INFORMATION SHEET

PRESIDING: Commissioner Kemerait, Presiding; Chair Mitchell and Commissioners Brown-Bland, Clodfelter, Duffley, Hughes, and McKissick, Jr.
PLACE: Raleigh, NC
DATE: Tuesday, July 11, 2023
TIME: 10:00 a.m. – 12:41 p.m.
DOCKET NO.: E-34, Sub 54 and E-34, Sub 55
COMPANY: Appalachian State University d/b/a New River Light and Power Company
DESCRIPTION: In the Matter of Application of Appalachian State University d/b/a New River Light and Power Company for General Rate Case and Petition for an Accounting Order to Defer Certain Capital Costs and New Tax Expenses

VOLUME NUMBER: 3

APPEARANCES
See Attached

WITNESSES
See Attached

EXHIBITS
See Attached

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|---|---|
| REPORTED BY: Joann Bunze | TRANSCRIPT PAGES: 116 |
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PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Tuesday, July 11, 2023

TIME: 10:00 a.m. - 12:41 p.m.

DOCKET NO: E-34, Sub 54 and E-34, Sub 55

BEFORE: Commissioner Karen M. Kemerait, Presiding

Chair Charlotte A. Mitchell

Commissioner ToNola D. Brown-Bland

Commissioner Daniel G. Clodfelter

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

Appalachian State University d/b/a

New River Light and Power Company

E-34, Sub 54

Application for General Rate Case

and

E-34, Sub 55

Petition for an Accounting Order to Defer Certain

Capital Costs and New Tax Expenses

VOLUME 3

A P P E A R A N C E S:

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# T A B L E O F C O N T E N T S

## E X A M I N A T I O N S

# E X H I B I T S

# NORTH CAROLINA UTILITIES COMMISSION

# APPEARANCE SLIP

**DATE:** 7-5-2023 **DOCKET NO.:** E-34, Subs 54 & 55

**ATTORNEY NAME and TITLE:** M.Gray Styers, Jr

**FIRM NAME:** Fox Rothschild

**ADDRESS:** 434 Fayetteville Street, Suite 2800

**CITY:** Raleigh **STATE:** NC **ZIP CODE:** 27601

**APPEARANCE ON BEHALF OF:** New River LIght & Power

**APPLICANT:** x **COMPLAINANT:** ___ **INTERVENOR:** ___

**PROTESTANT:** ___ **RESPONDENT:** ___ **DEFENDANT:** ___

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**(Signature Required for distribution of CONFIDENTIAL information)**

# NORTH CAROLINA UTILITIES COMMISSION

# APPEARANCE SLIP

**DATE:** 7-10-23 **DOCKET NO.:** E-34, Subs 54 & 55

**ATTORNEY NAME and TITLE:** David Drooz

**FIRM NAME:** Fox Rothschild

**ADDRESS:** 434 Fayetteville Street, Suite 2800

**CITY:** Raleigh **STATE:** NC **ZIP CODE:** 27601

**APPEARANCE ON BEHALF OF:** New River Light & Power

**APPLICANT:** x **COMPLAINANT:** ___ **INTERVENOR:** ___

**PROTESTANT:** ___ **RESPONDENT:** ___ **DEFENDANT:** ___

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# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

**DATE:** 07/10/23 **DOCKET NO.:** E-34, Sub 54 and Sub 55

**ATTORNEY NAME and TITLE:** Nick Jimenez, Senior attorney, and Munashe Magarira, Staff attorney

**FIRM NAME:** Southern Environmental Law Center

**ADDRESS:** 601 W Rosemary St, Suite 220, ~~Chapel~~

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**APPEARANCE ON BEHALF OF:** Appalachian Voices

**APPLICANT:** ___ **COMPLAINANT:** ___ **INTERVENOR:** ✓

**PROTESTANT:** ___ **RESPONDENT:** ___ **DEFENDANT:** ___

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# NORTH CAROLINA UTILITIES COMMISSION

## APPEARANCE SLIP

DATE: 7/10/23 DOCKET NO.: E34 Sub 54

ATTORNEY NAME and TITLE: Self-represented

Nancy LaPlaca (NRLP customer)

FIRM NAME: LaPlaca and Associates LLC

ADDRESS: 239 Wildwood Lane, B

CITY: Boone STATE: NC ZIP CODE: 28607

APPEARANCE ON BEHALF OF: Self (an actual residential customer)

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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# NORTH CAROLINA UTILITIES COMMISSION
## PUBLIC STAFF - APPEARANCE SLIP

DATE: July 10, 2023

DOCKET #:E-34, Subs 54,55
New River Light & Power

PUBLIC STAFF ATTORNEYS: Thomas J. Felling, William E.H. Creech, William S.F. Freeman

TO REQUEST A **CONFIDENTIAL** TRANSCRIPT, PLEASE PROVIDE YOUR EMAIL ADDRESS BELOW:

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TRANSPORTATION ______________________
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COUNSEL/MEMBER(s) REQUESTING A **CONFIDENTIAL** TRANSCRIPT WHO HAS SIGNED A CONFIDENTIALITY AGREEMENT WILL NEED TO SIGN BELOW.

/s/ Thomas J. Felling
/s/ William E.H. Creech
/s/ William S.F. Freeman

NRLP Cross Exam Barnes Direct EXHIBIT 1 I/A
DOCKET NO. E-34, SUB 54 AND 55



**STATE OF NORTH CAROLINA**
**UTILITIES COMMISSION**
**RALEIGH**

DOCKET NO. E-7, SUB 1146
DOCKET NO. E-7, SUB 819
DOCKET NO. E-7, SUB 1152
DOCKET NO. E-7, SUB 1110

| | |
|---|---|
| DOCKET NO. E-7, SUB 1146<br><br>In the Matter of<br>Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina<br><br>DOCKET NO. E-7, SUB 819<br><br>In the Matter of<br>Amended Application by Duke Energy Carolinas, LLC, for Approval of Decision to Incur Nuclear Generation Project Development Costs<br><br>DOCKET NO. E-2, SUB 1152<br><br>In the Matter of<br>Petition of Duke Energy Carolinas, LLC, for an Order Approving a Job Retention Rider<br><br>DOCKET NO. E-7, SUB 1110<br><br>In the Matter of<br>Joint Application by Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, for Accounting Order to Defer Environmental Compliance Costs | ORDER ACCEPTING STIPULATION, DECIDING CONTESTED ISSUES, AND REQUIRING REVENUE REDUCTION |

HEARD: Tuesday, January 16, 2018, at 7:00 p.m., in the Macon County Courthouse, Courtroom A, 5 W. Main Street, Franklin, North Carolina

Wednesday, January 24, 2018, at 7:00 p.m., in the Guilford County Courthouse, Courtroom 1C, 201 S. Eugene Street, Greensboro, North Carolina case. The Kroger Co. in its post-hearing Brief stated that "[i]f the Commission determines that the winter peak should also be considered in the allocation of production demand costs, an allocator based on the average of the single highest summer and single highest winter coincident peaks may also be appropriate." See Post-Hearing Brief of the Kroger Co., p. 7. The Commission concludes that DEC should file annual cost of service studies based on Winter Coincident Peak as well as the SCP and SWPA methodologies. In its next general rate case, the Company shall prepare cost of service studies based on each of these methodologies.

Although the Public Staff has traditionally supported the SWPA methodology, it is not unreasonable for the Stipulating Parties to have agreed to the use of SCP in this proceeding. Further, the Commission notes that the difference in the retail revenue requirements between the SCP and SWPA methodologies is immaterial on a jurisdictional basis.

The Commission finds and concludes that, for purposes of this proceeding, the Company may use the SCP methodology for allocation between jurisdictions and among customer classes under the provisions of the Stipulation and that the provisions of the Stipulation regarding cost of service methodology are just and reasonable to all parties in light of all the evidence presented.

Minimum System

The Company used a minimum system study to allocate distribution costs among customer classes. The Public Staff does not oppose the Company's cost of service study and allocation methodology for purposes of settlement. NCSEA witness Barnes objects to the use of a minimum system study to allocate costs to customers. Tr. Vol. 20, pp. 74-95. Moreover, witness Barnes also criticizes the specific methodology used by the Company, which he argues inflates the size and cost of the minimum system and increases the portion of the distribution system classified as customer-related. Tr. Vol. 20, p. 94-95.

Witness Hager explained that DEC's minimum system study allowed DEC to classify the distribution system into the portion that is customer-related (driven by number of customers) and the portion that is demand-related (driven by customer peak demand levels). Tr. Vol. 19, p. 35. The methodology behind the Company's minimum system study allows DEC to assess how much of its distribution system is installed simply to ensure that electricity can be delivered to each customer, regardless of the customer's frequency of use. Id. at 36. Witness Hager testified that "[w]ithout the minimum system, low use customers could easily avoid paying for the infrastructure necessary to provide service to them which is counter to cost causation principles." Id. She further explained that the methodology used by the Company is consistent with the guidance regarding allocation of distribution costs provided in the NARUC Cost of Service Manual. Id. at 37.

Witness Hager also explained that while the NARUC Cost of Service Manual suggests two methods of allocation, both of these methods identify a portion of FERC distribution asset accounts 364 to 368 as customer-related and a portion as demand related. Id. at 38. Therefore, witnesses Barnes' and Wallach's suggestion that all of the costs charges to accounts 364 to 368 should be allocated based on demand is inconsistent with the guidance provided in the NARUC Cost of Service Manual. Id.

On cross-examination by counsel for NCSEA, witness Hager testified regarding the Company's long history of using the minimum system method, stating that "the minimum system study has long been used in the cost of service study to develop the customer-related costs that are then passed to rate design and are the basis of rates that are ultimately approved by the Commission." Id. at 138-39. The Company "filed minimum system study results in every rate case for a long time" and the Commission "has approved the results of that." Id. at 143.

In response to questioning from Commissioner Clodfelter, witness Hager testified about the different variations of the minimum system method used by DEP and DEC. Tr. Vol. 20, pp. 27-29. Witness Hager explained that DEP determines the cost of constructing a minimum system configuration using today's costs and the cost of constructing a standard configuration in today's costs, and applies that ratio to the balance of plant account. Id. at 28. Alternatively, DEC calculates the current cost for a minimum size system and then applies a Handy-Whitman Index to adjust to book costs. Id. at 29. She noted, however, that while the methods differ, "they both have the same ultimate goal" and "get you back to the same place." Id. at 28, 30.

In its post-hearing Brief, NCSEA states that "the minimum system analysis is flawed." See NCSEA's Post-Hearing Brief, p. 37. NCSEA states that the minimum system methodology "assumes that some costs of the shared distribution system are effectively incurred solely for the purpose of connecting each customer and that these costs should therefore be classified as customer-related." Tr. Vol. 20, pp. 75-76. In effect, the minimum system methodology "double counts" demand-related costs because a minimum system is still capable of serving some level of demand. Id. at 76.[18]

Furthermore, NCSEA states that the Company's modified minimum system methodology does not examine actual costs, but rather defines costs for specified components and extrapolates those costs across the Company's system. Id. at 86. In the case of poles and conductors, this results in more items being included in the minimum system study than are actually on the Company's system and results in a negative assignment for these components in the demand charge. Id. at 87. Further, NCSEA states that the Company's modified minimum system methodology contains flaws in its analysis

[18] See also, Tr. Vol. 19, p. 36 ("But if someone, for whatever reason, wants electricity to light a single 100-Watt light bulb, that customer will require distribution assets such as poles and conductors and transformers to deliver that electricity."). NCSEA notes that, while small, a single 100-watt light bulb would nonetheless impose demand on the grid. See also, Official Exhibits, Vol. 20 (NCJC, et al., Hager/Pirro Cross Exhibit 1) ("Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.").

of poles and structures, overhead conductors, line transformers, and service drops. Id. at 90-94.

. The Commission is not persuaded by the evidence presented in this docket that the minimum system analysis employed by the Company is flawed in a way that precludes the Commission from accepting it as appropriate for cost allocation in this proceeding. However, the Commission gives some weight to NCSEA witness Barnes' argument that "[t]he Commission should reconsider its past acceptance of this method for the allocation for distribution costs, and disregard the results as a consideration in rate design." Tr. Vol. 20, p. 95. Witness Barnes stated in his testimony that "Many states confine the definition of customer costs to those costs that are directly attributable to a customer, such as metering and billing, excluding portions of the distribution system shared by multiple customers. A report commissioned by the National Association of Regulatory Utility Commissioners (NARUC) found that this basic customer method (100% demand for shared distribution facilities and 100% customer for meters and services) was the most common approach at the time of the report. There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. The most common method used is the basic customer method, which classifies all poles, wires, and transformers as demand-related and meters, meter-reading, and billing as customer-related. This general approach is used in more than thirty states.[19] Tr. Vol. 20, p. 79..

Further, witness Barnes stated in his testimony that:

> [i]t is not clear to me that the Commission has recently delved into the details of the different methodologies used by North Carolina utilities in conducting their minimum system studies. In fact, significant differences in methodology are apparent to me based on my review of the studies performed by DEP, DEC, and Dominion Energy North Carolina (Dominion). For instance, in its 2016 general rate case, Dominion classified only 31.08% of secondary poles in FERC Account 364 as customer related [in its most recent rate case.][20] DEP classified 95.9% of secondary poles in FERC Account 364 as customer related in its most recent rate case.[21]

Tr. Vol. 20, pp. 82-83.

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[19] F. Weston, et al., Charges for Distribution Service: Issues in Rate Design, p. 19, Regulatory Assistance Project (2000), available at http://pubs.narus.org/pub/536F0210-2354-D714-51CF-037E9E00A724.

[20] Application of Virginia Electric and Power Company, d/b/a Dominion North Carolina Power, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, Docket No. E-22, Sub 532 (March 31, 2016) DNCP Form E-1, Item 45F, p. 121.

[21] Duke Energy Progress, LLC's response to NCSEA Data Request No. 10-20, Attachment B, Docket No. E-2, Sub 1142 (detailing customer and demand percentages by FERC Account).

According to witness Barnes, DEC effectively classifies all shared secondary and primary poles in FERC Account 364 (as well as conductors in FERC Account 365) as customer-related. This is visible in the Company's COSS in the form of negative values for demand-related plant in service for FERC Accounts 364 and 365.[22] The negative values arise because the Company's calculated minimum system is larger than the actual FERC Account balance after removing direct assignments, which necessitates an adjustment. The true-up adjustment effectively results in a demand-related component of zero and a customer-related component of 100%. Similar differences are evident for other distribution Accounts, contributing to a wide range of estimates of residential customer units costs. Id.

The Commission recognizes that any approach to classifying costs has virtues and vices. It is important to effectively address issues such as those discussed by witness Barnes while at the same time recognizing the Company's substantial projected investments in its Power Forward programs. Just considering the grid modernization programs alone suggests that distribution system cost allocation among customer classes will take on heightened importance in future rate cases. The implications of using a suboptimal methodology or incorrectly applying an otherwise acceptable methodology, could be significant in the future. The Commission concludes that a more focused and explicit evaluation of options for distribution system cost allocation and an assessment of the extent to which any single allocation methodology is being consistently applied by the utilities is warranted. Therefore, the Commission directs the Public Staff to facilitate discussions with the electric utilities to evaluate and document a basis for continued use of minimum system and to identify specific changes and recommendations as appropriate. If the Public Staff ultimately recommends an alternative approach to minimum system as a result of this review, then the support for that position should be clearly defined. The Public Staff shall submit a report on its findings and recommendations to the Commission no later than the end of the first quarter of 2019 in a new, generic electric utility docket to be established by the Chief Clerk for this purpose.

Upon consideration of all the evidence in this docket, including the Stipulation, the Commission approves DEC's use of the minimum system methodology for cost allocation in this proceeding. The Commission places significant weight on the testimony of Company witness Hager regarding the Company's long history of employing the minimum system method and this method's alignment with cost causation principles. The Commission finds that the Company's use of the minimum system method for cost allocation in this proceeding is just and reasonable to all parties in light of all of the evidence presented.

**EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 29**

The evidence supporting this finding of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony of Public

[22] DEC Form E-1, Item 45D, p. 5.

NRLP Cross Exam Torres Direct EXHIBIT 2 I/A
DOCKET NO. E-34 SUBS 54 AND 55



# PUBLIC STAFF
# NORTH CAROLINA UTILITIES COMMISSION

Docket No. E-100, Sub 162

Before the North Carolina Utilities Commission

Report of the Public Staff on the
Minimum System Methodology of
North Carolina Electric Public Utilities

Report of
March 28, 2019

## Table of Contents

## I. Purpose of Report and Background

Pursuant to the Commission's *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction* issued in Docket No. E-7, Subs 819, 1110, 1146, and 1152, dated June 22, 2018 (2018 Rate Order), the Public Staff presents this report on its findings concerning the use of the minimum system methodology (MSM). Ordering Paragraph 38 of the 2018 Rate Order stated:

> "That the Public Staff shall facilitate discussions with the electric utilities to evaluate and document a basis for continued use of minimum system and to identify specific changes and recommendations as appropriate. If the Public Staff ultimately recommends an alternative approach to minimum system as a result of this review, then the support for that position should be clearly defined. The Public Staff shall submit a report on its findings and recommendations to the Commission no later than the end of the first quarter of 2019 in a new, generic electric utility docket to be established by the Chief Clerk for this purpose."

In compliance with the Commission's 2018 Rate Order, the Public Staff held meetings with Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP), and Dominion Energy North Carolina (DENC). At his request, the Public Staff also met with David Neal, the attorney representing the North Carolina Justice Center (NC Justice Center), North Carolina Housing Coalition (NC Housing Coalition), Natural Resources Defense Council (NRDC), and Southern Alliance for Clean Energy (SACE) (collectively, NC Justice Center, et al.) to discuss the use of the MSM going forward.

After its initial meeting with the electric utilities, the Public Staff requested DEC, DEP, and DENC to provide the following information in written responses:

1. Provide an overview and explanation of the current methodology for distribution plant classification.
2. Provide the history of the Company's use of the Minimum System.
3. Provide the history of allocating distribution costs as demand- and customer-related.
4. Explain the Company's current allocation of distribution costs and why it is appropriate.
5. Should the basic customer method of allocating costs be adopted?
6. Explain any other options for allocating distribution costs as customer- or demand-related.
7. Provide the Company's recommendations.

The responses to these initial questions are shown in Appendix 1.

The Public Staff conducted additional discovery on DEC, DEP, and DENC regarding their approach to the MSM, calculations, and application. The Public Staff also reviewed information provided by Mr. Neal regarding the allocation of distribution plant and the MSM.

The Public Staff also reviewed the National Association of Regulatory Utility Commissioners' "Electric Utility Cost Allocation Manual" (NARUC Manual), published in January 1992, for guidance on the allocation of electric utility costs. The NARUC Manual continues to be considered an important resource for the calculation and allocation of electric utility cost of service for regulatory commissions, consumer advocates, and parties before the Commission testifying on issues of cost-of-service and rate design.

## II. Overview of the Distribution System

The distribution portion of the typical electric power system is composed generally of wires, substations, transformers, and service connections that bring power to end-use consumers at a usable voltage level. Power generation resources are typically interconnected to the electric system by means of high voltage (100 kV and greater) transmission lines. Transmission-to-distribution substations "step down" these high voltages to what is recognized as the distribution components of the power delivery system. Customer meters represent the point at which the customer takes electric service from the utility. For accounting purposes, physical assets associated with the distribution system are assigned to specific FERC accounts and identified in cost of service studies,[1] as illustrated in Table 1.

**Table 1. FERC Accounts Related to the Distribution System.**

| FERC Account | Distribution Asset |
|---|---|
| 360-363 | Substations & Equipment |
| 364 | Poles, Towers, Fixtures |
| 365 | Overhead Conductors & Devices |
| 366 | Underground Conduit |
| 367 | Underground Conductor & Devices |
| 368 | Line Transformers |
| 369 | Service Connections/Drops |
| 370 | Meters |

[1] See Appendix 2 for a more detailed list and description of equipment included in each FERC account.

Residential customers, small to medium load non-residential customers, and most street and area lighting customers receive electric utility service from the distribution system. Larger non-residential customers, such as industrial customers, may receive service from either the distribution or transmission systems. This is an important distinction in the allocation of costs related to the distribution system. Under all cost-of-service methodologies, only customers receiving service at the distribution level are allocated costs associated with the distribution system.

## III. Overview of the Cost of Service Study

The cost-of-service study (COSS) is a tool for calculating and demonstrating how utility costs are functionalized, classified, and allocated or directly assigned among jurisdictions and customer classes. Without this basic tool, the utility, its customers, and other interested parties are unable to establish the cost and revenue relationships the Commission relies upon to determine just and reasonable rates.

Data used in a COSS is based on the official accounting books and records of the utilities. This data includes the number of customers and meters, the demand or capacity (kilowatts or kW) recorded during peak load periods, and the total energy (kilowatt-hours or kWh) used to serve each customer class, all of which ultimately drive the costs that each jurisdiction and customer class imposes on the utility system. Much of this data has historically been obtained through load research and direct measurement. However, with the deployment of advanced metering infrastructure (AMI) and the availability of more granular AMI data, utilities are able to ascertain more clearly and specifically how their customers utilize, and impose costs on their systems, and how rates can be designed to better reflect the true cost causation of utility service provided.

The four major steps in developing the COSS are: (1) the functionalization of the utility system; (2) the classification of costs; (3) the determination and definition of the customer classes; and (4) allocation of costs to jurisdictions and customer classes. The end result of this exercise is the calculation of a revenue requirement and return on rate base for each jurisdiction and customer class, which will serve as the foundation of rate design.

The first step, functionalizing the utility's costs, is used to categorize the costs associated with each major electric utility service function. This includes the production (generation) facilities needed to meet peak loads and generate required energy; high voltage transmission facilities to interconnect production facilities with the distribution system; distribution facilities needed to step down voltages to usable levels for most customers and to interconnect customers; and customer services such as metering, billing, and account management.

The second step, classifying each functionalized cost category, identifies costs as either the result of electric use or by the number and type of customer. Costs driven by electric use can be characterized in one of two ways: demand or energy. Electricity demand is measured in kilowatts (kW) and represents a rate of use. The measurement of demand is similar to the speedometer of a car, which registers how fast you are driving at any point in time. Just as car speed can vary from moment to moment, so can demand for electricity. Energy is measured in kilowatt-hours (kWh) and is a measurement of demand over time. Energy use is analogous to the car's odometer. Just as the car's odometer measures the total distance travelled in miles, measurement of energy usage reflects total electricity consumption over a period of time, typically a billing period. There are specific costs incurred by a utility related to a customer's demand (rate of energy use), as well as other costs that relate to a customer's total energy usage. Functionalized costs are typically classified as follows:

**Table 2. Classification of Electric Utility System Components.**

| Cost | Demand | Energy | Customer |
|---|---|---|---|
| Production | X | X | |
| Transmission | X | | |
| Distribution | X | | X |
| Customer | | | X |

The third step identifying the characteristics of the customer classes and rate schedules, to determine how customers will pay for utility service. Customer classes are developed from loads and load shapes of customers with similar usage characteristics.[2] Traditional COSS have generally identified customers as residential, non-residential or general service, industrial, and lighting. However, it is likely that additional customer classes will need to be established as the availability of AMI data will provide greater clarity into the variety of customers that are interconnected to the electric utility system.

The fourth step, assigning or allocating each cost to jurisdictions and customer classes, determines who pays for certain costs. Some costs are directly assignable to a particular jurisdiction or customer class because they are easily identified with a particular jurisdiction, customer class, or individual customer. Costs that cannot be directly assigned must be allocated based on their function and classification. Such costs are typically allocated using the demand, energy, and customer data determined earlier for the COSS. Costs that have been classified as production or transmission costs are allocated to the jurisdictions and customer classes, at least in part, on the basis of a peak demand factor. Distribution-classified costs are directly assigned to jurisdictions. However, the jurisdictional assignments are allocated to the customer classes based on non-coincident peak demand and the number of customers.

[2] The availability of AMI data is beginning to provide a better understanding of customer usage and load shapes that traditional load research could only estimate. A challenge going forward will be how to utilize new AMI data to determine whether the traditional classification of customers is appropriate for the widening variety of end-users that are presently classified as "residential" and "small general service." Once available, this data should help utilities and regulators to design rates that better reflect cost causation and reduce the potential for cross-subsidy among customer classes.

All costs incurred by the utility must be considered in the COSS, otherwise the utility is not able to reasonably recover its full costs to serve all of its customers. The COSS seeks to ensure that all jurisdictions and customer classes bear appropriate responsibility for the costs they impose upon the system. These cost causation principles serve as the foundation of rate design and should always represent the starting point for the rate designer to calculate and establish rates.

The selection of the methodology or approach to cost-of-service is a critical first step in the development of a COSS. The methodology is often a contentious issue among parties in a general rate case proceeding and has significant bearing on the development of a COSS and the allocation of production and transmission-related costs. The methodology selected dictates the process of calculating demand factors that are used in the allocation of demand-related costs. Some examples include a demand-only method based on the use of a single or multiple coincident peaks, versus a method that employs a weighted method using peak demand and energy to allocate certain costs of production and transmission. While not a subject of this report, the selection of a COSS methodology establishes a framework for the COSS itself and provides guidance on the relationships of demand, energy, and the number of customers that the rate designer will use to set rates for service.

## IV. Overview of Rate Design

The general purpose of electric utility rates is to produce revenues for service rendered. The purpose of a specific rate design is to ensure that the utility has a reasonable ability to recover its costs, provide a fair return to its shareholders, attract capital for future investment, and encourage efficient energy use. This report is focused on two principles and objectives that apply primarily to rates and rate schedules for residential and small general service customers, namely the classification of distribution costs as either "demand-related" or "customer-related" and the establishment of a basic customer charge that fairly and reasonably recovers costs.

The COSS informs rate design. The first step following the development of the COSS involves the determination of jurisdictional and customer class returns on rate base and associated revenue requirements. The second step involves the determination of demand, energy, and customer related components by jurisdiction and customer class. In addition, an understanding of the relationships of fixed versus variable costs, and marginal versus average costs, among others, is critical to ensuring that individual rate elements (e.g., basic customer charge, demand charge, energy charge, etc.) within a particular rate schedule are maintained as close to cost causation as possible.

For example, as a general rule, energy costs (costs measured on a per kWh basis) are recovered based on total energy (kWh) consumption. These costs typically consist of the cost of fuel consumed in electric generating plants, as well as other fuel-related (e.g., reagents) or energy-related (e.g., variable operating and maintenance costs and costs stemming from the production of coal combustion by-products) costs that are the direct result of operating the electric generating plants.

Likewise, demand costs (costs measured on a per kW basis) should be recovered based on some measurement of maximum demand (kW) at a particular point in time. Demand-related costs may be incurred and recovered based on a customer's maximum demand placed on the electric utility's entire system (e.g., on the generation units or the transmission system), often referred to as a "coincident peak demand" (CP), or based on demand placed on a more localized part of the electric utility system (e.g., the distribution system), often referred to as a "non-coincident peak demand" (NCP).

For generation and transmission assets, an individual customer's demand is typically measured as their contribution to total demand at the time of the utility's maximum aggregated demand (maximum demand of its customers, both wholesale and retail, at a single point in time). Generating plants and transmission assets are sized to meet a maximum system load, which is diversified and may or may not occur at the same time as the maximum demand of an individual customer of the utility.

For demand-related distribution assets, an individual customer's demand is typically measured as their contribution to the customer class maximum demand regardless of when it occurs relative to the maximum system demand. Some distribution assets are sized to meet a geographically localized maximum demand (e.g., primary conductor wires, distribution substation transformers) while other distribution assets are sized to meet the individual customer's maximum demand (e.g., distribution service transformers). However, distribution costs have both demand-related and fixed characteristics. While distribution related costs must be sized to meet some level of maximum demand, there is also a minimum cost for the distribution system that must be incurred regardless of demand.

In addition to the cost causation principles outlined above, the rate designer is also challenged with navigating different, often conflicting considerations. Those considerations are typically addressed in a general rate case and may include:

- Simplicity of rate designs;
- Rate and revenue stability;
- Migration of customers between rate schedules;
- Recovery of fixed and variable costs;
- Avoidance of rate shock;
- Mitigation of rate shock without exacerbating cross-class subsidies;
- Policy objectives that have been established by statue, rule, or prior Commission order;
- Innovative versus traditional rate designs;
- Appropriate price signals to customers; and
- Encouraging the efficient use of electricity.

The rate designer does not have the luxury of starting with a "clean slate" to meet all of these cost causation principles and other considerations. Many legacy rate schedules maintain rate designs that do not reflect many of today's energy realities.[3] For example, the basic residential rate schedule, which covers 90% of all residential customers, only utilizes two rate elements – a monthly flat basic customer charge and a per kWh energy charge. Any fixed costs not recovered from the flat monthly customer charge must be included in the variable energy charge. This traditional design was implemented for practical reasons, not for cost causation or theoretical rate design reasons. The recovery of fixed and non-energy variable costs through an energy charge leads to cross-subsidization within the residential class of customers. The ease of administering this rate design has been considered an acceptable trade-off until recently.

## V. <u>History and Use of the Minimum System Method in Classifying Distribution System Costs</u>

Cost-of-service analysts have traditionally recognized that costs associated with the distribution system exhibit characteristics that are both demand- and customer-related. The most basic, and least controversial, representation of customer-related distribution costs are those associated with facilities closest to the customer's point of delivery (e.g., the meter and service drop wires). However, the meter and service drop wires must be connected to the broader electrical grid in order to deliver energy to a customer. The distribution grid must be designed to be capable of meeting the maximum level of electrical demand placed on it by customer loads. The question then becomes, how much of the distribution grid should be considered demand-related versus how much should be considered customer-related, for cost recovery purposes? Historically, North Carolina's regulated electric utilities have relied on the MSM to answer this question.

The Public Staff reviewed Commission orders to gain an understanding of the history related to COSS and the application of MSM to the electric utilities. Our review focused on orders from the late 1960s and early 1970s, when Commission orders began to include detailed discussion of cost-of-service. At that time, electric utilities were experiencing significant growth in the demand for electric utility service and the need to build capacity to meet those demands, causing significant upward pressure on rates. The orders reflect that the Commission was concerned not only with the need to serve new electric demand, but also the need to balance the increasing costs between new and existing customers, as well as equitably balancing the rates of growth between residential and non-residential customers. While not an exhaustive list (see Appendix 3), the Public Staff notes several Commission orders that provide some foundation for the COSS, recognition that distribution system costs are both demand- and customer-related, and the use of MSM in apportioning distribution system costs. The Commission's June 28, 1973 Order in Docket No. E-22, Sub 141 was the only order found by the Public Staff that provides specific direction for calculating and applying the MSM. Since that time and until recently, the MSM has not been an issue that received prominent attention in Commission proceedings, even though there were numerous general rate cases in the 1970s and 1980s.

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[3] Energy efficiency programs, net metering, enhanced data, smart appliances, etc.

The MSM has also served as a foundation for establishing the flat monthly basic customer charge. Since the early 1970s, electric utilities have supported their requests to increase customer charges on the COSS determination of "customer-related" costs. There is no evidence to suggest utilities have ever requested a monthly customer charge that reflected the total cost per customer that was determined to be "customer-related" via the MSM.[4] In addition, the Public Staff is not aware of any case where it supported, or the Commission granted, a basic customer charge increase to reflect the total amount of costs designated as customer-related in a MSM study.

