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June 23, 2023

Ms. A. Shonta Dunston
Chief Clerk
N.C. Utilities Commission
430 N. Salisbury Street, Room 5063
Raleigh, NC 27603

Re: ***New River Light and Power Company***
Rebuttal Testimony and Exhibits of Randall E. Halley
Docket No. E-34, Subs 54 and 55

Dear Ms. Dunston:

Attached hereto, on behalf of New River Light and Power Company, is the Rebuttal Testimony and Exhibits of Randall E. Halley to be filed in the above-referenced dockets.

Twelve paper copies of same will be delivered to the Clerk's Office within 24 business hours of the electronic filing and the Exhibits, in native format, will be uploaded to NCUCExhibits@ncuc.net.

If you have any questions concerning this filing, or exhibits thereto, please do not hesitate to contact me.

Sincerely,

/s/ David T. Drooz
David T. Drooz

pbb

Attachments

cc: Parties and Counsel of Record
NC Commission Staff
NC Public Staff
Mr. Randall E. Halley
Mr. David Jamison
Mr. Edmond C. Miller
Mr. David Stark
Mr. M. Gray Styers, Jr.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-34, SUB 54
DOCKET NO. E-34, SUB 55

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-34, SUB 54 In the Matter of: Application for General Rate Case DOCKET NO. E-34, SUB 55 In the Matter of: Petition of Appalachian State University d/b/a New River Light and Power for an Accounting Order to Defer Certain Capital Costs and New Tax Expenses	**PRE-FILED REBUTTAL** **TESTIMONY OF** **RANDALL E. HALLEY**

June 23, 2023

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Randall E. Halley. I am a Managing Principal with Summit Utility Advisors, Inc. ("Summit"). My business address is 7614 Lake Drive, Orlando, Florida 32809.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of the Applicant, Appalachian State University ("ASU") d/b/a New River Light and Power ("NRLP").

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the prefiled testimony of the following witnesses in these dockets:

- Testimonies of Jack Floyd and John R. Hinton and Joint Testimonies of Sonja R. Johnson and Iris Morgan, witnesses for the Public Staff of the North Carolina Utilities Commission ("Public Staff");
- Testimonies of Jason W. Hoyle and Justin R. Barnes for Appalachian Voices.

In addition, I present certain revisions to my direct testimony and exhibits.

II. REVISIONS TO DIRECT TESTIMONY AND EXHIBITS

Q. Why are you submitting revisions to your direct testimony and exhibits?

A. The revisions are in response to matters raised in discovery with the other parties, review of the testimony of the other parties, and discussion with the other parties. This is discussed in more detail below.

Q. Please list your revisions based on the Public Staff's testimony.

A. NRLP has made several changes in response to Public Staff recommendations. These changes are to NRLP's revenue requirement and rate design. The modifications to revenue requirement include the following:

a) Removal of non-utility revenues and expenses.
b) Adjusted materials and supplies included in rate base.
c) Adjusted prepaid expenses included in rate base.
d) Adjusted working capital included in rate base.
e) Adjusted regulatory fee from reduction of revenue requirement.

The modifications to rate design based on discussions with Public Staff include the following:

a) Remove the initial recommended two-year phase in of base rates.
b) Add Schedule NBR for the Commercial General Service class and the Commercial Demand Service class.
c) Modify the Schedule PPR to reflect the total system avoided costs.
d) Maintain the existing SPP Schedules as established through NCUC Order dated November 22, 2022, for Docket No. E-100, Sub 175, to address any potential other types of renewable energy generation offered to NRLP in the future.
e) Decrease NRLP's Reconnection Charge in recognition of the functionality of NRLP's AMI system.

NRLP has made several changes to proposed tariff wording, as stated in the rebuttal testimony of NRLP witness Miller, in response to Public Staff recommendations. One of those changes relates to the phase-in of the new Commercial Demand rate that was proposed in my direct testimony. After discussion with the Public Staff, NRLP has agreed to eliminate the phase-in proposal due to its effect on other rate classes, and instead have a rate design that would achieve the percentage increases and rate of return index utilizing NRLP's updated revenue requirement, as shown in Halley Rebuttal Exhibit No. 1.

There are three important facts to note about this recommendation.

First, it was not possible to limit the rate impact for each customer class to 2% of the total system increase and attain a rate of return for each customer class at + or – 10% of the total system rate of return. The rate design above is a compromise intended to move the Commercial Demand class more toward their cost of service (i.e., a rate of return index of 1.0) without overly burdening the other classes. It is also important to note that the allocation factors used in the cost of service analysis were developed from NRLP's AMI data from each customer class. This allowed for a much more accurate allocation of costs to each customer class than was attainable in the cost of service analysis performed in NRLP's last rate case.

Second, the numbers in the table above will need to be changed to reflect the revenue requirement and rate of return approved by the Commission. However, the Public Staff and NRLP recommend that application of rate design principles shown in the table above should be similarly applied to the revenue requirement and rate of return ordered by the Commission.

Third and more generally, it is important to state in the Commission's final order and in notices to the public the percentage increase overall and for each rate class in conjunction with the decrease to the PPA factor. A large part of the proposed base rate increase is the reallocation of purchased power costs from the Purchased

Power Adjustment factor to base rates, and thus is not a net increase in the amount that will be billed to customers. The March 20, 2023, Scheduling Order clearly set out the net increase to customers after the PPA reduction, and NRLP encourages the Commission to continue with that approach in its final order.

Q. Please list your revisions based on Appalachian Voices' testimony.

A. In response to Appalachian Voices, NRLP has the following two modifications:

a) NRLP has offered to remove the annual reset of credits for customers on Schedule NBR. We understand that the Public Staff prefers a reset of the energy credits for NBR customers. NRLP does not wish to challenge the position of either Appalachian Voices or the Public Staff on this issue; therefore, we will wait for the Commission's decision without taking a position either way.

b) NRLP had agreed to adjust the amount of renewable energy utilized in its development of Schedule NBR and Schedule PPR to recognize for the portions of the hourly load data missing from its initial analysis. However, this adjustment would have increased the Supplemental Standby Charge (SSC) in the Schedule NBR calculations. NRLP determined it was best to not make this adjustment and cause an increase to SCC.

Q. Are there any other revisions to your original exhibits?

A. Yes. First, NRLP's Purchased Power Adjustment (PPA) was updated after the initial filing of this rate case proceeding. Based on the Order from the Commission dated March 2, 2023, in Docket No. E-34, Sub 56, NRLP's PPA was reduced from $0.045753 per kWh to $0.022313 per kWh. All exhibits that utilize the PPA have been updated.

Second, the amount of deferred UBIT taxes has changed since NRLP's initial filing. The most recent amount of UBIT deferral is $931,545. This is down from the original filing amount of $1,027,795.

Q. Which exhibits from your original testimony were updated for this rebuttal?

A. The following is a list of the exhibits submitted with my rebuttal that were modified from those submitted with my original pre-filed testimony:

1. Exhibit REH-3_NRLP Rebuttal – This exhibit contains the updated capital costs that were added to NRLP's Laydown Yard project.
2. Exhibit REH-8_NRLP Rebuttal – This exhibit contains the updated UBIT deferral amount for amortization purposes.
3. Exhibit REH-13_NRLP Rebuttal – This exhibit summarizes all the revenue requirement changes discussed herein.
4. Exhibit REH-14_NRLP Rebuttal – This exhibit contains the updated cost of service analysis.
5. Exhibit REH-16_NRLP Rebuttal – This exhibit contains the update rate design analysis as discussed herein.
6. Exhibit REH-19A(R)_NRLP Rebuttal – This exhibit contains the updated calculations for the Standby Supplemental Charge in Schedule NBR for the residential customer class from the updated cost of service analysis as discussed herein.
7. Exhibit REH-19B_NRLP Rebuttal – This exhibit contains the updated calculations for the avoided costs used in developing the rate for the Schedule PPR.

Q. Are there any new exhibits included with this rebuttal?

A. Yes. The following exhibits were developed based on discussions with the Public Staff:

1. Exhibit REH-19A(G)_NRLP Rebuttal – This exhibit was developed to calculate the Supplemental Standby Charge in Schedule NBR for the commercial general service customer class from the updated cost of service analysis as discussed herein.
2. Exhibit REH-19A(GL)_NRLP Rebuttal – This exhibit was developed to calculate the Supplemental Standby Charge in Schedule NBR for the commercial demand service customer class from the updated cost of service analysis as discussed herein.

III. RESPONSE TO RECOMMENDATIONS OF OTHER PARTIES

A. COST OF CAPITAL

Q. What is the cost of capital recommendation of Public Staff witness Hinton?

A. Mr. Hinton recommends a 50%/50% capital structure, a 3.23% long term debt rate, and an 8.90% rate of return on equity ("ROE"). His recommended overall return (or weighted average cost of capital) is 6.07%.

Q. Please explain any concerns you have with Mr. Hinton's cost of capital recommendation.

A. In my opinion, the overall return of 6.07% would not be sufficient for NRLP. The overall return is more important than the individual components, as it is the overall return that affects earnings. This is especially true where the cost of debt and capital structure are hypothetical or imputed for ratemaking.

Q. Why do earnings matter for a utility that has no investors?

A. As explained in my direct testimony and the rebuttal testimony of NRLP witness Jamison, NRLP finances its capital needs in large part from retained earnings. If the utility were approved for an inadequate overall return, its earnings would be lower. There would be less funds available from retained earnings to finance capital projects, react to unexpected contingencies, and manage cash flow volatility. NRLP does not have the luxury of issuing additional stock to raise more funds in the event of a retained earnings shortfall. The other option is to issue more debt, but whether for NRLP or an investor-owned utility, issuing more debt to make up for inadequate earnings is problematic. As explained by NRLP witness Jamison, there are limits on how much of the utility financing can be accomplished by debt, and it appears from his recommended capital structure that Mr. Hinton agrees that utility financing should not be debt-heavy. Consequently, if the overall return is too low, NRLP will have a shortfall of available cash flow or retained earnings to finance capital projects, and it will either have to issue more debt than reasonable, or the adequacy and reliability of its electric service could be jeopardized.

Q. Do you have concerns about the rate of return on common equity that is recommended by Mr. Hinton?

A. Yes. Of course the ROE is a major factor in the determining the overall rate of return.[1] Mr. Hinton uses three variations on the Discounted Cash Flow ("DCF") model, plus a Risk Premium model, to derive his recommended ROE of 8.90%. 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.

First, the 8.90% recommendation of Mr. Hinton is far off the most recent decisions of the Commission. In particular, the Commission approved a 9.80% ROE for both Aqua North Carolina (Docket No. W-218, Sub 573) and Carolina Water Service (Docket No. W-354, Sub 400). The approved overall returns in those cases were 6.885% and 7.22%, respectively. Also, these Aqua North Carolina and Carolina Water Service rate case orders approved multiyear rate plans for the first time, which help the utilities reduce regulatory lag. NRLP does not have that benefit. More generally, I am not aware of the Commission approving less than 9.40% ROE for any major utility in North Carolina in recent years, apart from the non-precedential settlement entered by NRLP in its 2017 rate case. *See* Halley Rebuttal Exhibit No. 2. In short, Mr. Hinton's ROE recommendation for NRLP is out of step with current Commission decisions.

Second, the Hinton Exhibit 1, page 1, shows authorized returns for distribution utilities in other states from January 2022 through March of 2023. This Exhibit shows data from other years as well, but given the regular changes in authorized

[1] In the present case, both Mr. Hinton and I recommend hypothetical or imputed debt cost rates and capital structure ratios, so there is also judgment in those components of the overall return, unlike cases where the actual embedded cost of debt and actual capital structure are used.

returns, the older data is not so relevant. Hinton Exhibit 1 does not support Mr. Hinton's rate of return recommendation for NRLP. First, his exhibit shows an average ROE for distribution companies of 9.17%, with an upward trend to 9.70% for the most recent order in March 2023. More important is the data on overall return, as debt rates and capital structure ratios also vary among utilities. Based on a data response provided by the Public Staff, the average overall return for distribution companies in the January 2022 – March 2023 timeframe is 6.67%. See Halley Rebuttal Exhibit No. 3. That is 60 basis points higher than the 6.07% recommendation of Mr. Hinton.

Third, Mr. Hinton calculates his recommended ROE by unfairly weighting it toward the DCF results. Hinton Exhibit 8 shows that instead of averaging one combined DCF result with a Risk Premium result, he averaged four results, of which three are from DCF models. His DCF results are much lower than his Risk Premium result, so he chose to weight the lower method three times as much. In the Aqua rate case, Docket No. W-218, Sub 573, Mr. Hinton averaged his three DCF results to reach a single combined DCF number and then averaged that with his Risk Premium result to arrive at his 9.50% ROE recommendation. In other words, he gave equal weight to the Risk Premium and the DCF in the Aqua case, but in the present case he gives DCF three times the weight. In most recent the Carolina Water Service case, W-354, Sub 400, Mr. Hinton likewise gave equal weighting to DCF results and his Risk Premium result, not three times the weighting for the DCF like he does in the present NRLP case. His ROE recommendation in that case was 9.45%. In the last NRLP rate case, Docket No.

E-34, Sub 46, Mr. Hinton gave equal weighting to DCF results and his Risk Premium result, not three times the weighting for the DCF like he does in the present NRLP case. If Mr. Hinton followed the same calculation method for NRLP as he did for his other testimony in utility cases this year, and for the last NRLP rate case, the result would be an average of his DCF results (8.49% + 8.62% + 8.80%)/3 = 8.64% combined with his Risk Premium result and divided by two (8.64% + 9.76%)/2 = 9.20%. In other words, he altered his own methodology to lower his ROE recommendation by 30 basis points in the present case. And even in the recent Aqua and Carolina water rate cases - where Mr. Hinton's methodology produced higher returns than his different approach in the present NRLP case - the Commission approved returns well above Mr. Hinton's recommendations.

Q. **What do you conclude about the cost of capital recommendation from the Public Staff?**

A. The Public Staff's recommendation is far too low. The methodology is skewed unfairly against NRLP. Their result is out of step with recent Commission orders as well as the most recent upward trend as summarized in Mr. Hinton's own exhibits and data response. In my opinion, the 9.6% ROE recommendation in my direct testimony is, if anything, on the low side because a higher ROE is supported by more recent decisions than the ones I relied on.

Q. Please respond to the cost of capital recommendation of Appalachian Voices witness Hoyle.

A. 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. His approach appears to be driven by the fact that NRLP does not have investors in the traditional sense, and does not issue stock, and therefore assumes a return on *equity* based upon a fixed *debt* rate. However, I believe the Commission should authorize a return for NRLP comparable to that of other North Carolina utilities in the same timeframe, at least for distribution companies. This is, in general, how the Commission has determined and approved NRLP's rate of return in its previous rate cases, acknowledging that the level of financing through retained earnings should be similar to the equity ratios and rates of return approved for other utilities. This traditional approach is consistent with long-standing regulatory rulemaking principles and also recognizes that NRLP finances its capital projects, from both debt and equity resources, as do other utilities.

Q. **What is your response to Mr. Hoyle's recommendation for a DCF analysis?**

A. 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. For example, in the recent rate case of Aqua North Carolina (decided in the Commission order issued June 5, 2023, in Docket No. W-218, Sub 573), the utility witness produced in rebuttal his DCF results of 10.22%, and Risk Premium results ranged from 12.06 to 12.31%. Mr. Hinton produced DCF results that averaged 9.03% and Risk Premium results of 9.94%. I can only conclude that the ROE models are at best a loose guide to an appropriate ROE range, and can reflect the outcome desired by the party.

The recommendation of Mr. Hoyle that NRLP should perform a DCF analysis, and then submit a compliance filing for rate of return based on that analysis, is odd. He seems unaware of the wide range of results that are possible from such an analysis – NRLP could submit a result that is much different from what his client seeks. Moreover, he has his own return recommendation of a 6.25% ROE without using a DCF analysis. It is not clear why he recommends that NRLP perform a DCF analysis and submit a compliance filing based on it when he has already concluded that 6.25% is an appropriate ROE.

Q. **What is your response to the 6.25% ROE recommendation of Mr. Hoyle?**

A. Mr. Hoyle's ROE number is derived from municipal bond interest rates. He has substituted a debt cost for an equity cost. This mixing of apples and oranges defeats the whole point of analyst recommendations (including Public Staff witness Hinton) and is contrary to Commission practice and decisions that approve capital structures with a substantial equity component and a calculated return on that equity. Moreover, it is so far outside the range of any ROE that the Commission has approved for any utility in recent memory that it cannot be considered to be representative of a reasonable return on investment to which regulated utilities are entitled an opportunity to earn as a fundamental principle of the regulatory compact where the obligation to provide reliable service is matched with the funding to meet the capital needs.

Q. **Are there other aspects of Mr. Hoyle's cost of capital testimony that concern you?**

A. Yes. He recommends a 78% to 22% equity to debt ratio. This recommendation approximately matches the actual capital structure of NRLP, but ignores the need to use a more balanced imputed capital structure for ratemaking purposes. At a reasonable ROE, instead of the ROE Mr. Hoyle recommends, his capital structure would produce excessive returns for NRLP.

Q. What would be the impact to NRLP of Mr. Hoyle's cost of capital recommendations?

A. The impact would be damaging to NRLP. He recommends an overall return of 5.39%, which is considerably lower than other recent authorized overall returns that I have seen. He states that his recommendation would reduce the revenue requirement for NRLP by $492,711.

Q. Have you made any changes to your original recommendation for cost of capital?

A. No. Although I believe recent events could justify a higher overall return, my recommended overall cost of capital remains at 7.007% as summarized below:

Capitalization Component	Ratio	Cost	Weighted Cost
Long-Term Debt	48%	4.20%	2.015%
Equity	52%	9.60%	4.992%
			7.007%

B. Net Billing Rider, PPR, and Basic Facilities Charge

Q. What modifications were made to the Net Billing Rider Schedule NBR?

A. During the discovery process, it was determined that the Schedule NBR should be specific to each of the residential, commercial general service and commercial demand service customer classes. The original Schedule NBR was developed using only the residential cost of service. The development of these schedules was consistent with the requirement in N.C.G.S § 62-126.4(b) to avoid cross subsidies.

Q. Is Mr. Barnes approach to valuing solar for use in a Net Billing Rider consistent with the guidelines established in N.C.G.S § 62-126.4(b)?

A. No. 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. He states on Page 28 of his testimony, "According to my analysis, the value of customer-sited PV generation exceeds the residential retail rate by 15% or more when avoided distribution costs based on embedded costs are used in the calculation."

The 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, given that:

(1) N.C.G.S. § 62-126.4(b) states in part "The Commission shall establish net metering rates under all tariff designs that ensure that the net metering retail customer pays its full fixed cost of service";

(2) a cost of service analysis was performed to identify the cost to serve each customer class; and

(3) retail rates were designed based on this cost of service analysis.

