STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-34, SUB 46

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Appalachian State University, d/b/a New River Light and Power Company, for an Adjustment of Rates and Charges for Electric Service in North Carolina	)))))	UPDATED COST OF SERVICE STUDY USING ADVANCED METERING SYSTEM DATA

NOW COMES Appalachian State University, d/b/a New River Light & Power Company ("NRLP"), through its attorney, and submits the following Updated Cost of Service Study using Advanced Metering System data:

1. Pursuant to paragraph 35 of the Stipulation dated as of January 19th, 2018, entered into between NRLP and the Public Staff, and Finding of Fact No. 38 and Ordering Paragraph No. 8 of the Order issued by the North Carolina Utilities Commission (the "Commission") on March 29, 2018, filed and entered in the captioned Docket, NRLP is required to submit an updated costs of service study using data produced by NRLP's Advanced Metering System ("AMI") (the "Updated COSS") to the Commission and the Public Staff by June 30, 2019. The Updated COSS is to update the cost of service study submitted by NRLP in connection with its Application to Adjust Retail Rates filed on July 28, 2017 in this Docket, using a full calendar's year worth of data based on data collected from NRLP's AMI system, installation of which was not completed until after the final Order was issued by the NCUC in this Docket.

2. In accordance with the foregoing, there is attached hereto a Summary Report that describes the impact of the AMI data and the Updated COSS.

Respectfully submitted, this the 18th day of June, 2019.

NEW RIVER LIGHT & POWER COMPANY

<u>Electronically Submitted</u>
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Summary Report
and
Cost of Service Study

North Carolina Utilities Commission
Docket No. E-34, Sub 46 (the “Docket”)

Paragraph No. 35 of the Stipulation between NRLP and the Public Staff (the “Public Staff”) of the North Carolina Utilities Commission (“NCUC”), dated January 19, 2018 (the “Stipulation”), and Finding of Fact No. 38 and Ordering Paragraph No. 8 of the NCUC’s Order Accepting Stipulation and Granting Increase in Rates, dated March 29, 2018 (the “Order”) filed in this Docket, Appalachian State University d/b/a New River Light and Power (“NRLP”) requires NRLP to submit an updated the cost of service analysis filed in the Docket using a full calendar year’s worth of billing data from its new Advanced Metering Infrastructure (“AMI”) system. The 2018 AMI billing data was used to allocate the fiscal year 2016 total system revenue requirement filed in this Docket to each of NRLP’s customer classes. The following will outline the process in summarizing this AMI data and impact to the cost of service analysis.

2018 AMI Load Data

NRLP worked with its vendor, Nexgrid, to provide the following information by customer class for the period January 2018 through December 2018 from the load data collected through NRLP’s AMI system:

1. Coincident Peak Demand (DEC Wholesale): Sum of the kW demands coincident with the 20 highest summer hours of 2018 demand for Duke Energy Carolinas (“DEC”);
2. Coincident Peak Demand (DEC Transmission): Sum of the kW demands coincident with the monthly peak demands of DEC for each month of 2018;
3. Coincident Peak Demand (BREMCO Distribution): Sum of the kW demands coincident with the monthly peak demands of Blue Ridge Electric Membership Corporation (“BREMCO”) for each month of 2018;
4. Coincident Peak Demand (NRLP): Sum of the kW demands coincident with the monthly peak demands of NRLP for each month of 2018;
5. Non-Coincident Peak Demand: Sum of the highest individual NRLP customer kW demands by month for 2018; and
6. Energy: Sum of all energy consumed by month for 2018.

All the above referenced information, except for item #5, was successfully pulled from the load data provided by the AMI system. The following summarizes these findings.

