate Schedules R, G and GL who operate solar PV systems for their own use, in parallel with NRLP's system, but the solar PV array must "not be designed to exceed the Customer's anticipated annual peak kilowatt demand or 20 kilowatts (kW) for a residential system or 1,000 kW for a non-residential system, whichever is less."[31] Accordingly, Schedule PPR would be the only option for ASU and for residential customers with system sizes larger than the caps described above. In addition, because both Schedule NBR and Schedule PPR apply only to solar PV systems, there does not appear to be a schedule proposed for other types of renewable energy resources or for facilities over 1,000 kW, except for Schedules SPP Demand, SPP No Demand, and SPP Fixed, filed in the most recent avoided cost proceeding (Docket No. E-100, Sub 175). These schedules contain a compensation formula but are unclear about the rate charged for electricity consumed and the customer-generator's right to self-consume. Although customer deployment of other forms of renewable energy resources might be relatively unlikely, I will note that ASU currently

[31] Application, Ex. B at 24.

operates a wind turbine, which appears to be compensated outside the buy-all-sell-all construct.[32]

**Q. What concerns do you have with Proposed Schedule PPR?**

A. I am concerned that Schedule PPR would perpetuate a billing structure that does not allow customer-generators to consume the energy they generate on-site, could be confusing to prospective DG customers, and relies on a valuation methodology that I have shown to be inaccurate. NRLP's proposed Schedule NBR, modified to correct the problems I identify, will be a major step forward from NRLP's existing buy-all-sell-all schedules so I see no good reason to maintain a buy-all-sell-all schedule in addition to Schedule NBR. To the extent that NRLP might intend Schedule PPR as a deterrent to retail rate customers who might otherwise be inclined to "oversize" their solar systems above the cap set by Schedule NBR, there are more effective ways of accomplishing that objective, such as imposing a cost-based charge on over-sized solar systems if those larger systems impose additional, unnecessary costs on the utility.

[32] NRLP response to AV DR 6-1.

# III. Residential BFC

## A. Summary of NRLP Proposal and the Summarized Response

**Q. What is NRLP's proposal for the residential BFC?**

A. NRLP proposes to increase the residential BFC from $12.58/month to $14.50/month, an increase of $1.92 (15.3%).[33]

**Q. How does NRLP justify the amount of its proposed residential BFC?**

A. The specific amount of $14.50/month is not based on a particular calculation or methodology. Rather, NRLP simply states that it is less than its residential fixed costs of $36.00/month.[34] The $36.00/month amount that NRLP quotes is based on the entirety of its proposed distribution revenue requirement for the residential class, as translated into $/customer-month.

**Q. Is NRLP's proposed residential BFC cost-based?**

A. No. The specific proposed amount is arbitrary, and in fact is higher than the customer-related unit cost indicated by its COSS, which is $13.86/month.

**Q. Please explain why NRLP's "fixed" cost of $36.00/month for residential customers is an inappropriate benchmark for consideration of the residential BFC.**

A. The costs of NRLP's shared distribution system upstream of a customer's service drop are caused by customer demands, not the number of customers on the system. This is properly reflected in NRLP's COSS. It is

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[33] Halley Direct at p. 44.
[34] *Id.*

irrelevant that those demand-related costs are embedded and therefore "fixed". Designing a residential BFC on the basis of a utility's embedded costs irrespective of the cost causation factor associated with those costs is not and has never been an accepted rate design methodology.

**Q. Please describe a more proper basis for setting the residential BFC.**

A. In order to reflect cost-causation, the BFC should be limited to those costs that are incurred based on the number of customers. There are different schools of thought on how the amount of such customer-related costs should be determined. One widely accepted methodology, often termed the Basic Customer Method, limits residential fixed charges to costs associated with meters and service drops (utility return plus O&M expenses), meter reading expenses, and customer billing expenses. This simple method of isolating customer-related costs is based on the general rationale that customer-specific costs are those costs caused by adding an incremental customer to the system, which generally involves the installation of a meter and service drop, and incremental metering and billing expenses. The primary attraction of this method is that it can be viewed as reflecting the *marginal costs* attributable to customer numbers, which is an important consideration in rate design.

Another method of determining customer-related costs that should be included in the residential BFC is to rely on the cost allocation and classification regime in a utility's cost of service study, such that customer-related costs are defined as those costs that are allocated to individual rate classes based on the number of customers in a class, and potentially a portion of more general utility costs to which one might attribute a customer-related component (e.g., a portion of general overhead costs that cannot be attributed to a specific utility function, or a portion of uncollectibles expense). This may produce a result that is identical to the Basic Customer Method or a different amount. The $13.86/month amount I noted above is based on the amounts that NRLP classifies as customer-related costs in its COSS, which is composed of all the costs that are allocated on the basis of customer numbers and certain others that are allocated based on certain revenue allocators that it represents are tied to customers. The primary attraction of this method is that it aligns the determination of the fixed charge with the cost causation factors accepted in the COSS.

**Q. Are there other factors that should be considered in rate design beyond such cost-based calculations?**

A. Yes. In practice, and as with all ratemaking decisions, the ultimate determination of an appropriate residential BFC should also consider other generally accepted ratemaking principles, such as gradualism, economic efficiency, utility revenue sufficiency, and avoiding wasteful use of service. The specific calculations described above are useful guideposts with respect to cost-causation, but it is often the case that they are not used in a fully determinative fashion given the need to balance multiple competing objectives. In other words, a certain amount of qualitative judgment is required.

In consideration of those factors, I made a third calculation that uses AV Witness Hoyle's conclusions on a proper capital structure and applies the associated reduction in class revenue requirements exclusively towards reducing the fixed charge. This approach is consistent with creating incentives for energy efficiency improvements by improving the opportunities for customers to substantially reduce their bills and ensures that the revenue requirement reductions will benefit all customers equally, and not create a windfall for high users of electricity. The results of this calculation for the residential and commercial non-demand classes are shown in Table 4 below.

**Table 4: Allocation of Revenue Requirement Reduction to BFCs**

| | Reduction in Revenue Requirement ($) | Reduction Revenue Requirement Per Customer Month ($) | Old Customer Charge ($/month) | New Customer Charge ($/month) |
|---|---|---|---|---|
| **Residential** | $151,983 | $1.77 | $12.58 | $10.81 |
| **Commercial Non-Demand** | $61,427 | $3.49 | $17.42 | $13.93 |

**Q. How do you suggest that the Commission achieve this balance of competing objectives in this case?**

A. In sections III(B) and III(C) of my testimony, I present calculations for a residential BFC based on NRLP's COSS, with certain modifications, and the Basic Customer Method. I recommend that the Commission consider those calculations as useful guideposts with due consideration given to other ratemaking objectives. With regards to those other ratemaking objectives, it is also relevant for the Commission to consider that: (1) the residential BFC was doubled in NRLP's last rate case from $6.29/month to its present level of $12.58/month, and (2) increases in fixed charges reduce customers' ability to reduce bills through energy efficiency investments, and because NRLP does not currently offer any significant DSM programs, the retail rate price signal is the sole incentive for customer investments in energy efficiency measures.

### B. Calculation of a Residential BFC Using NRLP's Methodology With Limited Adjustments

**Q. Please describe your objective in presenting a residential customer-related unit cost calculation based on NRLP's COSS.**

A. My objective in preparing this calculation was to preserve NRLP's general methods of attributing cost causation through the cost allocation structure in its COSS, but more accurately reflect the classification of costs in order to render the result more useful as a data point for setting the residential BFC. To that end, I retained the bulk of NRLP's classification regime and only modified the portions that are clearly erroneous. My adjustments are confined to issues of cost classification as they pertain to calculating the residential BFC rather than cost allocation or revenue requirements.

