NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

June 9, 2023

Ms. A. Shonta Dunston, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Docket No. E-34, Subs 54 and 55 – Application of Appalachian State University, d/b/a New River Light and Power Company for Adjustment of General Base Rates and Charges Applicable to Electric Service, and for an Accounting Order to Defer Certain Capital Costs and New Tax Expenses

Dear Ms. Dunston:

Attached for filing on behalf of the Public Staff in the above-referenced docket is the testimony of Jack Floyd, Engineer and Manager of the Rates and Energy Section, Energy Division, Public Staff – North Carolina Utilities Commission.

By copy of this letter, we are forwarding a copy to all parties of record by electronic delivery.

Sincerely,

Electronically submitted
/s/ Thomas J. Felling
Staff Attorney
thomas.felling@psncuc.nc.gov

Attachments

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CERTIFICATE OF SERVICE

I certify that a copy of the following Testimony has been served on all parties of record or their attorneys, or both, in accordance with Commission Rule R1-39, by United States Mail, first class or better; by hand delivery; or by means of facsimile or electronic delivery upon agreement of the receiving party.

This the 6th day June, 2023.

Electronically submitted
/s/ Thomas J. Felling
Staff Attorney

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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In the Matter of
Application of Appalachian State University, d/b/a New River Light and Power Company for Adjustment of General Base Rates and Charges Applicable to Electric Service

DOCKET NO. E-34, Sub 55

In the Matter of Petition of Appalachian State University d/b/a New River Light and Power Company for an Accounting Order to Defer Certain Capital Costs and New Tax Expenses</td><td>)
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JACK FLOYD
PUBLIC STAFF –
NORTH CAROLINA
UTILITIES COMMISSION</td></tr>
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June 6, 2023

Q. Please state your name, business address, and present position.

A. My name is Jack Floyd. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an engineer and the manager of the Rates and Energy Services Section of the Energy Division of the Public Staff – North Carolina Utilities Commission (Public Staff),

Q. Briefly state your qualifications and duties.

A. My qualifications and duties are attached as Appendix A.

Q. What is the mission of the Public Staff?

A. The Public Staff represents the interests and concerns of the using and consuming public in all public utility matters that come before the North Carolina Utilities Commission (the Commission). Pursuant to N.C. Gen. Stat. § 62-15(d), it is the Public Staff's duty and responsibility to review, investigate, and make appropriate recommendations to the Commission with respect to the following utility matters: (1) retail rates charged, service furnished, and complaints filed, regardless of retail customer class; (2) applications for certificates of public convenience and necessity; (3) transfers of franchises, mergers, consolidations, and combinations of public utilities; and (4) contracts of public utilities with affiliates or subsidiaries. The Public Staff is also responsible for appearing before state and federal courts and agencies in matters affecting public utility service.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to set forth the Public Staff's findings and recommendations resulting from our examination of the Application of Appalachian State University, d/b/a New River Light & Power Company (NRLP) in Docket No. E-34, Sub 54 filed on December 22, 2022, (Application) for the test year ended December 31, 2021 (Test Year). More specifically, my testimony addresses the following items contained in NRLP's Application:

- Various capital investments associated with a replacement substation, a renovated and expanded laydown yard, a warehouse expansion and renovation, a new supervisory control and data acquisition (SCADA) system, and the undergrounding of distribution circuits in certain residential subdivisions.
- The cost-of-service study (COSS) used in this case.
- Rates and rate schedules, including NRLP's proposed Net Billing Rider (Schedule NBC); Purchased Power for Renewable Energy Facilities (Buy-All-Sell-All) (Schedule PPR); and Interruptible Service Rider (Schedule IR); and

- Customer Class revenue apportionment and NRLP's proposed two-year phase-in of its requested revenue increase.

