# APPALACHIAN STATE UNIVERSITY DBA NEW RIVER LIGHT AND POWER COMPANY DOCKET NO. E-34 SUB 46

## DIRECT TESTIMONY OF SHEREE L. BROWN

## ON BEHALF OF APPALACHIAN STATE UNIVERSITY DBA NEW RIVER LIGHT AND POWER COMPANY

## JULY 28, 2017

**Q: PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.**

**A:** My name is Sheree L. Brown. I am a Managing Principal with Summit Utility Advisors, Inc. ("Summit"). Summit provides utility consulting services to New River Light and Power Company ("NRLP"), which is an operating unit of Appalachian State University ("ASU"). My business address is 180 Masters Drive, Brevard, North Carolina 28712.

**Q: ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?**

**A:** I am testifying on behalf of Appalachian State University d/b/a New River Light and Power ("NRLP").

**Q: PLEASE SUMMARIZE YOUR EDUCATION BACKGROUND AND RELEVANT EMPLOYMENT EXPERIENCE.**

**A:** I have a Bachelor of Science in Accountancy from the University of West Florida and a Masters in Business Administration from the University of Central Florida. I have 36 years of experience in utility consulting. My primary areas of expertise are in revenue requirements, cost of service, rates, feasibility analyses, and power supply evaluations. I have presented testimony at the Federal Energy Regulatory Commission and numerous state commissions, as well as district courts on matters relating to revenue requirements, rates, cost of service, mergers and acquisitions, stranded costs, and deregulation.

**Q: DO YOU HOLD ANY PROFESSIONAL REGISTRATIONS?**

**A:** Yes. I am a Certified Public Accountant in the State of Florida.

**A: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

**A:** The purpose of my testimony is to present NRLP's revenue requirements in the 2016 Test Year and to explain the need for adjustments to the revenue requirements in establishing the required level of revenues needed to recover ASU's costs of providing service, including a fair and reasonable return to ASU on its investment in facilities used to provide service to NRLP's customers. My testimony also addresses the need for a cost recovery mechanism for costs that

NRLP anticipates incurring beginning in January, 2018, related to Duke Energy Carolinas' ("DEC's") Asset Retirement Obligations associated with coal ash combustion residuals.

**Q: PLEASE DESCRIBE THE COSTS THAT ASU INCURS TO PROVIDE SERVICE TO NRLP'S CUSTOMERS.**

**A:** NRLP is an operating unit of ASU. NRLP maintains a staff of 26 employees who provide engineering, line maintenance, system design and construction, customer service and billing, and certain administrative functions. While NRLP has a limited administrative staff, ASU also provides a number of administrative services to NRLP through its own administrative departments, including legal, human resources, information technology, and other administrative services such as finance and facilities management. In addition to the costs incurred to operate and maintain the system, ASU's costs also include a fair and reasonable return on its investment in NRLP. The total costs of owning, operating, and maintaining the electric system make up the total revenue requirement of the system.

**Q: WHAT IS THE TEST YEAR IN THIS PROCEEDING?**

**A:** The Test Year in this proceeding is calendar year 2016. In addition, I will present known and measurable changes to the Test Year revenue requirements that represent real costs to NRLP and should be allowed for recovery through rates.

**Q: PLEASE PROVIDE A BREAKDOWN OF THE TEST YEAR REVENUE REQUIREMENT BEFORE ANY ADJUSTMENTS.**

**A:** Exhibit_(ASU-1) is a breakdown of the Test Year revenue requirement before any adjustments for known and measurable changes. Expenses included in the revenue requirement are total purchased power expenses of $12.8 million, distribution operating and maintenance expenses of $1.1 million, $.559 million for customer accounts expense, $.832 million for direct administrative expenses, $.202 million for services provided by ASU administrative staff, $.903 million for depreciation expense and other expenses totaling $45,803. The revenue requirement was offset by $104,181 in Other Operating Revenues.

Rate base consists of Electric Plant in Service less Accumulated Depreciation, Construction Work in Progress, Investments in Blue Ridge Electric Membership Corporation ("Blue Ridge" or "BREMCO") and North Carolina Electric Membership Corporation ("NCEMC"), and Cash Working Capital. With the exception of Cash

Working Capital, rate base items were per NRLP's balance sheet as of December 31, 2016.

**Q: WHAT METHOD DID YOU USE TO DETERMINE CASH WORKING CAPITAL?**

**A:** Cash Working Capital was determined based on the "1/8 O&M" methodology with adjustments to recognize a shorter lag on purchased power expenses. Many regulatory commissions have historically allowed the use of the 1/8 O&M methodology when a full lead-lag study has not been developed. This methodology assumes that a utility incurs its costs of providing service mid-month and receives its revenues for that service 45 days later. The 1/8 calculation is 45/365 days as applied to a utility's operating and maintenance expenses.

Unlike its other operating and maintenance expenses, NRLP does not pay for its purchased power until the middle of the month following service. While we have not performed a full lead-lag study, adjusting the 45 days by the longer period of time which NRLP has to pay its purchased power expense provides a conservative calculation of Cash Working Capital.

Fifteen days of purchased power and 45 days of all other operating and maintenance expenses was used to determine Cash Working

Capital for the unadjusted revenue requirement. Based on total expenses before adjustments, the Cash Working Capital is $861,024.

**Q: WHAT IS THE RETURN COMPONENT OF REVENUE REQUIREMENT?**

A: The return component of the revenue requirement shown on Exhibit_(ASU-1) is $1.72 million calculated using a 6.97% weighted average cost of capital as supported in the testimony of ASU's Witness, Randall E. Halley.

**Q: HOW WERE THE REVENUES CALCULATED ON EXHIBIT_(ASU-1)?**

**A:** The revenues on Exhibit_(SLB-1) were based on actual revenues received in the Test Year as reported in the 2016 financial statements.

**Q: WHAT WAS THE TOTAL REVENUE REQUIREMENT FOR THE TEST YEAR BEFORE ADJUSTMENTS?**

**A:** As shown on Exhibit_(SLB-1), the total revenue requirement for the Test Year before adjustments was $18.148 million.

**Q: WAS THERE A REVENUE DEFICIENCY IN THE TEST YEAR?**

**A:** Yes, as shown in Exhibit_(SLB-1), there was a revenue deficiency of $2.075 million, which is 12.91% of total revenues in the Test Year.

**Q: YOU INDICATED THAT YOU MADE SEVERAL PRO FORMA ADJUSTMENTS TO THE TEST YEAR REVENUE REQUIREMENTS. WHY WAS IT NECESSARY TO MAKE THESE ADJUSTMENTS?**

**A:** As explained by ASU's Witness, Edmond Miller, NRLP has not had a base rate case since 1996. During that time, NRLP has significantly improved the system and has absorbed the cost of those improvements, as well as inflationary increases in costs of operating and maintaining the system. As kilowatt-hour sales were rising, NRLP was able to avoid the need for a rate increase; however, in the past six (6) years, there has been a significant reduction in kilowatt-hour sales. This, combined with the increases in investment over the 20 years since the last base rate case, has resulted in returns that are not just and reasonable.

While NRLP is using a 2016 Test Year in accordance with North Carolina Utilities Commission's ("NCUC" or the "Commission") policy, the rates that will be set as a result of this proceeding will not be effective prior to a few known and measurable changes that have occurred or will occur in the course of this proceeding. By recognizing the known and measurable changes in setting the rates now, it is ASU's hope that it will be able to avoid the expense of another rate case "pancaked" so closely with this current case.