**Q. Please summarize how customer-related costs are calculated in NRLP's COSS.**

A. Table 5 shows the individual cost components that NRLP classifies as customer-related in its COSS, along with the cost allocation method and their relative contributions to the $13.86/month amount I previously noted.[35]

**Table 5: Customer-Related Classification in COSS**

| Line Ref. | Cost Type | $/Month | Allocation Method |
|---|---|---|---|
| 1 | Other Operating Income[36] | -$1.09 | Total Revenue Excluding Lighting |
| 2 | Expense Job & Contract ASU | $0.84 | Total Revenue Excluding Lighting |
| 3 | Meter Expense | $0.44 | Weighted Customer Without Lighting |
| 4 | Customer Install Expense | $0.25 | Weighted Customer Without Lighting |
| 5 | Maintenance Street Lights | $0.00 | N/A |
| 6 | Maintenance-Meters | $0.66 | Weighted Customer Without Lighting |
| 7 | Supervision Customer Accounts | $0.39 | Weighted Customer With Lighting |
| 8 | Meter Reading Expense | $0.01 | Customers Excluding Lighting |
| 9 | Customer Records & Collections | $6.12 | Weighted Customer With Lighting |
| 10 | Administration & Other | $4.23 | Total O&M Excluding Purchased Power |
| 11 | Interest Expense Consumer Deposits | $0.05 | Total Revenue |
| 12 | Uncollectible Accounts | $0.27 | Total Revenue Excluding ASU |
| 13 | Regulatory Commission Expense | $0.15 | Total Revenue |
| 14 | Unrelated Business Income Tax | $1.54 | Total Revenue |
| **15** | **TOTAL** | **$13.86** | |

[35] Based on REH-14 and NRLP response to AV 1-16.

[36] NRLP's COSS includes a customer-related component for non-rate additional revenue, which produces an effective negative amount applied towards customer-related costs.

With the exception of line 10 for “Administration & Other” costs, each line item in Table 3 is classified as exclusively customer-related, including those that are allocated based on some measure of revenue. For the “Administration & Other” category, the customer-related portion corresponds to the portion of total O&M excluding purchased power that is classified as customer-related.

As illustrated in Table 5, the vast majority of customer-related costs in the COSS are for Customer Records and Collections (44.2%), general administration (30.5%) and Income Tax (11.1%), which collectively total 85.8% of customer-related costs.

**Q. As it relates to calculating a reasonable residential BFC, do you agree with the customer-related classification regime that NRLP employs in its COSS?**

A. No. First, my primary disagreement is that NRLP attributes the entirety of the costs that are allocated using a revenue factor as customer-related. This is not appropriate because revenue from the fixed monthly customer charge accounts for only a portion of the revenue received from a customer class. Therefore, only a portion of a cost that is allocated based on revenue should be considered customer-related. For instance, only a portion of NRLP’s Unrelated Business Income Tax arises due to customer charges, nor are uncollectible expenses comprised exclusively of foregone collections of the fixed customer charge.

Second, I also disagree that expenses for Customer Installations should be considered customer-related. In general, customer installations expenses refer to activities the utility undertakes behind the meter for individual customers. Therefore they are not costs associated with connecting an additional customer to the system or billing that additional customer, nor do they necessarily have a direct relationship to the number of customers on the system.

Third, I disagree with the way NRLP handles expenses and revenue from ASU contracts. As shown in Table 5 NRLP applies a symmetrical classification of ASU contract expenses (Line 2) and the revenue from those activities (included in Line 1 as Other Operating Income), which is intended to fully cover those expenses. However, in the COSS, the ASU contract revenues fall well short of expenses due to timing differences in the incurrence of costs and when the associated revenue is received.[37] That is, a cost incurred during the last month of the test year would not be invoiced until after the test year, resulting in the cost being included in the test year but not the offsetting revenue. For that reason, the COSS produces an implied net “cost” for ASU contracts which equates to $0.28/customer-month for the residential class. In reality there is no such “cost” because the offsetting revenues will eventually be received and the “cost” is simply an

[37] NRLP response to AV 6-12.

artifact of timing differences between the recognition of expenses and revenues.

Finally, although it is true that it is commonplace for the Customer Records and Collections to be considered exclusively customer-related, NRLP's costs in this area appear to be considerably disconnected from customer numbers. I discuss this matter in further detail in Section III(D) of my testimony.

**Q. Does NRLP offer an explanation as to why it considers the costs that are allocated based on a revenue factor as exclusively customer-related?**

A. In response to data requests regarding the classification of Uncollectable and Regulatory Commission expenses, NRLP stated the following:

> Uncollectible Accounts are expenses NRLP incurs from customers not paying their bills. Therefore, this expense is customer related.[38]
>
> Regulatory Commission Expense is an expense incurred by NRLP for the oversight provided by the North Carolina Utilities Commission for the benefit of NRLP customers. Therefore, this expense is customer related.[39]

Neither of these statements meaningfully explains the cost-causation basis for considering these costs exclusively customer-related. Any given

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[38] NRLP response to AV 3-10(d).
[39] NRLP response to AV 3-10(e).

cost NRLP incurs could be explained as arising from the activities that NRLP undertakes to serve customers.

**Q. What is your calculation of residential customer-related costs using NRLP's COSS as a base, but incorporating other adjustments?**

A. I calculated a residential customer-related unit cost of $11.49/month. This amount is calculated by making the following adjustments to the line items listed in Table 3:

1. Adjust revenue-allocated line items based on the percentage of residential class revenue that is associated with the residential BFC (11.4%), such that each revenue-allocated line item is reduced to 11.4% of the amounts in NRLP's COSS.
2. Eliminate the customer installation costs classification as customer-related.
3. Exclude ASU Contract Expense as a customer-related line item, and symmetrically exclude ASU Contract Revenue from Other Operating Income.
4. Recalculate the customer-related percentage of Administration & Other costs to reflect the above changes.

Table 6 shows the calculated results from these adjustments. Exhibit JRB-3 and my workpapers show further details of the calculations supporting Table 4.

**Table 6: Adjusted Customer-Related Classification in COSS**

| Line Ref. | Cost Type | $/Month |
|---|---|---|
| 1 | Other Operating Income | -$0.06 |
| 2 | Expense Job & Contract ASU | $0.00 |
| 3 | Meter Expense | $0.44 |
| 4 | Customer Install Expense | $0.00 |
| 5 | Maintenance Street Lights | $0.00 |
| 6 | Maintenance-Meters | $0.66 |
| 7 | Supervision Customer Accounts | $0.39 |
| 8 | Meter Reading Expense | $0.01 |
| 9 | Customer Records & Collections | $6.12 |
| 10 | Administration & Other | $3.70 |
| 11 | Interest Expense Consumer Deposits | $0.01 |
| 12 | Uncollectible Accounts | $0.03 |
| 13 | Regulatory Commission Expense | $0.02 |
| 14 | Unrelated Business Income Tax | $0.17 |
| **15** | **TOTAL** | **$11.49** |

**Q. Do you have any further observations regarding the modified BFC shown in Table 4?**

A. Yes. My calculation does not make any adjustment to the classification or associated costs for Customer Records and Collection expenses, despite the questionable cost causation basis for these costs that I describe in Section III(D) of my testimony. Nor does it adjust the customer-related classification methodology for General and Administration expenses despite the fact that this general category of costs includes line items for things like consulting expenses, institutional advertising, and injury and damage expenses that have no readily identifiable relationship to customer numbers. Accordingly, my calculation represents an improvement over

NRLP's but likely still overstates the costs that truly vary based on customer numbers and the marginal costs associated with adding a customer to NRLP's system.