Q. Briefly explain the scope of your investigation regarding NRLP's Application.

A. The scope of my investigation consisted of a review of:

- NRLP's application;
- the COSS used in this proceeding to allocate costs among the various customer classes based upon appropriate cost causation principles, which served as the foundation for the utility's various rate schedules; and
- the conditions of service that serve to produce the requested revenue requirement reflected in NRLP's proposed base rate charges.

Finally, my investigation also included an analysis of the need for, and costs associated with, various NRLP capital investments made to provide adequate utility service included for recovery in this case.

Q. Are you providing any exhibits with your testimony?

A. Yes. Floyd Exhibit 1 provides the Public Staff's recommended revenue apportionment.

<u>I. Capital Investments</u>

Q. Please discuss the Public Staff's review of the large capital investments made by NRLP that are included for recovery in this rate case.

A. NRLP witness Edmond C. Miller identified five major capital projects that NRLP completed subsequent to its last rate case in Docket No. E-34, Sub 46 (Sub 46 case). Those projects are: (1) a new campus substation; (2) a new SCADA system; (3) renovation and expansion of a warehouse and office building; (4) reconstruction of a laydown yard for storage of large equipment and materials; and (5) undergrounding of certain distribution lines.

The Public Staff's investigation of these capital expenditures included a review of the costs (including bid solicitations); the basis for the expenditures; how these projects would improve the customer service; and how they would serve as a predicate for future new opportunities for enhanced customer services and efficiencies. I address each project need below:

1. <u>The new substation, which serves the main campus of Appalachian State University,</u> is the last of five NRLP substations to be converted to a new voltage delivery level as required by Blue Ridge Electric Membership Corporation (BREMCO), from whom NRLP purchases its transmission service requirements.

The conversion represents a more than 10-year process of converting each NRLP substation to receive power at 100 kilovolts (kV) from BREMCO's transmission system. In addition, the new substation includes new physical security features.

2. The recent implementation of an advanced metering infrastructure (AMI) network, as discussed in the Sub 46 Case, required a <u>new SCADA system</u> to allow NRLP to monitor customer usage and system conditions and allow for more prompt response to those system conditions. The combined AMI and SCADA systems also allow customers to have more involvement in their electricity purchases from the utility. While these capabilities are still evolving, the utility is now positioned to begin looking into and implementing new opportunities to assist customers with more energy efficiency (EE) measures, demand response, and time-of-use rate designs, all of which could help reduce or shift overall peak demand and energy consumption.

3. <u>The renovation and expansion of the warehouse</u> was necessary to improve employee access and efficiency, upgrade workspace, update environmental systems, shelter equipment from the weather, and accommodate greater storage for equipment and supplies.

4. The existing laydown yard was completely renovated to provide a safer and more efficient means of accessing large equipment and materials.
5. The undergrounding of distribution service was completed in response to chronic outages in some of NRLP's older residential neighborhoods. One customer at the public hearing on May 23, 2022, testified to the improved service quality experienced from the undergrounding projects.

Q. What is your recommendation regarding these capital investments?

A. Based on the Public Staff's review and in-person inspection of the facilities associated with each of the capital investments discussed above, I believe each was necessary and constructed in a reasonable and prudent manner. I do not object to their inclusion in rate base in this case. Public Staff Accounting witnesses Sonja R. Johnson and Iris Morgan address the treatment of the remaining book value of the old substation.

II. Cost of Service Study

Q. Have you reviewed NRLP's COSS in this proceeding?

A. Yes.

Q. What is the purpose of the COSS?

A. The purpose of any COSS is to measure and determine the appropriate share of revenues, expenses, and plant related to the provision of electric service that is the responsibility of individual jurisdictions and customer classes. Typically, these studies are developed based on billing determinant data such as number of customers, direct-metered energy sales (kWh), and registered demand (kW). When direct usage data is not available, load research is utilized. Cost-of-service studies use this load research data as the basis for assigning or allocating the system and jurisdictional revenues, expenses, and plant to the various customer classes. Development of the COSS is the first step in determining the appropriateness of cost-based rates for electric service.