**Q: WHAT ADJUSTMENTS ARE YOU PROPOSING TO THE REVENUE REQUIREMENTS?**

**A:** The adjustments I am proposing are:

- Adjusting revenues to reflect the current rates (including the most recently approved Purchased Power Adjustment) and the 2016 billing determinants as developed by ASU Witness Randall Halley;
- Increasing operating expenses and depreciation expense for the net effect of adding new Automated Metering Infrastructure and amortizing the remaining cost of the obsolete meters that are being removed in the process;
- Adjusting Electric Plant in Service and Accumulated Depreciation to include the AMI and remove the obsolete meters;
- Increasing rate base for the General Office Building renovations, which were completed in May, 2017, and increasing depreciation expense for depreciation on the addition;

- Annualizing salary increases that occurred in 2016 and early 2017;
- Adding a new engineering position that was filled in June, 2017;
- Adding salaries and benefits associated with the Vice Chancellor of Business Affairs position, which was vacant for much of 2016 and has recently been filled;
- Adjusting purchased power to reflect currently effective rates; and
- Removing a loss payout for a claim that was booked to Injuries and Damages expenses in 2016;
- Increasing rate base and depreciation expense for 3 new trucks that have been authorized for purchase, removing the old trucks from rate base and accumulated depreciation, and establishing a regulatory liability and amortization associated with gain on the trade-in of the old trucks;
- Establishing a regulatory asset and amortization of costs associated with removal and clean-up of a hydroelectric facility that was previously used by NRLP to provide power to its customers;

- Adjusting Cash Working Capital for the adjustments to operating and maintenance expenses; and
- Adjusting the revenue requirements for additional uncollectible accounts and regulatory fees that are based on a percentage of revenue.

I will address each of these items separately herein.

**Q: DID YOU MAKE A PRO FORMA ADJUSTMENT TO REVENUES?**

**A:** Yes. ASU's Witness, Randall E. Halley addresses the development of the revenues in his testimony. Mr. Halley evaluated the 2016 sales against weather normalized loads and determined that the sales were within a reasonable range; therefore, no adjustments were made to weather normalize the revenues. He developed the 2016 Test Year revenues using the billing data provided by NRLP applied to NRLP's current base rates and the current Purchased Power Adjustment Clause ("PPAC") rate. Since the current PPAC rate was not effective for all of 2016, this resulted in a small change in Test Year revenues. The revenues were broken down between base revenues and revenues from the PPAC. Details of this adjustment are provided by Mr. Halley in his direct testimony.

**Q: WERE THE REVENUES ADJUSTED TO REFLECT THE ADJUSTMENTS MADE TO PURCHASED POWER?**

**A:** Due to the annual adjustments in the Purchased Power Adjustment Clause, revenues would be expected to increase to cover the estimated cost of purchased power. Rather than include this adjustment as an additional revenue under current rates, an adjustment was made to show this anticipated increase in the PPAC as an offset to the increase required. This adjustment is explained more fully below and in Mr. Halley's direct testimony.

**Q: PLEASE EXPLAIN YOUR ADJUSTMENTS RELATED TO THE NEW AMI.**

**A:** NRLP is in the process of installing a new AMI system and removing its obsolete meters. This process is expected to be finalized by August 2017, which will be prior to the implementation of rates approved in this proceeding. This process results in several necessary adjustments. First, it was necessary to increase Plant in Service by the cost of the AMI system, including Allowance for Funds Used During Construction ("AFUDC") through the date of operation. Second, Construction Work in Progress ("CWIP") must be reduced by the amount of AMI recognized in CWIP as of December 31, 2016. Third, the old meters were removed, along with the associated accumulated depreciation as of December 31, 2016. I am requesting Regulatory Asset treatment of the remaining unrecovered investment with amortization over a 5-year period. Fourth, depreciation expense was adjusted to reflect depreciation of AMI and elimination of depreciation on the old meters. Fifth, accumulated depreciation was increased by one-half of the first year depreciation to recognize an average balance over the initial rate year. Lastly, I have included known additional operating and maintenance costs on the AMI system that NRLP will incur.

The majority of construction on the AMI system occurred in the first 5 months of 2017. As of June, 2017, total expenditures totaled $1,992,178. NRLP estimates that there will be an additional $52,500 spent in June and July, 2017 and that the commercial operation date will be August, 2017. With AFUDC calculated at the weighted average cost of capital from each month through the anticipated commercial operation date, the total AMI system that will be in Plant in Service as of August, 2017 will be $2,101,589. The CWIP balance included $88,618 of AMI system costs as of December 31, 2016, and this amount was removed. The detailed calculations of the AMI costs are shown in Exhibit_(SLB-2).

Depreciation expense on the AMI system will be straight line over a 20 year period. The depreciable life was based on information from the manufacturer. Depreciation expense has thus been increased by $105,080. Contracted annual licensing and maintenance will be $17,458 and costs of contracted data management (hosting) the AMI system will be $800/month beginning in May, 2017. Total annual costs will be $27,058. This amount has been added to Account 586, Meter Expense.

**Q: WHAT ADJUSTMENTS WERE MADE TO REMOVE THE OLD METERS?**

A: Adjustments to remove the old meters are shown on Exhibit_(SLB-3). Plant in Service as of December 31, 2016 included $940,426.72 for meters that will be removed from service and replaced with AMI meters. Accumulated depreciation on the meters that will be removed was $785,195.18 as of December 31, 2016, for a Net Plant in Service balance of $155,231.54. This balance was removed from Net Plant in Service. In addition, depreciation expense was reduced by $30,366.72

to remove depreciation associated with the meters that have been removed.

NRLP is requesting Regulatory Asset treatment of the remaining unrecovered balance of the replaced meters over a 5-year amortization period. To reflect this treatment, a Regulatory Asset was created for the net unrecovered balance of $155,231.54. Amortization of this balance over 5 years was included in the expenses. The 5-year amortization period would align with the remaining depreciable life of the meters.

**Q: WHAT ADJUSTMENT WAS MADE TO REFLECT THE GENERAL OFFICE BUILDING RENOVATION?**

**A:** The general office building renovations were started in March, 2016, and were completed in May, 2017. The total cost of renovation, including AFUDC calculated at the weighted average cost of capital, is $939,186, as shown on Exhibit_(SLB-4). Depreciation was based on NRLP’s current depreciation rate of 2.5716 for General Plant. The CWIP balance included $742,671 of office building renovation costs as of December 31, 2016, and this amount was removed.

**Q: PLEASE EXPLAIN THE NEED FOR ADJUSTMENTS ASSOCIATED WITH SALARIES AND WAGES.**

**A:** NRLP had two general pay adjustments. The first occurred in August, 2016, and the second occurred in January, 2017. In addition, the Vice Chancellor of Business Affairs position, which is supported by NRLP, was vacated in April, 2016 and was only recently re-filled. Further, NRLP recently filled its Engineering Supervisor position, which had been vacant throughout the 2016 Test Year. All of these changes had an impact on NRLP's cost of providing service to its customers and the new levels of payroll expense are being incurred at this time. Without recovery of these additional costs, NRLP will not earn a sufficient return on its investment in facilities to provide service to its customers.

**Q: WHAT IS THE ADDITIONAL COST ASSOCIATED WITH THE SALARY INCREASES THAT OCCURRED IN 2016 AND 2017?**

**A:** Exhibit_(SLB-5) sets forth the adjustments made to salaries and benefits associated with the salary increases that occurred in 2016 and 2017, as well as the additional costs for the Associate Vice Chancellor of Business Affairs and the new Engineering Supervisor.

For the general salary increase adjustment, NRLP provided a breakdown of the base salary by month from January 2016 through

July, 2017. In making this adjustment, I first eliminated the salary for the Associate Vice Chancellor of Business Affairs, since this cost is reflected in a separate adjustment. I then compared the 2016 salaries to the base salaries effective July, 2017, excluding the new Engineering Supervisor position, which is reflected in a separate adjustment. The known and measurable increase for salaries of all NRLP employees other than the Associate Vice Chancellor of Business Affairs and the new Engineer Supervisor is $66,189 on an annualized basis.

NRLP also provides benefits for its employees, which include health insurance and retirement contributions, in addition to Social Security ("FICA") and Medicare contributions. Health insurance contributions are $479.48 per month per employee and are paid into the North Carolina State Health Plan. FICA payments are 6.2% of gross pay, up to $127,200 per employee in 2017. Medicare payments are 1.45% of gross pay. NRLP employees participate in the Teachers' and State Employees' Retirement System ("TSERS"), which includes a 16.54% contribution from NRLP.

Since health insurance payments do not increase based on salary, it was not necessary to adjust health insurance costs for existing employees. It was thus necessary to include incremental benefit costs of $16,011, or 23.19% (16.54% retirement, 6.2% FICA, and 1.45% Medicare) of the base pay increases associated with the existing positions as of July, 2017. As shown on Exhibit_(SLB-5), the total adjustment to operating and maintenance expenses for the increase in salaries and benefits for existing employees is $82,200.