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.

In my direct testimony I proposed a monthly Standby Supplemental Charge (SSC) of $6.17 per kW of installed solar to recover NRLP's fixed costs that are not avoided from customers who choose to utilize Schedule NBR. Mr. Barnes proposes the elimination of this SSC. His recommendation stems from the "value of solar" methodology discussed above. The NRLP approach is based on a recognition of fixed costs incurred by the utility, recovered in part through volumetric rates, and thus would be under-recovered for customers who reduce usage of NRLP power through solar self-generation. The SSC is designed to recover those fixed costs from the NBR customers who otherwise would avoid them due to their reduced usage of power from NRLP. The goal is to prevent cross subsidies. 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.

Q. What other option does a customer have for compensation from NRLP for the purchase of energy from solar generation?

A. A customer can choose to utilize NRLP's proposed Schedule PPR. NRLP will purchase energy from any solar PV facility up to a size of 1,000 kW. The development of Schedule PPR followed the same principles used in designing the

Schedule NBR. NRLP's avoided costs were identified and fully credited in Schedule PPR for pass through to participating costs.

Q. Will NRLP continue to offer its existing Small Power Production (SPP) rate schedules?

A. Yes. NRLP will maintain the use of its existing SPP rate schedules for the purchase of any renewable energy generation on NRLP's system that does not meet the eligibility requirements of the NBR or PPR rate schedules.

Q. What is the purpose of a Basic Facilities Charge (BFC)?

A. A BFC is a mechanism used to recover a reasonable amount of a utility company's fixed costs of owning and operating a distribution system.

Q. How is a BFC typically calculated?

A. Utilities in North Carolina have historically used the minimum system method in determining their fixed distribution costs by customer class. In my direct testimony I propose to increase the residential BFC from its current $12.58 per month to $14.50 per month. The BFC is intended to recover a portion of fixed costs that do not vary with the customer's usage. Based on the NRLP cost of service study, the residential fixed cost per month is approximately $36.00. The proposed increase from $12.58 to $14.50 is intended to take a modest step toward sending the appropriate price signal of matching fixed utility costs with a fixed monthly BFC. Mr. Barnes uses the Basic Customer Method to argue that the fixed monthly costs to serve residential customers are below the current BFC, and therefore the BFC should be decreased rather than increased. This is a methodological difference between the parties. 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.

Q. Is Mr. Barnes approach of using only customer related costs appropriate for determining a BFC?

A. No. As explained above, the BFC is designed to recover a reasonable amount of a utility's fixed distribution costs. Lowering the BFC only shifts more fixed costs into the variable energy rate.

C. <u>Public Staff Accounting Adjustments</u>

Q. Which accounting adjustments proposed by the Public Staff do you agree with?

A. NRLP agrees with the following proposed accounting adjustments from Public Staff.

a) Removal of non-utility revenues and expenses.

b) Adjusted materials and supplies included in rate base.

c) Adjusted prepaid expenses included in rate base.

d) Adjusted working capital included in rate base.

e) Adjusted regulatory fee from reduction of revenue requirement.

Q. Which accounting adjustments proposed by the Public Staff do you not agree with?

A. NRLP disagrees with the Public Staff accounting adjustments not listed above; however, for purposes of this rate case I am providing rebuttal on just the following Public Staff adjustments that reduce NRLP's revenue requirement:

1. Reduction of rate of return from 7.007% to 6.07% (addressed in response to testimony of Public Staff witness Hinton, and only incorporated into the revenue requirement by Public Staff Accounting).
2. Disallowance of requested deferrals on the new and old campus substation.
3. Disallowance of requested deferral on previously paid Unrelated Business Income Tax (UBIT).
4. Adjustment to Allowance for Funds Used During Construction (AFUDC).
5. Customer growth and usage adjustments.
6. Adjustment to the test year inflationary factor.
7. Adjustment to depreciation expense.

Each of these items are discussed in more detail below.

Q. Why do you disagree with Public Staff's reduction of rate of return from 7.007% to 6.07%?

A. See my discussion in the Cost of Capital section above and the pre-filed rebuttal testimony of NRLP witness David Jamison.

Q. Why do you disagree with Public Staff's disallowance of requested deferrals on the new and old campus substation costs?

A. The Public Staff's adjustment is inappropriate. The old campus substation was decommissioned and removed from NRLP's books in October 2021. The new campus substation went into service in June 2022.

Regarding the old campus substation, NRLP has requested a three-year amortization of the remaining balance from October 2021. The Public Staff does not oppose a three-year amortization, but calculates it with the net book value balance remaining at July 31, 2023. Their explanation is that depreciation expense for the old campus substation is part of current rates and thus it is proper to reduce the remaining balance amount through the estimated date of new rates that will not include depreciation expense for the old substation. Based on the FERC plant accounting [FERC USOA 10. Additions and Retirements of Plant. B.(2)], a utility must make an adjustment to remove the plant in service and the related accumulated depreciation from the utility's books and stop depreciating the plant once the plant is retired and it is "not used and useful for providing service" to customers. By proposing to carry the net book value of the old campus substation through to July 31, 2023, the Public Staff is incorrectly treating the old campus substation as a regulatory asset instead of a normal plant in service item that is being retired.

Regarding the new campus substation, NRLP has requested a three-year amortization of the depreciation expense and cost of capital from the June 2022 in-service date to the initially estimated August 1, 2023, date of new rates. The Public Staff has adjusted this request in the following ways:

1. In the Public Staff's proposed deferral calculation, they only allowed seven months of depreciation expense and a return on the capital expenditures from

January 1, 2023, through July 31, 2023. The Public Staff stated the rate case application was not filed timely and within the 30-day notice of intent to file a rate case. The main reason for the December rate case filing after the June notice was that NRLP had to clean up the rate case adjustments, revise the rate design, and finalize the models. NRLP ran into some billing data issues related to the allocation factors that took longer to clean up than expected. In addition, some of the capital projects that NRLP was working on took longer than they planned. NRLP would never intentionally hold off on filing a rate case due to the negative earnings impact of staying out any longer than necessary. In sum, NRLP wanted to be sure that its rate filing was complete and in good form with the Commission.

This same issue was addressed in the Dominion North Carolina Power Docket No. E-22, Sub 479, Order Approving General Rate Increase, issued December 22, 2016. On page 73 of that Order the Public Staff contends that the utility's deferral request was inappropriate because the passage of 15 months from the time Bear Garden became commercially operational to the time Dominion submitted its request for deferral accounting was too long. The Commission ruled on Page 77 that "Given the attendant facts and circumstances as outlined above, DNCP's having failed to specifically request formal approval in a timelier manner does not, in this instance, warrant denial of its request." Public Staff's denial of NRLP's depreciation expense and return on capital expenditures from the new campus substation's in service date is inappropriate.

2. The Public Staff recommends the amortization period for this regulatory asset be set at the life of the new substation for 40 years. Use of an amortization period for the remaining useful life of the asset has only been done for assets that were being retired from service on the books of the utility (similar to the old campus substation). The Public Staff cites Docket No. E-7, Sub 1146, with regard to using the amortization period over the remaining useful life for AMR meters. The AMR meters in that docket were being retired from Duke's books and depreciation was stopped. The new Campus Substation is a NEW asset and is not an asset that is being retired from the Company's books.

Cost recovery of capital expenditures is a separate and distinct process from the deferral. NRLP is requesting deferral of certain post in-service costs that reflect the revenue requirement with the new campus substation. The costs to be deferred are the depreciation and the return on the investment for the completed plant in service from the date the assets are placed in service and are used and useful in providing electric service to the date NRLP is authorized to begin recovering the plant in service in rates over the life of the asset. The deferral also includes the financing costs related to the amounts that are unrecovered during the period between the in-service date of the asset and when the "rates" are effective. In Docket No. E-7, Sub 1146, the Commission's Order dated June 22, 2018, also reflects a deferral request and subsequent Commission approval related to DEC's Lee Combined Cycle Facility. The deferral request included post in-service costs of depreciation and the cost of capital similar to the new campus substation. The Order stated that the Company was authorized to establish a regulatory asset for deferral of post in-service costs for the Lee CC, with the post in-service costs to be amortized over a four-year period. The Public Staff's amortization of NRLP's deferred new campus substation post in-service costs over a 40-year period is inappropriate.

Q. Why do you disagree with Public Staff's disallowance of requested deferral on previously paid UBIT?

A. See the pre-filed testimony of NRLP's witnesses David Jamison and Dave Stark.

Q. Why do you disagree with the Public Staff's adjustment to AFUDC?

A. The Public Staff has proposed to calculate all NRLP's AFUDC based on Public Staff's proposed rate of return of 6.07%. Since AFUDC is calculated over a historical period, the appropriate cost of capital to use is NRLP's currently approved rate of return of 6.525%.

Q. Why do you disagree with the Public Staff's customer growth and usage adjustments?

A. The adjustment the Public Staff made to the actual 2021 customer billing data to account for customer growth to 2022 is significantly higher than the actual billing data for 2022. The table below summarizes this difference.

Customer Class	**Change in kWh from 2021 to 2022**		
	Public Staff's Adjustment	**Actual**	**Variance**
Residential	2,651,878	709,667	1,942,211
Commercial	345,929	285,194	60,735
Commercial - Demand	1,788,033	570,841	1,217,192
ASU	3,702,657	3,702,657	-
Lighting	(4,240)	(57,663)	53,423
Total	8,484,258	5,210,696	3,273,562

The revenue adjustment Public Staff made was also based on their adjusted kWh sales. It appears that Public Staff did not account for the increased cost of purchased power from these additional sales. Both of these issues would create an overstatement of net revenues which in turn improperly lowers NRLP's revenue requirement.

Q. Why do you disagree with the Public Staff's adjustment to the test year inflationary factor?

A. As part of the Public Staff's adjustment to recognize additional costs equivalent to those that could be experienced in 2022, Public Staff applied an inflationary factor to expenses that were not modified in other adjustments. NRLP did a similar exercise in the development of its revenue requirements. The inflationary factor utilized by Public Staff was 3.13% as compared to the 6.60% proposed by NRLP, causing a reduction of inflationary adjustments of $208,000. This adjustment seems counter intuitive when considering that the actual operating expenses from 2021 to 2022 increased by 34%. NRLP is not asking to match the actual cost increase for 2022, but simply asking Public Staff not to reduce its inflationary adjustment that is already significantly lower than what actually happened.

Q. Why do you disagree with the Public Staff's adjustment to depreciation expense?

A. The Public Staff did attempt to adjust the depreciation expense and accumulated depreciation to year-end December 31, 2022, levels. However, the Public Staff did not have the correct amounts in the accumulated depreciation adjustments. Public Staff was using an accumulated depreciation amount of $17,721,655 as there beginning balance prior to their proposed adjustments. This amount was taken from Line 208 of Exhibit REH-13, which already accounted for the adjustments Public Staff was proposing. The amount Public Staff should have used as their starting point for adjustments is $17,536,605 as shown on Line 202 of Exhibit REH-13. This error caused an unwarranted reduction in NRLP's revenue requirement.

Q. Is NRLP willing to work with the Public Staff prior to the scheduled hearing to rectify as many of these accounting issues as possible?

A. Yes. NRLP has had several discussions with Public Staff to work through these items and will continue to do so prior to the hearing. We understand the Public Staff may be revising some of its accounting schedules.

Q. DOES THIS CONCLUDE YOUR PREFILED REBUTTAL TESTIMONY?

A. Yes.

Description	% Base Rate Increase	% Increase with PPA	Rate of Return	Rate of Return Index
NC Retail	24.78%	13.88%	7.007%	1.00
Residential	19.44%	10.26%	8.866%	1.27
Commercial - General	28.10%	18.23%	8.093%	1.16
Commercial - Demand	34.74%	22.27%	3.867%	0.55
ASU	15.97%	3.79%	8.866%	1.27
Lighting	35.02%	23.67%	3.867%	0.55

Docket	Company	Return on Equity	Long-Term Debt Cost	Overall Rate of Return	Settled or Litigated	Date of Final Order	Link to Order
W-218, Sub 573	Aqua	9.80%	3.97%	6.89%	Litigated	6/5/2023	Order W-218, Sub 573
W-354, Sub 400	CWSNC	9.80%	4.64%	7.22%	Litigated	4/26/2023	Order W-354, Sub 400
W-1300, Sub 60	ONSWC	9.40%	4.60%	7.00%	Settled	6/13/2022	Order W-1300, Sub 60
W-354, Sub 384	CWSNC	9.40%	4.85%	7.14%	Settled	4/8/2022	Order W-354, Sub 384
G-9, Sub 781	Piedmont	9.70%	4.08%	7.27%	Settled	1/6/2022	Order G-9, Sub 781
E-2, Sub 1219	DEP	9.60%	4.04%	6.93%	Settled	4/16/2021	Order E-2, Sub 1219
E-7, Sub 1214	DEC	9.60%	4.27%	7.04%	Settled	3/31/2021	Order E-7, Sub 1214
W-1305, Sub 12	Pluris	9.40%	4.35%	6.49%	Settled	11/13/2020	Order W-1305, Sub 12
W-218, Sub 526	Aqua	9.40%	4.21%	6.81%	Settled	10/26/2020	Order W-218, Sub 526
G-9, Sub 743	Piedmont	9.70%	4.41%	7.14%	Settled	10/31/2019	Order G-9, Sub 743
W-354, Sub 360	CWSNC	9.75%	5.68%	7.75%	Settled	2/21/2019	Order W-354, Sub 360
W-218, Sub 497	Aqua	9.70%	4.63%	7.17%	Litigated	12/18/2018	Order W-218, Sub 497
W-354, Sub 356	CWSNC	9.60%	5.93%	7.84%	Settled	11/8/2017	Order W-354, Sub 356
G-5, Sub 565	Public Service Co. of NC	10.60%	6.96%	8.14%	Settled	10/28/2016	Order G-5, Sub 565
W-354, Sub 344	CWSNC	9.75%	6.60%	8.20%	Settled	12/7/2015	Order W-354, Sub 344

W-218, Sub 363	Aqua	9.75%	5.29%	7.52%	Settled	5/20/2014	Order W-218, Sub 363
G-9, Sub 631	Piedmont	10.60%	5.23%	8.55%	Settled	12/17/2013	Order G-9, Sub 631
E-7, Sub 1026	DEC	10.20%	5.26%	7.88%	Settled	9/24/2013	Order E-7, Sub 1026
E-2, Sub 1023	DEP	10.20%	4.57%	7.55%	Settled	5/30/2013	Order E-2, Sub 1023
E-7, Sub 989	DEC	10.50%	5.41%	8.11%	Settled	1/27/2012	Order E-7, Sub 989
W-218, Sub 319	Aqua	10.20%	5.56%	7.86%	Settled	11/3/2011	Order W-218, Sub 319
W-354, Sub 327	CWSNC	10.20%	6.60%	8.40%	Settled	3/22/2011	Order W-354, Sub 327
W-354, Sub 324	CWSNC	10.20%	6.60%	8.40%	Settled	2/10/2011	Order W-354, Sub 324
E-7, Sub 909	DEC	10.70%	5.82%	8.38%	Settled	12/7/2009	Order E-7, Sub 909
W-218, Sub 274	Aqua	10.45%	5.72%	8.09%	Settled	4/8/2009	Order W-218, sub 274
W-354, Sub 314	CWSNC	10.45%	6.58%	8.36%	Settled	1/9/2009	Order W-354, Sub 314
G-9, Sub 550	Piedmont	10.60%	6.89%	8.55%	Settled	10/24/2008	Order G-9, Sub 550