Q. Please explain NRLP's COSS in this proceeding.

A. In the Sub 46 case, the Commission ordered NRLP to update all load data in its COSS to incorporate a full year of data collected from its AMI system and file an updated COSS by the end of June 2019. NRLP filed its updated COSS on June 18, 2019.

In the present case, NRLP has used the data available from its AMI system to develop the demand- and energy-related inputs in the COSS, along with other load data, which is used to develop an allocation of costs to the various customer classes. NRLP Exhibit

REH-14 represents the COSS that was used to develop various allocation factors to apportion revenues, expenses, and rate base to the various customer classes. As a distribution-only utility,[1] NRLP does not have production costs similar to other investor-owned utilities. Production-related capacity costs are recovered pursuant to the terms of the purchase power agreement (PPA) with NRLP's provider, Carolina Power Partners (CPP). NRLP pays Duke Energy Carolinas, LLC (DEC), and BREMCO, for power delivery services from CPP to NRLP.[2]

NRLP uses class coincident peak data to allocate capacity-related costs associated with the PPA. DEC-related PPA transmission costs are allocated using DEC's transmission peak demand data. BREMCO's power delivery costs are allocated using BREMCO's coincident peak demand data. NRLP's distribution-related costs are allocated using NRLP's distribution peak demand data. Customer-related costs are allocated based on customer data weighted on the kW demands of each class.

Purchased power costs represent approximately 71% of NRLP's total expenses related to the provision of utility service. The

[1] NRLP purchases 100% of its power supply requirements at wholesale.

[2] CPP interconnects directly with DEC, which delivers power to BREMCO; BREMCO interconnects directly with NRLP.

remaining 29% of expenses are related to operating and maintaining the local distribution system, customer accounting, and general administration of the utility. In recent months, NRLP has experienced volatility in its purchased power costs, and the Commission addressed that volatility by allowing NRLP to update its purchased power adjustment rider more frequently than annually to mitigate the potential for rate shock associated with significant annual under-collections.[3]

Q. Does the Public Staff have any comments or recommendations related to the COSS in this proceeding?

A. No. NRLP has complied with the Commission's Sub 46 case order through the COSS filed in this proceeding. As evidenced through customer comments at the May 23, 2023, public hearing in this case, many NRLP customers would like to see more opportunities for customer-owned distributed energy resources directly connected to its distribution system. As customers begin to demand more options for electric vehicle (EV) charging, along with the ability to adopt and potentially own renewable energy resources, the COSS and necessary data to properly evaluate how customers are using and imposing costs on the NRLP system will become more paramount in

[3] See Order Approving Mid-Year Supplemental Purchased Power Adjustment dated July 26, 2022, in Docket No. E-34, Sub 53.

future rate cases. As a distribution-only electric utility, NRLP, as well as the Public Staff and the Commission, will need to devote even greater focus to the question of cost causation.

III. Rate Schedules

Q. Please discuss the proposed changes to the NRLP rate schedules.

A. NRLP is requesting several changes in this case to its portfolio of rate schedules. The more noteworthy changes include:

1. Closure of Schedule GLH;
2. Shift in cost recovery from an energy charge to a new NRLP Distribution Charge and Wholesale Power Supply Charge;
3. New net billing rider Schedule NBR;
4. New buy-all-sell-all (BASA) Schedule PPR; and,
5. New interruptible rider Schedule IR.

Closure of Schedule GLH – This schedule was promulgated in the Sub 46 case on the premise of offering high load factor non-residential customers another rate option. While the premise was sound, no customers have expressed interest in this schedule to date. NLRP witness Randall E. Halley's testimony and responses to discovery also indicate that there is little difference in load shapes between Schedules GL and GLH. This likely limits the opportunities for high load factor customers to save money without making significant changes to their consumption. The Public Staff does not object to this request to close Schedule GLH.