**Q: WHAT IS THE ADDITIONAL COST ASSOCIATED WITH THE REFILLING OF THE ASSOCIATE VICE CHANCELLOR OF BUSINESS AFFAIRS POSITION?**

**A:** Salaries and benefits of the Associate Vice Chancellor of Business Affairs are split equally between NRLP and ASU administration. NRLP's share of the additional cost associated with the refilling of the Associate Vice Chancellor of Business Affairs position is $71,383. The base pay of the new Associate Vice Chancellor of Business Affairs is $175,000 with $87,500 covered by NRLP. Benefits covered by NRLP are one-half of the health insurance payments, 6.2% FICA up to $63,600 (one-half of $127,200 FICA cap), Medicare of 1.45%, and retirement of 16.54%. Health insurance payments are $479.48 a month; therefore, 50% of the premiums for a year is $2,877. FICA, Medicare, and retirement add $19,685. Total benefits paid by

NRLP will thus be $22,561 a year. The total costs of the new Associate Vice Chancellor of Business Affairs to NRLP will be $110,061 a year. This amount must be offset by amounts paid to the previous Associate Vice Chancellor of Business Affairs whose position was terminated in April, 2016. Salaries and benefits in 2016 were $38,679. The net adjustment is thus $71,383. These adjustments are shown on Exhibit_(SLB-5) and the costs have been added to Account 920.001, Administrative and General Salaries and Account 920.002, Administrative and General Benefits.

**Q: WHAT IS THE ADDITIONAL COST ASSOCIATED WITH THE ENGINEERING SUPERVISOR POSITION?**

**A:** The Engineering Supervisor position was filled in June, 2017 at an annual salary of $95,000 and benefits of $28,734. These adjustments are shown on Exhibit_(SLB-5). The additional costs have been added to Account 580-Operations Supervision and Engineering.

**Q: WHAT ADJUSTMENTS WERE MADE TO PURCHASED POWER EXPENSE?**

**A:** Adjustments to purchased power expense were made to reflect DEC formula rates as of January 1, 2017. As explained above, no adjustments were made to reflect recovery of DEC's costs related to coal ash issues. Details of this adjustment are addressed by ASU Witness Randall Halley.

**Q: PLEASE EXPLAIN THE ADJUSTMENT MADE TO REMOVE A PORTION OF COSTS ASSOCIATED WITH INJURIES AND DAMAGES.**

**A:** In 2016, NRLP incurred a total of $145,027.17 in Injuries and Damages Expenses. Of this total, $67,200 represented a one-time loss payout. This amount was removed as non-recurring. The revised Injuries and Damages expense for 2016 is $77,827. I also reviewed the Injuries and Damages expenses from 2013 to 2015 to determine the reasonableness of the revised Injuries and Damages expense. As shown in the table below, from 2013 to 2015, the average Injuries and Damages expense was $77,649 (without adjustment for inflation); therefore, the revised 2016 expense was determined to be a reasonable level of Injuries and Damages expense.

| Injuries and Damages | |
|---|---|
| Year | Amount |
| 2013 | $80,289.79 |
| 2014 | $69,234.91 |
| 2015 | $83,421.70 |
| Average 2013-2015 | $77,648.80 |
| | |
| 2016 | $145,027.17 |
| Remove Non-recurring | -$67,200.00 |
| Revised 2016 | $77,827.17 |

**Q: YOU INDICATED THAT NRLP WAS ACQUIRING THREE NEW TRUCKS. PLEASE DESCRIBE THE ADJUSTMENTS TO REVENUE REQUIREMENTS ASSOCIATED WITH THIS ACQUISITION.**

**A:** NRLP is in the process of acquiring 3 new trucks for line maintenance and operations. These trucks will replace 3 existing trucks. The adjustments for adding the new trucks and removing the old trucks are shown on Exhibit_(SLB-6).

The price of the new trucks is $80,396. NRLP estimates salvage value at 10% and depreciates the balance over 114 months. Depreciation expense was thus increased by $7,612 for the new trucks. Plant in Service was increased by the price of the new trucks. Accumulated depreciation was increased by one-half of the first year of depreciation in order to provide an average net balance for the new trucks over the first year of operation.

The original cost of the trucks that are being replaced was $55,757. NRLP estimated 10% salvage value and depreciated 90% over a 114-month period. As of July 31, 2017, the accumulated depreciation on these trucks was $49,147. Two of the trucks were fully depreciated (to the 10% salvage value estimate) before 2016. The third truck will be fully depreciated as of August, 2017. In 2016, depreciation expense on the third truck was $1,594. The original cost and accumulated depreciation on the old trucks was removed from rate base. Depreciation was reduced by $1,594.

Trade-in value of the existing trucks was determined using NADA estimates. Trade-in value exceeded the estimated salvage value by $19,836. I have treated this gain as a Regulatory Liability with amortization over the 114-month estimated life of the new trucks. The amortization of $2,088 reduces the revenue requirement. I then adjusted rate base to provide an offset for the net unamortized Gain on Trade-In over the first year of operation of the new trucks.

**Q: PLEASE EXPLAIN THE NEED FOR THE ADJUSTMENT TO REMOVE THE HYDROELECTRIC FACILITY.**

A: The Payne Branch Dam on the Middle Fork River began commercial operation on October 30, 1924. It provided low-cost power to NRLP for almost 50 years. Recently, ASU applied for a grant from the Clean Water Management Trust Fund for design, permitting, and restoration of the Middle Fork River affected by the Payne Branch Dam. This work includes the removal of the Payne Branch Dam, as well as new floodplain construction, reconnection to the existing floodplain, constructing a new channel, creation or enhancement of floodplain wetlands or ponds, and vegetation management. A grant of $200,000 was received from the Clean Water Management Trust Fund with a requirement for $60,000 in matching funds to be provided by ASU. This cost has been allocated to NRLP with $30,000 to be paid in ASU's Fiscal Year ending June 30, 2017 and $30,000 to be paid in ASU's Fiscal Year ending June 30, 2018. Both payments are expected to be made by NRLP in its calendar year ending December 31, 2017.

Q: **HOW HAVE YOU ADJUSTED THE REVENUE REQUIREMENTS TO REFLECT THE PAYMENTS FOR REMOVAL OF THE PAYNE BRANCH DAM?**

A: I believe it is appropriate to amortize this cost over a 4-year period. To amortize this amount requires the creation of a regulatory asset for the unamortized balance. I have included a regulatory asset with a beginning balance of $60,000 and an ending balance of $45,000 for the first year, which gives an average balance of $52,500 in rate base. Amortization is $15,000 a year for the 4-year period. This amount has been included in the operating and maintenance expenses.

**Q: DID YOU ADJUST CASH WORKING CAPITAL?**

**A:** Yes. As explained above, Cash Working Capital was based on a 15-day lag on purchased power expenses and a 45-day lag on all other operating and maintenance costs. Cash Working Capital was adjusted for the impacts on operating and maintenance expenses associated with the other adjustments described herein. Based on total expenses, as adjusted, the required Cash Working Capital is $890,924.

**Q: HOW DID YOU DETERMINE THE TOTAL REVENUE REQUIREMENT?**

**A:** The revenue requirement is (i) the sum of all the operating and maintenance expenses, interest on customer deposits, and depreciation expense; minus (ii) other operating revenues; plus (iii) return on rate base at 6.97% as recommended by ASU Witness Mr. Halley; plus (iv) an adjustment to reflect uncollectible accounts and regulatory fees, which are calculated and assessed as a percentage of revenue.

**Q: WHAT RATES WERE APPLIED TO DETERMINE UNCOLLECTIBLE ACCOUNTS AND REGULATORY FEES?**

**A:** Uncollectible accounts were only .113% of total revenues in 2016. Regulatory fees are .14% of total revenues as set by NCUC in its Order dated July 11, 2016 under Docket No. M-100, Sub 142. The revenue requirement must be grossed-up for both uncollectible accounts and the regulatory fees, so an adjustment of (.253%/(1-.253%)) was made to the subtotal revenue requirement.