### C. Calculation of a Residential BFC Using the Basic Customer Method

**Q. Please describe your purpose in presenting a residential customer-related unit cost calculation based on the Basic Customer Method.**

A. My objective in presenting this calculation is to provide the Commission with a valuable point of comparison for the BFC calculated using NRLP's methodology. The Basic Customer Method of deriving a residential BFC is commonly accepted throughout the nation, and is arguably the single most common method of doing so. I believe my Basic Customer Method analysis will be particularly useful for the Commission's consideration because NRLP's COSS does not readily allow such a calculation, as its calculated customer-related costs do not include ownership costs and depreciation for meters and customer service drops.

**Q. Please summarize the results of your calculation of a residential BFC using the Basic Customer Method.**

A. Table 7 shows the summation of revenue requirements and the contribution each makes to the residential BFC, leading to a total monthly residential cost of $10.61/month, or $10.38/month if certain revenue-allocated expenses (the Other Expenses line in Table 5) are excluded.

**Table 7: Residential BFC - Basic Customer Method**

| **Rate Base Items** | **Revenue Requirement** | **$/month charge** |
|---|---|---|
| Meters | $78,839 | $0.92 |
| Services | $16,614 | $0.19 |
| *SUBTOTAL* | *$95,453* | *$1.11* |
| **Depreciation Expense** | **Revenue Requirement** | **$/month charge** |
| Depreciation (Meters) | $94,978 | $1.11 |
| Depreciation (Services) | $46,150 | $0.54 |
| *SUBTOTAL* | *$141,128* | *$1.65* |
| **O&M Expenses** | **Revenue Requirement** | **$/month charge** |
| Meter Expense | $37,407 | $0.44 |
| Maintenance-Meters | $56,916 | $0.66 |
| Meter Reading Expense | $583 | $0.01 |
| Supervision Customer Accounts | $33,553 | $0.39 |
| Customer Records & Collections | $524,748 | $6.12 |
| *SUBTOTAL* | *$653,207* | *$7.62* |
| **Other Expenses** | **Revenue Requirement** | **$/month charge** |
| Interest Expense Consumer Deposits | $531 | $0.01 |
| Uncollectible Accounts | $2,601 | $0.03 |
| Regulatory Commission Expense | $1,447 | $0.02 |
| Unrelated Business Income Tax | $14,964 | $0.17 |
| *SUBTOTAL* | *$19,544* | *$0.23* |
| **TOTAL** | **$909,332** | **$10.61** |
| **TOTAL Excluding Other Expenses** | **$889,788** | **$10.38** |

**Q. Please describe the relevant methodology and assumptions that you used in your calculation.**

A. The full derivation can be viewed in Exhibit JRB-4 and my associated workpapers, but the basic assumptions I used are as follows:

- System-wide net plant in service (i.e., rate base) and depreciation amounts were sourced from NRLP's Schedule 6 filing.
- The residential allocation of net meter and service drop net plant was based on total customers (80.4%).
- The utility return on net plant is based on the weighted cost of capital calculated by AV Witness Hoyle (5.39% vs. NRLP's proposed rate of 7.007%).
- The customer-related portion of revenue-allocated expenses (including income taxes) assigns a customer-related portion to the residential allocation based on residential BFC revenue vs. total residential revenue (i.e., the 11.4% proration that I previously discussed).

**Q. Do you have any further comments regarding your Basic Customer Method calculation of the residential BFC?**

A. Yes, notwithstanding the questions I raise regarding the exclusive classification of customer records and collections expenses described in Section III(D) of my testimony, I have not made any downward adjustment to those amounts in my calculation. In addition, my calculation includes the full cost of NRLP's AMI meters as customer-related costs despite the fact that AMI has a multitude of purposes that relate to the broader operation of the utility system (i.e., demand- and energy-related functions) as opposed to the basic function of measuring customer usage. Consequently, my Basic

Customer Method calculation implicitly overstates the true amount of customer-related costs.

### D. NRLP Data Indicates that Costs for Customer Records and Collections Does Not Vary Based on Customer Numbers

**Q. How do you recommend that the Commission address the matter of classification of records and collections expenses as it relates to the residential BFC?**

A. To be clear, neither of my BFC derivations makes any adjustment to the classification of records and collections expenses as customer-related. Both include the full amount of $6.12/month within the calculated residential BFC. However, I recommend that the Commission consider the issue of whether customer records and collection expenses are *exclusively* customer-related as it weighs the full suite of rate design objectives given the difficulties associated with isolating the cost causation attributes of the different aspects of increasingly complex customer management and billing systems.

**Q. Please summarize the types of costs that the general category of Customer Records and Collections includes.**

A. Customer Records and Collections basically encompasses the costs associated with billing customers and collecting revenues, including employee labor costs associated with preparing bills, postage, and credit card or banking fees.

**Q. Is there a rationale for considering such costs to be exclusively customer-related?**

A. Billing of course is an activity that relates to all utility functions insofar as the core purpose is to collect on costs incurred for utility service as a whole, which encompass the provision of energy supply, transmission, and distribution service. Nevertheless, the billing function has traditionally been classified as exclusively customer-related because it is necessary regardless of the amount of a customer's use of the system, and because there is a plausible connection between customer numbers and the costs associated with printing and delivering bills on a monthly basis to each customer, and processing the resulting receipts from those customers. For those reasons, to my knowledge, the classification of billing and collection costs as customer-related has not typically been a matter of significant controversy.

However, there are reasons to question whether that blanket rationale still holds true in a modernized utility system due to the fact that modern billing processes are highly automated and less dependent on manual intervention, modern systems often feature capabilities that extend well beyond the core function of basic billing and collection activities. Such capabilities may include offering different customer billing options, the ability to offer additional services based on the use of AMI systems, and other advanced customer systems that depart from the basic minimum requirements for billing customers. It is reasonable for cost causation purposes for the classification of certain utility system operations to evolve in line with the evolution of the characteristics of these operations.

**Q. Is there any evidence in the instant case indicating that NRLP's records and collection expenses are not exclusively attributable to the number of customers it serves?**

A. Yes. On a system-wide basis, NRLP's records and collection expenses increased from roughly $471,173 in its 2016 COSS to $779,344 in its 2021 COSS, an increase of $308,171 (65%). Over the same period, the number of customers that NRLP serves increased by only 10.1%, from 8,148 to 8,972.[40] The fact that the increase in expenses and increase in customers are dramatically different certainly suggests that there are important factors other than customer numbers that are driving records and collection costs.

**Q. To what factors does NRLP attribute the increases in records and collections costs?**

A. NRLP attributes the increase in expenses in this account to new billing software and payroll increases and the offering of new "automated services" such as pre-paid service, and potential future TOU rate offerings. It maintains that the costs should be considered customer-related on the basis that they have a direct correlation to the cost of providing billing to customers.[41]

[40] Exhibit REH-14.
[41] NRLP response to AV 5-6.

**Q. Is this explanation sufficient to explain why the customer records and collections expenses should continue to be considered exclusively customer-related?**

A. No. It fails to offer any explanation as to why those costs vary in relation to customer numbers, which is belied by the statistics that I previously cited. That is, it fails to address why billing activities themselves should be considered exclusively customer-related. After all, the need for billing is a consequence of the provision of all utility services so in itself it has no exclusive customer-related characteristic. Rather, the traditional classification of billing costs as customer-related derived from the premise that billing costs vary directly in relation to customer numbers. NRLP's billing expenses, or at least the recent increases, do not appear to have such a linear or direct relationship to customer numbers. In this regard, I am not saying that there is no such relationship, but rather that the relationship does not appear to be exclusive.