<u>New NRLP Distribution Charge and Wholesale Power Supply Charge</u> – NRLP has proposed to separate the energy charges contained in its rate schedules into two separate charges in order to better identify and recover the costs associated with its distribution system from costs associated with the PPA. This separation takes the current energy charges in Schedules R and G, and the demand and energy charges in Schedule GL, and isolates the recovery of distribution-related costs from costs associated with the energy purchased through the PPA. Schedule A (ASU Campus Service) already distinguishes distribution-related costs from PPA costs in its structure.

The Public Staff reviewed both the COSS and the calculations behind this change. As stated by NRLP witness Halley in his testimony, this rather significant structural change in rates is needed to better distinguish distribution-related costs from PPA costs. The proposed structural change will make all of NRLP's rate schedules structurally consistent and should aid the utility in better understanding cost causation going forward. Having a clearer understanding of cost causation will allow NRLP to more appropriately respond to the cross-subsidization of customer classes. This change is crucial given NRLP's proposed Schedule NBR (Net Billing Rider).

Schedule NBR – NRLP is proposing a new option for customers who have behind-the-meter (BTM) solar photovoltaic (PV) generation assets connected to their electric service. The only current option available to customers with BTM distributed PV generation is Schedule SPP, which is structured similarly to a BASA rate schedule based on the Public Utilities Regulatory Policy Act (PURPA). 16 U.S.C. § 2611 *et. sec.*

Witness Halley states that the new Schedule NBR is being developed in a manner that follows the criteria established by N. C. Gen. Stat. § 62.126.4. (S.L. 2017-192, or HB 589), which requires the Commission to "…ensure that the net metering retail customer pays its full fixed cost of service" and requires a grandfathering of existing customers already being served under a current net metering rate schedule. Schedule NBR will be available to customers on Schedules R, G, and GL and limited to: (1) residential PV systems of less than 20-kilowatt (kW) capacity; and (2) non-residential systems of less than 1,000 kW capacity. Schedule NBR also incorporates a January 1 annual resetting of energy credits that have accrued over the previous 12-month period. The reset will not impact the basic facilities charges or demand charges as applicable in

Schedules R, G, and GL. Schedule NBR also obligates participating customers to pay a Standby Supplemental Charge (SSC) that is intended to recover some of the fixed costs of distribution-related system costs.

The Public Staff reviewed the NRLP's proposal and finds that it makes a reasonable effort toward compliance with HB 589. In addition, Schedule NBR is similar to the net metering tariffs recently approved by the Commission for DEC and Duke Energy Progress, LLC (DEP) (collectively Duke).[4] NRLP's proposed SSC are similar to Duke's non-by-passable charges and grid access fees in that both are intended to recover fixed costs not readily avoided by the BTM generation. I reviewed the calculations associated with the proposed \$6.17/kW SSC. The value of the SSC is based on an allocation of the transmission- and distribution-related costs associated with the delivery of energy from the PPA that are not avoided.

One notable difference between Duke's net metering proposal and Schedule NBR is the excess energy credit resetting process. Duke's tariffs incorporate a monthly resetting process. Schedule NBR has an annual resetting process. While a monthly process is preferable because it would reduce cross-subsidization between participants on

[4] See Order Approving Revised Net Metering Tariffs, March 23, 2023, Docket No. E-100, Sub 180.

Schedule NBR and non-participants, I am not recommending monthly resetting for NRLP at this time for the following reasons. First, the structure of the various contracts between NRLP and CPP for purchased power, DEC for transmission services, and BREMCO for both transmission and distribution services and how those contracts use multiple coincident peaks to determine the costs of energy are large drivers of cost causation. At this time, it is unclear how Schedule NBR will impact BTM participation and the various coincident peaks that impact total purchased power costs. This concern leads to a second area of uncertainty around how annual versus monthly resetting would impact the calculation of the SSC, which is mainly driven by the influence of the coincident peaks. Third, this proposal represents NRLP's first net metering/billing tariff. Customers testifying at the public hearing expressed concerns around net metering/billing in general. I believe that monthly resetting could exacerbate those concerns by limiting benefits to participants who invest in solar PV generation. Finally, NRLP is a winter-peaking utility. Unlike Duke who was a summer-peaking utility when net metering was initiated in the early 2000s, annual resetting would provide some added benefit to participating customers by taking the excess energy produced during higher producing summer periods and using it to offset winter consumption.