**Q: WHAT IS THE ADJUSTED REVENUE REQUIREMENT?**

**A:** The adjusted revenue requirement is $18,709,918, as shown on Exhibit_SLB-7).

**Q: WHAT IS THE LEVEL OF INCREASE REQUIRED TO MEET NRLP'S ADJUSTED REVENUE REQUIREMENT?**

**A:** As shown on Exhibit_(SLB-7), a total revenue increase of $1,874,337 is required to meet NRLP's adjusted revenue requirement. This can be met through an increase in base rates, the PPAC, and/or miscellaneous service revenues.

**Q: DOES THIS REQUIRED INCREASE INCLUDE ANY INCREASE THAT WOULD BE INCLUDED IN NRLP'S NEXT PPAC ADJUSTMENT?**

**A:** Yes. As shown on line 202 through 204 of Exhibit_(SLB-7), if NRLP does not adjust base rates to incorporate the expected purchased power expenses, then the PPAC would be expected to increase by $298,693. The regulatory commission fee and uncollectible accounts would also increase by $756, resulting in a net increase of $297,937. We are, however, recommending that total ongoing purchased power costs (exclusive of the 2016 true-up[1]) be moved into the base rates at this time.

**Q: WHY ARE YOU RECOMMENDING THAT TOTAL PURCHASED POWER COSTS BE MOVED INTO BASE RATES AT THIS TIME?**

**A:** Periodically, base rates should be increased to reflect a utility's full cost of providing service, including purchased power. A PPAC is designed to eliminate the risk of over- or under-recovery of purchased power costs through base rates due to the need for estimating costs

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[1] As explained by ASU witness, Randall Halley, in June 2017, NRLP was charged a true-up of $203,645 for 2016. This is not an ongoing cost of purchased power and, as such, this has not been reflected in the purchased power expenses herein. It will, however, be part of the PPAC to be collected in the 2017 adjustment.

and sales in developing the rates. Over time, the adjustments become larger. By moving the purchased power costs into base rates, the PPAC can be theoretically reset at zero. Assuming that the actual purchased power expense is equal to the projected purchased power expense, moving the cost recovery into base rates would result in $0 PPAC revenues. The PPAC would, therefore, be reset to its intended use of adjusting for the difference between actual and estimated expenses.

**Q: WHAT IS THE TOTAL INCREASE REQUIRED TO COVER NRLP'S COSTS OF PROVIDING SERVICE AND PROVIDE A FAIR RETURN ON AND OF ASU'S INVESTMENT?**

A: The adjusted revenue requirement is $18,709,918 as shown on Exhibit_(SLB-7). As explained by ASU's Witness, Mr. Halley, we are proposing an increase of $119,304 in miscellaneous service expense. If this increase is approved, the base and PPAC rates must be sufficient to recover $18,590,614, which is an increase of $1,755,033 in base and PPAC rates. Of this increase, $297,937 would be realized through the PPAC; therefore, the net increase is $1,457,095. Revenues at present rates are $16,835,581 and will increase to $17,133,519 through the PPAC adjustment; therefore, the net overall increase to customers will be 8.50%.

The purchased power in base rates utilized for determining the PPAC charges should be adjusted to reflect the amount of purchased power estimated herein and included in the development of the revised base rates. As shown on Exhibit_(SLB-7), the revised base factor for the PPAC calculations should be $.0635. ASU Witness, Randall Halley, further explains the calculation of the PPAC revenues under present rates and proposed rates.

Q: **YOU INDICATED THAT NRLP'S COSTS ARE EXPECTED TO INCREASE IN JANUARY, 2018, DUE TO CHARGES FOR COAL COMBUSTION RESIDUALS IMPOSED BY DUKE ENERGY CAROLINAS. PLEASE EXPLAIN.**

A: As set forth in the *Joint Petition of Duke Energy Progress, LLS and Duke Energy Carolinas, LLC for an Accounting Order to Defer Environmental Compliance Costs*, Docket No. E-2, Sub 1103 and Docket No. E-7, Sub 1110 ("*Joint Petition")*, DEC is incurring substantial costs to comply with the North Carolina Coal Ash Management Act ("CAMA"), as amended by the Mountain Energy Act, as well as federal rules related to coal combustion residuals. In those dockets, DEC requested that the Commission approve its deferral of the costs incurred to comply with these rules until such time as the Commission has heard all the evidence in formal rate proceedings for both Duke Energy Progress and DEP. This approval was given and it is anticipated that DEC will be filing a general rate case sometime this year and that DEC will present its proposal for recovering its coal compliance costs in that rate case. The costs are expected to be material and could have significant impacts on the rates of all of DEC's customers.

Q: **HOW IS NRLP IMPACTED BY THE COSTS THAT MAY BE APPROVED BY THE NCUC IN DEC'S NEXT RATE CASE?**

A: While DEC must comply with the provisions of CAMA and the CCRA, many of DEC's costs that have been and will be incurred relate to the coal ash spill at Dan River and violations at other generation facilities. DEC's customers and other affected parties in the State have raised concerns that costs that were the result of DEC's mismanagement or violations should be borne by shareholders and not by DEC's consumers. The issues related to potential recovery of coal ash costs that are expected to be addressed in DEC's rate case could be cost prohibitive for many parties to challenge. Rather than addressing these issues separately at the Federal Energy Regulatory Commission, many of DEC's wholesale customers have agreed to accept the treatment ordered by the NCUC in a retail rate order.

DEC has recently filed at FERC several amendments to power supply agreements with a number of its wholesale customers in which this tie to retail treatment is set forth. On June 9, 2017, DEC filed its "Fifth Amended and Restated Electric Full Requirements Power Purchase and REPS Compliance Service Agreement Between Duke Energy Carolinas, LLC and Blue Ridge Electric Membership Corporation" with an effective date of July 1, 2017 ("DEC/BREMCO Amendment"). Excerpts from the DEC/BREMCO Amendment are attached hereto as Exhibit_(SLB-8). The full agreement can be found online at:

elibrary.ferc.gov
Accession Number 20170609-5082
Description: Duke Energy Carolinas, LLC submits tariff filing per 35.13(a)(2)(iii: DEC RS Nos. 315, 316, 317 and 335 Revised PPA Filing to be effective 7/1/2017 under ER17-1783 Filing Type: 10

In that agreement, DEC and BREMCO agreed to basic principles of coal ash cost recovery with some parity with NCUC treatment of the coal ash cost recovery issues.

Q: **PLEASE PROVIDE A SUMMARY OF THE DEC/BREMCO AMENDMENT.**

A: BREMCO has agreed to pay DEC's costs of complying with CAMA and CCRA from January, 2015 forward, with several exclusions. Those exclusions are costs associated with the Dan River coal ash spill; settlement costs, which are costs incurred to settle the issues addressed in DEC's settlement agreements with the U. S. Department of Justice and the Environmental Protection Agency; costs for any new legislation after December 31, 2016; and CCR Disallowances, or costs that NCUC does not allow DEC to recover in its retail rate order addressing the coal cost recovery issues. Timing of the payments will begin in July, 2017, for Beneficial Reuse costs which will go through DEC's fuel clause and in January, 2018, for all other compliance costs. As set forth in the DEC/BREMCO Amendment, the Beneficial Reuse costs for January through June, 2017 will be collected in July through December, 2017, along with the actual Beneficial Reuse costs incurred in July through December, 2017. For all other compliance costs, the DEC/BREMCO Amendment allows DEC to recover its actual 2015, actual 2016, and estimated 2017 costs over a 24 month period beginning January, 2018. Costs beginning in 2018 will be recovered as incurred. There are annual maximum payments that can be elected by BREMCO as a cap, with any excess being deferred over a longer period of time. All of the costs are subject to true-up or true-down based on actual costs and refund of any amounts collected that are ultimately disapproved by the NCUC.

Q: **WILL NRLP BE SUBJECT TO THE SAME TREATMENT?**

A: NRLP has not been allowed to participate in any settlement discussions between DEC and BREMCO and no modifications to the BREMCO/NRLP Electric Service Agreement have been made. Since costs under the DEC/BREMCO power purchase agreement are generally a pass-through in the BREMCO/NRLP agreement, it is anticipated that BREMCO will attempt to pass-through any of these costs incurred under the DEC/BREMCO Amendment. If BREMCO is successful in that endeavor, NRLP will incur an allocated share of DEC's coal ash compliance costs for 2015 through 2017 in 2018 and 2019, along with an allocated share of DEC's coal ash compliance costs for 2018 and 2019.