**Q. How does the increase in customer records and collection expenses affect the residential customer-related unit costs indicated by NRLP's COSS?**

A. The 2016 COSS produced a residential monthly customer cost of $4.82/month for these expenses, whereas the 2021 COSS produces a monthly cost of $6.12/month, a difference of $1.30/month.[42] One way to look at this is that the increase in these costs constitutes 68% of NRLP's proposed increase in the residential BFC.

### E. The Residential BFC Should Be Reduced

**Q. Please summarize the results of the different analyses you have identified for setting the residential BFC.**

A. Table 8 shows four different calculations based on the information presented by NRLP, my own calculations, and those of AV Witness Hoyle, as compared to NRLP's proposal.

**Table 8: Summary of Residential BFC Calculations**

| Residential BFC Calculation Basis | Amount ($/customer-month) | Methodology Description |
|---|---|---|
| NRLP Proposed | $14.50 | Specific amount proposed is arbitrary |
| NRLP COSS – Uncorrected | $13.86 | Full amount of customer-related costs from NRLP COSS |
| NRLP COSS – Corrected | $11.49 | NRLP COSS with certain exclusions and revised customer classification of revenue-allocated costs |
| Basic Customer Method | $10.61 | Limited to costs that vary directly to the number of residential customers |
| Corrected Revenue & Allocation | $10.81 | Application of calculated, reduced class revenue requirement to reduce the residential BFC |

**Q. What is your recommendation for setting the specific level of the residential BFC?**

A. The Commission would be justified in reducing the residential BFC by roughly $2.00/month for reasons of cost causation. There is a compelling

[42] Exhibit REH-14. The residential allocation of customer records and expenses increased by roughly $167,000, which translates to an increase of $1.95/month using current residential customer numbers. This differs from the $1.30/month amount quoted above due to the change in the number of residential customers between the last rate case and the instant proceeding.

argument for such an approach given my analysis of customer-related costs and the fact that NRLP does not presently offer any meaningful DSM programs, leaving the underlying rate structure as the sole source for such incentives.

Furthermore, it is important to consider that my calculations using two alternative methods of calculating a residential BFC were intentionally crafted to be inclusive rather than exclusive in terms of incorporating certain cost categories. For instance, they both maintain customer records and collections expenses as exclusively customer-related, and do not exclude or adjust for other items of questionable inclusion, such as AMI metering as exclusively customer-related, or in the case of the COSS-based method, the imputed customer-related components for general and administrative costs such as institutional advertising or consulting services. In consideration of all of these factors, my view is that the maximum cost-based residential BFC is $10.61/month, consistent with my calculations based on the Basic Customer Method.

## IV. Concluding Remarks and Summarized Recommendations

**Q. Please summarize your recommendations to the Commission regarding NRLP's proposed Schedules NBR and PPR and the reasons for those recommendations.**

A. The Commission should direct NRLP to modify Schedule NBR to: (a) eliminate the SSC component, and (b) and allow indefinite rollover of customer credits for excess energy in place of the proposed calendar year account reset. Both changes are appropriate in light of my analysis of the relative costs and benefits of customer-sited PV in NRLP's service territory, which indicates that Schedule NBR as a retail NEM tariff without any additional charges would provide appropriate, non-discriminatory compensation to participant customers and not create any meaningful cross-subsidies.

I further recommend that the Commission decline to approve NRLP's proposal to establish Schedule PPR because Schedule NBR, with my recommended changes, offers a more suitable structure for a largely common set of eligible customers and its existence as an alternative option could be confusing to prospective DG customers. Furthermore, I have shown that NRLP's calculations of the appropriate compensation rate for Schedule PPR are erroneous as they rely on the same solar value methodology as NRLP used for the proposed SSC component of Schedule NBR.

**Q. Please summarize your recommendations to the Commission on setting an appropriate residential BFC.**

A. I recommend that the Commission decline to adopt NRLP's proposal to increase the residential BFC by \$1.92/month to \$14.50/month and instead direct that it be reduced to no more than \$10.61/month in order to align it with costs that truly vary in relation to customer numbers, and to provide customers with the opportunity to exercise greater control over their electric bills and provide them with a relatively greater incentive for customer investments in energy efficiency measures. My recommendation is based on my calculations of a cost-based residential BFC using two different methodologies that produce a residential BFC ranging from $10.61/month to $11.49/month, and a separate calculation that uses a revised revenue requirements and allocation approach that produces a residential BFC of $10.81/month. On the balance, a maximum residential BFC of $10.61/month is reasonable considering cost causation and the balancing of other rate design objectives.

**Q. Does this conclude your testimony?**

A. Yes.

CERTIFICATE OF SERVICE

I certify that the parties of record on the service list have been served with the Direct Testimony of Justin R. Barnes on behalf of Appalachian Voices either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 6th day of June, 2023.

s/ Nick Jimenez
Nick Jimenez

Docket No. E-34, Subs 54 and 55
Exhibit JRB-1



# 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

**President**, May 2023 – present
**Director of Research**, July 2015 – April 2023
**Senior Analyst & Research Manager,** March 2013 – July 2015
EQ Research, LLC Cary, North Carolina

- Oversee state legislative, regulatory policy, utility IRP and general rate case tracking services 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 analysis to fulfill client requests, and for internal and published reports, focused primarily on drivers of distributed energy resource (DER) markets and policies.
- Provide expert witness testimony on topics including cost of service, rate design, distributed energy resource (DER) value, and DER policy including incentive program design, rate design issues, and competitive impacts of utility ownership of DERs.
- Managed the development of a solar power purchase agreement (PPA) toolkit for local governments, a comprehensive legal and policy resource for local governments interested in purchasing solar energy, and the planning and delivery of associated outreach efforts.

**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.
- 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 & OTHER REGULATORY ASSISTANCE

**Georgia Public Service Commission. Docket No. 44280**. Direct Testimony in October 2022 and Supplemental Testimony in November 2022. On behalf of Georgia Interfaith Power and Light. Georgia Power Company general rate case application. In Direct Testimony, provided a review and analysis of the cost allocation regime for coal combustion residual costs and provided recommended changes thereto; and evaluated the Company's proposals designed to shift residential customers to service under demand rate designs, including general analysis of the cost causation basis for demand rates and specific attributes and Company experience with its residential demand rate. In Supplemental Testimony, evaluated the Company's proposal to end its monthly netting DG tariff (i.e., NEM) and require mandatory demand rate service for future DG customers and recommended that NEM be retained without a mandatory demand rate requirement based on analysis demonstrating that doing so would not adversely affect non-DG customers.

**Wisconsin Public Service Commission. Docket No. 5-UR-110**. September 2022. On behalf of RENEW Wisconsin. Wisconsin Electric Power Company general rate case application. Provided an exhibit showing residential fixed charges among all major IOUs in the nation and testimony explaining the methodology used to develop the exhibit.

**Wisconsin Public Service Commission. Docket No. 6690-UR-127**. September 2022. On behalf of RENEW Wisconsin. Wisconsin Public Service Corporation general rate case application. Provided an exhibit showing residential fixed charges among all major IOUs in the nation and testimony explaining the methodology used to develop the exhibit.