## VI. Methods Used to Classify Distribution Costs

As stated above, there is broad consensus that the distribution system is comprised of equipment that is both demand- and customer-related; however, there is little consensus on the calculation and determination of the portions classified as either demand- or customer-related.[5,6] In order to classify the distribution system components, the utilities use a method that defines the scope and purpose of each component of the distribution system as it relates to demand and customers.

The NARUC Manual dedicates a full chapter on the classification and allocation of distribution plant, including what amounts to the best explanation and description of the two approaches to classifying distribution costs – the minimum-size method or the minimum-intercept method (also called zero-intercept). Another approach, known as "basic customer method" has been discussed in recent general rate cases before the Commission. Each of these approaches is briefly discussed below.

### A. Minimum-Size Method

According to the NARUC Manual, the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum load requirements of the utilities' customers.[7] This involves a determination of the minimum sizes of poles, conductors, cables, transformers, and services installed by the utility. An average unit cost for each minimum-size piece of equipment is then determined and used to calculate the total cost for the entire inventory of equipment installed. The total cost of this equipment is then classified as "customer-related" costs. The "demand-related" portion is defined as the difference between the total investment in similar equipment and the customer-related portion.

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[4] The most recent rate case for each utility is - Docket Nos. E-2, Subs 1023 and 1142; E-7, Subs 1026 and 1146; and E-22, Subs 479 and 532.

[5] "New Uses for an Old Tool: Using Cost of Service Studies to Design Rates in Today's Electric Utility Service World," P. Morgan and K. Crandall, EQ Research, LLC, April 2017.

[6] P. 29, "Charging for Distribution Utility Services: Issues in Rate Design", December, 2000, Frederick Weston, The Regulatory Assistance Project, (Weston Report).

[7] P. 90, NARUC Manual

B. Minimum-Intercept Method

The minimum-intercept method attempts to identify and quantify the portion of the distribution system that would correspond to a hypothetical "zero-load" or "zero-intercept" situation.[8] The NARUC Manual recognizes that the minimum-intercept method is theoretically the most accurate; however, it requires significant data to calculate. As part of the calculation, a cost curve is developed for existing equipment of various sizes and loads. Regression analysis is then applied to the curve to calculate the point at which the trend line intersects the cost axis. The value at the intersection represents the "zero-load" cost. The "zero-load" cost per unit of equipment is then applied to each quantity of distribution equipment, regardless of size, to determine a total cost of zero-load equipment. The ratio of the zero-load costs to the actual total investment in equipment is determined to be "customer-related". The remainder is considered to be "demand-related."

C. Basic Customer Method

The basic customer method is not included in the NARUC Manual, but was introduced by intervening parties participating in recent general rate cases. The basic customer approach classifies 100% of all poles, wires, and line transformers as "demand-related" costs.[9] All other costs (those related to meters and service connections) are classified as "customer-related."[10,11]

## VII. Minimum System Method Calculations Used By North Carolina Electric Utilities

The utilities each have slightly different approaches to calculating the MSM for classifying their respective distribution systems as demand- or customer-related. While all three have adopted a minimum-size approach, the differences cause the individual calculations for each utility to yield different results. The differences include variation in the size of individual pieces of equipment, specific unit costs of that equipment, and the mathematical calculations. The methods used by each utility are discussed below.

A. DEC

DEC describes its approach for FERC Accounts 364, 365, 367 and 368 as a "modified minimum-size method." Instead of using actual, historical embedded costs of distribution plant, DEC estimates the current cost of a minimum system needed to support minimal load, based on assumptions and concepts that are consistent with the NARUC Manual. It then discounts those costs to simulate a vintage of historical embedded cost

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[8] P.92, ibid.

[9] P. 30, Weston Report.

[10] P. 34, ibid.

[11] The Weston Report also makes general reference to substations and substation equipment and indicates that this equipment is all "demand-related." However, the Weston Report is silent on the classification of underground equipment and conduit.

of the minimum system. This simulated value is then multiplied by the total inventory of equipment in each FERC account for the current year. The result is then de-escalated based on the age of the equipment using a Handy-Whitman Index for the average year the equipment was placed in service. A comparison to the current year's value is then made.[12]

As a second step, an index is calculated using the mid-year weighted average age of equipment. The average weighted age is then computed by dividing the sum of the weighted ages by the sum of all vintage costs for the equipment. The resulting weighted average age is then subtracted from the current year. The year calculated is then used to determine the Handy-Whitman average age index value for that year.

The third step involves taking the Handy-Whitman index value for the average age and multiplying it by the current year minimum costs determined in the first step to obtain the average historical cost. This value is then multiplied by the total inventory of equipment to produce a minimum installed cost. This amount represents the customer-related portion of the FERC account balance.[13]

DEC considers 100% of FERC Accounts 366, 369, and 370 to be customer-related; 100% of FERC Accounts 360, 361, and 362 to be demand-related; FERC Account 363 is not applicable to DEC.

B. DEP

The approach used by DEP in its most recent rate cases to estimate the minimum system for FERC Accounts 364, 365, 367, and 368 is slightly different from that used by DEC. DEP has relied on a 2010 study,[14] rather than the method employed by DEC that uses actual plant adjusted based on age. DEP indicated that the results of both the DEC method and DEP method produce comparable results; however, DEP acknowledges that its calculation is more complex and time-consuming than DEC's approach, and since they produce similar results, DEP plans to incorporate the DEC method of calculating the minimum system in future rate cases.

C. DENC

DENC has generally followed a method for calculating the minimum system as established by the Commission's June 28, 1973 Order in Docket No. E-22, Sub 141 (Sub 141 Order). That order prescribed the use of minimum system approach for FERC Accounts 364, 365, 367, and 368. The distribution line portion of FERC Account 360 was to be classified as 100% customer-related, while FERC Account 369 consisted of

[12] The Handy-Whitman Index calculates the cost trends for utility construction.

[13] Based on the explanation found on pages 7 and 9 of the report provided to the Public Staff on November 8, 2018. The same process is calculated for each applicable FERC account balance. There is some variation of this process for FERC Accounts 365, 367, and 368, but the general process is applied to all FERC accounts. A more thorough description is provided in the report itself, which is attached as Appendix 1.

[14] The Public Staff believes this study is a study of distribution system assets.

minimum-sized overhead and underground cable/conductors. The remaining FERC distribution accounts (361, 362, 363, and 366) were not specifically addressed in the Sub 141 Order.

DENC currently uses a MSM based on taking baseline material unit costs and then scaling these unit costs up to the size of the existing distribution system to calculate the customer-related component. More specifically:

- FERC Accounts 360 and 361: Ratios are developed between the overhead and underground components using the delineation of demand-related and customer-related components calculated via minimum-intercept for FERC Accounts 364, 365, 366, and 367. The sum of the customer-related portions of these accounts is used to calculate the percentage of demand-related and customer-related portions of overhead and underground, and primary and secondary account balances, which are then applied to the total balance for Accounts 360 and 361.

- FERC Account 362 and 363: DENC considers 100% of FERC Account 362 to be demand-related; FERC Account 363 is not applicable to DENC.

- FERC Account 364: DENC uses the embedded historical unit cost of a 35-foot pole[15] as determined from Company records. This amount is then multiplied by the total number of poles at primary and secondary levels to determine the customer-related amount for FERC Account 364. The demand-related portion is calculated as the difference between the total balance of FERC Account 364 and the customer-related amount.

- FERC Account 365: DENC uses 4/0 and under wire[16] as the minimum-size component for overhead conductors. The embedded historical unit cost of one pound of 4/0 and under wire is determined from Company records. Using a pounds/foot estimate for the wire, this unit cost is multiplied by the number of wire-feet of conductor in the existing distribution system (at primary and secondary levels) to determine the customer-related portion of FERC Account 365. The demand-related portion is calculated as the difference between the total balance of FERC Account 365 and the customer-related amount.

- FERC Accounts 366 and 367: DENC uses the cost of #4 underground primary cable for primary distribution or #8 secondary cable for secondary distribution as the minimum-size components.[17] Both costs are calculated using regression analysis. The present day unit cost for each size of cable is scaled to an estimated historical cost for the system using a de-escalation factor based on the Handy-Whitman Index. The resulting unit cost for each size of cable is multiplied by the total circuit feet of primary and secondary cable, respectively,

[15] Ordering paragraph 7d in the Sub 141 Order.
[16] Ordering paragraph 7e in the Sub 141 Order.
[17] Ordering paragraph 7f in the Sub 141 Order.

to determine the basis for the customer-related portions of primary and secondary cable. The demand-related portion is calculated as the difference between the total balance of primary and secondary costs, respectively, of FERC Account 367 and the customer-related amounts. The same percentages determined for FERC Account 367 are then applied to FERC Account 366.

- FERC Account 368: DENC uses the cost of a zero-intercept transformer as the minimum system component. This zero-intercept unit cost is multiplied by the total number of transformers to determine the customer-related portion of FERC Account 368. The demand-related portion is calculated as the difference between the total balance of FERC Account 368 and the customer-related amount.

- FERC Account 369: DENC calculates the customer-related portion of this account separately for overhead and underground service drops. The minimum-size component of an overhead service is 80 feet of #2 aluminum service conductor.[18] The present day unit cost for this service is scaled to an estimated historical cost for the system using a de-escalation factor based on the Handy-Whitman Index. The resulting unit cost is multiplied by the total number of overhead customers to determine the customer-related portion. For underground services, DENC uses a #8 service conductor[19] from the pad or pole to the facility (calculated using regression analysis). The present day unit cost for underground service is scaled to an estimated historical cost for the system using a de-escalation factor based on the Handy-Whitman Index. The resulting unit cost is multiplied by the total number of underground customers to determine the customer-related portion. The sum of each customer-related amount (overhead and underground) is subtracted from the total balance of FERC Account 369 to determine the demand-related amount.

- FERC Account 370: DENC considers 100% of FERC Account 370 to be customer-related.

## VIII. Public Staff's Policy Objectives for Cost-of-Service and Rate Design

The Public Staff's objectives regarding cost-of-service and rate design have incorporated the central tenet that the electric utility system is planned, built, and operated on the basis of providing safe and reliable electric utility service at the least reasonable cost possible, while meeting both the capacity and energy needs of the consuming public.

The Public Staff has advocated that cost-of-service should be the foundation of establishing the appropriate apportionment of the revenue requirement. Once the revenue requirement is calculated, it must be apportioned among the customer classes. The process of apportioning the revenue requirement then relies upon the overall

[18] Ordering paragraph 7h in the Sub 141 Order.

[19] Ibid.

jurisdictional return on rate base (ROR) that is calculated for the utility. The Public Staff continues to believe that the apportionment among the classes should accomplish four goals:

- Limit any revenue increase assigned to any customer class such that each class is assigned an increase that is no more than two percentage points greater than the overall jurisdictional revenue percentage increase, thus avoiding rate shock;
- Maintain a ±10% "band of reasonableness" for RORs, relative to the overall jurisdictional ROR such that to the extent possible, the class ROR stays within this band of reasonableness following assignment of the proposed revenue changes;
- Move each customer class toward parity with the overall jurisdictional ROR; and
- Minimize subsidization of customer classes by other customer classes.

## IX. Public Staff's Conclusions and Recommendations

The establishment of the proper fixed charge component of electric rates, also called the basic customer charge, has been an issue since the late 1960s and continues today. Parties advocating positions in general rate cases have based their positions on the COSS to support their individual points-of-view. Utilities have frequently advocated basic customer charges that trend more toward the full customer value identified in COSS calculated using the MSM. Other parties have advocated for a method that minimizes the classification of distribution costs that are customer-related.

The Public Staff has traditionally advocated a position that supported a basic customer charge based on the utilities' MSM, while recognizing that full movement would likely result in rate shock for many customers, particularly low-income and low-usage customers.

Trends in utility service that indicate more customer-owned generation is being installed and that those customers are buying less energy from the utilities further exacerbates the fixed cost recovery equity issue, leading to higher energy charges as utility sales diminish. Such a reality will have a significant impact on low-usage and low-income customers if all customers are not equitably participating in the recovery of fixed costs. While sales may decrease, fixed costs will likely not.

As a result of the examination of MSM, the Public Staff believes there are fixed costs of electric service that should be recovered from all customers; however, we acknowledge that there is a debate over the extent to which the costs[20] of electric utility service are fixed. Utilities tend to suggest that a significant portion of the costs incurred to provide utility service is fixed.[21] However, many economists suggest that, over the long-run, most costs are not fixed.[22, 23] This debate is difficult to reconcile because on the one hand, the utility's cost-of-service and the rates charged to recover these costs, are typically the result of a short-term perspective. In other words, utilities collect revenues from rates that remain static only until the next general rate case or rider proceeding. On the other hand, capital investments in utility service are long-lived, and often "lumpy"[24] investments, intended to provide service for 25 or more years.

The Public Staff believes that certain aspects of utility service, and the associated costs, are fixed. Once capital investments are made and the equipment is deemed used and useful for utility service, those costs are incorporated into the utility's revenue requirement calculations and will remain there until fully recovered.

All customers should bear some responsibility for the fixed costs of utility service. Fixed costs are incurred to produce, transmit, distribute, and administer electric utility service and are essential components of that service. Any utility customer interconnected to the utility's transmission and distribution grid for the purpose of receiving electric service should be responsible for some portion of fixed costs. Customers who are able to avoid contributing toward the recovery of fixed costs through the modification of consumption patterns are shifting costs incurred to serve them to other customers and customer classes.

The Public Staff is concerned about the impact of fixed cost recovery on low-income customers. Increases in fixed charges can disproportionately impact low-income and low-usage customers. However, the Public Staff believes that any efforts undertaken by the electric utilities to help low-income customers should be narrowly tailored, rather than setting fixed cost recovery artificially low. Considering any revenue not recovered in the fixed charge is recovered in the energy charge, setting the fixed charge too low results in a disproportionate increase on low-income customers that are also high-usage customers.

After our review, the Public Staff believes[25] that the use of MSM by electric utilities for the purpose of classifying and allocating distribution costs is reasonable for

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[20] The Public Staff considers fixed costs to be those that do not materially change in proportion to the delivery of capacity, energy, or the number of customers.

[21] See responses in Appendix 2.

[22] P.336, "Principles of Public Utility Rates," Public Utilities Reports, Inc., Bonbright, James C., Columbia University Press, New York, 1961.

[23] "Caught in a Fix – The Problem with Fixed Charges for Electricity," Synapse Energy Economics, Inc., February 9, 2016.

[24] An investment's "lumpiness" refers to the fact that it cannot be added in discrete increments to just match incremental demand requirements. Examples are baseload generating plants, substations, and transmission and distribution networks.

[25] The position of the Public Staff in any future rate case is dependent on the application filed in that case. The Public Staff reserves the right to develop a new or different position concerning the MSM in any future proceeding before the Commission.

establishing the maximum amount to be recovered in the fixed or basic customer charge. While not precise, MSM is a logical methodology for classifying costs of a distribution system as demand- or customer-related. However, the Public Staff believes the following principles should also be applied in establishing the fixed charge:

- The minimum amount recovered in the fixed charge for any rate class should be an amount determined by the "basic customer method" which reflects the customer meter, service drop, and any other facilities uniquely attributable to specific customers that are not already recovered through extra facilities charges.[26]

- Any increase in the fixed charge for any rate class should not exceed an amount that would recover more than 25% of the revenue increase that was assigned to that customer class.

The Public Staff also recommends:

- That future cost-of-service studies should be designed to provide a more accurate picture of the fixed costs of utility service, both as an aggregate cost to each customer class, and on a dollar per customer, dollar per kW of demand, and dollar per kWh basis. The Public Staff believes this will begin to provide information on the costs that are truly unavoidable, as well as provide a different perspective of any cross-subsidy issues among the customer classes. The Public Staff also believes this will provide vital information regarding the amount of any basic customer charge or other unavoidable charge that may be established.