State	Company	Docket	Case Type	Order Date	Decision Type	Overall Return	Return on Equity	% Common Equity
Texas	Oncor Electric Delivery Co.	D-53601	Distribution	3/9/2023	Fully Litigated	6.65	9.70	42.50
Maryland	Delmarva Power & Light Co.	C-9681	Distribution	12/14/2022	Settled	6.62	9.60	50.50
Ohio	Duke Energy Ohio Inc.	C-21-0887-EL-AIR	Distribution	12/14/2022	Settled	6.86	9.50	50.50
Ohio	The Dayton Power & Light Co.	C-20-1651-EL-AIR	Distribution	12/14/2022	Fully Litigated	7.43	10.00	53.87
Illinois	Ameren Illinois	D-22-0297	Distribution	12/1/2022	Fully Litigated	5.90	7.85	50.00
Massachusetts	NSTAR Electric Co.	DPU 22-22	Distribution	11/30/2022	Fully Litigated	7.06	9.80	53.21
Illinois	Commonwealth Edison Co.	D-22-0302	Distribution	11/17/2022	Fully Litigated	5.94	7.85	49.45
Massachusetts	Massachusetts Electric Co.	DPU 22-73	Distribution	9/26/2022	Fully Litigated	NA	NA	NA
New Hampshire	Unitil Energy Systems Inc.	D-DE-21-030	Distribution	5/12/2022	Settled	7.42	9.20	52.00
New York	Orange & Rockland Utlts Inc.	C-21-E-0074	Distribution	4/14/2022	Settled	6.77	9.20	48.00
Maryland	Delmarva Power & Light Co.	C-9670	Distribution	3/2/2022	Settled	NA	NA	NA
New York	Niagara Mohawk Power Corp.	C-20-E-0380	Distribution	1/20/2022	Settled	6.08	9.00	48.00
						Average	**9.17**	**49.80**
Massachusetts	NSTAR Electric Co.	DPU 21-106	Distribution	12/22/2021	Fully Litigated	NA	NA	NA
Pennsylvania	Duquesne Light Co.	D-R-2021-3024750	Distribution	12/16/2021	Settled	NA	NA	NA
New Jersey	Rockland Electric Company	D-ER21050823	Distribution	12/15/2021	Settled	7.08	9.60	48.51
Illinois	Ameren Illinois	D-21-0365	Distribution	12/13/2021	Fully Litigated	5.78	7.36	51.00
Illinois	Commonwealth Edison Co.	D-21-0367	Distribution	12/1/2021	Fully Litigated	5.72	7.36	48.70
New York	Central Hudson Gas & Electric	C-20-E-0428	Distribution	11/18/2021	Settled	6.48	9.00	50.00
Pennsylvania	PECO Energy Co	D-R-2021-3024601	Distribution	11/18/2021	Settled	NA	NA	NA
Ohio	Ohio Power Co.	C-20-0585-EL-AIR	Distribution	11/17/2021	Settled	7.28	9.70	54.43
Maine	Versant Power	D-2020-00316	Distribution	10/28/2021	Fully Litigated	6.57	9.35	49.00
Pennsylvania	UGI Utilities Inc.	D-R-2021-3023618	Distribution	10/28/2021	Settled	NA	NA	NA
Massachusetts	Massachusetts Electric Co.	DPU 21-74	Distribution	9/8/2021	Fully Litigated	NA	NA	NA
Delaware	Delmarva Power & Light Co.	D-20-0149	Distribution	8/5/2021	Fully Litigated	6.80	9.60	NA
New Jersey	Atlantic City Electric Co.	D-ER20120746	Distribution	7/14/2021	Settled	6.99	9.60	50.21
Maryland	Potomac Electric Power Co.	C-9655	Distribution	6/28/2021	Fully Litigated	7.21	9.55	50.50
District of Columb	Potomac Electric Power Co.	FC-1156	Distribution	6/4/2021	Fully Litigated	7.17	9.28	50.68
						Average	**8.98**	**50.34**
Massachusetts	NSTAR Electric Co.	DPU 20-96	Distribution	12/30/2020	Fully Litigated	NA	NA	NA
Maryland	Baltimore Gas and Electric Co.	C-9645 (EL)	Distribution	12/16/2020	Fully Litigated	6.75	9.50	52.00
New Hampshire	Public Service Co. of NH	D-DE-19-057	Distribution	12/15/2020	Settled	6.87	9.30	54.40
Illinois	Ameren Illinois	D-20-0381	Distribution	12/9/2020	Fully Litigated	6.39	8.38	50.00
Illinois	Commonwealth Edison Co.	D-20-0393	Distribution	12/9/2020	Fully Litigated	6.28	8.38	48.16
New York	NY State Electric & Gas Corp.	C-19-E-0378	Distribution	11/19/2020	Settled	6.10	8.80	48.00
New York	Rochester Gas & Electric Corp.	C-19-E-0380	Distribution	11/19/2020	Settled	6.62	8.80	48.00
New Jersey	Jersey Cntrl Power & Light Co.	D-ER20020146	Distribution	10/28/2020	Settled	7.40	9.60	51.44
Massachusetts	Massachusetts Electric Co.	DPU-20-68	Distribution	9/23/2020	Fully Litigated	NA	NA	NA
Maryland	Delmarva Power & Light Co.	C-9630	Distribution	7/14/2020	Fully Litigated	6.84	9.60	50.53
New Hampshire	Liberty Utilities Granite St	D-DE-19-064	Distribution	6/30/2020	Settled	7.60	9.10	52.00
Massachusetts	Fitchburg Gas & Electric Light	DPU 19-130	Distribution	4/17/2020	Settled	7.99	9.70	52.45
Texas	AEP Texas Inc.	D-49494	Distribution	2/27/2020	Settled	6.45	9.40	42.50
Maine	Central Maine Power Co.	D-2018-00194	Distribution	2/19/2020	Fully Litigated	6.30	8.25	50.00
Texas	CenterPoint Energy Houston	D-49421	Distribution	2/14/2020	Settled	6.51	9.40	42.50
New Jersey	Rockland Electric Company	D-ER19050552	Distribution	1/22/2020	Settled	7.11	9.50	48.32
New York	Consolidated Edison Company of	C-19-E-0065	Distribution	1/16/2020	Settled	6.61	8.80	48.00
						Average	**9.10**	**49.22**
Massachusetts	NSTAR Electric Co.	DPU 19-115	Distribution	12/19/2019	Fully Litigated	NA	NA	NA
Maryland	Baltimore Gas and Electric Co.	C-9610 (EL)	Distribution	12/17/2019	Settled	6.94	9.70	NA
Illinois	Ameren Illinois	D-19-0436	Distribution	12/16/2019	Fully Litigated	6.71	8.91	50.00
Illinois	Commonwealth Edison Co.	D-19-0387	Distribution	12/4/2019	Fully Litigated	6.51	8.91	47.97
Massachusetts	Massachusetts Electric Co.	DPU-18-150	Distribution	9/30/2019	Fully Litigated	7.56	9.60	53.49
Maryland	Potomac Electric Power Co.	C-9602	Distribution	8/12/2019	Fully Litigated	7.45	9.60	50.46
Maine	Versant Power	D-2019-00019	Distribution	4/23/2019	NA	NA	NA	NA
Maryland	The Potomac Edison Co.	C-9490	Distribution	3/22/2019	Fully Litigated	7.15	9.65	52.82
New York	Orange & Rockland Utlts Inc.	C-18-E-0067	Distribution	3/14/2019	Settled	6.97	9.00	48.00
New Jersey	Atlantic City Electric Co.	D-ER18080925	Distribution	3/13/2019	Settled	7.08	9.60	49.94
						Average	**9.32**	**50.38**
Massachusetts	NSTAR Electric Co.	DPU 18-101	Distribution	12/27/2018	Fully Litigated	NA	NA	NA
Pennsylvania	Duquesne Light Co.	D-R-2018-3000124	Distribution	12/20/2018	Settled	NA	NA	NA
Pennsylvania	PECO Energy Co	D-R-2018-3000164	Distribution	12/20/2018	Settled	NA	NA	NA
Texas	Texas-New Mexico Power Co.	D-48401	Distribution	12/20/2018	Settled	7.89	9.65	45.00
Ohio	Duke Energy Ohio Inc.	C-17-0032-EL-AIR	Distribution	12/19/2018	Settled	7.54	9.84	50.75
Illinois	Commonwealth Edison Co.	D-18-0808	Distribution	12/4/2018	Fully Litigated	6.52	8.69	47.11
Illinois	Ameren Illinois	D-18-0807	Distribution	11/1/2018	Fully Litigated	6.99	8.69	50.00
New Jersey	Public Service Electric Gas	D-ER18010029	Distribution	10/29/2018	Settled	6.99	9.60	54.00
Pennsylvania	UGI Utilities Inc.	D-R-2017-2640058	Distribution	10/4/2018	Fully Litigated	7.48	9.85	54.02
Ohio	The Dayton Power & Light Co.	C-15-1830-EL-AIR	Distribution	9/26/2018	Settled	7.27	10.00	47.52
Rhode Island	The Narragansett Electric Co.	D-4770 (electric)	Distribution	8/24/2018	Settled	6.97	9.28	50.95
Delaware	Delmarva Power & Light Co.	D-17-0977	Distribution	8/21/2018	Settled	6.78	9.70	50.52
District of Columb	Potomac Electric Power Co.	FC-1150	Distribution	8/8/2018	Settled	7.45	9.53	50.44
New Jersey	Atlantic City Electric Co.	D-ER18060638	Distribution	7/25/2018	NA	NA	NA	NA
Maine	Versant Power	D-2017-00198	Distribution	6/28/2018	Fully Litigated	7.18	9.35	49.00
New York	Central Hudson Gas & Electric	C-17-E-0459	Distribution	6/14/2018	Settled	6.44	8.80	48.00
Maryland	Potomac Electric Power Co.	C-9472	Distribution	5/31/2018	Settled	7.03	9.50	50.44
Connecticut	The CT Light & Power Co	D-17-10-46	Distribution	4/18/2018	Settled	7.09	9.25	53.00
New York	Niagara Mohawk Power Corp.	C-17-E-0238	Distribution	3/15/2018	Settled	6.53	9.00	48.00
Maryland	Delmarva Power & Light Co.	C-9455	Distribution	2/9/2018	Settled	NA	NA	NA
						Average	**9.38**	**49.92**

Docket No. E-34, Sub 54
Appalachian State University
d/b/a New River Light and Power Company
Addition of Laydown Yard
Rate Base and Depreciation

Line	Month	Actual Expenditures	AFUDC [1]	Total at Commercial Operation Date
1	Aug-20	$ -	$ -	$ -
2	Sep-20	$ -	$ -	$ -
3	Oct-20	$ -	$ -	$ -
4	Nov-20	$ -	$ -	$ -
5	Dec-20	$ -	$ -	$ -
6	Jan-21	$ -	$ -	$ -
7	Feb-21	$ 1,364.74	$ 172.92	$ 1,537.66
8	Mar-21	$ 12,776.00	$ 1,540.98	$ 14,316.98
9	Apr-21	$ 1,540.00	$ 176.42	$ 1,716.42
10	May-21	$ 24,750.00	$ 2,686.06	$ 27,436.06
11	Jun-21	$ 1,757.03	$ 180.15	$ 1,937.18
12	Jul-21	$ -	$ -	$ -
13	Aug-21	$ 7,841.07	$ 710.71	$ 8,551.78
14	Sep-21	$ 370.06	$ 31.36	$ 401.42
15	Oct-21	$ 3,939.10	$ 310.70	$ 4,249.80
16	Nov-21	$ 217,440.30	$ 15,881.90	$ 233,322.20
17	Dec-21	$ 306,540.52	$ 20,610.92	$ 327,151.44
18	Jan-22	$ -	$ -	$ -
19	Feb-22	$ 840.00	$ 46.81	$ 886.81
20	Mar-22	$ 7,236.10	$ 361.92	$ 7,598.02
21	Apr-22	$ 6,160.00	$ 273.12	$ 6,433.12
22	May-22	$ 253.00	$ 9.79	$ 262.79
23	Jun-22	$ 2,850.00	$ 94.25	$ 2,944.25
24	Jul-22	$ -	$ -	$ -
25	Aug-22	$ -	$ -	$ -
26	Sep-22	$ 134,438.12	$ 2,204.97	$ 136,643.09
27	Oct-22	$ 231,875.00	$ 2,528.50	$ 234,403.50
28	Nov-22	$ 11,103.06	$ 60.37	$ 11,163.43
29	Dec-22	$ 37,770.84	$ -	$ 37,770.84
30	Total	$ 1,010,844.94	$ 47,881.85	$ 1,058,726.79
31				
32	Annual Depreciation [2]			$ 27,202.64
33				
34	Depreciation Expense as of December 31, 2022			$ -
35	Depreciation Expense as of July 31, 2023			$ 15,868.21
36	Accumulated Depreciation as of July 31, 2023			$ 15,868.21

Notes:

[1] Calculated at NRLP's currently approved ROR (%) 6.525%

[2] Assumed Depreciation Life (Years) 38.92

Docket No. E-34, Sub 54
Appalachian State University
d/b/a New River Light & Power Company
Amortize Deferral Balance Related to UBIT
For the Test Year Ended December 31, 2021

Line No	Description	Source		Amount
1	Total Deferred Costs to be amortized	NRLP UBIT Detail	$	931,545
2	Amortization period			3
3	Amortization expense	L1/L2	$	310,515
4	Regulatory Asset at August 1, 2023	L1	$	931,545
5	Less first year of amortization	L3		310,515
6	Total UBIT expense to be deferred	L4-L5	$	621,030

Docket No. E-34, Sub 54
Appalachian State University
d/b/a New River Light and Power Company
Proforma Adjusted Revenue Requirement
For Twelve Months Ended December 31, 2021

Line	Main	GL#	Description	Revenue Requirement	Proforma Adjustment	Adjusted Revenue Requirement
			Other Operating Income:			
1	415	4151000	Revenue Job & Contract ASU	$ (127,573.19)	$ 219,788.99	$ 92,215.80
2	415	4152000	Rev Job&Con TOB	$ (4,032.49)	$ 6,811.79	$ 2,779.30
3	419	4191100	Int Inc Other	$ (1,479.86)	$ 3,759.85	$ 2,279.99
4	421	4210000	Misc Non-Operating Income	$ (2.07)	$ 3.24	$ 1.17
5	451	4511000	Misc Svc Revenue-Conn & Reconnect Chrgs	$ (44,466.28)	$ -	$ (44,466.28)
6	454	4540000	Rent Electric Property	$ (17,683.45)	$ -	$ (17,683.45)
7	454	4541000	Rent Electric Property-Fiber	$ (9,808.64)	$ -	$ (9,808.64)
8	456	4560000	Oth Elect Revenue	$ (52,251.43)	$ -	$ (52,251.43)
9			**Total Other Operating Income**	**$ (257,297.41)**	**$ 230,363.87**	**$ (26,933.54)**
10						
11			**Operating Expenses:**			
12	403	4030000	Depreciation Expense	$ 973,921.49	$ -	$ 973,921.49
13			Plus: Depreciation of New Campus Substation		$ 89,475.11	$ 89,475.11
14			Plus: Depreciation of Laydown Yard		$ 27,202.64	$ 27,202.64
15			Plus: Depreciation of SCADA		$ 15,385.98	$ 15,385.98
16			Plus: Depreciation of Underground Conversions		$ 26,853.22	$ 26,853.22
17			Plus: Depreciation of Warehouse		$ 28,624.84	$ 28,624.84
18			Total Depreciation Expense	$ 973,921.49	$ 187,541.79	$ 1,161,463.28
19						
20	407	4070000	Amortization of Unrecovered Plant (Old Meters)	$ 31,046.30	$ (31,046.30)	$ -
21			Amortization of Unrecovered Plant (Old Campus Substation)	$ -	$ 40,175.39	$ 40,175.39
22			Amortization of Unrecovered Return (New Campus Substation)	$ -	$ 107,792.56	$ 107,792.56
23			Amortization of Unrecovered Taxes (UBIT)	$ -	$ 310,514.86	$ 310,514.86
24			Amortization of Rate Case Expenses	$ -	$ 83,333.33	$ 83,333.33
25			Total Amortization of Unrecovered Plant	$ 31,046.30	$ 510,769.85	$ 541,816.15
26						
27	414	4140000	Gain/Loss Disposing Utility Property	$ 33,663.47	$ -	$ 33,663.47
28	414	4140001	Sale Of Surplus Property	$ (15,525.91)	$ -	$ (15,525.91)
29			Total Property Transaction Costs	$ 18,137.56	$ -	$ 18,137.56
30						
31	416	4161000	Expense Job & Contract ASU	$ 87,871.21	$ (152,792.57)	$ (64,921.36)
32	416	4161001	Expense Job & Contract ASU-Labor	$ 52,643.50	$ (28,945.54)	$ 23,697.96
33	416	4161002	Expense Job & Contract ASU-Benefits	$ 40,456.60	$ (23,307.93)	$ 17,148.67
34	416	4161004	Expense Job & Contract ASU-Transportation	$ 2,867.98	$ (4,816.01)	$ (1,948.03)
35	416	4162001	Expense Job & Contract TOB-Labor	$ 2,056.38	$ (2,631.38)	$ (575.00)
36	416	4162002	Expense Job & Contract TOB-Benefits	$ 1,427.13	$ (2,677.49)	$ (1,250.36)
37	416	4162004	Expense Job & Contract TOB-Transportation	$ 148.24	$ (239.23)	$ (90.99)
38	416	4166001	Expense Job & Contract Camp Broadstone	$ -	$ -	$ -
39	416	4166002	Expense Job & Contract Camp Broadstone-Benefits	$ -	$ -	$ -
40	416	4166004	Expense Job & Contract Camp Broadstone-Transportation	$ -	$ -	$ -
41			Total Expense Job & Contract ASU	$ 187,471.04	$ (215,410.15)	$ (27,939.11)
42						
43	431	4310000	Interest Expense Consumer Deposits	$ 12,126.18	$ -	$ 12,126.18
44	431	4310010	Interest Expense - STIF Account	$ 939.91	$ -	$ 939.91
45			Total Interest Expense	$ 13,066.09	$ -	$ 13,066.09
46						
47	555	5550000	Purchased Power	$ 10,531,677.84	$ 4,398,412.51	$ 14,930,090.35
48	555	5550010	Purchased Power - Coal Ash Cost Recovery Expense (CACR)	$ (431,602.02)	$ 431,602.02	$ -
49	555	5551000	Purchased Power-Generation (Avoided Energy Cost)	$ 10,017.61	$ -	$ 10,017.61
50			Adjustment for PS Cust Growth	$ -	$ -	$ -
51			Total Purchased Power	$ 10,110,093.43	$ 4,830,014.53	$ 14,940,107.96
52						

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Appalachian State University
d/b/a New River Light and Power Company
Proforma Adjusted Revenue Requirement
For Twelve Months Ended December 31, 2021

Line	Main	GL#	Description	Revenue Requirement	Proforma Adjustment	Adjusted Revenue Requirement
53	580	5800001	Operations Superv & Engineering-Labor	$ 81,869.26	$ 16,058.35	$ 97,927.61
54	580	5800002	Operations Superv & Engineering-Benefits	$ 64,777.61	$ -	$ 64,777.61
55	580	5800004	Operations Superv & Engineering-Transportation	$ 5,481.65	$ -	$ 5,481.65
56			Total Operations Superv & Engineering	$ 152,128.52	$ 16,058.35	$ 168,186.87
57						
58	582	5820001	Station Expense-Labor	$ 16,568.41	$ 3,249.83	$ 19,818.24
59	582	5820002	Station Expense-Benefits	$ 10,864.75	$ -	$ 10,864.75
60	582	5820004	Station Expense-Transportation	$ 1,074.11	$ -	$ 1,074.11
61			Total Station Expense	$ 28,507.27	$ 3,249.83	$ 31,757.10
62						
63	583	5830000	Overhead Line Expense	$ 914.34	$ -	$ 914.34
64						
65	586	5860000	Meter Expense	$ 34,405.37	$ -	$ 34,405.37
66	586	5860001	Meter Expense-Labor	$ 10,499.71	$ 2,059.48	$ 12,559.19
67	586	5860002	Meter Expense-Benefits	$ 7,648.02	$ -	$ 7,648.02
68	586	5860004	Meter Expense-Transportation	$ 711.17	$ -	$ 711.17
69			Total Meter Expense	$ 53,264.27	$ 2,059.48	$ 55,323.75
70						
71	587	5870001	Customer Install Expense-Labor	$ 16,568.41	$ 3,249.83	$ 19,818.24
72	587	5870002	Customer Install Expense-Benefits	$ 10,864.75	$ -	$ 10,864.75
73	587	5870004	Customer Install Expense-Transportation	$ 1,074.11	$ -	$ 1,074.11
74			Total Customer Install Expense	$ 28,507.27	$ 3,249.83	$ 31,757.10
75						
76	588	5880000	Miscellaneous Distribution Expense	$ 13,531.81	$ -	$ 13,531.81
77	588	5880001	Miscellaneous Distribution Expense-Labor	$ 176,023.27	$ 34,526.30	$ 210,549.57
78	588	5880002	Miscellaneous Distribution Expense-Benefits	$ 133,689.88	$ -	$ 133,689.88
79			Total Miscellaneous Distribution Expense	$ 323,244.96	$ 34,526.30	$ 357,771.26
80						
81	590	5900001	Maintenance Superv & Engineering-Labor	$ 61,958.11	$ 12,152.85	$ 74,110.96
82	590	5900002	Maintenance Superv & Engineering-Benefits	$ 41,898.58	$ -	$ 41,898.58
83	590	5900004	Maintenance Superv & Engineering-Transportation	$ 4,030.23	$ -	$ 4,030.23
84			Total Maintenance Superv & Engineering	$ 107,886.92	$ 12,152.85	$ 120,039.77
85						
86	591	5910000	On Call Pay -Primary/Secondary	$ 13,345.50	$ -	$ 13,345.50
87	591	5910002	On Call Pay-Primary/Secondary Benefits	$ 8,985.27	$ -	$ 8,985.27
88			Total On Call Pay	$ 22,330.77	$ -	$ 22,330.77
89						
90	592	5920000	Maintenance Station Equipment	$ 2,006.40	$ -	$ 2,006.40
91	592	5920001	Maintenance Station Equipment-Labor	$ 8,344.40	$ 1,636.72	$ 9,981.12
92	592	5920002	Maintenance Station Equipment-Benefits	$ 811.02	$ -	$ 811.02
93	592	5920004	Maintenance Station Equipment-Transportation	$ 382.17	$ -	$ 382.17
94			Total Maintenance Station Equipment	$ 11,543.99	$ 1,636.72	$ 13,180.71
95						
96	593	5930000	Maintenance Overhead Lines	$ 235,624.28	$ -	$ 235,624.28
97	593	5930001	Maintenance Overhead Lines-Labor	$ 56,368.31	$ 11,056.43	$ 67,424.74
98	593	5930002	Maintenance Overhead Lines-Benefits	$ 41,866.51	$ -	$ 41,866.51
99	593	5930004	Maintenance Overhead Lines-Transportation	$ 3,969.62	$ -	$ 3,969.62
100			Total Maintenance Overhead Lines	$ 337,828.72	$ 11,056.43	$ 348,885.15
101						
102	594	5940000	Maintenance Underground Lines	$ 48,534.05	$ -	$ 48,534.05
103	594	5940001	Maintenance Underground Lines-Labor	$ 31,795.23	$ 6,236.51	$ 38,031.74
104	594	5940002	Maintenance Underground Lines-Benefits	$ 10,915.99	$ -	$ 10,915.99
105	594	5940004	Maintenance Underground Lines-Transportation	$ 2,079.73	$ -	$ 2,079.73
106			Total Maintenance Underground Lines	$ 93,325.00	$ 6,236.51	$ 99,561.51
107						