1. Coincident Peak Demand (DEC wholesale) – NRLP currently receives wholesale power from DEC based on a passthrough contractual arrangement with BREMCO. The demand component of this purchased power contract is based on NRLP's contribution to DEC's 20 highest hourly demands within the summer months ("20CP"). Exhibit 1 summarizes the AMI hourly load readings from each of NRLP's customer classes, as well as a comparison to NRLP's system demand, during those same 20CP times. Since the Street Lighting customer class does not have meters and it would be reasonable to assign some of these purchased power demand costs to street lighting, 50% of the estimated total demand of all street lighting was assumed for this 20CP demand allocation[1]. Line 23 of Exhibit 1 summarizes the average of these 20CP hours. The AMI load data produced a Retail Total System average of 30,171 kW. Compare that to the average NRLP Total System from the five substation master meters of 31,857 kW. This shows that the retail readings were 1,686 kW less, or 5.3% less, than the NRLP wholesale readings. This differential is within a reasonable range given that there are NRLP distribution system losses to account for as well as some missing data points within the retail AMI data. The last two columns summarize the missing data points for each of the 20 summer peak hours. Line 23 summarizes an average 799, or 9.7%, of the data points were missing for the 20 peak hours.

2. Coincident Peak Demand (DEC Transmission) – NRLP also must pay DEC for the transmission of its wholesale power purchases. DEC charges for transmission service based on a wholesale customer's contribution to each month's transmission system peak. Exhibit 2 summarizes the AMI hourly load readings from each of NRLP's customer classes as well as a comparison to NRLP's system demand during these monthly peak times. Since the Street Lighting customer class does not have meters and it would be reasonable to assign some of these transmission costs to street lighting, 50% of the estimated total demand of all street lighting was assumed for this monthly demand allocation[2]. Line 15 of Exhibit 2 summarizes the average of these monthly peak hours. The AMI load data produced a Retail Total System average of 33,578 kW. Compare that to the average NRLP Total System from the five substation master meters of 35,295 kW. This shows that the retail readings were 1,717 kW less, or 4.9% less, than the NRLP wholesale readings. This differential is within a reasonable range

[1] Since all street lights are not on and operating at the times of the Coincident Peak Demand, it was assumed that 50% of the total estimated demand was the appropriate demand for allocation purposes. This is the same assumption that was used in the original cost of service study filed with the Application for Adjustment of Retail Rates filed by NRLP on July 28, 2017.

[2] See Footnote 1.

given that there are NRLP distribution system losses to account for as well as some missing data points within the retail AMI data. The last two columns summarize the missing data points for each of the monthly peak hours. Line 15 summarizes an average 468, or 5.7%, of the data points were missing for the monthly peak hours.

3. Coincident Peak Demand (BREMCO Distribution) – NRLP must also pay BREMCO for the use of its distribution system to deliver wholesale power purchases from DEC's transmission system to NRLP's distribution system. BREMCO charges for distribution service based on NRLP's contribution to each of BREMCO's monthly system peaks. Exhibit 3 summarizes the AMI hourly load readings from each of NRLP's customer classes as well as a comparison to NRLP's system demand during these monthly peak times. Since the Street Lighting customer class does not have meters and it would be reasonable to assign some of these distribution costs to street lighting, 50% of the estimated total demand of all street lighting was assumed for this monthly demand allocation[3]. Line 15 of Exhibit 3 summarizes the average of these monthly peak hours. The AMI load data produced a Retail Total System average of 33,372 kW. Compare that to the average NRLP Total System from the five substation master meters of 35,071 kW. This shows that the retail readings were 1,698 kW less, or 4.8% less, than the NRLP wholesale readings. This differential is within a reasonable range given that there are NRLP distribution system losses to account for as well as some missing data points within the retail AMI data. The last two columns summarize the missing data points for each of the monthly peak hours. Line 15 summarizes an average 498, or 6.0%, of the data points were missing for the monthly peak hours.

4. Coincident Peak Demand (NRLP) – NRLP incurs costs for its distribution system and each retail customer class's contribution to NRLP's system peak is useful information when considering the allocation of various system investments and facilities O&M costs. Exhibit 4 summarizes the AMI hourly load readings from each of NRLP's customer classes as well as a comparison to NRLP's system demand during its monthly peak times. Since the Street Lighting customer class does not have meters and it would be reasonable to assign some of its distribution costs to street lighting, 50% of the estimated total demand of all street lighting was assumed for this monthly demand allocation[4]. As highlighted in yellow on Line 4, the March

[3] See Footnote 1.
[4] See Footnote 1.