- That cost causation principles in cost-of-service studies and rate design should be balanced with efforts to provide relief to low income customers. Any effort to provide relief to qualifying low-income customers should be considered separate from the setting of the general fixed cost recovery in a rate class.

- That utilities utilize data gained from AMI meters to implement rate design changes, including new customer classes, demand charges for all rate classes, and new rate designs.

- That the Commission should request that NARUC, or some other independent entity, undertake a study of these issues from a national perspective, so as to gain insight from best practices and ideas across the country.

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[26] Extra Facilities Charges are typically those charges associated with equipment that must be installed at or near the point of delivery due to the unique customer loads.

NRLP Cross Exam Barnes Direct EXHIBIT 3
DOCKET NO. E-34 SUBS 54 AND 55

I/A



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

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| **DOCKET NO. 34, SUB 54** | ) | |
| | ) | |
| **In the Matter of** | ) | |
| **Application for General Rate Case** | ) | |
| | ) | **RESPONSES OF NEW RIVER** |
| **DOCKET NO. 34, SUB 55** | ) | **LIGHT AND POWER** |
| | ) | **TO APPALACHIAN VOICES'** |
| **In the Matter of** | ) | **EIGHTH SET OF WRITTEN** |
| **Petition of Appalachian State University** | ) | **DISCOVERY REQUESTS** |
| **d/b/a New River Light and Power for an** | ) | |
| **Accounting Order to Defer Certain Capital** | ) | |
| **Costs and New Tax Expenses** | ) | |

New River Light and Power ("Company" or "NRLP") hereby responds to the eighth set of written discovery requests by New Appalachian Voices ("App Voices") in the above-captioned docket as follows:

Appalachian Voices
Eighth Set of Data Requests to NRLP
In the Matter of Application for General Rate Case
(NCUC Docket Nos. E-34, Sub 54, and E-34, Sub 55)
Item No. 8-1

**NEW RIVER LIGHT AND POWER**

**Request**:

Please refer to page 19, beginning at line 1 of NRLP witness Randall Halley's rebuttal testimony ("Halley Rebuttal"), which provides the following:

> I used a modified version of the minimum system method, in which I did not assign any rate base costs that would typically be included in the customer component. Utilizing the traditional minimum system approach would have generated a monthly distribution system cost for a residential customer at a level greater than the $36.00. My approach is more in line with past North Carolina utility regulation than the approach offered by Mr. Barnes. The minimum system method has been used in other electric rate case decisions, it has been supported by the Public Staff in past cases, and it is now required in N.C.G.S. 62-133.16(b) for electric multiyear rate plan cases.

a. Please provide Witness Halley's workpapers for his "modified version of the minimum system method" analysis in executable spreadsheet format with all formula and file linkages intact.

   **Response**: This spreadsheet was provided in NRLP's response to Appalachian Voices Data Request #2 in the file NRLP Response to App Voices DR2-7 - Exhibit REH-14 Cost of Service.xlsx. For ease of reference, NRLP is attaching this same file. The calculation for the monthly $36.00 residential customer cost is on Line 36.01.

b. Please identify the specific NCUC decisions, including the docket, date, and page numbers that support Witness Halley's statement that "My approach is more in line with past North Carolina utility regulation than the approach offered by Mr. Barnes."

   **Response**: The Commission approved an increase in the residential class BFC to $14.00 in Docket No. E-2, Sub 1142. See pages 106 and 114 of the Order issued February 23, 2018. DEP used the minimum system method in that case; the residential BFC result was a stipulated compromise for purposes of gradualism, which was the Public Staff's position, but did not result in a different methodology being used. The BFC for all other classes was stipulated at the amounts proposed by Duke.
   See also the Order of June 22, 2018, in Docket No. E-7, Sub 1146, pages 84-87 where the Commission approved DEC's use of the minimum system methodology in that case

for cost allocation purposes. For BFC rate design, the Commission simply tracked its decision in the DEP case by setting the residential BFC at $14.00, and noting that this reflected a compromise that fell within the competing positions of different parties. The Commission declined to endorse a methodology for rate design purposes as opposed to cost allocation purposes. Regarding use of the minimum system methodology for cost allocation, the Order summarizes testimony from Duke witness Hager:

> On cross-examination by counsel for NCSEA, witness Hager testified regarding the Company's long history of using the minimum system method, stating that "the minimum system study has long been used in the cost of service study to develop the customer-related costs that are then passed to rate design and are the basis of rates that are ultimately approved by the Commission." Id. at 138-39. The Company "filed minimum system study results in every rate case for a long time" and the Commission "has approved the results of that." Id. at 143.

In Docket No. E-2, Sub 1219, the Company did not propose to raise its BFC but noted it was justified by the minimum system methodology cost allocation. Intervenor testimony opposed that position. The Commission ruled with DEP in its April 16, 2021, order. At pages 176-77 the Order summarizes Duke witness Pirro as saying:

> Witness Pirro also disagreed with NCJC et al.'s position that the current residential BCC should be reduced. Tr. vol. 11, 1121-22. He explained that the rates and rate design supported by his testimony are based upon the COSS, including the minimum system study, performed by the Company, accepted by Public Staff, and approved in previous rate cases by the Commission. *Id*

In Docket No. E-100, Sub 180, the Commission order of March 23, 2023, states in footnote 2:

> This issue, commonly referred to by the parties and throughout this order as "cross-subsidization," can be explained in the following way. Duke's existing tariffs to residential customers include a fixed charge component, referred to as the monthly "basic facilities charge," and a charge based on electricity consumption. Duke contends that the basic facilities charge, as established in its general rate cases, does not fully cover all the fixed costs of service to an individual residential customer. **<u>The Commission has, to date, accepted Duke's cost-of-service studies and has set the basic facilities charge at levels that are less than Duke's cost-of-service studies show are necessary for full recovery of its fixed costs of service.</u>** The remaining portion of fixed costs not covered by the basic facilities charge is recovered instead through the variable volumetric charge for energy usage. For non-NEM

> customers, this paradigm generally leads to full recovery of all fixed and variable costs of service. NEM customers, however, are effectively able to reduce or even eliminate in some instances and for some billing periods their energy charges, thereby avoiding the portion of the utility's fixed costs that are recovered through the variable energy charge and not through the monthly basic facilities charge. The effect of this is that those fixed costs unrecovered from NEM customers must be recovered from non-NEM customers. This potential shifting of a portion of the utility's fixed costs of service from NEM to non-NEM customers is what is called "cross-subsidization."

(Emphasis added.)

NRLP has not researched past cases beyond these examples.

c. Is it Witness Halley's contention that N.C.G.S. 62-133.16(b) requires the use of the minimum system method for the purpose of classifying customer-related costs for the purpose of setting basic facilities charges in this proceeding?

<u>**Response**</u>: As stated in the testimony, N.C.G.S. 62-133.16(b) requires use of the minimum system method for electric multiyear rate plan cases. NRLP's rate case is not a multiyear rate plan; however, NRLP is not aware of any reason why a different method would be more appropriate for a traditional rate case than for a multiyear rate plan. The new legislation for multiyear rate plans signals a legislative preference for the minimum system method, and while that is not expressly required for traditional rate cases, it is appropriate to take into consideration for traditional rate cases.

Appalachian Voices
Eighth Set of Data Requests to NRLP
In the Matter of Application for General Rate Case
(NCUC Docket Nos. E-34, Sub 54, and E-34, Sub 55)
Item No. 8-2

**NEW RIVER LIGHT AND POWER**

**Request**:

Please refer to page 16, lines 12-13 of Halley Rebuttal, which provide that "[t]he value of solar can only be worth the amount of actual costs avoided by NRLP at the time a customer-sited PV generation is operating."

a. Please specifically explain how Mr. Barnes' analysis of solar value violates this precept.
b. Please explain how Mr. Barnes' methodology for identifying the value of solar energy at the time it is generated is different from NRLP's methodology for quantifying the value of load reduction under its proposed Interruptible Rate.

**Response**:

a. As stated in the testimony and supporting exhibits, the value of solar to the utility cannot exceed the actual cost of providing service to the customer. In Mr. Barnes Table 3 on Page 28 of his testimony, his Estimated Avoided Distribution Cost Rate ($/kWh) for NRLP is $0.05201. NRLP's actual cost for distribution service is $0.032612 per kWh (Line 4 of Exhibit REH-16-NRLP Rebuttal) for a residential customer. It is Mr. Halley's opinion that the avoided cost cannot be higher than the utility's actual cost to serve.

b. Mr. Halley cannot speak to the thought process Mr. Barnes had for using his methodology in identifying the value of solar. The Halley's methodology is explained in his testimony and the schedules/exhibits attached thereto.

Appalachian Voices
Eighth Set of Data Requests to NRLP
In the Matter of Application for General Rate Case
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Item No. 8-3

## NEW RIVER LIGHT AND POWER

**Request**:
Please refer to page 17, lines 13-17 of Halley Rebuttal, which discuss NRLP's approach to identifying the costs and benefits of customer-sited solar generation, and conclude as follows:

> NRLP believes its approach is consistent with the position of Duke Energy that it is appropriate to recover fixed costs from solar customers to prevent or reduce cross subsidies. This approach has been supported by the Public Staff. It is reflected in the Commission's March 23, 2023, order in Docket No. E-100, Sub 180.

Please identify with specificity the similarities and differences between Duke Energy's methodology and NRLP's methodology for determining the costs and benefits of customer-sited solar generation and provide specific references where applicable to Duke Energy's methodology.

**Response**: NRLP has not conducted a detailed comparison of the similarities and differences between Duke Energy's methodology and the NRLP methodology. The point being made in the quoted selection of witness Halley's testimony is that customers with their own generation should have a rate design that avoids cross-subsidization. Where a portion of fixed costs have been recovered through volumetric charges, a reduction in volumetric sales to customers with self-generation means those customers are not paying their fair share of fixed costs. Duke Energy sought to address that concern with a multi-pronged approach that includes a minimum monthly bill, a monthly grid access fee, and non-bypassable charges among other provisions. NRLP is taking a simpler approach of addressing fixed cost recovery in its proposed standby charge. See pages 6–8 and 34-35 of the Sub 180 Order. The principle is the same: recovery of fixed costs is appropriate in either net metering or net billing for customers with their own solar generation.

Appalachian Voices
Eighth Set of Data Requests to NRLP
In the Matter of Application for General Rate Case
(NCUC Docket Nos. E-34, Sub 54, and E-34, Sub 55)
Item No. 8-4

**NEW RIVER LIGHT AND POWER**

**Request:**

Please refer to Halley Rebuttal at page 17, lines 1-3, which state the following: "All of NRLP's distribution system costs are fixed and would not be avoided if a customer installed and used PV generation. Therefore, it is impossible for the value of solar in a net billing arrangement to be greater than the retail rates."

a. In referring to "distributed system costs", is Witness Halley referring solely to the embedded NRLP distribution costs as identified in the cost-of-service study?
b. Does Witness Halley consider all costs apart from NRLP distribution costs to be marginal costs that can be avoided by reducing load during peak times? If not, please identify which costs Mr. Halley considers to be marginal costs that can be avoided by reducing load during peak times and which he does not.
c. Please confirm that the costs that NRLP incurs for 3rd-party generation, transmission, and distribution services are based on demands during specified peak hours rather than on total energy usage during all hours of the year. If your response is anything other than an unqualified confirmation, please explain in detail.

**Response:**

a. Yes
b. NRLP's capacity production costs from CPP and transmission costs from DEC could be avoided by reducing loads during the peak hours.
c. The capacity production costs from CPP and the transmission costs from DEC are based on monthly coincident peak hours. The monthly distribution costs from BREMCO are based on NRLP's previous year's load ratio share multiplied by the current year's annual budget for total system operations divided by 12. The monthly energy production costs from CPP are based on the amount of energy purchased by NRLP.

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In the Matter of Application for General Rate Case
(NCUC Docket Nos. E-34, Sub 54, and E-34, Sub 55)
Item No. 8-5

**NEW RIVER LIGHT AND POWER**

**Request**:

Please refer to Halley Rebuttal at p. 12 stating "Mr. Hoyle takes an approach to cost of capital that is different from anything I have ever seen filed with this or any other Commission."

a. Please provide a list of all rate cases Mr. Halley has seen filed with the North Carolina Utilities Commission related to determining the cost of capital and/or return on equity for utility-type companies that are divisions of a state-controlled educational non-profit institution.
b. Please provide a list of all rate cases Mr. Halley has seen filed with any other public utility commission related to determining the cost of capital and/or return on equity for utility-type companies that are divisions of a state-controlled educational non-profit institution.

**Response**: Witness Halley's testimony referred to all utility rate cases he has reviewed, not just cases involving "utility-type companies that are divisions of a state-controlled educational non-profit institution." He believes fundamental ratemaking principles should apply similarly to regulated utilities across the board. However, with regard to state universities, the applicable cases are the rate cases for the electric distribution systems of Western Carolina University and New River Light & Power. As shown below, none of those cases appear to have adopted the municipal bond rate as a fair return on equity. Instead, the approved ROEs are substantially larger than the debt costs.

In Docket No. E-34, Sub 46, on March 29, 2018, the Commission approved a settlement cost of capital for NRLP as:

> 29. The Parties have agreed on a 6.525% overall rate of return. The Parties' further agreed that the overall rate of return reflects a hypothetical capital structure for NRLP consisting of 50% debt and 50% equity, that the reasonable and appropriate cost of debt for purposes of this proceeding is 3.80%, and that the reasonable and appropriate cost of equity for purposes of this proceeding is 9.25%.

In Docket No. E-34, Sub 32, in a May 1, 1997, recommended order, the Commission approved the following cost of capital for NRLP:

> 9. The overall rate of return which the Company should be allowed to earn on original cost rate base is 10.65%. This return is based on a capital structure of 6.42%

debt and 93.58% equity, with a cost rate of 5.62% for debt and 11.0% for common equity.

Similarly, the NRLP rate case order in Docket No. E-34, Sub 28, issued February 19, 1991, found that

> 10. The overall rate of return which the Company should be allowed to earn on original cost rate base is 11.65%. This return is based on a capital structure of 6.58% debt and 93.42% equity, with a cost rate of 6.62% for debt and 12.0% for common equity.

In the December 21, 1984, NRLP rate case order in Docket No. E-34, Sub 23, the Commission found:

> 13. The overall rate of return which the Company should be allowed to earn on the original cost rate base is 13.81%. This overall rate of return is derived by granting a 14.35% cost of equity on an equity ratio of 91.93% and a 7.65% cost of debt on a debt ratio of 8.07%.

In the WCU rate case order in Docket No. E-35, Sub 51, issued October 29, 2020, the Commission approved a settlement cost of capital:

> 20. The Parties agreed on a 6.32% overall rate of return. The stipulated overall rate of return reflects a hypothetical capital structure for WCU consisting of 50% debt and 50% equity.
>
> 21. The reasonable and appropriate cost of debt for purposes of this proceeding is 3.64% and the reasonable and appropriate cost of equity for purposes of this proceeding is 9.00%

In the WCU rate case order in Docket No. E-35, Sub 45, issued May 25, 2016, the Commission approved a settlement cost of capital:

> 19. The Parties agreed on a 6.740% overall rate of return. The stipulated overall rate of return reflects a hypothetical capital structure for WCU consisting of 50% debt and 50% equity. The reasonable and appropriate cost of debt for purposes of this proceeding is 4.23%, and the reasonable and appropriate cost of equity for purposes of this proceeding is 9.25%.

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Item No. 8-6

**NEW RIVER LIGHT AND POWER**

**Request**:

Please refer to the following:

Halley Rebuttal at page 10, lines 3-5: "I do not have his experience with using the models, but it is evident to me that his recommendation is unreasonably low for several reasons."
Halley Rebuttal at page 13, lines 13-17:

> Mr. Hoyle seems to think a DCF analysis would provide a better basis for determining a risk-adjusted ROE. I disagree. DCF models can be informative, but the models used by financial analysts can produce results that vary widely with the inputs used, and the inputs used appear to vary widely depending on whether the analyst is testifying for the utility or another party.

a. Please confirm that NRLP does not pay dividends to equity shareholders.