The Public Staff supports NRLP's proposal and believes it is appropriate to maintain an annual resetting and the SSC in the tariff design. The Public Staff also recommends that:

1. NRLP closely monitor the credits accumulated, consumption patterns, revenues, and costs related to the proposed Schedule NBR and file an annual report of net metering/billing activities by March 31 of each year;
2. Schedule NBR allow participants to retain ownership of any renewable energy credits from power generation by their systems. As a result, proposed Schedule NBR should be amended to include the following statement: "Any renewable energy credits (RECs) associated with electricity delivered to the grid by the Customer under Schedule NBR shall be retained by the Customer."
3. The Commission revisit the proposed design of Schedule NBR in five years and re-evaluate the energy resetting process and the SSC at that time.

Schedule PPR – Similar to Schedule NBR, NRLP is proposing another BTM generation tariff that will be available to customers with solar PV generation connected in parallel to NRLP's system. Customers with less than 1 megawatt (MW) of PV capacity and not on one of the Schedule SPP tariffs (PURPA schedules) will be able to participate. Schedule PPR is structured as a BASA tariff that obligates the participant to sell all of the energy produced to NRLP at a fixed energy credit.

The Public Staff has reviewed the supporting calculations associated with the energy credit. NRLP stated in discovery that the original filing calculated the credit based only on residential class costs. A revised credit that is reflective of total system costs would be more appropriate.

Similar to Schedule NBR, proposed Schedule PPR does not address the ownership of RECs resulting from renewable energy resources. Under Schedule PPR, NRLP is compensating customer-owned renewable generation at the full avoided costs rate, which does not include costs associated with renewable energy. This makes Schedule PPR effectively identical to Schedule NBR in terms of REC ownership.

The Public Staff also supports NRLP's proposed Schedule PPR and believes it provides another option for customer-owned renewable energy generation. Similar to Schedule NBR, the Public Staff believes the effects of BTM generation subscribed to Schedule PPR could impact the COSS in future rate cases and recommends that:

1. NRLP closely monitor the credits paid to participants for the energy they produce, revenues received from participants for

utility service, generation and consumption patterns, and costs related to the proposed Schedule PPR and file an annual report of activities by March 31 of each year;

2. Proposed Schedule NBR be amended to include the following statement: “Any renewable energy credits (RECs) associated with electricity delivered to the grid by the customer under Schedule PPR shall be retained by the Customer.”
3. The Commission revisit the proposed design of Schedule PPR in five years;
4. NRLP revise the Schedule PPR energy credit to reflect total system costs in its rebuttal testimony; and,
5. The energy credit paid pursuant to Schedule PPR be updated and revised consistent with NRLP’s approved PURPA avoided cost proceeding.

Schedule IR – NRLP is proposing a new interruptible rate schedule targeted to large, high load factor non-residential customers with at least 2 MW of load and with the ability to curtail 75% of that load when called upon to do so. Schedule IR is structured such that the participant would earn a credit of $14.26 per kW of load reduced, if the curtailment coincides with NRLP’s monthly coincident peak.

NRLP stated in response to discovery that the utility has been approached by potential non-residential customers about such a demand response program. While no such customers have either located in NRLP's service territory or actively petitioned NRLP for such a program, NRLP wants to be prepared to offer such a program to prospective participants. NRLP also stated in discovery that it would provide as much as three-day's advance notice of the coincident peak, and if the customer were to miss the coincident peak, no penalty would be assessed. Furthermore, credits would only be paid based on the average two-hour load prior to and after the announced curtailment period.