Q: **HAS BREMCO PROVIDED AN ESTIMATE OF THE COAL ASH COMPLIANCE COSTS THAT NRLP WILL INCUR UNDER THE DEC/BREMCO AGREEMENT?**

A: Yes. BREMCO has indicated that NRLP will incur $3.1 million in coal ash compliance costs for the period from 2015 through 2021. A year-by-year estimate was provided; however, that document is subject to a Confidentiality Agreement. It is anticipated that the majority of this $3.1 million will be incurred in 2015 through 2018. As of December 31, 2016, DEC had recorded $2.032 billion as an asset retirement obligation associated with closure of ash impoundments as reported in DEC's 2016 Federal Energy Regulatory Commission ("FERC") Form 1. Under the BREMCO/DEC agreement, the coal ash costs will be allocated using a 20 coincident peak ("CP") demand allocation method. In 2016, NRLP was .18% of DEC's total 20 CPs. Based on this allocation percentage, the total obligation to NRLP for the AROs recorded as of December 31, 2016, could be as high as $3.628 million; however, timing of the expenditures is not yet known. In DEC's *Joint Petition*, it noted that DEC had spent $434.4 million in the period January 1, 2015 through November 30, 2016, related to AROs. Based on the 2016 20 CPs, NRLP would be charged over $775,000 for just this time period.

Q: **WHAT IS NRLP'S PROPOSAL TO ADDRESS THIS POTENTIAL RECOVERY OF COSTS BEGINNING IN JANUARY, 2018?**

A: NRLP is proposing to establish a Coal Ash Cost Recovery rider ("NRLP CACR") beginning January 1, 2018. The NRLP CACR would allow NRLP to flow through any charges made by BREMCO for recovery of DEC's coal compliance costs without markup. Any refunds received by BREMCO for over-payments due to any potential disallowances ordered by the NCUC, along with any interest payments received on such refunds, would also flow through the NRLP CCCR. The proposed CACR is attached as Exhibit_(SLB-9).

Q: **PLEASE DESCRIBE HOW THE RIDER WOULD BE CALCULATED.**

A: NRLP typically receives invoices from Blue Ridge in the first week of the month following service. NRLP has several billing cycles throughout the month, with the first being on or around the 7$^{th}$ of the month. Due to the differences between the timing of the retail billing cycles and the wholesale billing cycle from Blue Ridge, it is necessary to estimate retail sales over which the wholesale costs will be recovered. The proposed rider uses actual costs billed by Blue Ridge for coal ash costs (excluding Beneficial Reuse Costs, which will be flowed through the Purchased Power Adjustment Clause) and estimated sales for the billing cycles falling from the 15th of the month following the month of wholesale service to the 14th of the following month to determine the expected cost per kilowatt-hour of sales during that billing cycle. The unit rate must be adjusted upward to allow for recovery of the regulatory commission fee of .14% which is assessed by the NCUC on revenues and by the average uncollectible accounts rate of .113%. A true-up has also been included in the CACR to allow for correction of any over- or under-recovery once actual kilowatt-hour sales for the billing cycle are known. This true-up feature assures that customers are only billed for the actual costs incurred by NRLP to pay for coal ash costs and the associated regulatory fees and uncollectible accounts. The formula used to calculate the CACR is set forth in the tariff in Exhibit_(SLB-9). Exhibit_(SLB-10) provides an example calculation of the CACR.

Q: **WHY DOES NRLP BELIEVE IT IS NECESSARY FOR THE COMMISSION TO APPROVE THE NRLP CACR AT THIS TIME WHEN THE AMOUNTS TO BE RECOVERED ARE STILL UNCERTAIN?**

A: This issue is very critical to NRLP's ability to pay for costs incurred under the power supply agreement with BREMCO. Based on the recently filed DEC/BREMCO Amendment, charges for Beneficial Reuse will be started even before filing of this rate case and charges for the remaining coal ash compliance costs will begin in January, 2018. These costs will include not only the actual costs incurred in 2018, but will also include one-half of the costs DEC incurred in 2015, 2016, and 2017. Without the ability to pass these costs through without delay, NRLP will be financially harmed.

Q: **WHY DOESN'T NRLP SIMPLY RUN THE COAL ASH COMPLIANCE COSTS THROUGH THE PURCHASED POWER ADJUSTMENT CLAUSE?**

A: While the PPAC is an adjustment mechanism that could be used to recover the coal ash compliance costs, the ability to estimate the costs for inclusion in the PPAC each year is limited and subject to substantial errors. In addition, while NRLP was hopeful that it could negotiate a reasonable payment stream, the DEC/BREMCO Amendment does not provide for any type of alternative payment methodology that will be specifically set for NRLP.

Blue Ridge is not regulated by the FERC or the NCUC and; therefore, there is no regulatory oversight of Blue Ridge's rates to NRLP. NRLP was not a party to the DEC/BREMCO Amendment and had no say in the outcome of the negotiations that occurred between Blue Ridge and DEC on this issue. Essentially, NRLP "falls through the cracks" for any regulatory control and, without legal intervention, NRLP will be subject to the charges for DEC coal ash compliance that are passed through BREMCO under the DEC/BREMCO Amendment. NRLP believes it will be much "cleaner" and transparent to ratepayers if such charges are specifically included as incurred, rather than estimated and trued up or down through the PPAC.

**Q: DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

**A:** Yes, it does.

# Docket No. E-34, Sub 46
# Appalachian State University
# d/b/a New River Light and Power Company
# Revenue Requirement Unadjusted
# For Twelve Months Ended December 31, 2016

| Line | Description | Revenue Requirement |
|---|---|---|
| | **Expenses:** | |
| 1 | Purchased Power | $ 12,833,738.40 |
| 2 | Distribution | $ 1,113,605.12 |
| 3 | Customer Service | $ 558,704.70 |
| 4 | Administrative & General | $ 832,057.79 |
| 5 | ASU Administrative Support | $ 201,580.00 |
| 6 | Depreciation | $ 902,971.32 |
| 7 | (Gain)Loss on Disposition of Property | $ 2,525.52 |
| 8 | Interest Expense | $ 12,933.20 |
| 9 | Jobbing Expenses | $ 30,344.14 |
| 10 | **Total Expenses** | **$ 16,488,460.19** |
| 11 | **Less: Other Operating Revenues** | $ (104,181.07) |
| | **Rate Base Calculations:** | |
| 12 | Electric Plant In Service | $ 28,495,777.63 |
| 13 | LESS: Accumulated Depreciation | $ (13,029,169.91) |
| 14 | Net Plant in Service | $ 15,466,607.72 |
| 15 | Construction Work in Progress | $ 893,581.76 |
| 16 | Investments - Blue Ridge Electric Membership Corporation | $ 6,973,505.98 |
| 17 | Investments - North Carolina Electric Membership Corporation | $ 407,837.00 |
| 18 | Prepayments | $ 29,823.80 |
| 19 | Cash Working Capital | $ 861,023.89 |
| 20 | Total Rate Base | $ 24,632,380.15 |
| 21 | Rate of Return | 6.97% |
| 22 | **Return on Rate Base** | **$ 1,715,645.28** |
| 23 | **Total Revenue Requirement** | **$ 18,099,924.40** |
| 24 | Uncollectible Accounts | $ 18,200.18 |
| 25 | Regulatory Commission Fee | $ 30,094.45 |
| 26 | **Adjusted Revenue Requirement** | **$ 18,148,219.03** |

# Docket No. E-34, Sub 46
# Appalachian State University
# d/b/a New River Light and Power Company
# Revenue Requirement Unadjusted
# For Twelve Months Ended December 31, 2016

| Line | Description | Revenue Requirement |
|---|---|---|
| | **Rate Revenues:** | |
| 27 | Residential | $ 4,965,837.46 |
| 28 | Commercial | $ 7,088,874.87 |
| 29 | ASU Campus | $ 3,683,516.56 |
| 30 | Security Lighting | $ 335,437.47 |
| 31 | **Total Rate Revenues** | **$ 16,073,666.36** |
| | | |
| | **Revenue Deficiency at Present Rates** | |
| 32 | Total Revenue Deficiency | **$ 2,074,552.67** |
| 33 | Percent Revenue Deficiency | **12.91%** |