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Appalachian State University
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Proforma Adjusted Revenue Requirement
For Twelve Months Ended December 31, 2021

Line	Main	GL#	Description	Revenue Requirement	Proforma Adjustment	Adjusted Revenue Requirement
108	595	5950000	Maintenance Line Transformers	$ 35,058.11	$ -	$ 35,058.11
109	595	5950001	Maintenance Line Transformers-Labor	$ 769.79	$ 150.99	$ 920.78
110	595	5950002	Maintenance Line Transformers-Benefits	$ 540.47	$ -	$ 540.47
111	595	5950004	Maintenance Line Transformers-Transportation	$ 51.99	$ -	$ 51.99
112			Total Maintenance Line Transformers	$ 36,420.36	$ 150.99	$ 36,571.35
113						
114	596	5961000	Maintenance Street Lights	$ 26,291.28	$ -	$ 26,291.28
115	596	5961001	Maintenance Street Lights-Labor	$ 20,865.21	$ 4,092.63	$ 24,957.84
116	596	5961002	Maintenance Street Lights-Benefits	$ 9,460.70	$ -	$ 9,460.70
117	596	5961004	Maintenance Street Lights-Transportation	$ 1,007.45	$ -	$ 1,007.45
118			Total Maintenance Street Lights	$ 57,624.64	$ 4,092.63	$ 61,717.27
119						
120	597	5970000	Maintenance-Meters	$ 11,439.07	$ -	$ 11,439.07
121	597	5970001	Maintenance-Meters-Labor	$ 38,214.18	$ 7,495.57	$ 45,709.75
122	597	5970002	Maintenance-Meters-Benefits	$ 24,422.26	$ -	$ 24,422.26
123	597	5970004	Maintenance-Meters-Transportation	$ 2,604.67	$ -	$ 2,604.67
124			Total Maintenance-Meters	$ 76,680.18	$ 7,495.57	$ 84,175.75
125						
126	598	5980000	Maintenance Misc Distribution Plant	$ 374.18	$ -	$ 374.18
127	598	5980001	Maintenance Misc Distribution Plant-Labor	$ 64,648.02	$ 12,680.46	$ 77,328.48
128	598	5980002	Maintenance Misc Distribution Plant-Benefits	$ (12,135.24)	$ -	$ (12,135.24)
129	598	5980004	Maintenance Misc Distribution Plant-Transportation	$ 2,327.63	$ -	$ 2,327.63
130			Total Maintenance Misc Distribution Plant	$ 55,214.59	$ 12,680.46	$ 67,895.05
131						
132	901	9010001	Supervision Customer Accounts-Labor	$ 25,333.87	$ 4,969.14	$ 30,303.01
133	901	9010002	Supervision Customer Accounts-Benefits	$ 17,877.96	$ -	$ 17,877.96
134	901	9010004	Supervision Customer Accounts-Transportation	$ 1,649.98	$ -	$ 1,649.98
135			Total Supervision Customer Accounts	$ 44,861.81	$ 4,969.14	$ 49,830.95
136						
137	902	9020000	Meter Reading Expense	$ -	$ -	$ -
138	902	9020001	Meter Reading Expense-Labor	$ 401.53	$ 78.76	$ 480.29
139	902	9020002	Meter Reading Expense-Benefits	$ 235.41	$ -	$ 235.41
140	902	9020004	Meter Reading Expense-Transportation	$ 9.99	$ -	$ 9.99
141			Total Meter Reading Expense	$ 646.93	$ 78.76	$ 725.69
142						
143	903	9030000	Customer Records & Collections Expense	$ 234,973.87	$ -	$ 234,973.87
144	903	9030001	Customer Records & Collections Expense-Labor	$ 234,866.65	$ 46,068.21	$ 280,934.86
145	903	9030002	Customer Records & Collections Expense-Benefits	$ 160,867.83	$ -	$ 160,867.83
146	903	9031000	Postage	$ 2,241.54	$ -	$ 2,241.54
147	903	9032000	Customer Records Cash Over/Short	$ 0.14	$ -	$ 0.14
148	903	9033000	Customer Records - Bank Service Fees	$ 11,415.48	$ -	$ 11,415.48
149	903	9034000	Customer Records - Credit Card Fees	$ 88,909.57	$ -	$ 88,909.57
150			Total Customer Records	$ 733,275.08	$ 46,068.21	$ 779,343.29
151						
152	910	9100000	Customer Assistance Expense	$ -	$ -	$ -
153						
154	911	9110000	Informational Advertising Expense	$ -	$ -	$ -
155						
156	920	9200000	Administrative & General	$ 216,021.00	$ 83,007.00	$ 299,028.00
157	920	9200001	Administrative & General-Salaries	$ 269,658.88	$ 52,892.57	$ 322,551.45
158	920	9200002	Administrative & General-Benefits	$ 222,030.83	$ -	$ 222,030.83
159			Total Administrative & General	$ 707,710.71	$ 135,899.57	$ 843,610.28
160						
161	921	9210000	Office Supplies And Expenses	$ 41,439.87	$ -	$ 41,439.87
162						

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d/b/a New River Light and Power Company
Proforma Adjusted Revenue Requirement
For Twelve Months Ended December 31, 2021

Line	Main	GL#	Description	Revenue Requirement	Proforma Adjustment	Adjusted Revenue Requirement
163	923	9230000	Consulting Fees	$ 230,607.38	$ -	$ 230,607.38
164	923	9230001	Investment Management Expense	$ 14,592.24	$ -	$ 14,592.24
165			Total Consulting & Investment Management Fees	$ 245,199.62	$ -	$ 245,199.62
166						
167	924	9240000	Property Insurance	$ 12,349.32	$ -	$ 12,349.32
168						
169	925	9250000	Injuries & Damages Expense	$ 101,105.67	$ -	$ 101,105.67
170	925	9250001	Injuries & Damages Expense-Labor	$ 4,425.00	$ 867.95	$ 5,292.95
171	925	9250002	Injuries & Damages Expense-Benefits	$ 4,756.01	$ -	$ 4,756.01
172	925	9250004	Injuries & Damages Expense-Transportation	$ 253.85	$ -	$ 253.85
173			Total Injuries & Damages Expense	$ 110,540.53	$ 867.95	$ 111,408.48
174						
175	926	9260000	Employee Pension & Benefits Expense	$ -	$ -	$ -
176	408	4081000	Taxes-Employers FICA	$ -	$ -	$ -
177	408	4082000	State Retirement-Employers	$ -	$ -	$ -
178			Total Pension, Benefits and Taxes	$ -	$ -	$ -
179						
180	930	9301000	Institutional Advertising Expense	$ 70,270.25	$ -	$ 70,270.25
181	930	9302000	Miscellaneous General Expense	$ 44,546.75	$ -	$ 44,546.75
182			PS Adjustment for O&M related to customer growth	$ -	$ -	$ -
183			Total Institutional And Miscellaneous	$ 114,817.00	$ -	$ 114,817.00
184						
185	932	9320000	Maintenance Of General Plant	$ 49,167.28	$ -	$ 49,167.28
186	932	9320001	Maintenance Of General Plant-Labor	$ 1,439.25	$ 282.30	$ 1,721.55
187	932	9320002	Maintenance Of General Plant-Benefits	$ 901.04	$ -	$ 901.04
188	932	9320004	Maintenance Of General Plant-Transportation	$ 40.92	$ -	$ 40.92
189			Total Maintenance Of General Plant	$ 51,548.49	$ 282.30	$ 51,830.79
190						
191			Inflation Adjustment through July 31, 2023	$ -	$ 240,410.75	$ 240,410.75
192						
193			**Total Operating Expenses**	**$ 14,781,547.07**	**$ 5,856,138.66**	**$ 20,637,685.73**
194						
195			**Rate Base Calculation:**			
196			Electric Plant In Service	$ 32,309,740.81		$ 32,309,740.81
197			New Campus Substation		$ 2,952,678.63	$ 2,952,678.63
198			New Laydown Yard		$ 1,058,726.79	$ 1,058,726.79
199			New SCADA		$ 214,172.80	$ 214,172.80
200			New Underground Conversions		$ 1,315,807.90	$ 1,315,807.90
201			New Warehouse		$ 1,114,078.88	$ 1,114,078.88
202			Adjusted Electric Plant In Service	$ 32,309,740.81	$ 6,655,464.99	$ 38,965,205.80
203						
204			Accumulated Depreciation (July 31, 2023)	$ (15,994,562.41)	$ (1,542,042.36)	$ (17,536,604.77)
205			New Campus Substation (July 31, 2023)		$ (96,931.37)	$ (96,931.37)
206			Laydown Yard (July 31, 2023)		$ (15,868.21)	$ (15,868.21)
207			SCADA (July 31, 2023)		$ (16,668.14)	$ (16,668.14)
208			Underground Conversions (July 31, 2023)		$ (26,853.22)	$ (26,853.22)
209			Warehouse (July 31, 2023)		$ (28,624.84)	$ (28,624.84)
210			Adjusted Accumulated Depreciation	$ (15,994,562.41)	$ (1,726,988.14)	$ (17,721,550.55)
211						

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Appalachian State University
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Proforma Adjusted Revenue Requirement
For Twelve Months Ended December 31, 2021

Line	Main	GL#	Description	Revenue Requirement	Proforma Adjustment	Adjusted Revenue Requirement
212			Net Plant in Service	$ 16,315,178.40	$ 4,928,476.85	$ 21,243,655.25
213			Plant Materials and Operating Supplies	$ 586,437.48	$ (64,390.00)	$ 522,047.48
214			Investments - Blue Ridge Electric Membership Corporation	$ 6,563,578.86	$ -	$ 6,563,578.86
215			Investments - North Carolina Electric Membership Corporation	$ 417,470.54	$ -	$ 417,470.54
216			Investments - Meridian Cooperative	$ 9,372.45	$ -	$ 9,372.45
217			Regulatory Asset (Payne Branch Dam)	$ 137,770.70	$ -	$ 137,770.70
218			Regulatory Asset (Unamortized Old Substation)	$ 120,526.18	$ (40,175.39)	$ 80,350.79
219			Regulatory Asset (New Substation)	$ -	$ 215,585.11	$ 215,585.11
220			Regulatory Asset (UBIT)	$ 886,312.27	$ (265,282.54)	$ 621,029.73
221			Prepayments	$ 81,592.79	$ (7,970.00)	$ 73,622.79
222			Customer Deposits	$ (235,508.47)	$ -	$ (235,508.47)
223			Cash Working Capital	$ 846,619.66	$ 25,817.34	$ 872,437.00
224			Total Rate Base	$ 25,729,350.86	$ 4,792,061.36	$ 30,521,412.23
225			Rate of Return (Grossed Up for UBIT)	7.007%	7.007%	7.007%
226			**Return on Rate Base**	**$ 1,802,855.62**	**$ 335,779.74**	**$ 2,138,635.35**
227						
228			**Net Revenue Requirement**	**$ 16,327,105.28**	**$ 6,422,282.27**	**$ 22,749,387.54**
229	904	9040000	Plus Uncollectible Accounts	$ 45,109.09	$ 6,396.70	$ 51,505.79
230	928	9280000	Regulatory Commission Expense	$ 27,224.49	$ 8,348.97	$ 35,573.46
231			Unrelated Business Income Tax	$ -	$ 367,938.31	$ 367,938.31
232			**Net Revenue Requirement to be Recovered from Rates**	**$ 16,399,438.86**	**$ 6,804,966.25**	**$ 23,204,405.11**
233						
234			**Retail Rate Revenues:**			
235	440		Residential	$ 5,845,335.80	$ 814,537.94	$ 6,659,873.74
236	442		Commercial	$ 6,655,168.74	$ 1,425,689.87	$ 8,080,858.61
237	445		ASU Campus	$ 3,486,675.37	$ 138,330.35	$ 3,625,005.72
238	444		Security Lighting (Adjustment to Reflect O&M Charges Only)	$ 300,006.68	$ (68,950.04)	$ 231,056.64
239			**Total Rate Revenues**	$ 16,287,186.59	$ 2,309,608.12	$ 18,596,794.71
240						
241			**Revenue Deficiency at Current Rates**			
242			Base Rate Revenue Increase			$ 4,607,610.40
243			Percent of Base Rate Increase			24.78%
244						
245			PPA Rate Revenue Reduction			$ (2,026,508.94)
246			Net Rate Revenue Increase			$ 2,581,101.45
247			Net Rate Revenue Percent Increase			13.88%

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Appalachian State University
d/b/a New River Light and Power Company
Cost of Service Analysis
For Twelve Months Ended December 31, 2021

Line	Description	Allocation Factors	Total System	Residential	Commercial General	Commercial Demand	ASU Campus	Lighting (O&M Only)
		Allocation Factors						
		Customer (c), Demand (d), Energy (e)						
	SPECIFIC ALLOCATOR:	Production (p), Transmission (t), Distribution (d), Customer (c)						
1.01	Residential	c c	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000
1.02	Commercial General	c c	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
1.03	Commercial Demand	c c	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000
1.04	ASU Campus	c c	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
1.05	Lighting	c c	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
	ENERGY ALLOCATOR:							
	Usage in kWh		205,526,911	61,988,218	23,255,764	72,850,193	44,774,302	2,658,434
2.01	Allocation %	e p	100.00%	30.16%	11.32%	35.45%	21.79%	1.29%
2.02	Allocation % (Excluding Lighting)		100.00%	30.56%	11.46%	35.91%	22.07%	0.00%
	Residential and Commercial Usage Only		158,094,175	61,988,218	23,255,764	72,850,193		
2.03	Allocation %	e p	100.00%	39.21%	14.71%	46.08%		
	DEMAND ALLOCATORS							
	DEC 20CP Peak Demands - Average kW		30,313	6,879	3,735	11,316	8,383	-
3.01	Allocation %	d t	100.00%	22.69%	12.32%	37.33%	27.66%	0.00%
	DEC Transmission Peak Demands - Average kW		28,835	8,359	3,603	10,782	6,090	-
3.02	Allocation %	d t	100.00%	28.99%	12.50%	37.39%	21.12%	0.00%
	BREMCO Distribution Peak Demands - Average kW		29,993	9,579	3,726	11,117	5,571	-
3.03	Allocation %	d t	100.00%	31.94%	12.42%	37.07%	18.57%	0.00%
	CPP CP Peak Demands - Average kW		28,533	8,234	3,574	10,667	6,058	-
3.04	Allocation %	d p	100.00%	28.86%	12.53%	37.39%	21.23%	0.00%
	NRLP Distribution Peak Demands - Average kW		30,403	8,886	3,966	11,433	6,118	-
3.05	Allocation %	d d	100.00%	29.23%	13.05%	37.60%	20.12%	0.00%
	Customer Class CP Peak Demands - Average kW		34,554	10,544	4,312	11,387	7,703	607
3.06	Allocation %	d d	100.00%	30.51%	12.48%	32.96%	22.29%	1.76%
	CUSTOMER ALLOCATORS:							
	Average Number of Customers		8,972	7,142	1,465	274	1	90
4.01	Allocation %	c c	100.00%	79.60%	16.33%	3.05%	0.01%	1.00%
4.02	Weighted Cust (excl. lighting)/Energy/NRLP Dist. Peak Demand Alloc [1]	c c	100.00%	42.36%	13.51%	28.55%	15.58%	0.00%
4.03	Weighted Cust (excl. lighting)/NRLP Dist. Peak Demand Alloc [2]	c c	100.00%	67.62%	15.63%	11.72%	5.04%	0.00%
4.04	Number of Customers Excluding Lighting Allocation %	c c	100.00%	80.41%	16.49%	3.09%	0.01%	0.00%
4.05	Weighted Cust/Cust Class CP Peak Demand Alloc [3]	c c	100.00%	67.33%	15.36%	10.53%	5.58%	1.19%

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d/b/a New River Light and Power Company
Cost of Service Analysis
For Twelve Months Ended December 31, 2021

Notes:

[1] 4.02 - Weighted Customer Allocation:
50.00% of NRLP Dist Peak Allocation 3.05
25.00% of Customer Allocation 4.04
25.00% of Energy Allocation 2.02

[2] 4.03 - Weighted Customer Allocation w/o Lighting:
25.00% of NRLP Dist Peak Allocation 3.05
75.00% of Customer Allocation 4.04

[3] 4.05 - Weighted Customer Allocation w/ Lighting:
25.00% of Cust Class CP Allocation 3.06
75.00% of Customer Allocation 4.01