AMI data for the retail customers indicates an issue by providing reading for that hour that appears to be inaccurate. As seen in the Retail Difference and % Retail Difference columns, these hourly readings were 8,701 kW, or 22.4% below the NRLP master meter readings, a reading that is not consistent with other hourly load data. Due to this apparent inaccuracy, the NRLP system peaks were adjusted in lines 20 through 31. The data for the month of March was replaced with the BREMCO system peak monthly data for March, which is more consistent with NRLP's other data. This was done as a proxy to provide a reasonable allocation for March. All other months were within a reasonable range. The last two columns summarize the missing data points for each of the monthly peak hours. Line 15 summarizes an average 524, or 6.4%, of the data points were missing for the monthly peak hours.

5. Non-Coincident Peak Demand – This category was intended to provide the maximum peak demand for each customer within each customer class. This information could have been used to develop a factor used as a potential allocation of system investments in meeting each customer's maximum demand on the distribution system. NRLP, however, is having difficulty retrieving this AMI data from Nexgrid. The issue is being worked on but was not rectified by the time this report was due to NCUC. Accordingly, this information is not available for this Updated COSS.

6. Energy – NRLP would use the energy consumed by each customer class to allocate the energy component of the wholesale power purchases as well as other variable expenses incurred by NRLP. Exhibit 5 summarizes the energy consumed by each customer class as taken from the AMI data. The energy for Street Lighting was estimated based on the number of lights by types and assuming they are on 12 hours a day. Line 15 of Exhibit 5 summarizes the total annual energy consumed by customer class. Line 15 also shows a 3.1% difference between the wholesale meter readings at NRLP substations and the retail meter readings measured at the customers' premises. This difference is well within a reasonable range of distribution system losses.

Cost of Service Study Modified with AMI Data Allocations

The cost of service model filed in the Docket is included as Attachment A as a starting reference point. The Rate of Return in the original cost of service study filed in this Docket was adjusted to the Stipulated 6.525% replacing the originally requested 6.97%. Since all settlement negotiations were handled outside of the cost of service model, this original model was not modified to match the stipulated rate changes by customer class. Starting with Attachment A as the base cost of service model for this exercise, the modified allocation factors from the 2018 AMI load data were introduced to the cost of service model and included as Attachment B.

Page 1 of Attachment B summarizes the new allocation factors developed from the 2018 AMI load data. Each allocation factor is highlighted in blue for easy recognition. As discussed above, the individual customer NCP peak demands were not available for this analysis. As a proxy, the kW demands for each customer class developed in the NRLP Distribution Peak Demands, Allocation Line 3.04, were utilized as the NCP Demands in the Allocation Line 3.05. The only exception for this was Street Lighting. The NCP for Street Lighting was estimated by taking the number of lights by type and adding all wattage together to determine a maximum demand when all lights are on. It should be noted that using this proxy for an NCP allocation factor would more than likely not allocate an equitable share to the residential class. The diversified demand coincident with the NRLP system peak of 10,523 kW for the residential class equates to an average kW of only a 1.65 kW per customer. The maximum kW of a typical residential home would be higher than this, which would increase the total residential class NCP demand.

The allocation factors used throughout the cost of service within Attachment B for the various expense line items have been updated to reflect the appropriate use of the modified allocation factors identified on page 1. As with the Attachment A cost of service model, the impact of the Updated COSS model is summarized on lines 36.07 and 36.08 of page 8. Table 1 below provides a summary comparison of the original cost of service, Attachment A, and the modified cost of service, Attachment B.