# Docket No. E-34, Sub 46
# Appalachian State University
# d/b/a New River Light and Power Company
# Addition of
# Automated Metering Infrastructure
# Rate Base, Depreciation, and O&M Adjustments

| Line | Month | Expenditures [1] | AFUDC [2] | Total at Commercial Operation Date |
|---|---|---|---|---|
| 1 | Jun-13 | $ 4,350.00 | $ 1,459.79 | $ 5,809.79 |
| 2 | Jul-13 | 2,400.00 | 786.91 | 3,186.91 |
| 3 | Aug-13 | 2,700.00 | 864.58 | 3,564.58 |
| 4 | Sep-13 | 3,600.00 | 1,125.35 | 4,725.35 |
| 5 | Oct-13 | - | - | - |
| 6 | Nov-13 | 5,500.00 | 1,636.20 | 7,136.20 |
| 7 | Dec-13 | 2,800.00 | 812.01 | 3,612.01 |
| 8 | Jan-14 | - | - | - |
| 9 | Feb-14 | 5,800.00 | 1,595.92 | 7,395.92 |
| 10 | Mar-14 | 4,126.30 | 1,105.02 | 5,231.32 |
| 11 | Apr-14 | 2,224.96 | 579.57 | 2,804.53 |
| 12 | May-14 | 4,554.51 | 1,153.25 | 5,707.76 |
| 13 | Jun-14 | 3,116.05 | 766.48 | 3,882.53 |
| 14 | Jul-14 | 2,756.00 | 658.10 | 3,414.10 |
| 15 | Aug-14 | 750.00 | 173.73 | 923.73 |
| 16 | Sep-14 | 1,800.00 | 404.16 | 2,204.16 |
| 17 | Oct-14 | 900.00 | 195.72 | 1,095.72 |
| 18 | Nov-14 | 525.00 | 110.48 | 635.48 |
| 19 | Dec-14 | - | - | - |
| 20 | Jan-15 | - | - | - |
| 21 | Feb-15 | - | - | - |
| 22 | Mar-15 | - | - | - |
| 23 | Apr-15 | - | - | - |
| 24 | May-15 | 1,200.00 | 202.96 | 1,402.96 |
| 25 | Jun-15 | - | - | - |
| 26 | Jul-15 | - | - | - |
| 27 | Aug-15 | - | - | - |
| 28 | Sep-15 | - | - | - |
| 29 | Oct-15 | - | - | - |
| 30 | Nov-15 | - | - | - |
| 31 | Dec-15 | - | - | - |
| 32 | Jan-16 | - | - | - |
| 33 | Feb-16 | - | - | - |
| 34 | Mar-16 | 860.54 | 88.97 | 949.51 |
| 35 | Apr-16 | 21,645.99 | 2,100.11 | 23,746.10 |
| 36 | May-16 | 3,922.04 | 355.69 | 4,277.73 |
| 37 | Jun-16 | 7,412.74 | 625.61 | 8,038.35 |

# Docket No. E-34, Sub 46
# Appalachian State University
# d/b/a New River Light and Power Company
# Addition of
# Automated Metering Infrastructure
# Rate Base, Depreciation, and O&M Adjustments

| Line | Month | Expenditures [1] | AFUDC [2] | Total at Commercial Operation Date |
|---|---|---|---|---|
| 38 | Jul-16 | - | - | - |
| 39 | Aug-16 | - | - | - |
| 40 | Sep-16 | 4,299.72 | 282.63 | 4,582.35 |
| 41 | Oct-16 | 20.00 | 1.19 | 21.19 |
| 42 | Nov-16 | 300.45 | 16.06 | 316.51 |
| 43 | Dec-16 | 1,054.02 | 49.95 | 1,103.97 |
| 44 | Jan-17 | - | - | - |
| 45 | Feb-17 | 49,249.77 | 1,740.20 | 50,989.97 |
| 46 | Mar-17 | 119,607.59 | 3,511.64 | 123,119.23 |
| 47 | Apr-17 | 769,706.58 | 18,026.20 | 787,732.78 |
| 48 | May-17 | 841,930.74 | 14,745.37 | 856,676.11 |
| 49 | Jun-17 | 123,064.74 | 1,432.72 | 124,497.46 |
| 50 | Jul-17 | 52,500.00 | 304.72 | 52,804.72 |
| 51 | Total | $ 2,044,677.74 | $ 56,911.29 | $ 2,101,589.03 |
| | | | | |
| 52 | Annual Depreciation, SL 20 Yrs | | | $ 105,079.45 |
| | | | | |
| | Accumulated Depreciation | | | |
| 53 | Beginning Balance | | $ - | |
| 54 | Ending Balance | | $ 105,079.45 | |
| 55 | Average Balance | | | $ 52,539.73 |
| | | | | |
| | CWIP | | | |
| 56 | Remove Balance in December 31, 2016 CWIP | | | $ (88,618.32) |
| | | | | |
| | Operating and Maintenance [3] | | | |
| 57 | Contracted annual licensing and maintenance | | $ 17,458.00 | |
| 58 | Annual hosting at $800/month | | $ 9,600.00 | |
| 59 | Total O&M Adjustments | | | $ 27,058.00 |

Notes:
[1] Actual expenditures through June 2017. Estimated final expenditures for July.
[2] At the weighted average cost of capital of 6.97%

## Docket No. E-34, Sub 46
## Appalachian State University
## d/b/a New River Light and Power Company
## Removal of
## Meters to be Replaced
## Rate Base, Depreciation, and Regulatory Asset Adjustments

| Line | Description | Amount |
|---|---|---|
| | **Remove Plant in Service and Accumulated Depreciation** | |
| 1 | Plant in Service at 12/31/16 | $ 940,426.72 |
| 2 | Accumulated Depreciation at 12/31/16 | $ 785,195.18 |
| 3 | Net Plant in Service at 12/31/16 | $ 155,231.54 |
| | **Remove Annual Depreciation Expense** | |
| 4 | Annual Depreciation Expense | $ 30,366.72 |
| | **Establish Regulatory Asset to Recover Remaining Balance** | |
| 5 | Regulatory Asset | |
| 6 | Beginning Balance | $ 155,231.54 |
| 7 | Less First Year Amortization | $ (31,046.31) |
| 8 | Ending Balance | $ 124,185.23 |
| 9 | Average Balance | $ 139,708.39 |
| | Amortization of Regulatory Asset to Recover Old Meters | |
| 10 | (5 year amortization) | $ 31,046.31 |

# Docket No. E-34, Sub 46
# Appalachian State University
# d/b/a New River Light and Power Company
# Addition of
# General Office Building Renovation
# To Rate Base

| Line | Month | Expenditures [1] | AFUDC [2] | Total at Commercial Operation Date |
|---|---|---|---|---|
| 1 | Mar-16 | $ 1,360.00 | $ 123.34 | $ 1,483.34 |
| 2 | Apr-16 | 12,240.00 | 1,033.01 | 13,273.01 |
| 3 | May-16 | 33,984.00 | 2,655.46 | 36,639.46 |
| 4 | Jun-16 | 12,470.05 | 896.81 | 13,366.86 |
| 5 | Jul-16 | 12,196.27 | 801.68 | 12,997.95 |
| 6 | Aug-16 | 21,689.62 | 1,292.30 | 22,981.92 |
| 7 | Sep-16 | 4,881.66 | 261.01 | 5,142.67 |
| 8 | Oct-16 | 67,323.18 | 3,190.29 | 70,513.47 |
| 9 | Nov-16 | 85,759.05 | 3,545.58 | 89,304.63 |
| 10 | Dec-16 | 490,767.23 | 17,340.89 | 508,108.12 |
| 11 | Jan-17 | 4,540.00 | 133.29 | 4,673.29 |
| 12 | Feb-17 | 72,318.25 | 1,693.66 | 74,011.91 |
| 13 | Mar-17 | 17,556.72 | 307.48 | 17,864.20 |
| 14 | Apr-17 | 5,302.00 | 61.73 | 5,363.73 |
| 15 | May-17 | 67,568.88 | 392.18 | 67,961.06 |
| 16 | Jun-17 | (4,500.00) | - | (4,500.00) |
| 17 | Total | $ 905,456.91 | $ 33,728.71 | $ 939,185.62 |
| | **Depreciation** | | | |
| 18 | Depreciation Expense | 0.21430% | | $ 24,152.10 |
| | **Accumulated Depr** | | | |
| 19 | Beginning Balance | | $ - | |
| 20 | Ending Balance | | $ 24,152.10 | |
| 21 | Average Balance | | | $ 12,076.05 |