Line	Description		Allocation Factors	Total System	Residential	Commercial General	Commercial Demand	ASU Campus	Lighting (O&M Only)
	Current Base Rate Revenues								
1.01	Energy Charges			$ 13,381,137	$ 5,581,667	$ 2,015,879	$ 3,950,083	$ 1,833,508	$ -
1.02	Demand Charges			$ 2,541,172	$ -	$ -	$ 1,732,317	$ 808,855	$ -
1.03	Customer Charges (Lighting includes O&M and purchased power only)			$ 2,674,486	$ 1,078,207	$ 306,209	$ 76,371	$ 982,643	$ 231,057
1.04	**Total Revenues from Current Rates**			**$ 18,596,795**	**$ 6,659,874**	**$ 2,322,088**	**$ 5,758,770**	**$ 3,625,006**	**$ 231,057**
REV1	Total Revenue Allocator	c c		100.00%	35.81%	12.49%	30.97%	19.49%	1.24%
REV2	Total Revenue Allocator Excluding ASU	c c		100.00%	44.48%	15.51%	38.46%	0.00%	1.54%
REV3	Total Revenue Allocator Excluding Lighting	c c		100.00%	36.26%	12.64%	31.36%	19.74%	0.00%
	Other Operating Income								
2.00	Revenue Job & Contract ASU	c c	REV3	$ (92,216)	$ (33,440)	$ (11,659)	$ (28,915)	$ (18,201)	$ -
2.01	Rev Job&Con TOB	c c	REV3	$ (2,779)	$ (1,008)	$ (351)	$ (871)	$ (549)	$ -
2.02	Int Inc Other	c c	REV3	$ (2,280)	$ (827)	$ (288)	$ (715)	$ (450)	$ -
2.03	Misc Non-Operating Income	c c	REV3	$ (1)	$ (0)	$ (0)	$ (0)	$ (0)	$ -
2.04	Misc Svc Revenue-Conn & Reconnect Chrgs	c c	REV3	$ 44,466	$ 16,125	$ 5,622	$ 13,943	$ 8,777	$ -
2.05	Rent Electric Property	c c	REV3	$ 17,683	$ 6,412	$ 2,236	$ 5,545	$ 3,490	$ -
2.06	Rent Electric Property-Fiber	c c	REV3	$ 9,809	$ 3,557	$ 1,240	$ 3,076	$ 1,936	$ -
2.07	Oth Elect Revenue	c c	REV3	$ 52,251	$ 18,948	$ 6,606	$ 16,384	$ 10,313	$ -
2.08	Total Other Operating Income		Sum	$ 26,934	$ 9,767	$ 3,405	$ 8,445	$ 5,316	$ -
2.09	**Total Revenues**		Sum	$ 18,623,728	$ 6,669,641	$ 2,325,494	$ 5,767,216	$ 3,630,322	$ 231,057

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Appalachian State University
d/b/a New River Light and Power Company
Cost of Service Analysis
For Twelve Months Ended December 31, 2021

Line	Description	Allocation Factors			Total System	Residential	Commercial General	Commercial Demand	ASU Campus	Lighting (O&M Only)
	Purchased Power									
3.00	CPP Energy Expense	e	p	2.01	$ 8,811,967	$ 2,657,745	$ 997,091	$ 3,123,452	$ 1,919,698	$ 113,980
3.01	CPP PEAK Prepaid Gas Discount	e	p	2.01	$ (422,092)	$ (127,305)	$ (47,760)	$ (149,613)	$ (91,953)	$ (5,460)
3.02	CPP Demand Expense	d	p	3.04	$ 5,171,700	$ 1,492,417	$ 647,789	$ 1,933,444	$ 1,098,050	$ -
3.03	CPP Generation Credit (Assigned to ASU as "Demand" & "Production")	d	p	1.04	$ (796,500)	$ -	$ -	$ -	$ (796,500)	$ -
3.04	DEC Transmission Expense	d	t	3.02	$ 686,169	$ 198,926	$ 85,738	$ 256,577	$ 144,928	$ -
3.05	BREMCO Distribution Expense	d	t	3.03	$ 1,404,233	$ 448,466	$ 174,462	$ 520,485	$ 260,820	$ -
3.06	BREMCO DEC 20CP Losses True Up	d	t	3.01	$ 74,612	$ 16,932	$ 9,193	$ 27,853	$ 20,634	$ -
3.07	Avoided Costs for Retail Customer Renewable Energy	e	p	2.01	$ 10,018	$ 3,021	$ 1,134	$ 3,551	$ 2,182	$ 130
PS	Adjustment for PS Cust Growth	e	p		$ -	$ -	$ -	$ -	$ -	$ -
3.08	Total Purchased Power Expense			Sum	$ 14,940,108	$ 4,690,202	$ 1,867,647	$ 5,715,750	$ 2,557,860	$ 108,650
	Total Purchased Power Expense				**$ 14,940,108**	**$ 4,690,202**	**$ 1,867,647**	**$ 5,715,750**	**$ 2,557,860**	**$ 108,650**
	Customer-Related	**c**			$ -	$ -	$ -	$ -	$ -	$ -
	Energy-Related	**e**			$ 8,399,893	$ 2,533,461	$ 950,464	$ 2,977,390	$ 1,829,928	$ 108,650
	Demand-Related	**d**			$ 6,540,215	$ 2,156,741	$ 917,182	$ 2,738,359	$ 727,932	$ -
	Total Purchased Power Expense				**$ 14,940,108**	**$ 4,690,202**	**$ 1,867,647**	**$ 5,715,750**	**$ 2,557,860**	**$ 108,650**
	Customer-Related	**c**			$ -	$ -	$ -	$ -	$ -	$ -
	Distribution-Related	**d**			$ -	$ -	$ -	$ -	$ -	$ -
	Transmission-Related	**t**			$ 2,165,014	$ 664,323	$ 269,393	$ 804,915	$ 426,383	$ -
	Production-Related	**p**			$ 12,775,094	$ 4,025,878	$ 1,598,253	$ 4,910,835	$ 2,131,477	$ 108,650
	Gross Income									
4.00	Revenues less Purchased Power			Sum	$ 3,683,620	$ 1,979,439	$ 457,847	$ 51,466	$ 1,072,462	$ 122,406

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Cost of Service Analysis
For Twelve Months Ended December 31, 2021

Line	Description	Allocation Factors		Total System	Residential	Commercial General	Commercial Demand	ASU Campus	Lighting (O&M Only)
	Electric Operating & Maintenance Expenses								
	Expense Job & Contract ASU								
5.00	Expense Job & Contract ASU	c c	REV3	$ (64,921)	$ (23,542)	$ (8,208)	$ (20,357)	$ (12,814)	$ -
5.01	Expense Job & Contract ASU-Labor	c c	REV3	$ 23,698	$ 8,593	$ 2,996	$ 7,431	$ 4,677	$ -
5.02	Expense Job & Contract ASU-Benefits	c c	REV3	$ 17,149	$ 6,219	$ 2,168	$ 5,377	$ 3,385	$ -
5.03	Expense Job & Contract ASU-Transportation	c c	REV3	$ (1,948)	$ (706)	$ (246)	$ (611)	$ (384)	$ -
5.04	Expense Job & Contract TOB-Labor	c c	REV3	$ (575)	$ (209)	$ (73)	$ (180)	$ (113)	$ -
5.05	Expense Job & Contract TOB-Benefits	c c	REV3	$ (1,250)	$ (453)	$ (158)	$ (392)	$ (247)	$ -
5.06	Expense Job & Contract TOB-Transportation	c c	REV3	$ (91)	$ (33)	$ (12)	$ (29)	$ (18)	$ -
5.07	Expense Job & Contract Camp Broadstone	c c	REV3	$ -	$ -	$ -	$ -	$ -	$ -
5.08	Expense Job & Contract Camp Broadstone-Benefits	c c	REV3	$ -	$ -	$ -	$ -	$ -	$ -
5.09	Expense Job & Contract Camp Broadstone-Transportation	c c	REV3	$ -	$ -	$ -	$ -	$ -	$ -
5.10	Total Expense Job & Contract ASU		Sum	$ (27,939)	$ (10,131)	$ (3,533)	$ (8,761)	$ (5,515)	$ -
	Operations Superv & Engineering								
6.00	Operations Superv & Engineering-Labor	d d	3.06	$ 97,928	$ 29,882	$ 12,222	$ 32,272	$ 21,832	$ 1,720
6.01	Operations Superv & Engineering-Benefits	d d	3.06	$ 64,778	$ 19,766	$ 8,084	$ 21,348	$ 14,441	$ 1,138
6.02	Operations Superv & Engineering-Transportation	d d	3.06	$ 5,482	$ 1,673	$ 684	$ 1,806	$ 1,222	$ 96
6.03	Total Operations Superv & Engineering		Sum	$ 168,187	$ 51,321	$ 20,990	$ 55,427	$ 37,495	$ 2,954
	Station Expense								
7.00	Station Expense-Labor	d d	3.06	$ 19,818	$ 6,047	$ 2,473	$ 6,531	$ 4,418	$ 348
7.01	Station Expense-Benefits	d d	3.06	$ 10,865	$ 3,315	$ 1,356	$ 3,581	$ 2,422	$ 191
7.02	Station Expense-Transportation	d d	3.06	$ 1,074	$ 328	$ 134	$ 354	$ 239	$ 19
7.03	Total Station Expense		Sum	$ 31,757	$ 9,690	$ 3,963	$ 10,466	$ 7,080	$ 558
8.00	Overhead Line Expense	d d	3.06	$ 914	$ 279	$ 114	$ 301	$ 204	$ 16
	Meter Expense								
9.00	Meter Expense	c c	4.03	$ 34,405	$ 23,263	$ 5,378	$ 4,031	$ 1,734	$ -
9.01	Meter Expense-Labor	c c	4.03	$ 12,559	$ 8,492	$ 1,963	$ 1,471	$ 633	$ -
9.02	Meter Expense-Benefits	c c	4.03	$ 7,648	$ 5,171	$ 1,195	$ 896	$ 385	$ -
9.03	Meter Expense-Transportation	c c	4.03	$ 711	$ 481	$ 111	$ 83	$ 36	$ -
9.04	Total Meter Expense		Sum	$ 55,324	$ 37,407	$ 8,647	$ 6,481	$ 2,788	$ -

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Cost of Service Analysis
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Line	Description	Allocation Factors			Total System	Residential	Commercial General	Commercial Demand	ASU Campus	Lighting (O&M Only)
	Customer Install Expense									
10.00	Customer Install Expense-Labor	c	c	4.03	$ 19,818	$ 13,400	$ 3,098	$ 2,322	$ 999	$ -
10.01	Customer Install Expense-Benefits	c	c	4.03	$ 10,865	$ 7,346	$ 1,698	$ 1,273	$ 548	$ -
10.02	Customer Install Expense-Transportation	c	c	4.03	$ 1,074	$ 726	$ 168	$ 126	$ 54	$ -
10.03	Total Customer Install Expense			Sum	$ 31,757	$ 21,473	$ 4,964	$ 3,720	$ 1,600	$ -
	Miscellaneous Distribution Expense									
11.00	Miscellaneous Distribution Expense	d	d	3.06	$ 13,532	$ 4,129	$ 1,689	$ 4,459	$ 3,017	$ 238
11.01	Miscellaneous Distribution Expense-Labor	d	d	3.06	$ 210,550	$ 64,247	$ 26,277	$ 69,387	$ 46,939	$ 3,699
11.02	Miscellaneous Distribution Expense-Benefits	d	d	3.06	$ 133,690	$ 40,794	$ 16,685	$ 44,058	$ 29,804	$ 2,348
11.03	Total Miscellaneous Distribution Expense			Sum	$ 357,771	$ 109,170	$ 44,651	$ 117,905	$ 79,760	$ 6,285
	Maintenance Superv & Engineering									
12.00	Maintenance Superv & Engineering-Labor	d	d	3.06	$ 74,111	$ 22,614	$ 9,249	$ 24,424	$ 16,522	$ 1,302
12.01	Maintenance Superv & Engineering-Benefits	d	d	3.06	$ 41,899	$ 12,785	$ 5,229	$ 13,808	$ 9,341	$ 736
12.02	Maintenance Superv & Engineering-Transportation	d	d	3.06	$ 4,030	$ 1,230	$ 503	$ 1,328	$ 898	$ 71
12.03	Total Maintenance Superv & Engineering			Sum	$ 120,040	$ 36,629	$ 14,981	$ 39,560	$ 26,761	$ 2,109
	On Call Pay									
13.00	On Call Pay -Primary/Secondary	d	d	3.06	$ 13,346	$ 4,072	$ 1,666	$ 4,398	$ 2,975	$ 234
13.01	On Call Pay-Primary/Secondary Benefits	d	d	3.06	$ 8,985	$ 2,742	$ 1,121	$ 2,961	$ 2,003	$ 158
13.02	Total On Call Pay			Sum	$ 22,331	$ 6,814	$ 2,787	$ 7,359	$ 4,978	$ 392
	Maintenance Station Equipment									
14.00	Maintenance Station Equipment	d	d	3.06	$ 2,006	$ 612	$ 250	$ 661	$ 447	$ 35
14.01	Maintenance Station Equipment-Labor	d	d	3.06	$ 9,981	$ 3,046	$ 1,246	$ 3,289	$ 2,225	$ 175
14.02	Maintenance Station Equipment-Benefits	d	d	3.06	$ 811	$ 247	$ 101	$ 267	$ 181	$ 14
14.03	Maintenance Station Equipment-Transportation	d	d	3.06	$ 382	$ 117	$ 48	$ 126	$ 85	$ 7
14.04	Total Maintenance Station Equipment			Sum	$ 13,181	$ 4,022	$ 1,645	$ 4,344	$ 2,938	$ 232
	Maintenance Overhead Lines									
15.00	Maintenance Overhead Lines	d	d	3.06	$ 235,624	$ 71,898	$ 29,407	$ 77,651	$ 52,529	$ 4,139
15.01	Maintenance Overhead Lines-Labor	d	d	3.06	$ 67,425	$ 20,574	$ 8,415	$ 22,220	$ 15,031	$ 1,184
15.02	Maintenance Overhead Lines-Benefits	d	d	3.06	$ 41,867	$ 12,775	$ 5,225	$ 13,797	$ 9,334	$ 735
15.03	Maintenance Overhead Lines-Transportation	d	d	3.06	$ 3,970	$ 1,211	$ 495	$ 1,308	$ 885	$ 70
15.04	Total Maintenance Overhead Lines			Sum	$ 348,885	$ 106,459	$ 43,542	$ 114,976	$ 77,779	$ 6,129

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Cost of Service Analysis
For Twelve Months Ended December 31, 2021

Line	Description	Allocation Factors			Total System	Residential	Commercial General	Commercial Demand	ASU Campus	Lighting (O&M Only)
	Maintenance Underground Lines									
16.00	Maintenance Underground Lines	d	d	3.06	$ 48,534	$ 14,810	$ 6,057	$ 15,995	$ 10,820	$ 853
16.01	Maintenance Underground Lines-Labor	d	d	3.06	$ 38,032	$ 11,605	$ 4,747	$ 12,533	$ 8,479	$ 668
16.02	Maintenance Underground Lines-Benefits	d	d	3.06	$ 10,916	$ 3,331	$ 1,362	$ 3,597	$ 2,434	$ 192
16.03	Maintenance Underground Lines-Transportation	d	d	3.06	$ 2,080	$ 635	$ 260	$ 685	$ 464	$ 37
16.04	Total Maintenance Underground Lines			Sum	$ 99,562	$ 30,380	$ 12,426	$ 32,811	$ 22,196	$ 1,749
	Maintenance Line Transformers									
17.00	Maintenance Line Transformers	d	d	3.06	$ 35,058	$ 10,698	$ 4,375	$ 11,554	$ 7,816	$ 616
17.01	Maintenance Line Transformers-Labor	d	d	3.06	$ 921	$ 281	$ 115	$ 303	$ 205	$ 16
17.02	Maintenance Line Transformers-Benefits	d	d	3.06	$ 540	$ 165	$ 67	$ 178	$ 120	$ 9
17.03	Maintenance Line Transformers-Transportation	d	d	3.06	$ 52	$ 16	$ 6	$ 17	$ 12	$ 1
17.04	Total Maintenance Line Transformers			Sum	$ 36,571	$ 11,159	$ 4,564	$ 12,052	$ 8,153	$ 642
	Maintenance Street Lights									
18.00	Maintenance Street Lights	c	c	1.05	$ 26,291	$ -	$ -	$ -	$ -	$ 26,291
18.01	Maintenance Street Lights-Labor	c	c	1.05	$ 24,958	$ -	$ -	$ -	$ -	$ 24,958
18.02	Maintenance Street Lights-Benefits	c	c	1.05	$ 9,461	$ -	$ -	$ -	$ -	$ 9,461
18.03	Maintenance Street Lights-Transportation	c	c	1.05	$ 1,007	$ -	$ -	$ -	$ -	$ 1,007
18.04	Total Maintenance Street Lights			Sum	$ 61,717	$ -	$ -	$ -	$ -	$ 61,717
	Maintenance-Meters									
19.00	Maintenance-Meters	c	c	4.03	$ 11,439	$ 7,735	$ 1,788	$ 1,340	$ 576	$ -
19.01	Maintenance-Meters-Labor	c	c	4.03	$ 45,710	$ 30,907	$ 7,145	$ 5,355	$ 2,303	$ -
19.02	Maintenance-Meters-Benefits	c	c	4.03	$ 24,422	$ 16,513	$ 3,817	$ 2,861	$ 1,231	$ -
19.03	Maintenance-Meters-Transportation	c	c	4.03	$ 2,605	$ 1,761	$ 407	$ 305	$ 131	$ -
19.04	Total Maintenance-Meters			Sum	$ 84,176	$ 56,916	$ 13,157	$ 9,862	$ 4,242	$ -
	Maintenance Misc Distribution Plant									
20.00	Maintenance Misc Distribution Plant	d	d	3.06	$ 374	$ 114	$ 47	$ 123	$ 83	$ 7
20.01	Maintenance Misc Distribution Plant-Labor	d	d	3.06	$ 77,328	$ 23,596	$ 9,651	$ 25,484	$ 17,239	$ 1,358
20.02	Maintenance Misc Distribution Plant-Benefits	d	d	3.06	$ (12,135)	$ (3,703)	$ (1,515)	$ (3,999)	$ (2,705)	$ (213)
20.03	Maintenance Misc Distribution Plant-Transportation	d	d	3.06	$ 2,328	$ 710	$ 290	$ 767	$ 519	$ 41
20.04	Total Maintenance Misc Distribution Plant			Sum	$ 67,895	$ 20,718	$ 8,474	$ 22,375	$ 15,136	$ 1,193