**Wisconsin Public Service Commission. 3270-UR-124**. September 2022. On behalf of RENEW Wisconsin. Madison Gas and Electric general rate case application. Provided an exhibit showing residential fixed charges among all major IOUs in the nation and testimony explaining the methodology used to develop the exhibit. (*Note: Exhibit was introduced at the hearing and testimony on the methodology provided orally at the hearing; written testimony was not filed).*

**Michigan Public Service Commission. Case No. U-20836.** May 2022. On behalf of the Michigan Energy Innovation Business Council and The Institute for Energy Innovation. DTE Electric Company general rate case application. Addressed the utility's proposal for changes to its DG Tariff, including excluding generation capacity value from the export rate and requiring DG customers to take service under a newly proposed residential demand rate. Also evaluated the cost causation and other rate attributes of the proposed residential demand rate.

**Virginia State Corporation Commission. Docket No. PUR-2021-00171**. January 2022. On behalf of Appalachian Voices. Old Dominion Power Company general rate case application. Evaluation of the cost basis for the residential customer charge, AMI deployment and the timeline for deployment of TOU rates, class allocation of distribution and production demand costs, and the Company's proposal for a DSM/EE pilot program and cost recovery rider.

**Michigan Public Service Commission. Case No. U-20963.** June 2021. On behalf of the Michigan Energy Innovation Business Council and the Institute for Energy Innovation. Consumers Energy Company general rate case. Provided an evaluation of the utility's proposed home battery program and offered recommendations for modifications to the program to improve its cost-effectiveness and delivery of benefits to participants and non-participants through changes to battery operational plans, elimination of restrictions on consumer use of the batteries, battery sizing modifications to fit actual customer needs, and use of solar-paired storage to provide greater resiliency.

**Colorado Public Utilities Commission. Proceeding No. 20AL-0432E.** March 2021. On behalf of the Colorado Solar and Storage Association and the Solar Energy Industries Association. Public Service Company of Colorado (Xcel Energy Colorado) general rate case. Provided analysis and recommendations on several non-residential rate design issues, including the utility's practice of switching small commercial customers to demand rates, relaxing the demand threshold at which commercial customers are subject to demand rates, the utility's proposal for modifying time-varying pricing windows, and the establishment of a pilot time-of-use rate for Secondary General (SG) commercial customers intended to remedy the misalignment between the SG non-coincident demand rate design and cost causation and set a foundation for a default time-varying rate option for SG class customers.

**Kentucky Public Service Commission. Docket Nos. 2020-00349 and 2020-00350**. March 2021 (Phase 1) and July/August 2021 (Phase 2). On behalf of the Kentucky Solar Energy Industries Association. Kentucky Utilities and Louisville Gas and Electric general rate case applications. Provided an analysis of the utilities' current tariffs governing purchases from qualifying facilities and recommended changes to align them with state regulations, recent precedent, and accepted methodologies of energy and capacity pricing.

**South Carolina Public Service Commission. Docket Nos. 2020-264-E and 2020-265-E.** February 2021. On behalf of the Solar Energy Industries Association and the North Carolina Sustainable Energy Association. Docket for establishing a Solar Choice tariff for customers of Duke Energy Carolinas and Duke Energy Progress. Provided testimony in support of a stipulated settlement discussing the critical role that a proposed smart thermostat rebate and enabling technologies more generally play in the successfully meeting the legislative objectives for Solar Choice tariffs.

**South Carolina Public Service Commission. Docket No. 2020-229-E.** January 2021. On behalf of the Solar Energy Industries Association and the North Carolina Sustainable Energy Association. Docket for establishing a Solar Choice tariff for customers of Dominion Energy South Carolina. Provided an analysis of the proposed Solar Choice tariff from the standpoint of NEM successor best practices, alignment with the enabling statute, and cost of service basis. Offered an alternative Solar Choice tariff proposal based on this analysis. Surrebuttal testimony provided an evaluation of solar customer cost of service correcting erroneous assumptions used by the Office of Regulatory Staff in its direct testimony.

**Virginia State Corporation Commission. Docket No. PUR-2020-00134**. January 2021. On behalf of the Behind the Meter Solar Alliance. Docket for Dominion Virginia's 2020 RPS Plan. Offered testimony supporting the designation of small-scale resource carve-out eligibility being limited to behind the meter resources, based on the underlying Virginia statute and other public policy reasons.

**South Carolina Public Service Commission. Docket No. 2019-182-E.** October 2020. On behalf of the Solar Energy Industries Association and the North Carolina Sustainable Energy Association. Docket for establishing a cost-benefit analysis methodology and protocols for net metering and DERs. Provided discussion of historic regulatory use of DG cost-benefit and cost of service studies, how results should be viewed, and a discussion of the role of economic benefits and resiliency in DER cost-benefit analyses.

**Kentucky Public Service Commission. Docket No. 2020-00174**. October 2020. On behalf of the Kentucky Solar Industries Association. Kentucky Power general rate case. Provided an evaluation and critique of the cost of service support for, and design of, Kentucky Power's proposed net metering successor tariff and offered recommendations for developing cost-based DER rate designs. Also recommended changes to the utility's QF tariff and calculation of capacity costs.

**New Jersey Board of Public Utilities. Docket No. EO18101111**. September 2020. On behalf of Sunrun, Inc. Public Service Gas and Electric energy storage deployment plan proposal. Offered alternative proposal for a program utilizing non-utility owned energy storage assets under an aggregator model with elements for benefits sharing and ratepayer risk reduction.

**Virginia State Corporation Commission. Docket No. PUR-2020-00015.** July 2020. On behalf of Appalachian Voices. Appalachian Power Company general rate case. Analysis of the cost basis for the residential customer charge, the Company's winter declining block rate proposal, and a proposed Coal Asset Retirement Rider (Rider CAR) providing for advance collection of anticipated accelerated depreciation of coal generation assets. Provided an alternative residential customer charge recommendation and an alternative rates proposal for addressing winter bill volatility for electric heating customers.

**North Carolina Utilities Commission. Docket No. E-2 Sub 1219**. April 2020. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Progress general rate case. Provided analysis of available rate options for electric vehicle charging and recommended the adoption of residential and non-residential EV-specific rate options and appropriate design characteristics for those rate options.

**North Carolina Utilities Commission. Docket No. E-7 Sub 1214**. January 2020. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Carolinas general rate case. Provided analysis of available rate options for electric vehicle charging and recommended the adoption of residential and non-residential EV-specific rate options and appropriate design characteristics for those rate options.

**Virginia State Corporation Commission. Docket No. PUR-2019-00060.** November 2019. On behalf of Appalachian Voices. Old Dominion Power Company general rate case application. Analysis of the cost basis for the residential customer charge, proposal to change the residential customer charge from a monthly charge to a daily charge, and design of proposed customer green power program and utility owned commercial behind the meter solar proposal. Proposed modified optional rate structure for mid- to large-size non-residential customers with on-site solar and/or low load factors.

**Georgia Public Service Commission. Docket No. 42516.** October 2019. On behalf of Georgia Interfaith Power and Light, Southface Energy Institute, and Vote Solar. Georgia Power Company general rate case application. Analysis of the cost basis for the residential customer charge, the validity of the utility's minimum-intercept study, and a proposal to change the residential customer charge from a monthly charge to a daily charge.

**Hawaii Public Utilities Commission. Docket No. 2018-0368**. July 2019. On behalf of the Hawaii PV Coalition. Hawaii Electric Light Company (HELCO) general rate case application. Provided analysis of HELCO's proposed changes to its decoupling rider to make the decoupling charge non-bypassable and the alignment of the proposed modifications with state policy goals and the policy rationale for decoupling.