Notes:
[1] Actual expenditures through June 2017.
[2] At the weighted average cost of capital of 6.97%

# Docket No. E-34, Sub 46
# Appalachian State University
# d/b/a New River Light and Power Company
# Labor Adjustments

| Line | Description | Amount |
|---|---|---|
| | ***Regular Salary Increases*** | |
| 1 | Salaries for the year at regular pay rates | $ 1,347,080 |
| 2 | Less Associated Vice Chancellor of Business Affairs under separate adjustment | $ (26,625) |
| 3 | 2016 Employees | $ 1,320,455 |
| | | |
| 4 | July, 2017 salaries at regular pay rates | $ 123,473 |
| 5 | Less new Engineering Supervisor position | $ (7,920) |
| 6 | Salaries excluding new position | $ 115,554 |
| 7 | Annualize salaries | $ 1,386,644 |
| | | |
| 8 | Increase in salaries | $ 66,189 |
| | Increase in benefits | |
| 9 | FICA at 6.2% | $ 4,104 |
| 10 | Medicare at 1.45% | $ 960 |
| 11 | Retirement Employer Contribution at 16.54% | $ 10,948 |
| 12 | Total Increase in Benefits associated with Salary Increases | $ 16,011 |
| | | |
| 13 | Total Increase in Salaries and Benefits for Existing Positions as of 12/31/16 | $ 82,200 |
| 14 | A&G Related | *$ 29,531* |
| 15 | Customer Service Related | *$ 18,823* |
| 16 | Distribution Related | *$ 32,943* |
| 17 | Contract Related | *$ 903* |
| | | |
| | ***Associate Vice Chancellor Position*** | |
| 18 | Remove Salary for January through March, 2016 when position was vacated[1] | $ (31,995) |
| 19 | Remove Benefits for prior AVC for January through March, 2016 | $ (6,684) |
| 20 | Add Annualized Salary for new AVC position filled in June, 2017 | $ 87,500 |
| | Add Annualized Benefits for new AVC position filled in June, 2017 | |
| 21 | FICA at 6.2% on 50% of first $127,200 | $ 3,943 |
| 22 | Medicare at 1.45% | $ 1,269 |
| 23 | Retirement Employer Contribution at 16.54% | $ 14,473 |
| 24 | 50% of Contributions to State Health Plan | $ 2,877 |
| 25 | Total Increase in Benefits associated with AVC Position | $ 22,561 |
| | | |
| 26 | Total Increase in Salaries and Benefits for Associate Vice Chancellor Posiiton | $ 71,383 |

# Docket No. E-34, Sub 46
# Appalachian State University
# d/b/a New River Light and Power Company
# Labor Adjustments

| Line | Description | Amount |
|---|---|---|
| | ***Engineering Supervisor Position*** | |
| 27 | Annualized Salary for new Engineering Supervisor Position filled July, 2017 | $ 95,000 |
| | Annualized Benefits for new Engineering Supervisor | |
| 28 | FICA at 6.2% | $ 5,890 |
| 29 | Medicare at 1.45% | $ 1,378 |
| 30 | Retirement Employer Contribution at 16.54% | $ 15,713 |
| 31 | Contributions to State Health Plan | $ 5,754 |
| 32 | Total Increase in Benefits associated with new Engineering Supervisor | $ 28,734 |
| 33 | Total Increase in Salaries and Benefits for new Engineering Supervisor | $ 123,734 |
| 34 | ***Total Increase in Salaries and Benefits for Rate Year*** | **$ 277,318** |

Notes:

[1] Includes termination payments.

# Docket No. E-34, Sub 46
# Appalachian State University
# d/b/a New River Light and Power Company
# Addition of New Trucks
# and Removal of Old Trucks

| Line | Description | Amount |
| --- | --- | --- |
| | **Depreciation Expense** | |
| 1 | New Trucks | $ 80,346.00 |
| 2 | Amount Estimated for Salvage | $ 8,034.60 |
| 3 | Truck value to be depreciated | $ 72,311.40 |
| 4 | Depreciation Rate (Months) | $ 114.00 |
| 5 | Annual Depreciation | $ 7,611.73 |
| 6 | Remove Annual Depreciation on 2008 Colorado Truck | $ 1,593.67 |
| 7 | Adjustment to Depreciation Expense | $ 6,018.06 |
| | **Adjustment to Rate Base** | |
| 8 | New Trucks | $ 80,346.00 |
| | Minus Old Trucks at Original Cost | |
| | Old Trucks-Original Cost | |
| 9 | 2002 CHEV 1500 TRUCK S/N V52136224 #40 (PP-020042) | $ 22,847.60 |
| 10 | 2005 CHEV SILVERADO S/N 291627 #43 (PP-050045) | $ 16,087.25 |
| 11 | 2008 COLORADO TRUCK EXT CAB #47 (PP-080049) | $ 16,822.08 |
| 12 | Total Plant in Service at 12/31/2016 | $ 55,756.93 |
| 13 | **Adjustment to Plant in Service** | $ 24,589.07 |
| | Accumulated Depreciation on Old Trucks | |
| 14 | 2002 CHEV 1500 TRUCK S/N V52136224 #40 (PP-020042) | $ 20,562.84 |
| 15 | 2005 CHEV SILVERADO S/N 291627 #43 (PP-050045) | $ 14,478.53 |
| 16 | 2008 COLORADO TRUCK EXT CAB #47 (PP-080049) | $ 14,105.38 |
| 17 | Total Accumulated Depreciation as of 12/31/2016 | $ 49,146.75 |
| 18 | Beginning Balance of Accumulated Depreciation on New Trucks | $ - |
| 19 | Ending Balance of Accumulated Depreciation on New Trucks | $ 7,611.73 |
| 20 | Average Balance of Accumulated Depreciation on New Trucks | $ 3,805.86 |
| 21 | **Adjustment to Accumulated Depreciation** | $ (45,340.88) |

# Docket No. E-34, Sub 46
# Appalachian State University
# d/b/a New River Light and Power Company
# Addition of New Trucks
# and Removal of Old Trucks

| Line | Description | Amount |
|---|---|---|
| | **Gain on Trade-in[a]** | |
| | Salvage Value (Estimated and not Depreciated | |
| 22 | 2002 CHEV 1500 TRUCK S/N V52136224 #40 (PP-020042) | $ 2,284.76 |
| 23 | 2005 CHEV SILVERADO S/N 291627 #43 (PP-050045) | $ 1,608.73 |
| 24 | 2008 COLORADO TRUCK EXT CAB #47 (PP-080049) | $ 1,682.21 |
| 25 | Total Salavage Value not Depreciated | $ 5,575.69 |
| | Actual Trade-in Value | |
| 26 | 2002 CHEV 1500 TRUCK S/N V52136224 #40 (PP-020042) | $ 7,637.00 |
| 27 | 2005 CHEV SILVERADO S/N 291627 #43 (PP-050045) | $ 7,675.00 |
| 28 | 2008 COLORADO TRUCK EXT CAB #47 (PP-080049) | $ 10,100.00 |
| 29 | Total Trade-In Value | $ 25,412.00 |
| | Gain on Trade-in | |
| 30 | 2002 CHEV 1500 TRUCK S/N V52136224 #40 (PP-020042) | $ 5,352.24 |
| 31 | 2005 CHEV SILVERADO S/N 291627 #43 (PP-050045) | $ 6,066.28 |
| 32 | 2008 COLORADO TRUCK EXT CAB #47 (PP-080049) | $ 8,417.79 |
| 33 | Total Gain on Trade-in | $ 19,836.31 |
| 34 | Annual Amortization of Gain over 114 months | $ 2,088.03 |
| | Adjustment to Rate Base for Unamortized Gain | |
| 35 | Beginning Balance | $ 19,836.31 |
| 36 | Ending Balance | $ 17,748.27 |
| 37 | Average Balance of Unamortized Gain | $ 18,792.29 |

[a] The 2002 and 2005 trucks were fully depreciated by 12/31/2016 but remained on the books. The 2008 truck will be fully depreciated by August, 2017. NRLP depreciates on the basis of 90% of original cost and assumes a 10% salvage value.