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Cost of Service Analysis
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Line	Description	Allocation Factors		Total System	Residential	Commercial General	Commercial Demand	ASU Campus	Lighting (O&M Only)
	Supervision Customer Accounts								
21.00	Supervision Customer Accounts-Labor	c c	4.05	$ 30,303	$ 20,404	$ 4,656	$ 3,191	$ 1,691	$ 361
21.01	Supervision Customer Accounts-Benefits	c c	4.05	$ 17,878	$ 12,038	$ 2,747	$ 1,883	$ 998	$ 213
21.02	Supervision Customer Accounts-Transportation	c c	4.05	$ 1,650	$ 1,111	$ 254	$ 174	$ 92	$ 20
21.03	Total Supervision Customer Accounts		Sum	$ 49,831	$ 33,552	$ 7,656	$ 5,247	$ 2,781	$ 594
	Meter Reading Expense								
22.00	Meter Reading Expense	c c	4.04	$ -	$ -	$ -	$ -	$ -	$ -
22.01	Meter Reading Expense-Labor	c c	4.04	$ 480	$ 386	$ 79	$ 15	$ 0	$ -
22.02	Meter Reading Expense-Benefits	c c	4.04	$ 235	$ 189	$ 39	$ 7	$ 0	$ -
22.03	Meter Reading Expense-Transportation	c c	4.04	$ 10	$ 8	$ 2	$ 0	$ 0	$ -
22.04	Total Meter Reading Expense		Sum	$ 726	$ 584	$ 120	$ 22	$ 0	$ -
	Customer Records								
23.00	Customer Records & Collections Expense	c c	4.05	$ 234,974	$ 158,213	$ 36,103	$ 24,743	$ 13,116	$ 2,800
23.01	Customer Records & Collections Expense-Labor	c c	4.05	$ 280,935	$ 189,159	$ 43,165	$ 29,582	$ 15,681	$ 3,347
23.02	Customer Records & Collections Expense-Benefits	c c	4.05	$ 160,868	$ 108,316	$ 24,717	$ 16,939	$ 8,979	$ 1,917
23.03	Postage	c c	4.05	$ 2,242	$ 1,509	$ 344	$ 236	$ 125	$ 27
23.04	Customer Records Cash Over/Short	c c	4.05	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
23.05	Customer Records - Bank Service Fees	c c	4.05	$ 11,415	$ 7,686	$ 1,754	$ 1,202	$ 637	$ 136
23.06	Customer Records - Credit Card Fees	c c	4.05	$ 88,910	$ 59,865	$ 13,661	$ 9,362	$ 4,963	$ 1,059
23.07	Total Customer Records		Sum	$ 779,343	$ 524,748	$ 119,745	$ 82,064	$ 43,501	$ 9,286
	Maintenance Of General Plant								
24.00	Maintenance Of General Plant	d d	3.06	$ 49,167	$ 15,003	$ 6,136	$ 16,203	$ 10,961	$ 864
24.01	Maintenance Of General Plant-Labor	d d	3.06	$ 1,722	$ 525	$ 215	$ 567	$ 384	$ 30
24.02	Maintenance Of General Plant-Benefits	d d	3.06	$ 901	$ 275	$ 112	$ 297	$ 201	$ 16
24.03	Maintenance Of General Plant-Transportation	d d	3.06	$ 41	$ 12	$ 5	$ 13	$ 9	$ 1
24.04	Total Maintenance Of General Plant		Sum	$ 51,831	$ 15,816	$ 6,469	$ 17,081	$ 11,555	$ 910
25.00	Inflation Adjustment Through July 31, 2023	d d	3.06	$ 240,411	$ 73,359	$ 30,004	$ 79,228	$ 53,596	$ 4,223
26.00	Subtotal Electric Operating & Maintenance Expense			$ 17,534,378	$ 5,830,565	$ 2,213,013	$ 6,328,271	$ 2,954,890	$ 207,639
26.02	Subtotal Electric O&M Excluding Purchased Power			$ 2,594,270	$ 1,140,363	$ 345,367	$ 612,521	$ 397,030	$ 98,989
26.03	**Electric O&M Excluding Purchased Power Allocator**	w w		100.00%	43.96%	13.31%	23.61%	15.30%	3.82%

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Cost of Service Analysis
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Line	Description	Allocation Factors	Total System	Residential	Commercial General	Commercial Demand	ASU Campus	Lighting (O&M Only)
	Electric O&M Excluding Purchased Power		**$ 2,594,270**	**$ 1,140,363**	**$ 345,367**	**$ 612,521**	**$ 397,030**	**$ 98,989**
	Customer-Related	c	$ 1,034,935	$ 664,547	$ 150,756	$ 98,637	$ 49,398	$ 71,597
	Energy-Related	e	$ -	$ -	$ -	$ -	$ -	$ -
	Demand-Related	d	$ 1,559,335	$ 475,816	$ 194,611	$ 513,884	$ 347,632	$ 27,392
	Electric O&M Excluding Purchased Power		**$ 2,594,270**	**$ 1,140,363**	**$ 345,367**	**$ 612,521**	**$ 397,030**	**$ 98,989**
	Customer-Related	c	$ 1,034,935	$ 664,547	$ 150,756	$ 98,637	$ 49,398	$ 71,597
	Distribution-Related	d	$ 1,559,335	$ 475,816	$ 194,611	$ 513,884	$ 347,632	$ 27,392
	Transmission-Related	t	$ -	$ -	$ -	$ -	$ -	$ -
	Production-Related	p	$ -	$ -	$ -	$ -	$ -	$ -
	General & Administrative Expenses							
	Administration - Other							
27.00	Customer Assistance Expense	w w 26.03	$ -	$ -	$ -	$ -	$ -	$ -
27.01	Informational Advertising Expense	w w 26.03	$ -	$ -	$ -	$ -	$ -	$ -
27.02	Administrative & General	w w 26.03	$ 299,028	$ 131,444	$ 39,809	$ 70,602	$ 45,764	$ 11,410
27.03	Administrative & General-Salaries	w w 26.03	$ 322,551	$ 141,784	$ 42,940	$ 76,156	$ 49,364	$ 12,307
27.04	Administrative & General-Benefits	w w 26.03	$ 222,031	$ 97,598	$ 29,558	$ 52,423	$ 33,980	$ 8,472
27.05	Office Supplies And Expenses	w w 26.03	$ 41,440	$ 18,216	$ 5,517	$ 9,784	$ 6,342	$ 1,581
27.06	Consulting Fees	w w 26.03	$ 230,607	$ 101,368	$ 30,700	$ 54,448	$ 35,292	$ 8,799
27.07	Investment Management Expense	w w 26.03	$ 14,592	$ 6,414	$ 1,943	$ 3,445	$ 2,233	$ 557
27.08	Property Insurance	w w 26.03	$ 12,349	$ 5,428	$ 1,644	$ 2,916	$ 1,890	$ 471
27.09	Injuries & Damages Expense	w w 26.03	$ 101,106	$ 44,443	$ 13,460	$ 23,872	$ 15,473	$ 3,858
27.10	Injuries & Damages Expense-Labor	w w 26.03	$ 5,293	$ 2,327	$ 705	$ 1,250	$ 810	$ 202
27.11	Injuries & Damages Expense-Benefits	w w 26.03	$ 4,756	$ 2,091	$ 633	$ 1,123	$ 728	$ 181
27.12	Injuries & Damages Expense-Transportation	w w 26.03	$ 254	$ 112	$ 34	$ 60	$ 39	$ 10
27.13	Employee Pension & Benefits Expense	w w 26.03	$ -	$ -	$ -	$ -	$ -	$ -
27.14	Taxes-Employers FICA	w w 26.03	$ -	$ -	$ -	$ -	$ -	$ -
27.15	State Retirement-Employers	w w 26.03	$ -	$ -	$ -	$ -	$ -	$ -
27.16	Institutional Advertising Expense	w w 26.03	$ 70,270	$ 30,889	$ 9,355	$ 16,591	$ 10,754	$ 2,681
27.17	Miscellaneous General Expense	w w 26.03	$ 44,547	$ 19,581	$ 5,930	$ 10,518	$ 6,817	$ 1,700
	PS Adjustment for O&M related to customer growth	e d	$ -	$ -	$ -	$ -	$ -	$ -
27.18	Total Administrative-Other	Sum	$ 1,368,825	$ 601,694	$ 182,227	$ 323,187	$ 209,487	$ 52,230
28.00	**Total O&M**	Sum	$ 18,903,203	$ 6,432,259	$ 2,395,241	$ 6,651,458	$ 3,164,376	$ 259,869
27.01	Total O&M Allocator		100.00%	34.03%	12.67%	35.19%	16.74%	1.37%
27.03	Total O&M Less Purchased Power	Sum	$ 3,963,095	$ 1,742,058	$ 527,594	$ 935,708	$ 606,517	$ 151,218
27.04	Total O&M Less Purchased Power Allocator		100.00%	43.96%	13.31%	23.61%	15.30%	3.82%

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d/b/a New River Light and Power Company
Cost of Service Analysis
For Twelve Months Ended December 31, 2021

Line	Description	Allocation Factors			Total System	Residential	Commercial General	Commercial Demand	ASU Campus	Lighting (O&M Only)
	Total O&M Excluding Purchased Power				$ 3,963,095	$ 1,742,058	$ 527,594	$ 935,708	$ 606,517	$ 151,218
	Customer-Related	c			$ 1,581,001	$ 1,015,185	$ 230,300	$ 150,681	$ 75,462	$ 109,374
	Energy-Related	e			$ -	$ -	$ -	$ -	$ -	$ -
	Demand-Related	d			$ 2,382,093	$ 726,873	$ 297,295	$ 785,027	$ 531,055	$ 41,845
	Total O&M Excluding Purchased Power				$ 3,963,095	$ 1,742,058	$ 527,594	$ 935,708	$ 606,517	$ 151,218
	Customer-Related	c			$ 1,581,001	$ 1,015,185	$ 230,300	$ 150,681	$ 75,462	$ 109,374
	Distribution-Related	d			$ 2,382,093	$ 726,873	$ 297,295	$ 785,027	$ 531,055	$ 41,845
	Transmission-Related	t			$ -	$ -	$ -	$ -	$ -	$ -
	Production-Related	p			$ -	$ -	$ -	$ -	$ -	$ -
	Depreciation and Property Transaction Expense									
29.00	Depreciation	d	d	3.06	$ 1,161,463	$ 354,409	$ 144,955	$ 382,764	$ 258,932	$ 20,403
29.01	Amortization of Unrecovered Plant	d	d	3.06	$ 541,816	$ 165,330	$ 67,621	$ 178,557	$ 120,790	$ 9,518
29.02	Gain/Loss Disposing Utility Property	d	d	3.06	$ 33,663	$ 10,272	$ 4,201	$ 11,094	$ 7,505	$ 591
29.03	Sale Of Surplus Property	d	d	3.06	$ (15,526)	$ (4,738)	$ (1,938)	$ (5,117)	$ (3,461)	$ (273)
29.04	Total Depreciation and Property Transaction Expense			Sum	$ 1,721,417	$ 525,274	$ 214,840	$ 567,299	$ 383,766	$ 30,239
	Interest Expense									
	Interest Expense:									
30.00	Interest Expense Consumer Deposits	c	c	REV1	$ 13,066	$ 4,679	$ 1,631	$ 4,046	$ 2,547	$ 162
30.01	Total Interest Expense			Sum	$ 13,066	$ 4,679	$ 1,631	$ 4,046	$ 2,547	$ 162
	Total Expenses									
31.00	Total Expenses				$ 20,637,686	$ 6,962,212	$ 2,611,712	$ 7,222,803	$ 3,550,689	$ 290,270
31.01	Total Expenses Less Purchased Power				$ 5,697,578	$ 2,272,010	$ 744,065	$ 1,507,053	$ 992,830	$ 181,620
	Total Expenses				$ 20,637,686	$ 6,962,212	$ 2,611,712	$ 7,222,803	$ 3,550,689	$ 290,270
	Customer-Related	c			$ 1,594,067	$ 1,019,864	$ 231,931	$ 154,727	$ 78,009	$ 109,536
	Energy-Related	e			$ 8,399,893	$ 2,533,461	$ 950,464	$ 2,977,390	$ 1,829,928	$ 108,650
	Demand-Related	d			$ 10,643,725	$ 3,408,887	$ 1,429,316	$ 4,090,685	$ 1,642,753	$ 72,084
	Total Expenses Less Purchased Power				$ 5,697,578	$ 2,272,010	$ 744,065	$ 1,507,053	$ 992,830	$ 181,620
	Customer-Related	c			$ 1,594,067	$ 1,019,864	$ 231,931	$ 154,727	$ 78,009	$ 109,536
	Energy-Related	e			$ -	$ -	$ -	$ -	$ -	$ -

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Cost of Service Analysis
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Line	Description	Allocation Factors	Total System	Residential	Commercial General	Commercial Demand	ASU Campus	Lighting (O&M Only)
	Demand-Related	**d**	$ 4,103,510	$ 1,252,146	$ 512,134	$ 1,352,326	$ 914,821	$ 72,084
	Total Expenses		**$ 20,637,686**	**$ 6,962,212**	**$ 2,611,712**	**$ 7,222,803**	**$ 3,550,689**	**$ 290,270**
	Customer-Related	**c**	$ 1,594,067	$ 1,019,864	$ 231,931	$ 154,727	$ 78,009	$ 109,536
	Distribution-Related	**d**	$ 4,103,510	$ 1,252,146	$ 512,134	$ 1,352,326	$ 914,821	$ 72,084
	Transmission-Related	**t**	$ 2,165,014	$ 664,323	$ 269,393	$ 804,915	$ 426,383	$ -
	Production-Related	**p**	$ 12,775,094	$ 4,025,878	$ 1,598,253	$ 4,910,835	$ 2,131,477	$ 108,650
	Total Expenses Less Purchased Power		**$ 5,697,578**	**$ 2,272,010**	**$ 744,065**	**$ 1,507,053**	**$ 992,830**	**$ 181,620**
	Customer-Related	**c**	$ 1,594,067	$ 1,019,864	$ 231,931	$ 154,727	$ 78,009	$ 109,536
	Distribution-Related	**d**	$ 4,103,510	$ 1,252,146	$ 512,134	$ 1,352,326	$ 914,821	$ 72,084
	Transmission-Related	**t**	$ -	$ -	$ -	$ -	$ -	$ -
	Production-Related	**p**	$ -	$ -	$ -	$ -	$ -	$ -
	Net Income and Return on Rate Base							
32.00	Net Income Before Taxes	Sum	$ (2,013,957)	$ (292,572)	$ (286,218)	$ (1,455,587)	$ 79,632	$ (59,213)
	Rate Base							
33.00	Plant In Service	d d 3.06	$ 38,965,206	$ 11,889,852	$ 4,863,009	$ 12,841,118	$ 8,686,750	$ 684,476
33.01	Less: Accumulated Depreciation	d d 3.06	$ (17,721,551)	$ (5,407,558)	$ (2,211,718)	$ (5,840,198)	$ (3,950,773)	$ (311,303)
33.02	Net Plant in Service	Sum	$ 21,243,655	$ 6,482,294	$ 2,651,291	$ 7,000,920	$ 4,735,977	$ 373,173
33.03	Construction Work in Progress	d d 3.06	$ 522,047	$ 159,298	$ 65,154	$ 172,043	$ 116,383	$ 9,170
33.04	Investments - Blue Ridge Electric Membership Corporation	d d 3.03	$ 6,563,579	$ 2,096,189	$ 815,461	$ 2,432,818	$ 1,219,110	$ -
33.05	Investments - North Carolina Electric Membership Corporation	d d 3.03	$ 417,471	$ 133,326	$ 51,867	$ 154,737	$ 77,540	$ -
33.06	Investments - Meridian Cooperative	d d 3.03	$ 9,372	$ 2,993	$ 1,164	$ 3,474	$ 1,741	$ -
33.07	Regulatory Asset (Payne Branch Dam)	d d 3.03	$ 137,771	$ 43,999	$ 17,117	$ 51,065	$ 25,589	$ -
33.08	Regulatory Asset (Unamortized Old Substation)	d d 3.06	$ 80,351	$ 24,518	$ 10,028	$ 26,480	$ 17,913	$ 1,411
33.09	Regulatory Asset (New Substation)	d d 3.06	$ 215,585	$ 65,784	$ 26,906	$ 71,047	$ 48,062	$ 3,787
33.10	Regulatory Asset (UBIT)	d d 3.06	$ 621,030	$ 189,501	$ 77,507	$ 204,662	$ 138,450	$ 10,909
33.11	Prepayments	d d 3.06	$ 73,623	$ 22,465	$ 9,188	$ 24,263	$ 16,413	$ 1,293
33.12	Customer Deposits	d d 3.06	$ (235,508)	$ (71,863)	$ (29,392)	$ (77,613)	$ (52,503)	$ (4,137)
33.13	Working Capital	d d 3.06	$ 872,437	$ 266,216	$ 108,884	$ 287,515	$ 194,498	$ 15,326
33.14	**Total Rate Base**	Sum	**$ 30,521,412**	**$ 9,414,721**	**$ 3,805,174**	**$ 10,351,411**	**$ 6,539,173**	**$ 410,933**
33.15	**Current Return on Rate Base Before Taxes**	Calc	**-6.599%**	**-3.108%**	**-7.522%**	**-14.062%**	**1.218%**	**-14.409%**

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Appalachian State University
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Cost of Service Analysis
For Twelve Months Ended December 31, 2021