**Virginia State Corporation Commission. Docket No. PUR-2019-00067**. July 2019.* On behalf of the Southern Environmental Law Center. Appalachian Power Company residential electric vehicle (EV) rate proposal. Provided review and analysis of the proposal and developed comments discussing principles of time-of-use (TOU) rate design and proposing modifications to the Company's proposal to support greater equity among rural ratepayers and greater rate enrollment. ***This work involved comment preparation rather than testimony.**

**New York Public Service Commission. Case No. 19-E-0065.** May 2019. On behalf of The Alliance for Solar Choice. Consolidated Edison (ConEd) general rate case application. Provided review and analysis of the competitive impacts and alignment with state policy of ConEd's energy storage, distributed energy resource management system, and earnings adjustment mechanism (EAM) proposals. Proposed model for improving the utilization of customer-sited storage in existing demand response programs and an alternative EAM supportive of utilization of third party-owned battery storage.

**South Carolina Public Service Commission. Docket No. 2018-318-E.** March 2019. On behalf of Vote Solar. Duke Energy Progress general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, AMI-enabled rate design plans, excess deferred income tax rider rate design, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

**South Carolina Public Service Commission. Docket No. 2018-319-E.** February 2019. On behalf of Vote Solar. Duke Energy Carolinas general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, AMI-enabled rate design plans, excess deferred income tax rider rate design, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

**New Orleans City Council. Docket No. UD-18-07**. February 2019. On behalf of the Alliance for Affordable Energy. Entergy New Orleans general rate case application. Analysis of the cost basis for the residential customer charge, rate design for AMI, DSM and Grid Modernization Riders, and DSM program performance incentive proposal. Developed recommendations for the residential customer charge, rider rate design, and a revised DSM performance incentive mechanism.

**New Hampshire Public Utilities Commission. Docket No. DE 17-189**. May 2018. On behalf of Sunrun Inc. Review of Liberty Utilities application for approval of customer-sited battery storage program, analysis of time-of-use rate design, program cost-benefit analysis, cost-effectiveness of utility-owned vs. non-utility owned storage assets. Developed a proposal for an alternative program utilizing non-utility owned assets under an aggregator model with elements for benefits sharing and ratepayer risk reduction.

**North Carolina Utilities Commission. Docket No. E-7 Sub 1146**. January 2018. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Carolinas general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, allocation of coal ash remediation costs, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

**Ohio Public Utilities Commission. Docket No. 17-1263-EL-SSO**. November 2017*. On behalf of the Ohio Environmental Council. ***Testimony prepared but not filed due to settlement in related case.** Duke Energy Ohio proposal to reduce compensation to net metering customers. Provided analysis of capacity value of solar net metering resources in the PJM market and distribution of that value to customers. Also analyzed the cost basis of the utility proposal for recovery of net metering credit costs, focused on PJM settlement protocols and how the value of DG customer exports is distributed among ratepayers, load-serving entities, and distribution utilities based on load settlement practices.

**North Carolina Utilities Commission, Docket No. E-2 Sub 1142**. October 2017. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Progress general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, allocation of coal ash remediation costs, and advanced metering infrastructure deployment plans and cost-benefit analysis.

**Public Utility Commission of Texas, Control No. 46831**. June 2017. On behalf of the Energy Freedom Coalition of America. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate DG rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits, and alignment of demand ratchets with cost causation principles and state policy goals, focused on impacts on customer-sited storage.

**Utah Public Service Commission, Docket No. 14-035-114**. June 2017. On behalf of Utah Clean Energy. Rocky Mountain Power application for separate distributed generation (DG) rate class. Provided analysis of grandfathering of existing DG customers and best practices for review of DG customer rates and DG value. Developed proposal for addressing revisions to DG customer rates in the future.

**Colorado Public Utilities Commission, Proceeding No. 16A-0055E**. May 2016. On behalf of the Energy Freedom Coalition of America. Public Service Company of Colorado application for solar energy purchase program. Analysis of program design from the perspective of customer demand and needs, and potential competitive impacts. Proposed alternative program design.

**Public Utility Commission of Texas, Control No. 44941**. December 2015. On behalf of Sunrun, Inc. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits.

**Oklahoma Corporation Commission, Cause No. PUD 201500274**. November 2015. On behalf of the Alliance for Solar Choice. Analysis of Oklahoma Gas & Electric proposal to place distributed generation customers on separate rates, rate impacts, cost basis of proposal, and alignment with rate design principles.

**South Carolina Public Service Commission, Docket No. 2015-54-E**. May 2015. On behalf of The Alliance for Solar Choice. South Carolina Electric & Gas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

**South Carolina Public Service Commission, Docket No. 2015-53-E**. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Carolinas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

**South Carolina Public Service Commission, Docket No. 2015-55-E**. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Progress application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

**South Carolina Public Service Commission, Docket No. 2014-246-E**. December 2014. On behalf of The Alliance for Solar Choice. Generic investigation of distributed energy policy. Distributed energy best practices, including net metering and rate design for distributed energy customers.

## 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 Masters Thesis Awards (2007)
- Sustainable Futures Institute Graduate Scholar Michigan Tech University (2005-2006)

## Solar Value - South Facing

| Residential Proposed Revenue Requirement | | | | | Savings per kW | | | |
|---|---|---|---|---|---|---|---|---|
| **Type** | **Revenue** | **Demand** | **Unit Cost ($/kW)** | **$/kWh Rate** | **Solar Unit Value ($/kW)** | **Unit Value $/kWh Production** | | |
| Customer | 1,242,766 | | | | | | | |
| Distribution - NRLP | 2,020,382 | 8,886 | $227.37 | $0.03259 | $67.73517 | $0.05201 | | |
| BREMCO - Transmission | 492,126 | 9,579 | $51.38 | $0.00794 | $8.30361 | $0.00638 | | |
| DEC - Transmission | 210,351 | 8,359 | $25.16 | $0.00339 | $5.37948 | $0.00413 | | |
| CPP - Production | 1,578,131 | 8,234 | $191.66 | $0.02546 | $43.07992 | $0.03308 | | |
| Energy | 2,678,965 | | | $0.04322 | | $0.04322 | | |
| PPAC Energy | 2,224,943 | | | $0.03589 | | $0.03589 | **% Retail Rate** | |
| TOTAL | $10,447,664 | | | $0.14849 | $124.49818 | **$0.12269** | 82.6% | Not including distribution |
| **Source** | *REH-19A* | *REH-14 p 1* | *Calculated* | *Calculated* | *Calculated* | *Calculated* | | |

| | | | |
|---|---|---|---|
| Residential Sales (kWh) | 61,988,218 | Value Including Distribution | **$0.17470** |
| | | % of Retail Rate | 117.6% |

| **Solar Contribution to CP** | **Capacity %** | **Source** |
|---|---|---|
| BREMCO - Transmission | 16.16% | *Calculated* |
| DEC - Transmission | 21.38% | *Calculated* |
| CPP - Production | 22.48% | *Calculated* |
| | | |
| NRLP - Distribution | 29.8% | *Calculated* |
| Solar Production Rate (kWh/kW) | 1,302 | *Calculated* |
| Capacity Factor | 14.9% | *Calculated* |