The Public Staff reviewed the proposal, the supporting calculations for the curtailment credit, and the terms and conditions of Schedule IR. The credit is based on the contract demand charge associated with the purchased power agreement plus an adjustment for system losses. As designed, if the curtailment reduces NRLP's monthly coincident peak, the participant will receive the bulk of the benefit (cost savings). However, the overall system would also receive some benefit from reduced purchased power costs. Intangible benefits would also accrue to the community in the form of increased economic activity.

With respect to the terms and conditions contained in the language of the tariff included in Exhibit B of the Application, I interpret it to mean that the payment of the credit would occur <u>only</u> in the event that the participant is able to curtail load at the time of the coincident peak. No credits will be paid if the participant is unable to curtail or if the curtailment does not align with the coincident peak. If this interpretation is incorrect, the Public Staff recommends that NRLP clarify these terms in its rebuttal testimony or at the evidentiary hearing. The Public Staff has no objection to the proposed Schedule IR provided the payment of the credit is made clear for the record.

Q. Please discuss NRLP's proposed reconnection fees.

A. NRLP did not propose any changes to its reconnection fees ($25 during regular business hours and $60 after regular business hours) in this proceeding. NRLP stated in discovery that the utility maintained the current reconnection fees because the administrative costs to process payments and execute the reconnection are unchanged. The utility further stated that if the AMI meter failed to execute the reconnection, NRLP personnel would still need to visit the customer premise to make the reconnection. The Public Staff does not dispute NRLP's assertions around these tasks and potential difficulties of executing this work. This issue was also an issue in the Sub 46 case.[5] NRLP made a decision at that time to continue onsite, in-person reconnections and wishes to maintain that practice. Such

[5] *See* Public Staff Witness Evan Lawrence's testimony in Docket No. E-34, Sub 46.

an action may be necessary in certain situations when there are safety concerns or the inability to properly communicate with the individual meter being disconnected or reconnected. However, those concerns are also present with meters and customer accounts associated with NRLP's prepaid utility service, which allows service to be disconnected and reconnected electronically or remotely.

The Public Staff also acknowledges there are administrative costs associated with the disconnection and reconnection processes. However, I believe those costs are much less than the current $25 and $60 rates represent, mainly due to the utility's ability to avoid onsite visits by NRLP personnel and customers' ability to self-serve through the online payment option.[6] These administrative processes are similar to those offered by Duke. Duke was able to reduce the costs of reconnection resulting from the deployment of AMI meters, and the Public Staff believes NRLP could do the same. Based on this information, I recommend that NRLP amend its reconnection process to allow customers the ability to self-serve and reap the benefit of the AMI. With this self-serve process, NRLP should also be able to replace its current disconnection and reconnection fees with a single fee that reflects only the administrative costs associated with the disconnection and subsequent reconnection of service. I

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[6] *See* web link https://nrlp.appstate.edu/pay-billcustomer-portal

recommend that NRLP update its reconnect fees to reflect these costs and refresh its disconnection/reconnection process consistent with my recommendations when it files its rebuttal testimony in this proceeding.

Q. Does NRLP propose to increase its residential class Basic Facilities Charge?

A. Yes. NRLP proposes to increase the residential basic facilities charge (BFC) from $12.58 to $14.50. The proposed BFC represents 40% of the $36 per month customer-related unit cost-to-serve calculated in the COSS. The Public Staff does not object to the proposed increase because the amount is well below the customer-related cost of service.

IV. Revenue Apportionment and the Phase-In of the Rate Increase

Q. Please explain how NRLP apportioned the proposed revenue requirement.

A. NRLP Exhibit REH-14 illustrates the return on rate base (ROR) associated with each customer class. Witness Halley's testimony states that NRLP relied on the Public Staff's revenue apportionment principles to spread the impact of proposed revenue changes among customer classes. Those principles include:

1. Employing a ±10% "band of reasonableness" relative to the overall jurisdictional rate of return, such that to the extent

possible, the class rates of return after the rate changes stay within this band of reasonableness following revenue assignment;

2. Limiting the revenue increase to no more than two percentage points greater than the overall jurisdictional revenue increase;
3. Moving all classes toward parity with the system; and,
4. Minimizing subsidization of customer classes by other customer classes.