Line	Description	Allocation Factors	Total System	Residential	Commercial General	Commercial Demand	ASU Campus	Lighting (O&M Only)
34.00	**Proposed Return on Rate Base Grossed Up for Taxes**	Pulled	**7.007%**	**8.866%**	**8.093%**	**3.867%**	**8.866%**	**3.867%**
34.01	Targeted Net Income	Calc	$ 2,138,605	$ 834,709	$ 307,953	$ 400,289	$ 579,763	$ 15,891
34.02	**Revenue Requirement before Uncollectible Accounts Adder**	Sum	**$ 22,749,357**	**$ 7,787,155**	**$ 2,916,259**	**$ 7,614,646**	**$ 4,125,136**	**$ 306,161**
34.03	Uncollectible Accounts	c c REV2	$ 51,506	$ 22,911	$ 7,988	$ 19,811	$ -	$ 795
34.04	Regulatory Commission Expense	c c REV1	$ 35,573	$ 12,740	$ 4,442	$ 11,016	$ 6,934	$ 442
34.05	Unrelated Business Income Tax	c c REV1	$ 367,938	$ 131,766	$ 45,943	$ 113,937	$ 71,721	$ 4,571
34.06	**Total Revenue Requirement to Recover from Rates**	Sum	**$ 23,204,375**	**$ 7,954,571**	**$ 2,974,632**	**$ 7,759,411**	**$ 4,203,791**	**$ 311,969**
34.07	Total Current Base Rate Revenues	Pulled	$ 18,596,795	$ 6,659,874	$ 2,322,088	$ 5,758,770	$ 3,625,006	$ 231,057
34.08	**Total Revenue Increase(Decrease) Required**	Sum	**$ 4,607,580**	**$ 1,294,697**	**$ 652,544**	**$ 2,000,640**	**$ 578,786**	**$ 80,912**
34.09	**Total Percent Increase(Decrease) Required**	Calc	**24.78%**	**19.44%**	**28.10%**	**34.74%**	**15.97%**	**35.02%**
34.10	PPA Rate Revenue Reduction	Pulled	$ (2,026,509)	$ (611,204)	$ (229,302)	$ (718,303)	$ (441,475)	$ (26,226)
34.11	**Net Rate Revenue Increase**	Sum	**$ 2,581,071**	**$ 683,494**	**$ 423,242**	**$ 1,282,338**	**$ 137,311**	**$ 54,687**
34.12	**Net Rate Revenue Percent Increase**	Calc	**13.88%**	**10.26%**	**18.23%**	**22.27%**	**3.79%**	**23.67%**
	Total Revenue Requirement to Recover from Rates		**$ 23,204,375**	**$ 7,954,571**	**$ 2,974,632**	**$ 7,759,411**	**$ 4,203,791**	**$ 311,969**
	Customer-Related	c	$ 2,022,151	$ 1,177,514	$ 286,899	$ 291,046	$ 151,348	$ 115,344
	Energy-Related	e	$ 8,399,893	$ 2,533,461	$ 950,464	$ 2,977,390	$ 1,829,928	$ 108,650
	Demand-Related	d	$ 12,782,330	$ 4,243,596	$ 1,737,269	$ 4,490,974	$ 2,222,516	$ 87,974
	Total Revenue Requirement to Recover from Rates		**$ 23,204,375**	**$ 7,954,571**	**$ 2,974,632**	**$ 7,759,411**	**$ 4,203,791**	**$ 311,969**
	Customer-Related	c	$ 2,022,151	$ 1,177,514	$ 286,899	$ 291,046	$ 151,348	$ 115,344
	Distribution-Related	d	$ 6,242,115	$ 2,086,855	$ 820,087	$ 1,752,615	$ 1,494,584	$ 87,974
	Transmission-Related	t	$ 2,165,014	$ 664,323	$ 269,393	$ 804,915	$ 426,383	$ -
	Production-Related	p	$ 12,775,094	$ 4,025,878	$ 1,598,253	$ 4,910,835	$ 2,131,477	$ 108,650
35.00	**Cost of Service Summary:**							
35.01	NRLP Customer Related		$ 2,022,151	$ 1,177,514	$ 286,899	$ 291,046	$ 151,348	$ 115,344
35.02	NRLP Distribution Related		$ 6,242,115	$ 2,086,855	$ 820,087	$ 1,752,615	$ 1,494,584	$ 87,974
35.03	BREMCO Transmission Related		$ 1,478,845	$ 465,397	$ 183,655	$ 548,339	$ 281,454	$ -
35.04	DEC Transmission Related		$ 686,169	$ 198,926	$ 85,738	$ 256,577	$ 144,928	$ -
35.05	CPP Production Demand Related		$ 4,375,200	$ 1,492,417	$ 647,789	$ 1,933,444	$ 301,550	$ -
35.06	CPP Production Energy Related		$ 8,399,893	$ 2,533,461	$ 950,464	$ 2,977,390	$ 1,829,928	$ 108,650
35.07	Total		$ 23,204,375	$ 7,954,571	$ 2,974,632	$ 7,759,411	$ 4,203,791	$ 311,969

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Cost of Service Analysis
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Line	Description	Allocation Factors	Total System	Residential	Commercial General	Commercial Demand	ASU Campus	Lighting (O&M Only)
36.00	**Monthly Fixed Cost per Customer Summary:**							
36.01	NRLP Customer and Distribution Related			$ 38.09	$ 62.98	$ 621.36	$ 137,160.98	
36.02	BREMCO Transmission Related			$ 5.43	$ 10.45	$ 166.72	$ 23,454.52	
36.03	DEC Transmission Related			$ 2.32	$ 4.88	$ 78.01	$ 12,077.36	
36.04	CPP Production Demand Related			$ 17.41	$ 36.85	$ 587.85	$ 25,129.13	
36.05	Total			$ 63.25	$ 115.15	$ 1,453.94	$ 197,821.98	

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Current and Proposed Rate Design
For Twelve Months Ended December 31, 2021
Proposed Rates Based on Cost of Service

Line	Description	Billing Determinants	Current Rates	Current Rate Revenues	Proposed Rates	Proposed Revenue	Increase (Decrease)	Percent Increase
1	Residential Service:							
2	Basic Facilities Charge	7,142	$ 12.58	$ 1,078,207	$ 14.50	$ 1,242,766	$ 164,559	15.26%
3	Energy Charge:							
4	NRLP Distribution Charge - All kWh	61,988,218	$ 0.090044	$ 5,581,667	$ 0.032612	$ 2,021,560	$ (3,560,107)	20.25%
5	Wholesale Power Supply Charge - All kWh				$ 0.075663	$ 4,690,215	$ 4,690,215	
6	PPA Energy - All kWh		$ 0.022313	$ 1,383,143	$ 0.012453	$ 771,939	$ (611,204)	-44.19%
7	Total Energy - All kWh		$ 0.112357	$ 6,964,810	$ 0.120728	$ 7,483,714	$ 518,903	7.45%
8	*Total Residential Service*			*$ 8,043,017*		*$ 8,726,480*	*$ 683,463*	8.50%
9								
10	Commercial General Service:							
11	Basic Facilities Charge	1,465	$ 17.42	$ 306,209	$ 17.50	$ 307,615	$ 1,406	0.46%
12	Energy Charge:							
13	NRLP Distribution Charge - All kWh	23,255,764	$ 0.086683	$ 2,015,879	$ 0.034373	$ 799,370	$ (1,216,509)	32.30%
14	Wholesale Power Supply Charge - All kWh				$ 0.080309	$ 1,867,647	$ 1,867,647	
15	PPA Energy - All kWh		$ 0.022313	$ 518,906	$ 0.012453	$ 289,604	$ (229,302)	-44.19%
16	Total Energy - All kWh		$ 0.108996	$ 2,534,785	$ 0.046826	$ 2,956,622	$ 421,836	16.64%
17	*Total Commercial General Service*			*$ 2,840,994*		*$ 3,264,237*	*$ 423,243*	14.90%
18								
19	Commercial Demand Service:							
20	Basic Facilities Charge	274	$ 23.22	$ 76,371	$ 30.00	$ 98,670	$ 22,299	29.20%
21	Demand Charge:							
22	NRLP Distribution Charge - All kW	209,470	$ 8.27	$ 1,732,317	$ 2.27	$ 475,497	$ (1,256,820)	0.00%
23	Wholesale Power Supply Charge - All kW				$ 6.00	$ 1,256,820	$ 1,256,820	
24	Energy Charge:							
25	NRLP Distribution Charge - All kWh	72,850,193	$ 0.054222	$ 3,950,083	$ 0.020171	$ 1,469,461	$ (2,480,622)	50.08%
26	Wholesale Power Supply Charge - All kWh				$ 0.061207	$ 4,458,942	$ 4,458,942	
27	PPA Energy - All kWh		$ 0.022313	$ 1,625,506	$ 0.012453	$ 907,203	$ (718,303)	-44.19%
28	Total Energy - All kWh		$ 0.076535	$ 5,575,590	$ 0.032624	$ 6,835,606	$ 1,260,017	22.60%
29	*Total Commercial Demand Service*			*$ 7,384,277*		*$ 8,666,593*	*$ 1,282,316*	17.37%
30								
31	ASU Campus Service:							
32	Distribution Facilities Charge:							
33	All kW at ASU Substation (plus on-site generation)	92,441	$ 10.63	$ 982,643	$ 17.81	$ 1,646,366	$ 663,723	67.54%
34	Power Demand Charge:							
35	All kW at ASU Substation	92,441	$ 8.75	$ 808,855	$ 7.87	$ 727,507	$ (81,348)	-10.06%
36	Energy Charge:							
37	All kWh at ASU Substation	44,774,302						
38	Base Energy Charge - All kWh		$ 0.040950	$ 1,833,508	$ 0.040870	$ 1,829,926	$ (3,582)	-0.20%
39	PPA Energy - All kWh		$ 0.022313	$ 999,049	$ 0.012453	$ 557,574	$ (441,475)	-44.19%
40	Total Energy Charge - All kWh		$ 0.063263	$ 2,832,557	$ 0.053323	$ 2,387,500	$ (445,057)	
41	*Total ASU Campus Service*			*$ 4,624,055*		*$ 4,761,374*	*$ 137,319*	2.97%
42								
43	Lighting Service:							
44	Schedule OL Base Charge							
45	**Investment and Energy Charge:**							
46	***High Pressure Sodium:***							
47	150 Watt HPS Cobra Head	142	$ 8.90	$ 15,166	$ 13.68	$ 23,304	$ 8,138	53.66%
48	250 Watt HPS Cobra Head	408	$ 12.93	$ 63,305	$ 18.48	$ 90,487	$ 27,181	42.94%
49	250 Watt HPS Shoebox	7	$ 12.93	$ 1,086	$ 20.86	$ 1,752	$ 666	61.35%
50	***Mercury Vapor:***							
51	175 Watt MV	196	$ 9.26	$ 21,780	$ 12.64	$ 29,734	$ 7,954	36.52%
52	400 Watt MV TV	4	$ 16.97	$ 815	$ 24.21	$ 1,162	$ 347	42.65%
53	***Metal Halide:***							
54	250 Watt MH Cobra Head	258	$ 15.33	$ 47,462	$ 19.17	$ 59,354	$ 11,893	25.06%
55	250 Watt MH Decashield	3	$ 15.33	$ 552	$ 18.87	$ 679	$ 128	23.11%
56	400 Watt MH Cobra Head	364	$ 19.54	$ 85,351	$ 26.63	$ 116,329	$ 30,978	36.30%
57	400 Watt MH Flood TV	-	$ 19.54	$ -	$ 26.98	$ -	$ -	0.00%
58	400 Watt MH Shoebox	5	$ 19.54	$ 1,172	$ 28.96	$ 1,737	$ 565	48.18%
59	**Energy Charge Only (Town of Boone Owned Lighting):**							
60	***Sodium Vapor:***							
61	150 Watt Sodium Vapor TOB	79	$ 4.39	$ 4,162	$ 6.42	$ 6,091	$ 1,929	46.35%
62	250 Watt Sodium Vapor TOB	216	$ 7.31	$ 18,948	$ 10.71	$ 27,756	$ 8,808	46.49%
63	400 Watt Sodium Vapor TOB	163	$ 11.68	$ 22,846	$ 17.13	$ 33,513	$ 10,666	46.69%
64	750 Watt Sodium Vapor TOB	1	$ 21.92	$ 263	$ 32.12	$ 385	$ 122	46.55%
65	***Mercury Vapor:***							
66	175 Watt MV TOB	163	$ 5.12	$ 10,015	$ 7.50	$ 14,662	$ 4,647	46.40%
67	400 Watt MV TV TOB	6	$ 11.68	$ 841	$ 17.13	$ 1,234	$ 393	46.69%
68	***Metal Halide:***							
69	250 Watt Metal Halide - TOB	1	$ 7.31	$ 88	$ 10.71	$ 128	$ 41	46.49%
70	400 Watt Metal Halide - TOB	1	$ 11.68	$ 140	$ 17.13	$ 206	$ 65	46.69%

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Line	Description	Billing Determinants	Current Rates	Current Rate Revenues	Proposed Rates	Proposed Revenue	Increase (Decrease)	Percent Increase
71	*Schedule LEDL Base Charge*							
72	**Investment and Energy Charge:**							
73	50 Watt Yard Light (No Longer Available)	4	$ 4.07	$ 195	$ 4.51	$ 217	$ 21	10.85%
74	96 Watt LED TV Bronze	4	$ 6.85	$ 329	$ 10.31	$ 495	$ 166	50.50%
75	101 Watt LED Bronze Cobra Head	4	$ 6.85	$ 329	$ 12.80	$ 615	$ 286	86.88%
76	110 Watt LED (No Longer Available)	7	$ 6.85	$ 576	$ 7.82	$ 657	$ 82	14.18%
77	119 Area Light LED Shoebox (No Longer Available)	98	$ 9.98	$ 11,736	$ 11.04	$ 12,980	$ 1,243	10.59%
78	160 Watt Cobra Head LED	12	$ 11.06	$ 1,593	$ 11.95	$ 1,721	$ 129	8.08%
79	**Energy Charge Only (Town of Boone Owned Lighting):**							
80	20 Watt LED TOB	1	$ 0.44	$ 5	$ 0.86	$ 10	$ 5	94.70%
81	27 Watt LED TOB	17	$ 0.63	$ 129	$ 1.16	$ 236	$ 107	83.57%
82	40 Watt LED TOB	25	$ 0.94	$ 282	$ 1.71	$ 514	$ 232	82.27%
83	50 Watt LED TOB	3	$ 1.13	$ 41	$ 2.14	$ 77	$ 36	89.53%
84	TOB 80 Watt LED	33	$ 1.82	$ 721	$ 3.43	$ 1,357	$ 636	88.28%
85	92 Watt LED TOB	17	$ 2.14	$ 437	$ 3.94	$ 804	$ 367	84.14%
86	100 Watt LED TOB	81	$ 2.33	$ 2,265	$ 4.28	$ 4,163	$ 1,899	83.83%
87	106 Watt LED TOB	54	$ 2.45	$ 1,588	$ 4.54	$ 2,942	$ 1,355	85.32%
88	TOB 110 Watt LED	20	$ 2.51	$ 602	$ 4.71	$ 1,131	$ 528	87.71%
89	120 Watt LED TOB	17	$ 2.77	$ 565	$ 5.14	$ 1,049	$ 483	85.56%
90	TOB 136 Watt LED	2	$ 3.14	$ 75	$ 5.83	$ 140	$ 64	85.52%
91	150 Watt LED TOB	173	$ 3.46	$ 7,183	$ 6.42	$ 13,338	$ 6,155	85.69%
92	TOB 180 Watt LED	24	$ 4.15	$ 1,195	$ 7.71	$ 2,220	$ 1,025	85.78%
93	*Schedule OL PPA Charge*							
94	**Investment and Energy Charge:**							
95	***High Pressure Sodium:***							
96	150 Watt HPS Cobra Head		$ 1.22	$ 2,079	$ 0.68	$ 1,159	$ (920)	-44.26%
97	250 Watt HPS Cobra Head		$ 2.04	$ 9,988	$ 1.14	$ 5,581	$ (4,406)	-44.12%
98	250 Watt HPS Shoebox		$ 2.04	$ 171	$ 1.14	$ 96	$ (76)	-44.12%
99	***Mercury Vapor:***							
100	175 Watt MV		$ 1.43	$ 3,363	$ 0.80	$ 1,882	$ (1,482)	-44.06%
101	400 Watt MV TV		$ 3.26	$ 156	$ 1.82	$ 87	$ (69)	-44.17%
102	***Metal Halide:***							
103	250 Watt MH Cobra Head		$ 2.04	$ 6,316	$ 1.14	$ 3,529	$ (2,786)	-44.12%
104	250 Watt MH Decashield		$ 2.04	$ 73	$ 1.14	$ 41	$ (32)	-44.12%
105	400 Watt MH Cobra Head		$ 3.26	$ 14,240	$ 1.82	$ 7,950	$ (6,290)	-44.17%
106	400 Watt MH Flood TV		$ 3.26	$ -	$ 1.82	$ -	$ -	0.00%
107	400 Watt MH Shoebox		$ 3.26	$ 196	$ 1.82	$ 109	$ (86)	-44.17%
108	**Energy Charge Only (Town of Boone Owned Lighting):**							
109	***Sodium Vapor:***							
110	150 Watt Sodium Vapor TOB		$ 1.22	$ 1,157	$ 0.68	$ 645	$ (512)	-44.26%
111	250 Watt Sodium Vapor TOB		$ 2.04	$ 5,288	$ 1.14	$ 2,955	$ (2,333)	-44.12%
112	400 Watt Sodium Vapor TOB		$ 3.26	$ 6,377	$ 1.82	$ 3,560	$ (2,817)	-44.17%
113	750 Watt Sodium Vapor TOB		$ 6.11	$ 73	$ 3.41	$ 41	$ (32)	-44.19%
114	***Mercury Vapor:***							
115	175 Watt MV TOB		$ 1.43	$ 2,797	$ 0.80	$ 1,565	$ (1,232)	-44.06%
116	400 Watt MV TV TOB		$ 3.26	$ 235	$ 1.82	$ 131	$ (104)	-44.17%
117	***Metal Halide:***							
118	250 Watt Metal Halide - TOB		$ 2.04	$ 24	$ 1.14	$ 14	$ (11)	-44.12%
119	400 Watt Metal Halide - TOB		$ 3.26	$ 39	$ 1.82	$ 22	$ (17)	-44.17%
120	*Schedule LEDL PPA Charge*							
121	**Investment and Energy Charge:**							
122	50 Watt Yard Light (No Longer Available)		$ 0.41	$ 20	$ 0.23	$ 11	$ (9)	-43.90%
123	96 Watt LED TV Bronze		$ 0.78	$ 37	$ 0.44	$ 21	$ (16)	-43.59%
124	101 Watt LED Bronze Cobra Head		$ 0.82	$ 39	$ 0.46	$ 22	$ (17)	-43.90%
125	110 Watt LED (No Longer Available)		$ 0.90	$ 76	$ 0.50	$ 42	$ (34)	-44.44%
126	119 Area Light LED Shoebox (No Longer Available)		$ 0.97	$ 1,141	$ 0.54	$ 635	$ (506)	-44.33%
127	160 Watt Cobra Head LED		$ 1.32	$ 190	$ 0.74	$ 107	$ (84)	-43.94%
128	**Energy Charge Only (Town of Boone Owned Lighting):**							
129	20 Watt LED TOB		$ 0.16	$ 2	$ 0.09	$ 1	$ (1)	-43.75%
130	27 Watt LED TOB		$ 0.22	$ 45	$ 0.12	$ 24	$ (20)	-45.45%
131	40 Watt LED TOB		$ 0.33	$ 99	$ 0.18	$ 54	$ (45)	-45.45%
132	50 Watt LED TOB		$ 0.41	$ 15	$ 0.23	$ 8	$ (6)	-43.90%
133	TOB 80 Watt LED		$ 0.65	$ 257	$ 0.36	$ 143	$ (115)	-44.62%
134	92 Watt LED TOB		$ 0.75	$ 153	$ 0.42	$ 86	$ (67)	-44.00%
135	100 Watt LED TOB		$ 0.81	$ 787	$ 0.45	$ 437	$ (350)	-44.44%
136	106 Watt LED TOB		$ 0.86	$ 557	$ 0.48	$ 311	$ (246)	-44.19%
137	TOB 110 Watt LED		$ 0.90	$ 216	$ 0.50	$ 120	$ (96)	-44.44%
138	120 Watt LED TOB		$ 0.98	$ 200	$ 0.55	$ 112	$ (88)	-43.88%
139	TOB 136 Watt LED		$ 1.11	$ 27	$ 0.62	$ 15	$ (12)	-44.14%
140	150 Watt LED TOB		$ 1.22	$ 2,533	$ 0.68	$ 1,412	$ (1,121)	-44.26%
141	TOB 180 Watt LED		$ 1.47	$ 423	$ 0.82	$ 236	$ (187)	-44.22%