   **Response**: NRLP does not have equity shareholders in the traditional sense, although it is required by statute to remit "net profits" to the Appalachian State University Endowment.

b. Please confirm that NRLP does not have any common equity shareholders.
   **Response**: NRLP does not have equity shareholders in the traditional sense, although it is required by statute to remit "net profits" to the Appalachian State University Endowment.

c. Please confirm that NRLP does not have any common equity shares.
   **Response**: NRLP does not have common equity shares as it does not issue stock.

d. Please confirm that NRLP does not have an earnings per share ("EPS") metric.
   **Response**: NRLP does not have an EPS metric.

e. Does Mr. Halley disagree that a DCF analysis utilizing a retention growth rate (i.e., DCF analysis based on growth driven by retained earnings) would provide a better basis for determining an ROE for a retail electric provider that has no common equity shareholders, EPS, or dividend payments? Please explain why or why not.

**Response**: Mr. Halley does not have expertise with DCF analyses, was not asked to perform one for NRLP or compare its results to risk-adjusted ROE, and therefore does not have an opinion on this statement, other than the general observations discussed in his testimony.

Appalachian Voices
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(NCUC Docket Nos. E-34, Sub 54, and E-34, Sub 55)
Item No. 8-7

**NEW RIVER LIGHT AND POWER**

**Request**:

Please refer to Halley Rebuttal at page 15, lines 14-15, where Mr. Halley reiterates his original cost of capital recommendation with the following statement: "Although I believe recent events could justify a higher overall return, my recommended overall cost of capital remains at 7.007% as summarized below."

a. Please explain why Mr. Halley continues to support his original recommended cost of debt for NRLP of 4.2% given that recent events have seen municipal bond yields in the range of ASU's credit rating decline to around 3.8% as of early June and NRLP's embedded cost of debt is below 4.2%.

   **Response**: Mr. Halley believes that the overall returns and the ROEs approved for other utilities are the most appropriate guidance for determining overall return and ROE for NRLP.

b. If, in the near future, new debt were to be issued on behalf of NRLP at 1.6% - municipal bond yields in the range of ASU's credit rating as of late June 2021 – would Mr. Halley support a cost of debt for NRLP of 1.6%? Please explain why or why not.

   **Response**: As discussed in Mr. Halley's direct testimony, use of the actual cost of debt may make sense in connection with use of the actual capital structure. With an imputed debt component in the capital structure, use of the actual cost of debt would unfairly depress the overall rate of return. Mr. Halley has no basis to believe that municipal bond yields are an appropriate proxy for the cost of debt for NRLP. NRLP witness Jamison would have more knowledge on that issue.

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In the Matter of Application for General Rate Case
(NCUC Docket Nos. E-34, Sub 54, and E-34, Sub 55)
Item No. 8-8

**NEW RIVER LIGHT AND POWER**

**Request**:

Please refer to page 16, lines 8-9 of the Halley Rebuttal, which provide the following: "Mr. Barnes utilizes theoretical exercises to imply that the value of solar is greater than the actual cost of NRLP's retail rates billed to its customers."

a. Does Witness Halley disagree with Mr. Barnes' calculations of demand unit costs using data from NRLP's cost of service study? Please explain in detail any errors that Witness Halley has identified in Mr. Barnes' calculations of demand unit costs.
b. Does Witness Halley believe that the demand unit costs used in Mr. Barnes' analysis are theoretical?
c. Please describe any disagreements that Witness Halley has with any of the five effective capacity contribution scenarios Mr. Barnes evaluated and why that renders them less accurate than the effective capacity contributions used by Witness Halley.
d. Please identify all ways in which Mr. Barnes' calculations are "theoretical"; explain how Witness Halley's calculations differ for each of these aspects; and explain how those differences render Witness Halley's calculations less theoretical.

**Response**: Mr. Halley cannot speak to Mr. Barnes calculations. However, Mr. Barnes' calculations do generate an avoided cost higher the actual cost of service to NRLP customers. It is Mr. Halley's opinion that, as a practical matter, the avoided cost cannot be higher than the utility's actual cost to serve.

Appalachian Voices
Eighth Set of Data Requests to NRLP
In the Matter of Application for General Rate Case
(NCUC Docket Nos. E-34, Sub 54, and E-34, Sub 55)
Item No. 8-9

**NEW RIVER LIGHT AND POWER**

**Request**:

Please refer to page 16, lines 16-20, of NRLP witness David Jamison's rebuttal testimony ("Jamison Rebuttal"), which reference university endowment funding from utility operations and provide as follows: "It is analogous to paying dividends to stockholders - there is no guarantee or contractual right of the endowment to receive a certain level of payments from the utility's earnings, but any amount above the utility's long-term internal capital and operating needs must go to the endowment."

a. Witness Halley's Exhibit REH-13 showed an unadjusted 2021 return on rate base (Line 226) greater than $1.8 million. Please provide the dollar amount and the percentage amount of NRLP's actual return on rate base for the years 2016-2021 and the dollar amount and percentage of NRLP's actual return on rate base that was paid into ASU's endowment fund for the years 2016-2021.
b. Please provide documentation of all investments NRLP has received from the ASU endowment and documentation of all non-debt and non-NRLP-retained earnings capital ASU has provided to NRLP during the previous 10 years.

**Response**:

a. Objection in that this request mis-states and mischaracterizes Halley Direct Exhibit REH-13. The net income and return on investment are shown on Exhibit 2 to the Petition to Defer provided herewith for the four years 2018 through 2021 which can be found at this link https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=93226414-790e-4aa5-9ef2-44a7f5c52913.

b. The University has not provided any cash investments or any other University funds to NRLP in the past 10 years. Therefore, there is no documentation to provide.

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Item No. 8-10

**NEW RIVER LIGHT AND POWER**

**Request**:

Please refer to page 10, lines 13-15, of Jamison Rebuttal, which provide the following: "the University is limited in the amount of debt that can be added to its balance sheet without exceeding target metrics identified in our Debt Management policy."

a. Please provide a written copy of Appalachian State University's debt management policy ("Debt Policy").
b. Please cite all the statutory provisions governing or requiring the target metrics set forth in the Debt Policy.
c. Please specify the amount of debt that can be added to Appalachian State University's balance sheet and the relevant target metrics set forth in the Debt Policy.
d. Has Appalachian State University ever taken on debt in excess of the target metrics set forth in the Debt Policy or any prior versions of the same? If so, please identify the instances when this has occurred, the level of debt at issue, and the impact on the university's credit rating.

**Response**:

a. The University's Debt Management Policy is enclosed.

b. Chapter 116D of the North Carolina General Statues outlines the general provisions for the issuance of Higher Education Bonds. Article 5, "Managing Debt Capacity" was added by S.L. 2015-97. Under this provision, the Board of Governors is required to provide the estimated debt capacity of the UNC System for the upcoming 5 fiscal years to the Governor and the General Assembly. The act specifically requires the calculation target and ceiling ratios for debt to obligated resources and target and floor percentages for the five-year payout ratio.

c. Before discussing the Appalachian's debt capacity, there are some extremely important factors that need to be taken into consideration. First (and I cannot stress this enough), debt capacity does not equate to debt affordability. This distinction is critical to understanding public financing decision. Debt capacity alone is not the only metric or factor that the University considers when deciding whether or not to issue debt, in what amounts, and under what terms. A broader analysis must include a general assessment of the institution's overall projected fiscal position in order to assist leadership and other stakeholders to identify trends and challenges that may arise in the future. Debt affordability is a much more detailed and comprehensive calculation, performed down to the project level, to ensure that the appropriate levels of resources or future revenues can support capital projects in the long run. Lastly, debt capacity and the use of the ratios absolutely cannot predict any ratings outcome provided by a rating agency. There are numerous qualitative and quantitative factors that are considered when a rating is provided.

The ratios and the targets outlined in the Debt Capacity Study are defined in the University's Debt Management Policy.

The most recent debt capacity study projects Appalachian's debt capacity for all operations to be as follows:

| **Fiscal Year** | **Debt to Obligated Resources (Calculated)** | **Debt Obligated Resources (Ceiling)** | **Debt Capacity Calculation** |
|---|---|---|---|
| **2023** | 1.23 | 1.5 | 72,637,626 |
| **2024** | 1.11 | 1.5 | 111,273,023 |
| **2025** | 1.01 | 1.5 | 144,706,686 |
| **2026** | 0.91 | 1.5 | 179,415,151 |
| **2027** | 0.82 | 1.5 | 213,515,656 |

Other relevant target metrics are defined in the University Debt Management Policy and outlined in the Debt Capacity Study, which speak for themselves

d. The university has met the statutorily required and defined target ratios for all years the Debt Capacity Study has been produced. There have been some instances where the non-statutorily required ratios have not met the metrics. This may apply to only one or more projected future fiscal years. In these situations, the overall trend is considered when evaluating the projected results. These factors are something that management would take into consideration; however, there may be strategic reasons to exceed a target ratio at any point in time to meet the goals of the University's capital plan. Additionally, the Debt Capacity ratio calculations are based on a more conservative available funds calculation.

Again, I want to reiterate that Debt Capacity is only one tool that is used to evaluate the complex capital structure of a public university. Debt Capacity should not be confused with debt affordability and cannot be used to predict a credit rating outcome; it is simply a way to understand the effect the levels of debt have on financial ratios as related to the University's balance sheet, which could identify markers to consider for the fiscal health of the institution.

As a result, in response to the question pertaining to the effect these ratios have on the University's credit rating I cannot answer what impact these specific set of ratios has had, or may have, on credit ratings. A separate set of financial ratios, proprietary to the ratings agency, is used as one quantitative factor presented to the ratings committee along with other qualitative factors. That being said, it is safe to assume that, if the University maxed out its debt capacity, it could have a negative impact on affordability calculations and subsequent ratings.

Appalachian Voices
Eighth Set of Data Requests to NRLP
In the Matter of Application for General Rate Case
(NCUC Docket Nos. E-34, Sub 54, and E-34, Sub 55)
Item No. 8-11

**NEW RIVER LIGHT AND POWER**

**Request**:

Please refer to page 12, lines 4-16 of Jamison Rebuttal.

Please confirm that the requirements set forth therein would not apply to bonds or debt related to NRLP's utility operations.

**Response**:

Please see the Advice Letter from the North Carolina Attorney General's Office regarding the authority to issue debt for electric utilities, provided herewith.

Appalachian Voices
Eighth Set of Data Requests to NRLP
In the Matter of Application for General Rate Case
(NCUC Docket Nos. E-34, Sub 54, and E-34, Sub 55)
Item No. 8-12

**NEW RIVER LIGHT AND POWER**

**Request**:

Please refer to page 12, lines 17-23, and page 13, lines 1-5 of Jamison Rebuttal.

a. Please cite the statutory provisions that govern the delegation of bond approval authority to the university boards of trustees.
b. Please confirm that for present purposes, the sole entity with approval authority over NRLP utility operation bonds is the Appalachian State University Board of Trustees.
c. Please confirm whether the Debt Policy, specifically the target metrics governing the amount of debt that can appear on the balance sheet, would apply to this debt.

**Response**:

a. Please see the Advice Letter from the North Carolina Attorney General's Office regarding the authority to issue debt for electric utilities, provided herewith.
b. Please see the Advice Letter from the North Carolina Attorney General's Office regarding the authority to issue debt for electric utilities, provided herewith.
c. Confirmed, NRLP's debt balances are considered in the balances used to calculate the target metrics.

Appalachian Voices
Eighth Set of Data Requests to NRLP
In the Matter of Application for General Rate Case
Item No. 8-13

**NEW RIVER LIGHT AND POWER**

**Request**:

Please refer to page 13, lines 6-10 of Jamison Rebuttal and page 13, lines 13-23, and page 14, lines 1-8 of Halley Rebuttal.

a. Please confirm that the debt capacity study identified therein is the same study required under N.C.G.S. § 116D-56. If not, please cite the statute requiring a debt capacity study.
b. Is it NRLP's contention that a DCF analysis would not be necessary in part because the debt capacity studies NRLP conducts help it to develop a comprehensive financing strategy that optimizes NRLP's capital structure in light of its status as a division of a state-controlled educational non-profit institution?

**Response**:

a. Confirmed

b. Yes. A DCF analysis is not necessary to develop a comprehensive financing strategy for NRLP. The process and considerations discussed in Mr. Jamison's prefiled rebuttal testimony are both necessary and sufficient for that purpose.

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



# JUSTIN R. BARNES

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## 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**

| Type | Revenue | Demand | Unit Cost ($/kW) | $/kWh Rate | Savings per kW Solar Unit Value ($/kW) | Unit Value $/kWh Production | % Retail Rate | |
|---|---|---|---|---|---|---|---|---|
| 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 | | |
| 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**

| Type | Revenue | Demand | Unit Cost ($/kW) | $/kWh Rate | Savings per kW Solar Unit Value ($/kW) | Unit Value $/kWh Production | % Retail Rate | |
|---|---|---|---|---|---|---|---|---|
| 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 | | |
| 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**

| Type | Revenue | Demand | Unit Cost ($/kW) | $/kWh Rate | Savings per kW Solar Unit Value ($/kW) | Unit Value $/kWh Production | % Retail Rate | |
|---|---|---|---|---|---|---|---|---|
| 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 | | |
| 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**

| Type | Revenue | Demand | Unit Cost ($/kW) | $/kWh Rate | Savings per kW Solar Unit Value ($/kW) | Unit Value $/kWh Production | % Retail Rate | |
|---|---|---|---|---|---|---|---|---|
| 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 | | |
| 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** |

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**RECONCILIATION OF COMPANY &**
**PUBLIC STAFF PROPOSED GROSS REVENUE INCREASE**
**For the Test Year Ended December 31, 2021**

**Public Staff Accounting Exhibit I**
**Schedule 1**

| Line No. | Item | Revenue Effect | |
|---|---|---|---|
| 1. | **Company's proposed increase** | **$ 4,671,936** | **[1]** |
| 2. | **Public Staff adjustments: [2]** | | |
| 3. | Gross up Company proposed increase to revenue requirement level | 1,418,918 | |
| 4. | Impact of reducing rate of return from 7.007% to 6.07% | (399,230) | |
| 5. | Adjustment to Campus Substation deferral | (156,253) | |
| 6. | Remove UBIT deferral | (497,518) | |
| 7. | Removal of non-utility items | 5,508 | |
| 8. | Include materials and supplies inventory | (4,780) | |
| 9. | Adjust prepaid expenses | (592) | |
| 10. | Adjustment to reduce AFUDC | (1,585) | |
| 11. | Adjustment to working capital | (22,760) | |
| 12. | Customer growth and usage | (881,901) | |
| 13. | Test year inflation | (224,685) | |
| 14. | Adjustment to regulatory fee | (12,549) | |
| 15. | Adjustment to depreciation expense | 173,548 | |
| 16. | Rounding | 48,613 | |
| 17. | **Total Public Staff adjustments (Sum of Lines 3-16)** | **(555,266)** | |
| 18. | **Public Staff recommended increase (L1 + L17)** | **$ 4,116,670** | **[3]** |

[1] Per Company Exhibit REH-13.
[2] Calculated based on Public Staff Accounting Exhibit I, Schedules 2, 3, 4, 5 and back up schedules.
[3] Public Staff Accounting Exhibit 1, Schedule 5, Line 5.