Each principle is an important consideration when assigning revenue requirement to the classes.

Q. What is NRLP's approach for apportioning its proposed base revenue increase?

A. NRLP set the target ROR for each customer class equal to the overall system ROR. This approach complies with each above-listed principle but one. Strictly applying this approach to the proposed revenue increase results in a significant increase for the Commercial-Demand and "Lighting" customer classes (40.63% and 38.95%, respectively, versus the overall increase of 24.87%), well outside of the bounds for limiting the increase to no more than two percentage points above the overall increase.

Q. How has NRLP mitigated the impact of its proposed revenue increase?

A. Yes. NRLP has proposed to phase in its increase over a two-year period by reassigning some of the proposed first year base rate revenue increase from the Commercial-Demand class to the Residential and ASU customer classes. NRLP did not propose a similar strategy for the Lighting customer class. This strategy results in higher increases in the first year, followed by decreases in the second year, for the Residential and ASU classes. The Commercial-Demand class receives a lesser revenue increase the first year, followed by an additional increase thereafter, equal to the combined revenue decreases to the Residential and ASU classes.

Q. What is the Public Staff's opinion of this approach?

A. While the approach works in some respects, phasing in the increase is not acceptable as proposed. The Public Staff prefers an approach that balances the effects of each rate principle to the greatest extent possible. However, it is impossible to abide by each of the rate principles given the extent of the revenue increase that is supported by the Public Staff's audit and review in this case.

Q. Please explain which revenue apportionment principle the Public Staff believes should take precedent.

A. The Public Staff's proposed revenue apportionment assigns the Public Staff's recommended revenue increase in a manner that focuses on achieving compliance with the band of reasonableness first, followed by tempering the level of increase experienced by a particular customer class. This process also minimizes cross-subsidization.

Q. What is the Public Staff's position regarding assignment of the Public Staff's proposed base revenue increase?

A. Floyd Exhibit 1 illustrates the Public Staff's analysis of its proposed class revenue apportionment. Taking the revenue requirement recommended by Public Staff witnesses Johnson and Morgan, I proceeded to calculate RORs and percent increases for each class, and I do so in one year rather than NRLP's proposed two-year phase in.

Q. Please discuss the results of your revenue apportionment analysis.

A. My calculations of RORs and percentage increases could not adhere to the Public Staff's apportionment principles for any of the classes. I was able to move all classes except the ASU class toward parity (moving from negative to positive RORs), but I was not able to keep the percentage increases within two percentage points above the overall increase for the Commercial-General, Commercial-Demand, and the Lighting classes, nor could I satisfactorily address cross-subsidization. Any attempt to resolve these principles results in the same rate shock for some classes that NRLP was trying to avoid with its proposed phase in. As a result of this exercise, I am recommending that the Commission focus on mitigating rate shock first.

My calculations as illustrated in Floyd Exhibit 1 represent a best attempt at balancing the objectives of each of the four principles. More importantly, my apportionment avoids a phasing in of the increase over two years and tempers the potential for rate shock for the Commercial-Demand and Lighting classes by employing a more consistent percent increase for each class.

I believe this approach reasonably balances the principles of revenue apportionment for the following reasons: (1) the COSS in this proceeding relied upon NRLP-specific AMI data, which provides a more detailed and accurate understanding of NRLP customer usage and demand and (2) phasing in a revenue increase of this magnitude and reapportioning the increase to customer classes who are already paying rates that are closer to costs,[7] is not good policy as it exacerbates the cross-subsidization issue.