Docket No. E-34, Sub 54
Appalachian State University
d/b/a New River Light and Power Company
Current and Proposed Rate Design
For Twelve Months Ended December 31, 2021
Proposed Rates Based on Cost of Service

Line	Description	Billing Determinants	Current Rates	Current Rate Revenues	Proposed Rates	Proposed Revenue	Increase (Decrease)	Percent Increase
142	Schedule OL Total Charge							
143	**Investment and Energy Charge:**							
144	***High Pressure Sodium:***							
145	150 Watt HPS Cobra Head		$ 10.12	$ 17,244	$ 14.36	$ 24,462	$ 7,218	41.86%
146	250 Watt HPS Cobra Head		$ 14.97	$ 73,293	$ 19.62	$ 96,068	$ 22,775	31.07%
147	250 Watt HPS Shoebox		$ 14.97	$ 1,257	$ 22.00	$ 1,848	$ 591	46.98%
148	***Mercury Vapor:***							
149	175 Watt MV		$ 10.69	$ 25,143	$ 13.44	$ 31,616	$ 6,473	25.74%
150	400 Watt MV TV		$ 20.23	$ 971	$ 26.03	$ 1,249	$ 278	28.66%
151	***Metal Halide:***							
152	250 Watt MH Cobra Head		$ 17.37	$ 53,778	$ 20.31	$ 62,884	$ 9,106	16.93%
153	250 Watt MH Decashield		$ 17.37	$ 625	$ 20.01	$ 720	$ 95	15.21%
154	400 Watt MH Cobra Head		$ 22.80	$ 99,590	$ 28.45	$ 124,279	$ 24,688	24.79%
155	400 Watt MH Flood TV		$ 22.80	$ -	$ 28.80	$ -	$ -	0.00%
156	400 Watt MH Shoebox		$ 22.80	$ 1,368	$ 30.78	$ 1,847	$ 479	34.98%
157	**Energy Charge Only (Town of Boone Owned Lighting):**							
158	***Sodium Vapor:***							
159	150 Watt Sodium Vapor TOB		$ 5.61	$ 5,318	$ 7.10	$ 6,735	$ 1,417	26.65%
160	250 Watt Sodium Vapor TOB		$ 9.35	$ 24,235	$ 11.85	$ 30,711	$ 6,475	26.72%
161	400 Watt Sodium Vapor TOB		$ 14.94	$ 29,223	$ 18.95	$ 37,072	$ 7,850	26.86%
162	750 Watt Sodium Vapor TOB		$ 28.03	$ 336	$ 35.53	$ 426	$ 90	26.77%
163	***Mercury Vapor:***							
164	175 Watt MV TOB		$ 6.55	$ 12,812	$ 8.30	$ 16,227	$ 3,415	26.65%
165	400 Watt MV TV TOB		$ 14.94	$ 1,076	$ 18.95	$ 1,365	$ 289	26.86%
166	***Metal Halide:***							
167	250 Watt Metal Halide - TOB		$ 9.35	$ 112	$ 11.85	$ 142	$ 30	26.72%
168	400 Watt Metal Halide - TOB		$ 14.94	$ 179	$ 18.95	$ 227	$ 48	26.86%
169	Schedule LEDL Total Charge							
170	**Investment and Energy Charge:**							
171	50 Watt Yard Light (No Longer Available)		$ 4.48	$ 215	$ 4.74	$ 228	$ 13	5.84%
172	96 Watt LED TV Bronze		$ 7.63	$ 366	$ 10.75	$ 516	$ 150	40.89%
173	101 Watt LED Bronze Cobra Head		$ 7.67	$ 368	$ 13.26	$ 637	$ 268	72.90%
174	110 Watt LED (No Longer Available)		$ 7.75	$ 651	$ 8.32	$ 699	$ 48	7.37%
175	119 Area Light LED Shoebox (No Longer Available)		$ 10.95	$ 12,877	$ 11.58	$ 13,615	$ 738	5.73%
176	160 Watt Cobra Head LED		$ 12.38	$ 1,783	$ 12.69	$ 1,828	$ 45	2.53%
177	**Energy Charge Only (Town of Boone Owned Lighting):**							
178	20 Watt LED TOB		$ 0.60	$ 7	$ 0.95	$ 11	$ 4	57.78%
179	27 Watt LED TOB		$ 0.85	$ 173	$ 1.28	$ 260	$ 87	50.18%
180	40 Watt LED TOB		$ 1.27	$ 381	$ 1.89	$ 568	$ 187	49.08%
181	50 Watt LED TOB		$ 1.54	$ 55	$ 2.37	$ 85	$ 30	54.00%
182	TOB 80 Watt LED		$ 2.47	$ 978	$ 3.79	$ 1,500	$ 521	53.31%
183	92 Watt LED TOB		$ 2.89	$ 590	$ 4.36	$ 890	$ 300	50.89%
184	100 Watt LED TOB		$ 3.14	$ 3,052	$ 4.73	$ 4,601	$ 1,549	50.74%
185	106 Watt LED TOB		$ 3.31	$ 2,145	$ 5.02	$ 3,253	$ 1,108	51.67%
186	TOB 110 Watt LED		$ 3.41	$ 818	$ 5.21	$ 1,251	$ 432	52.83%
187	120 Watt LED TOB		$ 3.75	$ 765	$ 5.69	$ 1,161	$ 396	51.73%
188	TOB 136 Watt LED		$ 4.25	$ 102	$ 6.45	$ 155	$ 53	51.65%
189	150 Watt LED TOB		$ 4.68	$ 9,716	$ 7.10	$ 14,750	$ 5,034	51.82%
190	TOB 180 Watt LED		$ 5.62	$ 1,619	$ 8.53	$ 2,457	$ 838	51.78%
191	Estimated kWh Usage	2,658,434						
192	Pole Charges							
193	Shakespeare Fiberglass Bronze Poles	11	$ 6.81	$ 899	$ 12.83	$ 1,694	$ 795	88.44%
194	30' Wood Pole	8	$ 3.40	$ 326	$ 4.33	$ 416	$ 89	27.34%
195	***Total Lighting***			***$ 384,449***		***$ 488,451***	$ 104,002	27.05%
196								
197	Total System:							
198								
199	**Total Customers (Excluding Lighting)**	**8,882**						
200	**Total kWh Usage**	**205,526,911**						
201	**Total Base Revenues**			**$ 18,690,798**		**$ 23,347,650**	**$ 4,656,852**	**24.92%**
202	**Total PPA Revenues**			**$ 4,585,993**		**$ 2,559,484**	**$ (2,026,509)**	**-44.19%**
203	**Total Revenues**			**$ 23,276,791**		**$ 25,907,134**	**$ 2,630,343**	**11.30%**
204	*Facilities Charge*			*$ 2,443,429*		*$ 3,295,417*	*$ 851,988*	*34.87%*
205	*Demand Charge*			*$ 2,541,172*		*$ 1,203,004*	*$ (1,338,168)*	*-52.66%*
206	*Energy Charge*			*$ 17,907,742*		*$ 19,663,442*	*$ 1,755,700*	*9.80%*
207	*Lighting Charges:*							
208	*O&M Related*			*$ 231,057*		*$ 311,984*	*$ 80,928*	*35.03%*
209	*Investment Related*			*$ 94,003*		*$ 143,304*	*$ 49,301*	*52.45%*
210	*Total Lighting Charges*			*$ 325,060*		*$ 455,288*	*$ 130,228*	*40.06%*

Docket No. E-34, Sub 54
Appalachian State University
d/b/a New River Light and Power Company
Renewable Solar Energy Net Billing Rider
Developed for Schedule NBR - Commercial General Service

Line	Description	Actual Billing Data	CP Peaks as % of Max Output
1	<u>Production from Customer Solar Generation [1]:</u>		
2	Energy Produced (kWh)	50,414.790	n/a
3	Output at BREMCO CP Demand (kW)	11.790	29.12%
4	Output at DEC CP Demand (kW)	11.790	29.12%
5	Output at CPP CP Demand (kW)	10.540	26.03%
6	Max Output (kW)	40.485	100.00%

Line	Description	From Exhibit REH-16: Rate Design			Calculation of Charge to Collect Costs *NOT* Avoided from Customer Solar Generation						
		Proposed General Service Rates [2]	Unadjusted General Service Billing Determinants	Unadjusted Proposed General Service Revenues	Solar Generation Output	Adjusted General Service Billing Determinants	Adjusted Proposed General Service Revenues	Unrecovered Costs	Name Plate Solar Generation Capacity	Percent of Unrecovered Costs to Collect	Monthly Charge per Name Plate Capacity
7	<u>Proposed Commercial General Service Rate:</u>										
8	Basic Facilities Charge	$ 17.50	1,465	$ 307,615		1,465	$ 307,615	$ -	40.485	100.00%	$ -
9	Energy Charge:										
10	NRLP Distribution Related	$ 0.034373	23,255,764	$ 799,370	50,415	23,205,349	$ 797,637	$ (1,733)	40.485	100.00%	$ 3.57
11	Wholesale Power Supply Charge:										
12	BREMCO Distribution Related	$ 0.007897	23,255,764	$ 183,651	50,415	23,205,349	$ 183,253	$ (398)	40.485	70.88%	$ 0.58
13	DEC Transmission Related	$ 0.003687	23,255,764	$ 85,744	50,415	23,205,349	$ 85,558	$ (186)	40.485	70.88%	$ 0.27
14	CPP Production Demand Related	$ 0.027855	23,255,764	$ 647,789	50,415	23,205,349	$ 646,385	$ (1,404)	40.485	73.97%	$ 2.14
15	CPP Production Energy Related	$ 0.040870	23,255,764	$ 950,463							$ -
16	Total Wholesale Power Supply	$ 0.080309		$ 1,867,647							$ 2.99
17	PPAC Energy	$ 0.012453	23,255,764	$ 289,604							$ -
18	Total Commercal General Service			$ 3,264,237						**Monthly kW Charge for Customer's Installed Name Plate Capacity**	**$ 6.56**

Notes:
[1] As taken from hourly load profiles from all solar output for 12 months ended December 31, 2021.
[2] Proposed Commercial General Service Rates Based on Cost of Service.

Docket No. E-34, Sub 54
Appalachian State University
d/b/a New River Light and Power Company
Renewable Solar Energy Net Billing Rider
Developed for Schedule NBR - Commercial Demand Service

Line	Description	Actual Billing Data	CP Peaks as % of Max Output
1	**Production from Customer Solar Generation [1]:**		
2	Energy Produced (kWh)	50,414.790	n/a
3	Output at BREMCO CP Demand (kW)	11.790	29.12%
4	Output at DEC CP Demand (kW)	11.790	29.12%
5	Output at CPP CP Demand (kW)	10.540	26.03%
6	Max Output (kW)	40.485	100.00%

Line	Description	From Exhibit REH-16: Rate Design			Calculation of Charge to Collect Costs *NOT* Avoided from Customer Solar Generation						
		Proposed Demand Service Rates [2]	Unadjusted Demand Service Billing Determinants	Unadjusted Proposed Demnd Service Revenues	Solar Generation Output	Adjusted Demand Service Billing Determinants	Adjusted Proposed Demand Service Revenues	Unrecovered Costs	Name Plate Solar Generation Capacity	Percent of Unrecovered Costs to Collect	Monthly Charge per Name Plate Capacity
7	**Proposed Commercial Demand Service Rate:**										
8	Basic Facilities Charge	$ 30.00	274	$ 98,670		274	$ 98,670	$ -	40.485	100.00%	$ -
9	Demand Charge:										
10	NRLP Distribution Charge	$ 2.27	209,469.98	$ 475,497	11.790	209,458.19	$ 475,470	$ (27)	40.485	100.00%	$ 0.06
11	Wholesale Power Supply Charge	$ 6.00	209,469.98	$ 1,256,820	10.540	209,459.44	$ 1,256,757	$ (63)	40.485	73.97%	$ 0.10
12	Energy Charge:										-
13	NRLP Distribution Related	$ 0.020171	72,850,193	$ 1,469,461	50,415	72,799,778	$ 1,468,444	$ (1,017)	40.485	100.00%	$ 2.09
14	Wholesale Power Supply Charge:										
15	BREMCO Distribution Related	$ 0.004072	72,850,193	$ 296,669	50,415	72,799,778	$ 296,463	$ (205)	40.485	70.88%	$ 0.30
16	DEC Transmission Related	$ 0.001906	72,850,193	$ 138,816	50,415	72,799,778	$ 138,720	$ (96)	40.485	70.88%	$ 0.14
17	CPP Production Demand Related	$ 0.014359	72,850,193	$ 1,046,067	50,415	72,799,778	$ 1,045,343	$ (724)	40.485	73.97%	$ 1.10
18	CPP Production Energy Related	$ 0.040870	72,850,193	$ 2,977,390							$ -
19	Total Wholesale Power Supply	$ 0.061207		$ 4,458,942							$ 1.54
20	PPAC Energy	$ 0.012453	72,850,193	$ 907,203							$ -
21	Total Commercal General Service			$ 8,666,593						**Monthly kW Charge for Customer's Installed Name Plate Capacity**	**$ 3.64**

Notes:
[1] As taken from hourly load profiles from all solar output for 12 months ended December 31, 2021.
[2] Proposed Commercial Demand Service Rates Based on Cost of Service.

Docket No. E-34, Sub 54
Appalachian State University
d/b/a New River Light and Power Company
Renewable Solar Energy Net Billing Rider
Developed for Schedule NBR - Residential Service

Line	Description	Actual Billing Data	CP Peaks as % of Max Output
1	Production from Customer Solar Generation [1]:		
2	Energy Produced (kWh)	50,414.790	n/a
3	Output at BREMCO CP Demand (kW)	11.790	29.12%
4	Output at DEC CP Demand (kW)	11.790	29.12%
5	Output at CPP CP Demand (kW)	10.540	26.03%
6	Max Output (kW)	40.485	100.00%

		From Exhibit REH-16: Rate Design			Calculation of Charge to Collect Costs *NOT* Avoided from Customer Solar Generation						
Line	Description	Proposed Residential Rates [2]	Unadjusted Residential Billing Determinants	Unadjusted Proposed Residential Rate Revenues	Solar Generation Output	Adjusted Residential Billing Determinants	Adjusted Proposed Residential Rate Revenues	Unrecovered Costs	Name Plate Solar Generation Capacity	Percent of Unrecovered Costs to Collect	Monthly Charge per Name Plate Capacity
7	Proposed Residential Rate:										
8	Basic Facilities Charge	$ 14.50	7,142	$ 1,242,766		7,142	$ 1,242,766	$ -	40.485	100.00%	$ -
9	Energy Charge:										
10	NRLP Distribution Related	$ 0.032612	61,988,218	$ 2,021,560	50,415	61,937,803	$ 2,019,916	$ (1,644)	40.485	100.00%	$ 3.38
11	Wholesale Power Supply Charge:										
12	BREMCO Distribution Related	$ 0.007508	61,988,218	$ 465,408	50,415	61,937,803	$ 465,029	$ (379)	40.485	70.88%	$ 0.55
13	DEC Transmission Related	$ 0.003209	61,988,218	$ 198,920	50,415	61,937,803	$ 198,758	$ (162)	40.485	70.88%	$ 0.24
14	CPP Production Demand Related	$ 0.024076	61,988,218	$ 1,492,428	50,415	61,937,803	$ 1,491,215	$ (1,214)	40.485	73.97%	$ 1.85
15	CPP Production Energy Related	$ 0.040870	61,988,218	$ 2,533,458							$ -
16	Total Wholesale Power Supply	$ 0.075663		$ 4,690,215							$ 2.64
17	PPAC Energy	$ 0.012453	61,988,218	$ 771,939							$ -
18	Total Residential Service			$ 8,726,480						Monthly kW Charge for Customer's Installed Name Plate Capacity	$ 6.02

Notes:
[1] As taken from hourly load profiles from all solar output for 12 months ended December 31, 2021.
[2] Proposed Residential Rates Based on Cost of Service.

Docket No. E-34, Sub 54
Appalachian State University
d/b/a New River Light and Power Company
Avoided Cost for Buy All / Sell All of Renewable Solar Energy
Developed for Schedule PPR

Line	Description	Actual Billing Data	CP Peaks as % of Max Output
1	**Production from Customer Solar Generation [1]:**		
2	Energy Produced (kWh)	50,414.790	n/a
3	Output at BREMCO CP Demand (kW)	11.790	29.12%
4	Output at DEC CP Demand (kW)	11.790	29.12%
5	Output at CPP CP Demand (kW)	10.540	26.03%
6	Max Output (kW)	40.485	100.00%

Line	Description	Wholesale Power Supply Costs	Retail Energy Purchases	Wholesale Power Supply Costs per Retail kWh	Percent of Wholesale Power Supply Costs Avoided	Avoided Cost ($/kWh)
7	**Wholesale Power Supply Cost in Base Rates [2]:**					
8	BREMCO Distribution Related	$ 1,478,845	205,526,911	$ 0.007195	29.12%	$ 0.002095
9	DEC Transmission Related	$ 686,169	205,526,911	$ 0.003339	29.12%	$ 0.000972
10	CPP Production Demand Related	$ 4,375,200	205,526,911	$ 0.021288	26.03%	$ 0.005542
11	CPP Production Energy Related	$ 8,399,893	205,526,911	$ 0.040870	100.00%	$ 0.040870
12	Total Wholesale Power Supply in Base Rates	$ 14,940,108		$ 0.072692		$ 0.049479
13	**PPAC Energy [3]**	$ 2,559,484	205,526,911	$ 0.012453	100.00%	$ 0.012453
14	Total Wholesale Power Supply Costs	$ 17,499,592		$ 0.085145		
15	**Total Avoided Cost as $/kWh**					**$ 0.061932**

Notes:

[1] As taken from hourly load profiles from all solar output for 12 months ended December 31, 2021.

[2] As taken from Exhibit_(REH-14) - Cost of Service Analysis for total system costs.

[3] As taken from Exhibit_(REH-16) - Rate Design Analysis under proposed rates.