**NEW RIVER LIGHT AND POWER COMPANY**

Docket Nos. E-34, Sub 54 and Sub 55
INDEX TO PUBLIC STAFF ACCOUNTING EXHIBIT I
For the Test Year Ended December 31, 2021

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**CALCULATION OF GROSS REVENUE EFFECT FACTORS**

**Public Staff Accounting Exhibit I**
**Schedule 1-1**

| Line No. | Item | Capital Structure [1] (a) | Cost Rates [2] (b) | | Retention Factor (c) | | Gross Revenue Effect [5] (d) |
|---|---|---|---|---|---|---|---|
| 1. | **Rate Base Factor** | | | | | | |
| 2. | Long-term debt | 50.00% | 3.23% | | 0.9958339 | [3] | 0.0162200 |
| 3. | Common equity | 50.00% | 8.90% | | 0.7670411 | [4] | 0.0580200 |
| 4. | Total (Sum of Lines 1-3) | 100.00% | | | | | 0.0742400 |
| 5. | **Net Income Factor** | | | | | | |
| 6. | Total revenue | | 1.0000000 | | | | |
| 7. | Gross receipts tax | | - | [6] | | | |
| 8. | Uncollectible rate | | 0.277% | [7] | | | |
| 9. | Balance | | 0.9972300 | | | | |
| 10. | Regulatory fee (L6 x 0.0014) | | 0.0013961 | [6] | | | |
| 11. | Balance (L9 - L10) | | 0.9958339 | | | | |
| 12. | N.C. state income tax (2.5%) | | 0.0248958 | [6] | | | |
| 13. | Balance (L10-L12) | | 0.9709381 | | | | |
| 14. | Federal income tax (21%) | | 0.2038970 | [6] | | | |
| 15. | Retention factor (L13-L14) | | 0.7670411 | | | | |

[1] Per Public Staff witness Hinton.
[2] Per Public Staff witness Hinton.
[3] Line 13.
[4] Line 15.
[5] Column (a) x Column (b), divided by Column (c).
[6] Statutory rate.
[7] Per Company.

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**ORIGINAL COST RATE BASE**
**For the Test Year Ended December 31, 2021**

**Public Staff Accounting Exhibit I**
**Schedule 2**

-

| Line No. | Item | Per Application [1] (a) | Public Staff Adjustments [2] (b) | After Public Staff Adjustments [3] (c) |
|---|---|---|---|---|
| 1. | Electric plant in service | $ 39,112,701 | $ (21,353) | $ 39,091,348 |
| 2. | Accumulated depreciation | (16,780,786) | (1,081,182) | (17,861,968) |
| 3. | Net plant in service (L1 + L2) | 22,331,916 | (1,102,535) | 21,229,380 |
| 4. | Investment in capital credits | 6,851,122 | - | 6,851,122 |
| 5. | Regulatory assets and liabilities | 1,368,623 | (771,793) | 596,830 |
| 6. | Materials and supplies | 644,819 | (64,390) | 580,428 |
| 7. | Prepaid expenses | 100,931 | (7,970) | 92,961 |
| 8. | Customer Deposits | (229,105) | - | (229,105) |
| 9. | Cash working capital on purchasd power expense | 868,192 | (268,672) | 599,520 |
| 10. | Cash working capital for other O&M expenses | 571,541 | (37,904) | 533,637 |
| 11. | Total original cost rate base (Sum of Lines 3-12) | $ 32,508,038 | $ (2,253,264) | $ 30,254,773 |

[1] Per Company Exhibit REH-13
[2] Public Staff Accounting Exh bit I, Schedule 2-1.
[3] Column (a) plus Column (b).

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**SUMMARY OF PUBLIC STAFF**
**RATE BASE ADJUSTMENTS**
**For the Test Year Ended December 31, 2021**

**Public Staff Accounting Exhibit I**
**Schedule 2-1**

| Line No. | Item | Adjust Old and New Campus Substation Deferrals [1] (a) | Remove UBIT Deferral [2] (b) | Include Materials and Supplies [3] (c) | Adjust Prepaid Expenses [4] (d) | Adjustment To Reduce AFUDC [6] (e) | Adjustment to Accumulated Depreciation [7] (f) | Working Capital [8] (g) | Total Rate Base Adjustment [10] (i) |
|---|---|---|---|---|---|---|---|---|---|
| 1. | Electric plant in service (net of cost-free capital) | $ - | | | | $ (21,353) | | | $ (21,353) |
| 2. | Accumulated depreciation | | | | | | $ (1 081 182) | | (1 081 182) |
| 3. | Net plant in service (L1 + L2) | - | - | - | - | (21,353) | (1,081,182) | - | (1,102,535) |
| 4. | Construction work in progress | | | | | | | | - |
| 5. | Investment in capital credits | | | | | | | | - |
| 6. | Regulatory assets and liabilities | (86,596) | (685,197) | | | | | | (771,793) |
| 7. | Materials and supplies | | | (64,390) | | | | | (64,390) |
| 8. | Prepaid expenses | | | | (7,970) | | | | (7,970) |
| 9. | Customer Deposits | | | | | | | | - |
| 10. | Accounts payable - plant in service | | | | | | | | - |
| 11. | Cash working capital on purchasd power expense | | | | | | | (268,672) | (268,672) |
| 12. | Cash working capital for other O&M expenses | | | | | | | (37 904) | (37 904) |
| 13. | Total original cost rate base (Sum of Lines 3-12) | $ (86,596) | $ (685,197) | $ (64,390) | $ (7,970) | $ (21,353) | $ (1,081,182) | $ (306,576) | $(2,253,264) |
| 14. | Revenue requirement impact | $ (6,429) | $ (50,869) | $ (4,780) | $ (592) | $ (1,585) | $ (80,267) | $ (22,760) | $ (167,282) |

[1] Public Staff Accounting Exhibit I, Schedules 2-1(a)(1) and (2).
[2] Public Staff Accounting Exhibit I, Schedule 2-1(b).
[3] Public Staff Accounting Exhibit I, Schedule 2-1(c).
[4] Public Staff Accounting Exhibit I, Schedule 2-1(d).
[5] Public Staff Accounting Exhibit I, Schedule 2-1(e).
[6] Public Staff Accounting Exhibit I, Schedule 2-1(f).
[7] Public Staff Accounting Exhibit I, Schedule 2-1(g).
[8] Public Staff Accounting Exhibit I, Schedule 2-1(h).
[9] Public Staff Accounting Exhibit I, Schedule 2-1(i).
[10] Sum of columns (a) - (i).

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**Adjustment to New Campus Substation Deferral**
**For the Test Year Ended December 31, 2021**

**Public Staff Accounting Exhibit I**
**Schedule 2-1(a)(1)**

| Line No | Description | Depreciation Rate | Amount | |
|---|---|---|---|---|
| 1 | Plant amount when in service on June 2022 | | $ 2,952,679 | [1] |
| 2 | Deprecia ion expense hrough December 31, 2022 | 2.50% | 36,908 | [2] |
| 3 | **Public Staff net plant in service as of December 31, 2022 (L1 - L2)** | | 2,915,770 | |
| 4 | Deprecia ion expense hrough July 31, 2023 | 2.50% | 43,060 | [3] |
| 5 | **Public Staff net plant in service as of July 31, 2023 (L3 - L4)** | | 2,872,710 | |
| 6 | Average balance for cost of capital calcula ion [(L3 + L5)/2] | | $ 2,894,240 | |
| 7 | Approved rate of return in last rate case | | 6.525% | [1] |
| 8 | Public Staff calculated 7 months cost of capital to be deferred [(L6 x L7)/12x7] | | $ 110,162 | |
| | **Income Statement Impact:** | | | |
| 9 | Public Staff allowed deferred depreciation expense with return (L4 x L7/12 x 7) | | $ 44,699 | |
| 10 | Public Staff allowed deferred cost of capital (L8) | | 110,162 | |
| 11 | Total allowed deferred amount on new campus substation (L9 + L10) | | 154,861 | |
| 12 | Amortization period per Public Staff | | 40 | [4] |
| 13 | Annual amortization per Public Staff (L11/L12) | | $ 3,872 | |
| 14 | Annual amortization per Company | | 107,793 | [1] |
| 15 | Public Staff adjustment to annual amortization (L13 - L14) | | **$ (103,921)** | |
| | **Rate Base Impact:** | | | |
| 16 | Public Staff calculated deferred amount (L11) | | $ 154,861 | |
| 17 | One year of amortization (L13) | | (3,872) | |
| 18 | Public Staff unamortized Balance to be included in Rate Base (L15 + L16) | | 150,989 | |
| 19 | Company unamortized Balance to be included in Rate Base | | 215,585 | [1] |
| 20 | Public Staff Adjustment to unamortized balance (L17 - L18) | | **$ (64,596)** | |

[1] Per Company.
[2] Line 1 multiplies annual depreciation rate of 2 50% provided by Company , then divided by 12 and multiplied by 6.
[3] Line 3 multiplies annual depreciation rate of 2 50% provided by Company , then divided by 12 and multiplied by 7.
[4] Per Public Staff engineer Floyd.

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**Adjustment to Old Campus Substation Deferral**
**For the Test Year Ended December 31, 2021**

**Public Staff Accounting Exhibit I**
**Schedule 2-1(a)(2)**

| Line No | Description | | Amount | |
|---|---|---|---|---|
| | **Income Statement Impact:** | | | |
| 1 | Public Staff net plant in service as of July 31, 2023 | $ | 87,526 | [1] |
| 2 | Amortization Period (Years) | | 3 | [1] |
| 3 | Annual Amotization Amount per Public Staff | | 29,175 | |
| 4 | Annual Amotization Amount per Company | | 40,175 | [2] |
| 5 | Public Staff adjustment to annual amortization (L3 - L4) | $ | (11,000) | |
| | **Rate Base Impact:** | | | |
| 6 | Amount per Public Staff as of July 31, 2023 (Line 1) | $ | 87,526 | |
| 7 | One year of amortization (Line 3) | | (29,175) | |
| 8 | Public Staff unamortized Balance to be included in Rate Base (L6 - L7) | | 58,351 | |
| 9 | Company unamortized Balance to be included in Rate Base | | 80,351 | [2] |
| 10 | Public Staff Adjustment to unamortized balance (L8 - L9) | $ | (22,000) | |

[1] Per Public Staff.
[2] Per Company.

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**Adjustment to Unrelated Business Income Tax Deferral**
**For the Test Year Ended December 31, 2021**

**Public Staff Accounting Exhibit I**
**Schedule 2-1(b)**

| Line No | Description | Amount | |
|---|---|---|---|
| | **Income Statement Impact:** | | |
| 1 | Annual amortization per Company | $ 342,598 | [1] |
| 2 | Annual Amotization Amount per Public Staff | - | |
| 3 | Public Staff adjustment amortization expense (L2 - L1) | $ (342,598) | |
| | **Rate Base Impact:** | | |
| 4 | Deferred amount per Company | $ 685,197 | [1] |
| 5 | Deferred amount per Public Staff | - | |
| 6 | Public Staff adjustment to rate base (L7 - L6) | $ (685,197) | |

[1] Per Company.

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**CALCULATION OF MATERIALS AND SUPPLIES**
**For the Test Year Ended December 31, 2021**

**Public Staff Accounting Exhibit I**
**Schedule 2-1(c)**

| Line No. | Item | Amount [1] |
|---|---|---|
| 1. | December 2020 | $ 459,836 |
| 2. | January 2021 | 454,784 |
| 3. | February | 442,216 |
| 4. | March | 473,478 |
| 5. | April | 482,343 |
| 6. | May | 490,969 |
| 7. | June | 521,090 |
| 8. | July | 578,349 |
| 9. | August | 550,460 |
| 10. | September | 570,819 |
| 11. | October | 580,114 |
| 12. | November | 595,712 |
| 13. | December 2021 | 586,437 |
| 14. | Total Sum of (L1 thru L13) | 6,786,609 |
| 15. | Thirteen month average (L14 / 13 months) | 522,047 |
| 16. | Amount included by Company | 586,437 |
| 17. | Public Staff adjustment (L15 - L16) | **$ (64,390)** |

[1] Per examination of E-1, Item 3.

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**CALCULATION OF PREPAYMENTS**
**For the Test Year Ended December 31, 2021**

**Public Staff Accounting Exhibit I**
**Schedule 2-1(d)**

| Line No. | Item | Prepaid Insurance [1] (a) | Other Prepayments [1] (b) | Total Prepayments {2] (c) |
|---|---|---|---|---|
| 1. | December 2020 | $ - | $ 67,234 | $ 67,234 |
| 2. | January 2021 | (5,020) | 79,330 | 74,310 |
| 3. | February | 13,638 | 76,705 | 90,343 |
| 4. | March | 11,772 | 66,149 | 77,921 |
| 5. | April | 9,906 | 55,273 | 65,179 |
| 6. | May | 8,040 | 71,101 | 79,141 |
| 7. | June | 6,175 | 80,418 | 86,593 |
| 8. | July | 5,146 | 77,016 | 82,161 |
| 9. | August | 4,116 | 66,228 | 70,344 |
| 10. | September | 3,087 | 55,930 | 59,017 |
| 11. | October | 2,058 | 59,662 | 61,720 |
| 12. | November | 1,029 | 64,522 | 65,551 |
| 13. | December 2021 | - | 77,593 | 77,593 |
| 14. | Total Sum of (L1 thru L13) | 59 948 | 897 160 | 957 108 |
| 15. | Thirteen month average (L14 / 13 months) | $ 4 611 | $ 69 012 | 73,623 |
| 16. | Amount included by Company | | | 81,593 [3] |
| 17. | Public Staff adjustment (L15 - L16) | | | **$ (7,970)** |

[1] Per examination of E-1, Item 3, Account 165.
[2] Column (a) plus Column (b).
[3] Per Company Exhibit REH-13.

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**ADJUSTMENT TO REDUCE AFUDC TO REFLECT**
**ACTUAL IN-SERVICE DATES AND RECOMMENDED ROR**
**For the Test Year Ended December 31, 2021**