Customer energy usage and demand form the basis for cost causation. However, in order to honor the cost causation principle of rate design, revenue apportionment must overcome this initial hurdle of a significant overall revenue increase. If the Utility's revenue increase is justified, then customer classes are responsible for paying the costs to serve them. In addition, setting rates that require some customer classes to pay the costs of mitigating rate shock of other customer classes is usually inappropriate. This is because the principle of limiting an increase to no more than two percentage points above the overall increase effectively does the same thing. The extent of the increase in this case prevents the Public Staff from achieving a balance of the principles. At some point, certain principles must take precedent.

I recognize that some level of cross-subsidization is unavoidable in this case, and the way that I have applied the principles of revenue apportionment acknowledges this reality. I also recognize the need for gradualism in any significant rate increase. While NRLP's

[7] Under current rates, the Public Staff determined that the Residential customer class was underpaying their costs to serve as evidenced by a negative ROR (-0.43%). However, this was the least negative RORs of the other customer classes with negative RORs. The ASU customer class had a positive ROR (3.15%) under current rates.

proposal provides a gradual approach to the overall increase, it uses the Residential and ASU customer classes to accomplish the gradualism. I do not find this methodology acceptable for the proposed phase-in of the total revenue increase.

Q. **Is there any action that NRLP could take to mitigate the effect of its proposed revenue increase that the Public Staff could support?**

A Yes. The Public Staff could support a phase in of the total revenue increase over two years under three conditions. First, the Utility must avoid exacerbating cross-subsidization by asking customer classes, who are already paying rates closer to their cost to serve, to pay an additional amount simply to mitigate rate shock for another customer class, who should be paying a larger proportionate share of the revenue increase. This condition means that NRLP must be willing to forgo a portion of its otherwise justified revenue increase for one year. Secondly, NRLP should not earn or accrue any additional financial incentive (interest on deferred revenues or other financial compensation) in the interim. Finally, NRLP's proposed revenue apportionment (as provided for in NRLP Exhibit REH-15) should be recalculated to reflect the Public Staff's revenue apportionment principles by moving all customer classes into the band of reasonableness by the end of the phase-in period (end of year two). Elimination (or minimization) of cross-subsidization and moving all customer classes ROR toward parity should occur as a result of moving all customer classes into the band of reasonableness.

Q. What is the Public Staff's assessment of NRLP's quality of service for its customers?

A. Overall, I conclude that the quality of service provided by NRLP to its customers is good.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

JACK L. FLOYD

I am a graduate of North Carolina State University with a Bachelor of Science Degree in Chemical Engineering. I am licensed in North Carolina as a Professional Engineer. I have more than 17 years of experience in the water and wastewater treatment field, nine of which have been with the Public Staff's Water Division. In addition, I have been with the Electric Division for almost 20 years.

Prior to my employment with the Public Staff, I was employed by the North Carolina Department of Natural Resources, Division of Water Quality as an Environmental Engineer. In that capacity, I performed various tasks associated with environmental regulation of water and wastewater systems, including the drafting of regulations and general statutes.

In my capacity with the Public Staff's Water Division, I investigated the operations of regulated water and sewer utility companies and prepared testimony and reports related to those investigations.

Currently, my duties with the Public Staff include evaluating the operation of regulated electric utilities, including rate design, cost-of-service, and demand side management and energy efficiency resources. My duties also Include assisting in the preparation of reports to the Commission; preparing testimony regarding my investigation activities; reviewing Integrated Resource Plans; and making recommendations to the Commission concerning the level of service for electric utilities.

Comparison of Rates of Return and Indices
With Public Staff Adjustments

	% Revenue Increase	Rate of Return *		Rate of Return Index
NC Retail	21.24%	6.06%		1.00
Residential	16.71%	9.09%	**	1.50
Commercial - General	25.00%	7.01%	**	1.16
Commercial - Demand	30.00%	1.33%	**	0.22
ASU	12.77%	8.85%	**	1.46
Lighting	29.00%	2.45%	**	0.40

* These rates of return are after Public Staff's proposed revenue increase.

** These rate classes are outside the Public Staff's
recommended +/- 10% band of reasonableness.