Table 1
New River Light and Power
Comparison of Cost of Service Analysis
For Twelve Months Ended December 31, 2016

Line	Description	Total System	Residential	Commercial Non-Demand	Commercial Demand	Comm Demand High LF	ASU Campus	Security Lighting
1	**Attachment A - COS Filed in the Docket with Modified Rate of Return at 6.525%:**							
2	Current Rate Revenues	$ 16,835,581	$ 5,133,268	$ 2,128,008	$ 4,113,885	$ 1,253,370	$ 3,863,382	$ 343,668
3	Revenue Increase(Decrease) Required	$ 1,776,778	$ 939,245	$ 196,245	$ 595,596	$ 123,104	$ (75,205)	$ (2,208)
4	Proposed Rate Revenues	$ 18,612,359	$ 6,072,513	$ 2,324,254	$ 4,709,481	$ 1,376,475	$ 3,788,177	$ 341,460
5	Percent Increase(Decrease) Required	10.55%	18.30%	9.22%	14.48%	9.82%	-1.95%	-0.64%
6								
7	**Attachment B - COS with Modified Rate of Return at 6.525% and AMI Load Allocatoins:**							
8	Current Rate Revenues	$ 16,835,581	$ 5,133,268	$ 2,128,008	$ 4,113,885	$ 1,253,370	$ 3,863,382	$ 343,668
9	Revenue Increase(Decrease) Required	$ 1,776,778	$ 211,232	$ 206,470	$ 985,526	$ 202,281	$ 173,313	$ (2,044)
10	Proposed Rate Revenues	$ 18,612,359	$ 5,344,500	$ 2,334,478	$ 5,099,411	$ 1,455,651	$ 4,036,695	$ 341,624
11	Percent Increase(Decrease) Required	10.55%	4.11%	9.70%	23.96%	16.14%	4.49%	-0.59%

As can be seen, the residential, commercial demand and commercial demand high LF customer classes have the largest swings with the AMI load data allocation factors. The updated cost of service model has shifted costs from residential to the commercial classes. Most of this difference is caused by the CP allocation factors used for the demand component of the purchased power costs. The CP allocation factor used in Attachment A allocated 28.45% to the residential class while the 20CP allocation factor in Attachment B allocates 18.98%. The CP allocation factor used in Attachment A was derived from a NRLP system average 12CP taken from NRLP's master meters at each of its substations. These readings were used as a proxy for each customer class since hourly load data was not available at that time. The 20CP allocation factor used in Attachment B is based on each customer class' actual load at each specific hour of DEC's 20CP. This is a much more accurate method of allocating DEC's demand costs to each customer class. This allocation of purchased power demand costs should stay relatively consistent until NRLP switches power suppliers in 2022. As discussed above, the current DEC demand costs are determined based on a summer 20CP demand. Beginning January 2022, NRLP's power supplier will be NTE Energy. At that time the demand charge will be determined on a 12CP, much like the current DEC transmission peak. This would bring the allocation of the residential class back to the 30% range.

As discussed above, the individual customer NCP allocation factor is not currently an accurate representation of the demand placed on NRLP's distribution facilities by each customer. Therefore, the Updated COSS included as Attachment B does not equitably allocate certain distribution costs to each customer class. More specifically, it is under allocating distribution facilities' costs to the residential class. This, in and of itself, is reason not to rely on the Update COSS findings. Once NRLP can retrieve each rate class's individual customer maximum monthly demands, a reasonable NCP allocation factor can be used to provide an accurate cost of service outcome.

Given that NRLP will switch power suppliers in 2022, the customer NCP demand allocator needs to be updated with actually billing data and NRLP will be filing a rate case in 2021 in connection with its move to NTE Energy, we believe that the rates and charges approved in the Docket are still just and reasonable when consideration is given to all of the above. As previously indicated, NRLP is currently working with Nexgrid to rectify the lack of all individual customer monthly maximum demands for the 2018 test year as well as to ensure that this information will continually be available for future needs.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing by electronic delivery to the following person via email at the following address which is the last address known to me:

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This the 18th day of June, 2019.

<u>s/ Michael S. Colo</u>
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