**Public Staff Accounting Exhibit I**
**Schedule 2-1(f)**

| Line No. | Month | Substation Expenditures [1] (a) | AFUDC on Substation Expenditures [2] (b) | Laydown Yard Expenditures [3] | AFUDC on Laydown Yard Expenditures [2] | SCADA Expenditures [4] | AFUDC on SCADA Expenditures [2] | Underground Conversion Expenditures [5] | AFUDC on Underground Conversion Expenditures [2] | Warehouse Expenditures [6] (c) | AFUDC on Warehouse Expenditures [2] (d) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Aug-20 | - | - | - | - | - | - | - | - | - | - |
| 2 | Sep-20 | - | - | - | - | - | - | - | - | - | - |
| 3 | Oct-20 | - | - | - | - | - | - | - | - | - | - |
| 4 | Nov-20 | 12,800 | 1,270 | - | - | - | - | 122 | 11 | - | - |
| 5 | Dec-20 | 41,720 | 3,912 | - | - | 4,594 | 381 | 1,412 | 125 | 33,404 | 2,951 |
| 6 | Jan-21 | (2,514) | (222) | - | - | (2,067) | (160) | (3,079) | (255) | (7,945) | (659) |
| 7 | Feb-21 | 8,000 | 663 | 1,365 | 106 | 4,202 | 303 | 1,286 | 100 | 1,330 | 103 |
| 8 | Mar-21 | 7,000 | 543 | 12,776 | 922 | 1,415 | 95 | - | - | - | - |
| 9 | Apr-21 | 9,000 | 650 | 1,540 | 103 | 1,728 | 106 | - | - | - | - |
| 10 | May-21 | 6,000 | 401 | 24,750 | 1,524 | 4,337 | 244 | - | - | 29,163 | 1,796 |
| 11 | Jun-21 | 101,492 | 6,249 | 1,757 | 99 | 4,076 | 208 | - | - | 7,678 | 432 |
| 12 | Jul-21 | - | - | - | - | - | - | - | - | 17,081 | 872 |
| 13 | Aug-21 | 86,615 | 4,422 | 7,841 | 359 | - | - | 178,923 | 8,200 | 20,381 | 934 |
| 14 | Sep-21 | 339,013 | 15,537 | 370 | 15 | 72 | 3 | 140,269 | 5,700 | 66,714 | 2,711 |
| 15 | Oct-21 | 48,586 | 1,974 | 3,939 | 140 | - | - | 244,589 | 8,675 | 142,675 | 5,060 |
| 16 | Nov-21 | 122,564 | 4,347 | 217,440 | 6,594 | 85,754 | 2,162 | 49,509 | 1,501 | 119,789 | 3,633 |
| 17 | Dec-21 | 1,226,599 | 37,197 | 306,541 | 7,727 | 44,653 | 898 | 374,560 | 9,442 | 225,840 | 5,693 |
| 18 | Jan-22 | (71,756) | (1,809) | - | - | (87) | (1) | (1,291) | (26) | (1,320) | (27) |
| 19 | Feb-22 | 91,763 | 1,846 | 840 | 13 | 575 | 6 | 38,894 | 585 | 77,817 | 1,171 |
| 20 | Mar-22 | 558,860 | 8,410 | 7,236 | 72 | 55,168 | 275 | 44,597 | 446 | 116,940 | 1,170 |
| 19 | Apr-22 | 41,875 | 419 | 6,160 | 31 | 1,439 | - | 49,388 | 247 | 27,241 | 136 |
| 20 | May-22 | 190,281 | 2,864 | 253 | 3 | 1,079 | 5 | 58,035 | 581 | 180,075 | 1,802 |
| 21 | Jun-22 | 40,125 | N/A | 2,850 | 14 | - | N/A | 85,792 | 428 | 16,951 | 85 |
| 22 | Jul-22 | N/A | N/A | N/A | N/A | - | N/A | 1,178 | N/A | N/A | - |
| | Aug-22 | N/A | | N/A | N/A | | | | | | |
| | Sep-22 | | | 134,438 | 14,818 | | | | | | |
| | Oct-22 | | | 231,875 | 25,558 | | | | | | |
| | Nov-22 | | | 11,103 | 1,224 | | | | | | |
| | Dec-22 | | | 37 771 | 4 163 | | | | | | |
| 23 | Total | $ 2 858 022 | 88,674 | $ 1 010 845 | $ 63 485 | $ 206 939 | 4,525 | $1 264 185 | 35,760 | $1 073 813 | 27 863 |
| 24 | AFUDC per Company | | 94,656 | | 47,882 | | 7,234 | | 51,623 | | 40,265 |
| 25 | Public Staff adjustments | | $ (5 983) | | $ 15 603 | | $ (2 709) | | $ (15 863) | | $ (12 402) |
| 26 | Total Public Staff adjustment | | | | | | | | | | $ (21 353) |

[1] Per Company Exhibit REH-2A.
[2] Public Staff Calculation
[3] Per Company Exhibit REH-3.
[4] Per Company Exhibit REH-4.
[5] Per Company Exhibit REH-5.
[6] Per Company Exhibit REH-6.

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**ADJUSTMENT TO AFUDC RATE**
**For the Test Year Ended December 31, 2021**

**Public Staff Accounting Exhibit I**
**Schedule 2-1(f)(1)**

| Line No. | Item | Amount | |
|---|---|---|---|
| 1. | Overall annual rate of return recommended by Public Staff | 6.07% | [1] |
| 2. | Monthly rate to produce semiannual compounding | 0.0049915 | [2] |

[1] Public Staff Accounting Exhibit I, Schedule 4.
[2] Equivalent to the 6th root of one-half the annual rate.

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**ADJUSTMENT TO ACCUMULATED DEPRECIATION**
**For the Test Year Ended December 31, 2021**

**Public Staff Accounting Exhibit I**
**Schedule 2-1(f)**

| Line No. | | | | | | | |
|---|---|---|---|---|---|---|---|
| 1. | Total Unadjusted Accumulated Depreciation at December 31, 2022 | | | | $ | (16,780,786) | [1] |
| 2. | Total Unadjusted Depreciation Expense at December 31, 2021 | $ | 1,067,225 | [1] | | | |
| 3. | Average Monthly Depreciation Expense | $ | 88,935.43 | | | | |
| 4. | Number of Months from December 31, 2021 to August 1, 2023 | | 7 | | | | |
| 5. | Accumulated Depreciation for this Period | $ | 622,548 | | $ | (622,548) | [2] |
| 6. | Accumulated Depreciation at July 31, 2023 per the Company | | | | $ | (17,403,334) | |
| 7. | Accumulated Depreciation at July 31, 2023 per the Company | | | | $ | (17,721,655) | [1] |
| 8. | New Campus Substation (July 31, 2023) | | | | | (52,194) | [3] |
| 9. | Laydown Yard (July 31, 2023) | | | | | (15,973) | [4] |
| 10. | SCADA (July 31, 2023) | | | | | (16,668) | [5] |
| 11. | Underground Conversions (July 31, 2023) | | | | | (26,853) | [6] |
| 12. | Warehouse (July 31, 2023) | | | | | (28,625) | [7] |
| 13 | Accumulated Depreciation at July 31, 2023 per the PS | | | | | (17,861,968) | |
| 14. | Accumulated Depreciation at December 31, 2022 per the NRLP | | | | | (16,780,786) | |
| 15. | Public Staff Adjustment | | | | **$** | **(1,081,182)** | |

[1] Per Company Exhibit REH-13.
[2] Line 1 - Line 3
[3] Per Public Staff.
[4] Per Company Supplemental Exhibit REH 3.
[5] Per Company Exhibit REH-4.
[6] Per Company Exhibit REH-5.
[7] Per Company Exhibit REH-6.

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**ADJUSTMENT TO WORKING CAPITAL**
**For the Test Year Ended December 31, 2021**

**Public Staff Accounting Exhibit I**
**Schedule 2-1(g)**

| Line No. | Item | Amount | |
|---|---|---|---|
| 1. | Working capital per Public Staff: | | |
| 2. | O&M expense, excluding purchased power | $ 3,868,677 | [1] |
| 3. | Working capital factor | 0.125 | [2] |
| 4. | Working capital subtotal (L2 x L3) | $ 483,585 | |
| 5. | Estimated revenue lag days | 40.00 | [3] |
| 6. | Estimated purchased power expense lag days | 30.50 | [4] |
| 7. | Net lag days (L5 - L6) | 9.50 | |
| 8. | Adjusted purchased power expense | $ 14,940,108 | [5] |
| 9. | Average daily amount (L8/365) | 40,932 | |
| 10. | Working capital related to purchased power (L7 x L9) | 388,852 | |
| 11. | Total working capital per Public Staff (L4 + L10) | 872,437 | |
| 12. | Working capital per University | 1,439,733 | [6] |
| 13. | Adjustment to working capital (L11 - L12) | $ (567,296) | |

[1] Public Staff Accounting Exhibit I, Schedule 3, Column (c), Lines 17-12.
[2] Traditional one-eighth working capital formula.
[3] Based on a 15.25-day half service period, a 4-day lag in billing, and a 20-day lag in payment.
[4] Based on Company testimony that purchased power bills are paid one month after midpoint of calendar month.
[5] Public Staff Accounting Exhibit I, Schedule 3, Line 12, Column (c).
[6] Per Company Exhibit REH-13.

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**NET OPERATING INCOME FOR RETURN**
**For the Test Year Ended December 31, 2021**

**Public Staff Accounting Exhibit I**
**Schedule 3**

| | | Present Rates | | |
|---|---|---|---|---|
| Line No. | Item | Per Revised Application [1] (a) | Public Staff Adjustments [2] (b) | Per Public Staff [3] (c) |
| 1. | **Electric operating revenues:** | | | |
| 2. | Electric sales revenues | $ 18,596,795 | $ 744,034 | $ 19,340,829 |
| 3. | Other electric revenue | 52,251 | - | 52,251 |
| 4. | Miscellaneous service revenue | 44,466 | - | 44,466 |
| 5. | Rent from electric property | 27,492 | - | 27,492 |
| 6. | Jobbing and contrac ing | 131,606 | (226,601) | (94,995) |
| 7. | Miscellaneous non-opera ing income | 2 | (3) | (1) |
| 8. | Other interest income | 1,480 | (3,760) | (2,280) |
| 9. | **Total operating revenues (sum of Lines 2-8)** | 18,854,092 | 513,670 | 19,367,762 |
| 10. | **Operating revenue deductions:** | | | |
| 11. | Operations and maintenance (O&M) expense: | | | |
| 12. | Purchased power | 14,940,108 | - | 14,940,108 |
| 13. | Distribution expenses | 1,500,068 | 64,480 | 1,564,548 |
| 14. | Customer accounts expense | 829,900 | - | 829,900 |
| 15. | Uncollectibles | 51,506 | 2,068 | 53,574 |
| 16. | Administrative and general expense | 1,420,655 | - | 1,420,655 |
| 17. | Total O&M expense (Sum of Lines 12-16) | 18,742,237 | 66,548 | 18,808,785 |
| 18. | Depreciation expense | 1,161,463 | 194,687 | 1,356,150 |
| 19. | Amortization of regulatory assets and liabili ies | 573,900 | (457,520) | 116,380 |
| 20. | Payroll taxes | - | - | - |
| 21. | Regulatory fee | 35,650 | (8,594) | 27,056 |
| 22. | (Gain)/Loss on sale of utility property | 18,138 | - | 18,138 |
| 23. | Interest expense on customer deposits | 13,066 | - | 13,066 |
| 24. | Jobbing and contrac ing expenses | 198,200 | (226,139) | (27,939) |
| 25. | Unrelated Business Income Tax | 373,280 | (62,519) | 310,761 |
| 26. | Inflation adjustment through July 31, 2023 | 240,411 | (172,343) | 68,068 |
| 27. | | | | |
| 28. | Total operating revenue deductions (Sum of Lines 17-24) | 21,356,344 | (665,879) | 20,690,465 |
| 29. | Net operating income for a return (L9 - L25) | $ (2,502,252) | $ 1,179,549 | $ (1,322,703) |

[1] Per Company Exhibit REH-13.
[2] Public Staff Accounting Exhibit I, Schedule 3-1, Column (j).
[3] Column (a) plus (b).

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**SUMMARY OF PUBLIC STAFF**
**NET OPERATING INCOME ADJUSTMENTS**
**For the Test Year Ended December 31, 2021**

**Public Staff Accounting Exhibit I**
**Schedule 3-1**

| Line No. | Item | Remove Non-Utility Items [1] (a) | Remove UBIT Amortization [2] (b) | Customer Growth, Usage, And Weather [3] (c) | Test Year Inflation Adjustment [4] (d) | Adjust Substation Amortization [5] (d) | Adjust Uncoll. And Reg Fee [6] (e) | Annualize Depreciation Expense [7] (f) | Adjust UBIT [7] (g) | Total Public Staff Adjustments [8] (h) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1. | **Electric operating revenues:** | | | | | | | | | |
| 2. | Electric sales revenues | | | $ 744,034 | | | | | | $ 744,034 |
| 3. | Temporary construction revenue | | | | | | | | | - |
| 4. | Miscellaneous service revenue | | | | | | | | | - |
| 5. | Ren from electric property | | | | | | | | | - |
| 6. | Jobbing and contracting | (226,601) | | | | | | | | (226,601) |
| 7. | Miscellaneous non-operating income | (3) | | | | | | | | (3) |
| 8. | Other interest income | (3,760) | | | | | | | | (3,760) |
| 9. | **Total operating revenues (sum of Lines 2-8)** | (230,364) | - | 744,034 | - | - | - | - | - | 513,670 |
| 10. | **Operating revenue deductions:** | | | | | | | | | |
| 11. | Operations and maintenance (O&M) expense: | | | | | | | | | |
| 12. | Purchased power | | | | | | | | | - |
| 13. | Distribution expenses | | | 64,480 | - | | | | | 64,480 |
| 14. | Customer accounts expense | | | | | | | | | - |
| 15. | Uncollectibles | | | 2,061 | | | 7 | | | 2,068 |
| 16. | Administrative and general expense | | | | | | | | | |
| 17. | Total O&M expense (Sum of Lines 12-16) | - | - | 66,541 | - | - | 7 | - | - | 66,548 |
| 18. | Depreciation expense | | | | | | | 194,687 | | 194,687 |
| 19. | Amortization of regulatory assets and liabilities | | (342,598) | | | (114,922) | | | | (457,520) |
| 20. | Payroll taxes | | | | | | | | | - |
| 21. | Regulatory fee | | | 1,039 | | | (9,633) | | | (8,594) |
| 22. | (Gain)/Loss on sale of utility property | | | | | | | | | - |
| 23. | Interest expense on customer deposits | | | | | | | | | - |
| 24. | Jobbing and contracting expenses | (226,139) | | | | | | | | (226,139) |
| 25. | Unrelated Business Income Tax | | | | | | | | (62,519) | (62,519) |
| 26. | Inflation adjustment through July 31, 2023 | | | | (172,343) | | | | | (172,343) |
| 27. | Total operating revenue deductions (Sum of Lines 17-24) | (226,139) | (342,598) | 67,580 | (172,343) | (114,922) | (9,625) | 194,687 | (62,519) | (665,879) |
| 28. | Net operating income for a return (L9 - L25) | $ (4,225) | $ 342,598 | $ 676,454 | $ 172,343 | $ 114,922 | $ 9,625 | $ (194,687) | $ 62,519 | $ 1,179,549 |
| 29. | Revenue requirement impact | $ 5,508 | $ (446,649) | $ (881,901) | $ (224,685) | $ (149,824) | $ (12,549) | $ 253,815 | $ (62,519) | $ (1,537,791) |

[1] Public Staff Accounting Exhibit I, Schedule 3-1(a).
[2] Public Staff Accounting Exhibit I, Schedule 3-1(b).
[3] Public Staff Accounting Exhibit I, Schedule 3-1(c).
[4] Public Staff Accounting Exhibit I, Schedule 1-1(a)(1).
[5] Public Staff Accounting Exhibit I, Schedule 3-1(d).
[6] Public Staff Accounting Exhibit I, Schedule 3-1(e).
[7] Public Staff Accounting Exhibit I, Schedule 3-1(f).
[8] Sum of columns (a) - (i).

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**ADJUSTMENT TO REMOVE**
**NON-UTILITY ITEMS**
**For the Test Year Ended December 31, 2021**

**Public Staff Accounting Exhibit I**
**Schedule 3-1(a)**

| Line No. | Item | Amount [1] |
|---|---|---|
| 1. | Removal of non-electric service items: | |
| 2. | Revenues | |
| 3. | Jobbing and contracting | $ (226,601) |
| 4. | Miscellaneous non-operating income | $ (3) |
| 5. | Other interest income | $ (3,760) |
| | | |
| 6. | Expenses: | |
| 7. | Jobbing and contracting expenses | $ (226,139) |

[1] Per Company DR response 17.

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**CUSTOMER GROWTH, USAGE, AND WEATHER ADJUSTMENTS**
**For the Test Year Ended December 31, 2021**

**Public Staff Accounting Exhibit I**
**Schedule 3-1(b)**

| Line No. | Item | kWh Adjustment [1] | Applicable Rate ($/kWh) [1] | Adjustment [3] |
|---|---|---|---|---|
| | | (a) | (b) | (c) |
| 1. | Operating revenues: | | | |
| 2. | Customer growth: | | | |
| 3. | Residential | 2,327,221 | $ 0.10640 | $ 247,616 |
| 4. | Commercial | 243,406 | $ 0.09880 | 24,049 |
| 5. | Commercial - Demand | 1,311,156 | $ 0.07800 | 102,270 |
| 6. | Lighting | (4,240) | $ 0.12130 | (514) |
| 7. | Usage: | | | |
| 8. | Residential | 324,657 | $ 0.08900 | 28,894 |
| 9. | Commercial | 102,523 | $ 0.08570 | 8,786 |
| 10. | Commercial - Demand | 476,877 | $ 0.07700 | 36,720 |
| 11. | ASU | 3,702,657 | $ 0.08000 | 296,213 |
| 12. | Total adjustment to revenues (L2 + L3) | 8,484,257 | | $ 744,034 |
| 13. | O&M expenses (Not annualized for usage else where) | 8,484,257 [1] | $ 0.00760 [2] | 64,480 |

[1] Provided by Public Staff witness Hinton.
[2] Public Staff Accounting Exhibit I, Schedule 3-1(c)(1).
[3] Column (a) x Column (b).