## Solar Value - Southwest Facing

| Residential Proposed Revenue Requirement | | | | | Savings per kW | | | |
|---|---|---|---|---|---|---|---|---|
| **Type** | **Revenue** | **Demand** | **Unit Cost ($/kW)** | **$/kWh Rate** | **Solar Unit Value ($/kW)** | **Unit Value $/kWh Production** | | |
| Customer | 1,242,766 | | | | | | | |
| Distribution - NRLP | 2,020,382 | 8,886 | 227.3668692 | $0.03259 | $61.91763 | $0.04941 | | |
| BREMCO - Transmission | 492,126 | 9,579 | 51.37550893 | $0.00794 | $9.02830 | $0.00721 | | |
| DEC - Transmission | 210,351 | 8,359 | 25.16461299 | $0.00339 | $6.00608 | $0.00479 | | |
| CPP - Production | 1,578,131 | 8,234 | 191.6603109 | $0.02546 | $46.49159 | $0.03710 | | |
| Energy | 2,678,965 | | | $0.04322 | | $0.04322 | | |
| PPAC Energy | 2,224,943 | | | $0.03589 | | $0.03589 | **% Retail Rate** | |
| TOTAL | $10,447,664 | | | $0.14849 | $123.44360 | **$0.12821** | 86.3% | Not including distribution |
| | *REH-19A* | *REH-14 p 1* | *Calculated* | *Calculated* | *Calculated* | *Calculated* | | |

| | | | |
|---|---|---|---|
| Residential Sales (kWh) | 61,988,218 | | |
| | | Value Including Distribution | **$0.17763** |
| | | % of Retail Rate | 119.6% |

| **Solar Contribution to CP** | **Capacity %** | **Source** |
|---|---|---|
| BREMCO - Transmission | 17.57% | *Calculated* |
| DEC - Transmission | 23.87% | *Calculated* |
| CPP - Production | 24.26% | *Calculated* |
| | | |
| NRLP - Distribution | 27.2% | *Calculated* |
| Solar Production Rate (kWh/kW) | 1,253 | *Calculated* |
| Capacity Factor | 14.3% | *Calculated* |

## Solar Value - Southeast Facing

| Residential Proposed Revenue Requirement | | | | | Savings per kW | | | |
|---|---|---|---|---|---|---|---|---|
| **Type** | **Revenue** | **Demand** | **Unit Cost ($/kW)** | **$/kWh Rate** | **Solar Unit Value ($/kW)** | **Unit Value $/kWh Production** | | |
| Customer | 1,242,766 | | | | | | | |
| Distribution - NRLP | 2,020,382 | 8,886 | 227.3668692 | $0.03259 | $66.92182 | $0.05352 | | |
| BREMCO - Transmission | 492,126 | 9,579 | 51.37550893 | $0.00794 | $6.94132 | $0.00555 | | |
| DEC - Transmission | 210,351 | 8,359 | 25.16461299 | $0.00339 | $4.42447 | $0.00354 | | |
| CPP - Production | 1,578,131 | 8,234 | 191.6603109 | $0.02546 | $36.76063 | $0.02940 | | |
| Energy | 2,678,965 | | | $0.04322 | | $0.04322 | | |
| PPAC Energy | 2,224,943 | | | $0.03589 | | $0.03589 | **% Retail Rate** | |
| TOTAL | $10,447,664 | | | $0.14849 | $115.04824 | **$0.11760** | 79.2% | Not including distribution |
| | *REH-19A* | *REH-14 p 1* | *Calculated* | *Calculated* | *Calculated* | *Calculated* | | |
| | | | | | | | | |
| Residential Sales (kWh) | 61,988,218 | | | | Value Including Distribution | **$0.17111** | | |
| | | | | | % of Retail Rate | **115.2%** | | |
| **Solar Contribution to CP** | **Capacity %** | **Source** | | | | | | |
| BREMCO - Transmission | 13.51% | *Calculated* | | | | | | |
| DEC - Transmission | 17.58% | *Calculated* | | | | | | |
| CPP - Production | 19.18% | *Calculated* | | | | | | |
| | | | | | | | | |
| NRLP - Distribution | 29.4% | *Calculated* | | | | | | |
| Solar Production Rate (kWh/kW) | 1,250 | *Calculated* | | | | | | |
| Capacity Factor | 14.3% | *Calculated* | | | | | | |

## Solar Value - NRLP

| Residential Proposed Revenue Requirement | | | | | Savings per kW | | | |
|---|---|---|---|---|---|---|---|---|
| **Type** | **Revenue** | **Demand** | **Unit Cost ($/kW)** | **$/kWh Rate** | **Solar Unit Value ($/kW)** | **Unit Value $/kWh Production** | | |
| Customer | 1,242,766 | | | | | | | |
| Distribution - NRLP | 2,020,382 | 8,886 | $227.37 | $0.03259 | $67.73517 | $0.05201 | Uses Solar Value (South) amounts | |
| BREMCO - Transmission | 492,126 | 9,579 | $51.38 | $0.00794 | $14.96055 | $0.01201 | | |
| DEC - Transmission | 210,351 | 8,359 | $25.16 | $0.00339 | $7.32794 | $0.00588 | | |
| CPP - Production | 1,578,131 | 8,234 | $191.66 | $0.02546 | $49.88918 | $0.04006 | | |
| Energy | 2,678,965 | | | $0.04322 | | $0.04322 | | |
| PPAC Energy | 2,224,943 | | | $0.03589 | | $0.03589 | **% Retail Rate** | |
| TOTAL | $10,447,664 | | | $0.14849 | $139.91283 | **$0.13707** | 92.3% | Not including distribution |
| **Source** | *REH-19A* | *REH-14 p 1* | *Calculated* | *Calculated* | *Calculated* | *Calculated* | | |
| | | | | | | | | |
| Residential Sales (kWh) | 61,988,218 | | | | Value Including Distribution | **$0.18908** | | |
| | | | | | % of Retail Rate | 127.3% | | |
| **Solar Contribution to CP** | **Capacity %** | **Source** | | | | | | |
| BREMCO - Transmission | 29.12% | *REH-19A* | | | | | | |
| DEC - Transmission | 29.12% | *REH-19A* | | | | | | |
| CPP - Production | 26.03% | *REH-19A* | | | | | | |
| | | | | | | | | |
| Solar Production (kWh) | 50,415 | *REH-19A* | | | | | | |
| Solar Nameplate (kW) | 40.485 | *REH-19A* | | | | | | |
| Solar Production Rate (kWh/kW) | 1,245 | *REH-19A* | | | | | | |
| Capacity Factor | 14.2% | *Calculated* | | | | | | |

## Solar Value - NRLP Corrected

**Residential Proposed Revenue Requirement**

| Type | Revenue | Demand | Unit Cost ($/kW) | $/kWh Rate | Savings per kW Solar Unit Value ($/kW) | Unit Value $/kWh Production | | |
|---|---|---|---|---|---|---|---|---|
| Customer | 1,242,766 | | | | | | | |
| Distribution - NRLP | 2,020,382 | 8,886 | 227.3668692 | $0.03259 | $67.73517 | $0.05201 | Uses Solar Value (South) amounts | |
| BREMCO - Transmission | 492,126 | 9,579 | 51.37550893 | $0.00794 | $10.35223 | $0.00831 | | |
| DEC - Transmission | 210,351 | 8,359 | 25.16461299 | $0.00339 | $5.07070 | $0.00407 | | |
| CPP - Production | 1,578,131 | 8,234 | 191.6603109 | $0.02546 | $34.52202 | $0.02772 | | |
| Energy | 2,678,965 | | | $0.04322 | | $0.04322 | | |
| PPAC Energy | 2,224,943 | | | $0.03589 | | $0.03589 | **% Retail Rate** | |
| TOTAL | $10,447,664 | | | $0.14849 | $117.68012 | **$0.11922** | 80.3% | Not including distribution |
| | *REH-19A* | *REH-14 p 1* | *Calculated* | *Calculated* | *Calculated* | *Calculated* | | |

| | | | |
|---|---|---|---|
| Residential Sales (kWh) | 61,988,218 | Value Including Distribution | **$0.17122** |
| | | % of Retail Rate | 115.3% |

| Solar Contribution to CP | Capacity % | Source |
|---|---|---|
| BREMCO - Transmission | 20.15% | *Calculated* |
| DEC - Transmission | 20.15% | *Calculated* |
| CPP - Production | 18.01% | *Calculated* |
| | | |
| Solar Production (kWh) | 50,415 | *REH-19A* |
| Solar Nameplate (kW) | 40.485 | *REH 19A (Not Used)* |
| Solar Production Rate (kWh/kW) | 1,245 | *REH-19A* |
| Capacity Factor | 14.2% | *Calculated* |

| Proration of REV allocated amounts for customer-related component | | # Customer Months |
|---|---|---|
| | | 7142 |
| Residential Test Year Revenue | $9,496,021 | |
| Residential Customer Charge Revenue | $1,078,217 | |
| % Customer-Related Revenue | 11.4% | |
| *SOURCE: REH-16* | | |

**NRLP Proposed Customer Charge Components**

| Fixed Charge Components | COSS Line # | Total R Class Cost ($) | Cost $/Month | EQ Adjustment | Customer % (Relative to NLRP) | Note |
|---|---|---|---|---|---|---|
| Other Operating Income | 2.00 through 2.07 | -$93,303 | ($1.09) | Prorate | 11.4% | Prorate for customer component of residential revenue, exclude ASU Component |
| Expense Job & Contract ASU | 5.00 through 5.09 | $71,873 | $0.84 | Exclude | 0.0% | Exclude to make symmetric with revenue from ASU services |
| Meter Expense | 9.00 through 9.03 | $37,407 | $0.44 | None | 100.0% | |
| Customer Install Expense | 10.00 through 10.02 | $21,472 | $0.25 | Exclude | 0.0% | Should not have a customer component |
| Maintenance Street Lights | 18.00 through 18.03 | $0 | $0.00 | None | 100.0% | |
| Maintenance-Meters | 19.00 through 19.03 | $56,916 | $0.66 | None | 100.0% | |
| Supervision Customer Accounts | 21.00 through 21.02 | $33,553 | $0.39 | None | 100.0% | |
| Meter Reading Expense | 22.00 through 22.03 | $583 | $0.01 | None | 100.0% | |
| Customer Records | 23.00 through 23.06 | $524,748 | $6.12 | None | 100.0% | |
| Administration Other | Portion 27.00 - 27.17 | $362,321 | $4.23 | Recalculate | 87.5% | Recalculate customer % based on other classification changes |
| Interest Expense Consumer Deposits | 30 | $4,679 | $0.05 | Prorate | 11.4% | Prorate for customer component of residential revenue |
| Uncollectible Accounts | 34.03 | $22,911 | $0.27 | Prorate | 11.4% | Prorate for customer component of residential revenue |
| Regulatory Commission Expense | 34.04 | $12,747 | $0.15 | Prorate | 11.4% | Prorate for customer component of residential revenue |
| Unrelated Business Income Tax | 34.05 | $131,791 | $1.54 | Prorate | 11.4% | Prorate for customer component of residential revenue |
| | **TOTAL** | **$1,187,698** | **$13.86** | | | |
| | **TOTAL W/O Admin** | **$825,377** | **$9.63** | | | |
| | **Customer - Electric O&M Excluding PP** | **$746,552** | **$8.71** | | | |

**Administration Other Customer Classification**

| | |
|---|---|
| Total R Electric O&M Excluding PP | $1,222,367 |
| Customer Electric O&M Excluding PP | $746,552 |
| Customer % | **61.1%** |

**EQ Research Proposed Customer Charge Components**

| Fixed Charge Components | Total R Class Cost ($) | Customer-Related $ | Cost $/Month |
|---|---|---|---|
| Other Operating Income | -$93,303 | -$5,175 | -$0.06 |
| Expense Job & Contract ASU | $71,873 | $0 | $0.00 |
| Meter Expense | $37,407 | $37,407 | $0.44 |
| Customer Install Expense | $21,472 | $0 | $0.00 |
| Maintenance Street Lights | $0 | $0 | $0.00 |
| Maintenance-Meters | $56,916 | $56,916 | $0.66 |
| Supervision Customer Accounts | $33,553 | $33,553 | $0.39 |
| Meter Reading Expense | $583 | $583 | $0.01 |
| Customer Records | $524,748 | $524,748 | $6.12 |
| Administration Other | $362,321 | $317,019 | $3.70 |
| Interest Expense Consumer Deposits | $4,679 | $531 | $0.01 |
| Uncollectible Accounts | $22,911 | $2,601 | $0.03 |
| Regulatory Commission Expense | $12,747 | $1,447 | $0.02 |
| Unrelated Business Income Tax | $131,791 | $14,964 | $0.17 |
| **TOTAL** | **$1,187,698** | **$984,594** | **$11.49** |
| | **TOTAL W/O Admin** | **$667,576** | $7.79 |
| | **Customer - Electric O&M Excluding PP** | **$653,207** | $7.62 |

**ASU Services Revenue Adjustment**

| | |
|---|---|
| ASU Revenue | $47,723 |
| ASU Costs | $71,873 |
| Non-ASU Revenue | -$45,580 |

**Revised Administration - Other Customer %**

| | |
|---|---|
| Total Residential Electric O&M Excluding PP | $1,222,367 |
| Customer - Electric O&M Excluding PP | $653,207 |
| % Customer | 53.4% |
| Total Residential Administration Other ($) | $593,249 |
| Recalculated Customer Component ($) | $317,020 |
| Math Check | $1.09 |

| | |
|---|---|
| Residential Customers | 7142 |
| Residential Customer % | 80.41% |

*From Schedule 6*

| **Depreciation** | **Test Year** | **Residential Portion** |
|---|---|---|
| Meters | $118,118 | $94,978 |
| Services | $57,393 | $46,150 |
| TOTAL | $175,511 | $141,128 |

*From Schedule 6*

| **Net Plant** | **Test Year** | **Residential Portion** | **Residential Revenue Req** |
|---|---|---|---|
| Meters | $1,818,075 | $1,461,914 | $78,839 |
| Services | $383,126 | $308,072 | $16,614 |
| TOTAL | $2,201,202 | $1,769,986 | $95,453 |
| | | | |
| Return % | 5.393% | Per Revenue requirements testimony | |

**Residential Customer Charge Calculation**

| **Rate Base Items (NRLP Return)** | **Revenue Req** | **$/month charge** |
|---|---|---|
| Meters | $78,839 | $0.92 |
| Services | $16,614 | $0.19 |
| *SUBTOTAL* | $95,453 | $1.11 |
| | | |
| **Depreciation Expense** | **Revenue Req** | **$/month charge** |
| Depreciation (Meters) | $94,978 | $1.11 |
| Depreciation (Services) | $46,150 | $0.54 |
| *SUBTOTAL* | $141,128 | $1.65 |
| | | |
| **O&M Expenses** | **Revenue Req** | **$/month charge** |
| Meter Expense | $37,407 | $0.44 |
| Maintenance-Meters | $56,916 | $0.66 |
| Meter Reading Expense | $583 | $0.01 |
| Supervision Customer Accounts | $33,553 | $0.39 |
| Customer Records & Collections | $524,748 | $6.12 |
| *SUBTOTAL* | $653,207 | $7.62 |
| | | |
| **Other Expenses (Rev Allocated)** | **Revenue Req** | **$/month charge** |
| Interest Expense Consumer Deposits | $531 | $0.01 |
| Uncollectible Accounts | $2,601 | $0.03 |
| Regulatory Commission Expense | $1,447 | $0.02 |
| Unrelated Business Income Tax | $14,964 | $0.17 |
| *SUBTOTAL* | $19,544 | $0.23 |
| | | |
| **TOTAL** | **$909,332** | **$10.61** |
| | | |
| **TOTAL Excluding Other Expenses** | **$889,788** | **$10.38** |