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**O&M EXPENSES TO ADJUST**
**FOR GROWTH IN KWH SALES**
**For the Test Year Ended December 31, 2021**

**Public Staff Accounting Exhibit I**
**Schedule 3-1(b)(1)**

| Line No. | Item | Amount | [1] |
|---|---|---|---|
| 1 | Per books O&M expenses net of labor, consulting fees, and purchased power: | | |
| 2 | Account 580 | $ 8,814 | |
| 3 | Account 582 | 1,680 | |
| 4 | Account 583 | 1,394 | |
| 5 | Account 586 | 36,288 | |
| 6 | Account 587 | 1,680 | |
| 7 | Account 588 | 20,771 | |
| 8 | Account 590 | 6,328 | |
| 9 | Account 592 | 18,003 | |
| 10 | Account 593 | 454,651 | |
| 11 | Account 594 | 86,617 | |
| 12 | Account 595 | 37,058 | |
| 13 | Account 596 | 78,427 | |
| 14 | Account 597 | 14,475 | |
| 15 | Account 598 | 9,407 | |
| 16 | Account 901 | 2,610 | |
| 17 | Account 902 | - | |
| 18 | Account 903 | 326,114 | |
| 19 | Account 910 | - | |
| 20 | Account 911 | - | |
| 21 | Account 921 | 53,627 | |
| 22 | Account 924 | 12,542 | |
| 23 | Account 925 | 125,381 | |
| 24 | Account 930 | 179,296 | |
| 25 | Account 932 | 85,997 | |
| 26 | Total expenses for growth adjustment | $ 1,561,158 | |
| 27 | Test year kWh usage | 205,526,911 | [2] |
| 28 | Expenses per kWh for growth adjustment | $ 0.00760 | [3] |
| 29 | Addi ional expenses for infla ion adjustment: | | |
| 30 | Account 923 | 389,431 | [1] |
| 31 | ASU Administrative support | 226,823 | [2] |
| 32 | Total expenses for inflation adjustment | $ 2,177,412 | [3] |

[1] Per Company response to PSDR 17, Item 2.
[2] Per Company Exhibit REH-13.
[3] Line 26 divided by Line 27.
[4] Line 26 plus Line 30 plus Line 31.

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**TEST YEAR INFLATION ADJUSTMENT**
**For the Test Year Ended December 31, 2021**

**Public Staff Accounting Exhibit I**
**Schedule 3-1(c)**

| Line No. | Item | Amount | |
|---|---|---|---|
| 1. | CPI-U index - December 2021 | 278.802 | [1] |
| 2. | CPI-U index - December 2022 | 296.797 | [1] |
| 3. | Mid point index (L1 + L2, divided by 2) | 287.800 | |
| 4. | Half-year inflation factor (L2/L3, minus 1) | 3.13% | |
| 5. | Total expenses for inflation adjustment | 2,177,412 | [2] |
| 6. | Test year inflation per Public Staff (L4 x L5) | 68,068 | |
| 7. | Test year inflation per Company | 240,411 | [3] |
| 8. | Public Staff adjustment to inflation | **$ (172,343)** | |

[1] Per monthly CPI-U Detailed Reports, Table 1.
[2] Public Staff Accounting Exhibit I, Schedule 3-1(c)(1) Line 32.
[3] Per Company Exhibit REH-13.

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**ADJUSTMENT TO UNCOLLECTIBLES EXPENSE AND REGULATORY FEE**
**For the Test Year Ended December 31, 2021**

**Public Staff Accounting Exhibit I**
**Schedule 3-1(d)**

| Line No. | Item | Current Rates (a) | |
|---|---|---|---|
| 1. | Total pro forma sales revenue per Company | $ 18,596,795 | [1] |
| 2. | Uncollectibles rate | 0.2770% | [2] |
| 3. | Uncollectibles expense on Company present revenues | 51,513 | |
| 4. | Uncollectibles expense per Company | 51,506 | |
| 5. | Adjustment to uncollectibles expense (L3 - L4) | $ 7 | |
| | | | |
| 6. | Revenues net of uncollectibles expense (L1 - L3) | $ 18,545,282 | |
| 7. | Regulatory fee rate | 0.1400% | [3] |
| 8. | Regulatory fee on Company present revenues (L6 x L7) | 25,963 | |
| 9. | Regulatory fee per Company | 35,596 | |
| 10. | Adjustment to regulatory fee (L8 - L9) | $ (9,633) | |

[1] Public Staff Exhibit I, Schedule 3, Column (a), Line 2.
[2] Public Staff Accounting Exhibit I, Schedule 1-1, Line 8.
[3] Statutory rate.

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**ADJUSTMENT TO DEPRECIATION EXPENSE**
**For the Test Year Ended December 31, 2021**

**Public Staff Accounting Exhibit I**
**Schedule 3-1(e)**

| Line No. | Account | tem | Depreciable Balance 12/31/2022 [1] (a) | Depreciation Rate [1] (b) | Depreciation Expense Per Public Staff [2] (c) | NRLP Proposed Depreciation Expense [1] (d) | Public Staff Adjustment [3] (e) |
|---|---|---|---|---|---|---|---|
| 1. | 360 | Land & Land Rights | $ 93,756 | 0.000% | $ - | $ - | $ - |
| 2. | 362 | Station Equipment | 8,090,732 | 3.000% | 242,722 | 174,846 | 67,876 |
| 3. | 364 | Poles, Towers and Fixtures | 1,964,701 | 3.500% | 68,765 | 66,906 | 1,859 |
| 4. | 365 | Overhead Conductors and Devices | 2,455,540 | 2.600% | 63,844 | 62,855 | 989 |
| 5. | 366 | Underground Conduit | 4,597,798 | 2.050% | 94,255 | 71,531 | 22,724 |
| 6. | 367 | Underground Conductors & Devices | 3,894,399 | 2.450% | 95,413 | 82,407 | 13,006 |
| 7. | 368 | Transformers | 4,223,727 | 2.950% | 124,600 | 108,332 | 16,268 |
| 8. | 369 | Services | 1,792,001 | 3.300% | 59,136 | 57,393 | 1,743 |
| 9. | 370 | Meters | 2,420,309 | 3.250% | 78,660 | 118,118 | (39,458) |
| 10. | 373 | Area Lighting | 962,838 | 3.250% | 31,292 | 29,952 | 1,340 |
| 11. | 384 | Fiber | 53,187 | 0.040% | 21 | 2,128 | (2,107) |
| 12. | 389 | Land & Land Rights | 91,916 | 0.000% | - | - | - |
| 13. | 390 | Structures & Improvements, including Public Staff AFUDC adjustment | 4,933,933 | 2.572% | 126,901 | 275,810 | (148,909) |
| 14. | 391 | Office Furniture & Equipment | 895,126 | 10.000% | 89,512 | 28,533 | 60,979 |
| 15. | 392 | Transportation Equipment | 1,484,062 | 10.250% | 152,116 | 40,701 | 111,415 |
| 16. | 393 | Stores Equipment | 68,000 | 5.000% | 3,400 | 2,037 | 1,363 |
| 17. | 394 | Tools, Shops and Garage Equipment | 131,203 | 5.000% | 6,561 | 3,472 | 3,089 |
| 18. | 395 | Laboratory Equipment | 101,973 | 5.345% | 5,450 | 5,388 | 62 |
| 19. | 396 | Power Operated Equipment | 218,848 | 11.897% | 26,036 | 5,269 | 20,767 |
| 20. | 397 | Communications Equipment | 401,089 | 7.180% | 28,798 | 13,668 | 15,130 |
| 21. | 398 | Miscellaneous Equipment | 26,997 | 10.000% | 2,700 | 889 | 1,811 |
| 22. | | Total depreciation expense (Sum of Lines 1 - 22 ) | $ 38,902,136 | | 1,300,182 | 1,150,233 | 149,949 |
| | | | | | - | (44,738) [4] | - |
| | | | | | $ 1,300,182 | $ 1,105,495 | $ 194,687 |

[1] Audit Report plus Company adjustments per Company books.
[2] Column (a) multiplied by Column (b).
[3] Column (c) minus Column (d).
[4] To remove 2022 depreciation expense for Campus Substation.

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**ADJUSTMENT TO REFLECT INCOME TAXES**
**For the Test Year Ended December 31, 2021**

**Public Staff Accounting Exhibit I**
**Schedule 3-1(f)**

| Line No. | Item | KwH Sales (a) | |
|---|---|---|---|
| 1. | Net Income Before Taxes | $ 1,834,952 | [1] |
| 2. | Non ASU & TOB Usage (per KPMG) | 73.21% | [2] |
| 3. | Taxable Net Income | 1,343,368 | |
| 4. | Composite tax rate | 23.13% | |
| 5. | Unrelated Business Income Taxes (UBIT) per PS | 310,761 | |
| 6. | UBIT per NRLP | 373,280 | |
| 7. | Public Staff adjustment to UBIT | **$ (62,519)** | |

[1] Per Public Staff witness Sailor.
[2] Per Company Exhibit REH-16.

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**RETURN ON ORIGINAL COST NET INVESTMENT**
**For the Test Year Ended December 31, 2021**

**Public Staff Accounting Exhibit I**
**Schedule 4**

| | | Before Public Staff Proposed Increase | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Item | Capitalization Ratio | | Original Cost Rate Base | | Cost Rates | | Weighted Cost Rates | | Net Operating Income | |
| | | (a) | | (b) | | (c) | | (d) | | (e) | |
| 1. | Long-term debt | 50.00% | [1] | $ 15,127,387 | [3] | 3.23% | [1] | 1.615% | [4] | $ 488,615 | [6] |
| 2. | Common equity | 50.00% | [1] | 15,127,387 | [3] | -11.97% | [8] | -5.985% | [4] | (1,811,318) | [7] |
| 3. | Total (L1 + L2) | 100.00% | | $ 30,254,773 | [2] | | | -4.370% | | $ (1,322,703) | [5] |

| | | After Public Staff Proposed Increase | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Item | Capitalization Ratio | | Original Cost Rate Base | | Cost Rates | | Weighted Cost Rates | | Net Operating Income | |
| | | (a) | | (b) | | (c) | | (d) | | (e) | |
| 4. | Long-term debt | 50.00% | [1] | $ 15,127,387 | [9] | 3.23% | [1] | 1.615% | [4] | $ 488,615 | [6] |
| 5. | Common equity | 50.00% | [1] | 15,127,387 | [9] | 8.90% | [1] | 4.450% | [4] | 1,346,337 | [6] |
| 6. | Total (L4 + L5) | 100.00% | | $ 30,254,773 | [2] | | | 6.07% | | $ 1,834,952 | |

[1] Per Public Staff witness Hinton.
[2] Public Staff Accounting Exh bit I, Schedule 2, Line 13, Column (c).
[3] Line 3, Column (b) x Column (a).
[4] Column (a) x Column (c).
[5] Public Staff Accounting Exh bit I, Schedule 3, Line 26, Column (c).
[6] Column (b) x Column (c).
[7] Line 3 - Line 1.
[8] Column (e) divided by Column (b).
[9] Line 6, Column (b) x Column (a).

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**CALCULATION OF PUBLIC STAFF'S**
**ADDITIONAL REVENUE REQUIREMENT**
**For the Test Year Ended December 31, 2021**

**Public Staff Accounting Exhibit I**
**Schedule 5**

| Line No. | Item | Amount | |
|---|---|---|---|
| 1. | Required net operating income | $ 1,834,952 | [1] |
| 2. | Net operating income before proposed increase | (1,322,703) | [2] |
| 3. | Additional net operating income required (L1 - L2) | 3,157,655 | |
| 4. | Retention factor | 0.7670411 | [3] |
| 5. | Public Staff recommended increase in overall revenue requirement (L3 / L4) | $ 4,116,670 | |

[1] Public Staff Accounting Exhibit I, Schedule 4, Line 6.
[2] Public Staff Accounting Exhibit I, Schedule 4, Line 3.
[3] Public Staff Accounting Exhibit I, Schedule 1-1, Line 15.

I/A

Public Staff Zhang
**Settlement Exhibit I**
**Schedule 1**

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**RECONCILIATION OF COMPANY &**
**PUBLIC STAFF PROPOSED GROSS REVENUE INCREASE**
**For the Test Year Ended December 31, 2021**

| Line No. | Description | Revenue Effect | |
|---|---|---|---|
| 1. | **Company's proposed increase** | **$ 4,671,936** | **[1]** |
| 2. | **Public Staff adjustments: [2]** | | |
| 3. | Impact of reducing rate of return from 7.007% to 6.165% | (315,145) | |
| 4. | Adjustment to Campus Substation deferral | (121,569) | |
| 5. | Remove UBIT deferral | (253,460) | |
| 6. | Removal of non-utility items | 4,242 | |
| 7. | Adjustment to materials and supplies inventory | (1,216) | |
| 8. | Adjustment to prepaid expenses | (1,244) | |
| 9. | Adjustment to reduce AFUDC | (1,434) | |
| 10. | Adjustment to working capital | (31,730) | |
| 11. | Adjustment to customer growth | (53,165) | |
| 12. | Adjustment to rate case expense | 56,987 | |
| 13. | Adjustment to regulatory fee | (2,039) | |
| 14. | Adjustment to depreciation expense | 63,647 | |
| 15. | Adjustment to UBIT expense | 40,946 | |
| 16. | Updates per Public Staff | 231,244 | |
| 17. | Rounding | 0 | |
| 18. | **Total Public Staff adjustments (Sum of Lines 3-17)** | **(383,936)** | |
| 19. | **Public Staff recommended increase (L1 + L18)** | **$ 4,288,000** | **[3]** |

[1] Per Company Exhibit REH-13.
[2] Calculated based on Settlement Exhibit I, Schedules 2, 3, 4 and back up schedules.
[3] Settlement Exh bit 1, Schedule 3, Line 9, Column (d).

Public Staff Zhang

**Settlement Exhibit I**
**Schedule 2**

**NEW RIVER LIGHT AND POWER COMPANY**
**Docket Nos. E-34, Sub 54 and Sub 55**
**ORIGINAL COST RATE BASE**
**For the Test Year Ended December 31, 2021**

| Line No. | Description | Per Application [1] (a) | Public Staff Adjustments [2] (b) | After Public Staff Adjustments [3] (c) |
|---|---|---|---|---|
| 1. | Electric plant in service | $ 38,965,206 | $ 127,358 | $ 39,092,563 |
| 2. | Accumulated depreciation | (17,721,551) | 1,193,651 | (16,527,900) |
| 3. | Net plant in service (L1 + L2) | 21,243,655 | 1,321,009 | 22,564,664 |
| 4. | Investment in capital credits | 6,990,422 | (139,300) | 6,851,122 |
| 5. | Regulatory assets and liabilities | 1,118,903 | (278,975) | 839,928 |
| 6. | Materials and supplies | 586,437 | 41,305 | 627,742 |
| 7. | Prepaid expenses | 81,593 | 1,876 | 83,469 |
| 8. | Customer Deposits | (235,508) | 6,403 | (229,105) |
| 9. | Cash working capital on purchasd power expense | 613,977 | (131,412) | 482,565 |
| 10. | Cash working capital for other O&M expenses | 565,036 | (343,677) | 221,360 |
| 11. | Total original cost rate base (Sum of Lines 3-10) | $ 30,964,515 | $ 477,228 | $ 31,441,744 |

[1] Per Company Exhibit REH-13
[2] Settlement Exhibit I, Schedule 2-1.
[3] Column (a) plus Column (b).