**Docket No. E-34, Sub 46**
**Appalachian State University**
**d/b/a New River Light and Power Company**
**Proforma Adjusted Revenue Requirement**
**For Twelve Months Ended December 31, 2016**

| Line | Main | GL# | Description | Revenue Requirement | Proforma Adjustment | Adjusted Revenue Requirement |
|---|---|---|---|---|---|---|
| | | | **Other Operating Income:** | | | |
| 1 | 415 | 4151000 | Revenue Job & Contract ASU | $ (23,777.17) | $ - | $ (23,777.17) |
| 2 | 415 | 4152000 | Rev Job&Con TOB | $ (6,824.00) | $ - | $ (6,824.00) |
| 3 | 415 | 4156000 | Revenue Job & Contract Cmp Broadstone | $ (509.12) | $ - | $ (509.12) |
| 4 | 419 | 4191100 | Int Inc Other | $ (9,831.23) | $ - | $ (9,831.23) |
| 5 | 421 | 4210000 | Misc Non-Operating Income | $ (51.24) | $ - | $ (51.24) |
| 6 | 451 | 4511000 | Misc Svc Revenue-Conn & Reconnect Chrgs | $ (10,645.31) | $ - | $ (10,645.31) |
| 7 | 442 | 4423000 | Temporary Construct Revenue | $ (21,974.45) | $ - | $ (21,974.45) |
| 8 | 454 | 4540000 | Rent Electric Property | $ (24,568.55) | $ - | $ (24,568.55) |
| 9 | 454 | 4541000 | Rent Electric Property-Fiber | $ (6,000.00) | $ - | $ (6,000.00) |
| 10 | | | **Total Other Operating Income** | **$ (104,181.07)** | **$ -** | **$ (104,181.07)** |
| 11 | | | **Operating Expenses:** | | | |
| 12 | 403 | 4030000 | Depreciation Expense | $ 902,971.32 | | $ 902,971.32 |
| 13 | | | Plus: Depreciation on General Office Building Renovation | | $ 24,152.10 | $ 24,152.10 |
| 14 | | | Less Depreciation on Old Trucks | | $ (1,593.67) | $ (1,593.67) |
| 15 | | | Plus: Depreciation on New Trucks | | $ 7,611.73 | $ 7,611.73 |
| 16 | | | Less: Old Meters | | $ (30,366.72) | $ (30,366.72) |
| 17 | | | Plus: New AMI Meters | | $ 105,079.45 | $ 105,079.45 |
| 18 | | | Total Depreciation Expense | $ 902,971.32 | $ 104,882.88 | $ 1,007,854.20 |
| 19 | | | Amortization of Gain on Old Trucks | $ - | $ (2,088.03) | $ (2,088.03) |
| 20 | | | Amortization of Regulatory Asset (Old Meters) | $ - | $ 31,046.31 | $ 31,046.31 |
| 21 | | | Amortization of Regulatory Asset-Hydroelectric Removal and Clean-up | $ - | $ 15,000.00 | $ 15,000.00 |
| 22 | 414 | 4140000 | Gain/Loss Disposing Utility Property | $ 3,375.87 | $ - | $ 3,375.87 |
| 23 | 414 | 4140001 | Sale Of Surplus Property | $ (850.35) | $ - | $ (850.35) |
| 24 | | | Total Property Transaction Costs | $ 2,525.52 | $ - | $ 2,525.52 |
| 25 | 416 | 4161000 | Expense Job & Contract ASU | $ 3,651.94 | $ - | $ 3,651.94 |
| 26 | 416 | 4161001 | Expense Job & Contract ASU-Labor | $ 9,511.50 | $ - | $ 9,511.50 |
| 27 | 416 | 4161002 | Expense Job & Contract ASU-Benefits | $ 9,609.27 | $ - | $ 9,609.27 |
| 28 | 416 | 4161004 | Expense Job & Contract ASU-Transportation | $ 1,400.51 | $ - | $ 1,400.51 |
| 29 | 416 | 4162001 | Expense Job & Contract TOB-Labor | $ 3,355.94 | $ - | $ 3,355.94 |
| 30 | 416 | 4162002 | Expense Job & Contract TOB-Benefits | $ 1,823.83 | $ - | $ 1,823.83 |
| 31 | 416 | 4162004 | Expense Job & Contract TOB-Transportation | $ 594.85 | $ - | $ 594.85 |
| 32 | 416 | 4166001 | Expense Job & Contract Camp Broadstone | $ 218.69 | $ - | $ 218.69 |
| 33 | 416 | 4166002 | Expense Job & Contract Camp Broadstone-Benefits | $ 107.11 | $ - | $ 107.11 |
| 34 | 416 | 4166004 | Expense Job & Contract Camp Broadstone-Transportation | $ 70.50 | $ - | $ 70.50 |
| 35 | | | Total Expense Job & Contract ASU | $ 30,344.14 | $ - | $ 30,344.14 |
| 36 | 431 | 4310000 | Interest Expense Consumer Deposits | $ 12,933.20 | $ - | $ 12,933.20 |
| 37 | | | Total Interest Expense | $ 12,933.20 | $ - | $ 12,933.20 |
| 38 | 555 | 5550000 | Purchased Power | $ 12,825,500.24 | $ 16,039.45 | $ 12,841,539.69 |
| 39 | 555 | 5551000 | Purchased Power-Generation (Avoided Energy Cost) | $ 8,238.16 | $ - | $ 8,238.16 |
| 40 | | | Total Purchased Power | $ 12,833,738.40 | $ 16,039.45 | $ 12,849,777.85 |
| 41 | 580 | 5800001 | Operations Superv & Engineering-Labor | $ 24,979.71 | $ 95,000.00 | $ 119,979.71 |
| 42 | 580 | 5800002 | Operations Superv & Engineering-Benefits | $ 13,515.99 | $ 28,734.26 | $ 42,250.25 |
| 43 | 580 | 5800004 | Operations Superv & Engineering-Transportation | $ 2,977.30 | $ - | $ 2,977.30 |
| 44 | | | Total Operations Superv & Engineering | $ 41,473.00 | $ 123,734.26 | $ 165,207.26 |

**Docket No. E-34, Sub 46**
**Appalachian State University**
**d/b/a New River Light and Power Company**
**Proforma Adjusted Revenue Requirement**
**For Twelve Months Ended December 31, 2016**

| Line | Main | GL# | Description | Revenue Requirement | Proforma Adjustment | Adjusted Revenue Requirement |
|---|---|---|---|---|---|---|
| 45 | 582 | 5820001 | Station Expense-Labor | $ 6,930.09 | $ - | $ 6,930.09 |
| 46 | 582 | 5820002 | Station Expense-Benefits | $ 3,673.98 | $ - | $ 3,673.98 |
| 47 | 582 | 5820004 | Station Expense-Transportation | $ 822.98 | $ - | $ 822.98 |
| 48 | | | Total Station Expense | $ 11,427.05 | $ - | $ 11,427.05 |
| 49 | 583 | 5830000 | Overhead Line Expense | $ 1,722.20 | $ - | $ 1,722.20 |
| 50 | 586 | 5860000 | Meter Expense | $ 3,268.41 | $ 27,058.00 | $ 30,326.41 |
| 51 | 586 | 5860001 | Meter Expense-Labor | $ 18,727.87 | $ - | $ 18,727.87 |
| 52 | 586 | 5860002 | Meter Expense-Benefits | $ 11,526.88 | $ - | $ 11,526.88 |
| 53 | 586 | 5860004 | Meter Expense-Transportation | $ 2,500.47 | $ - | $ 2,500.47 |
| 54 | | | Total Meter Expense | $ 36,023.63 | $ 27,058.00 | $ 63,081.63 |
| 55 | 587 | 5870001 | Customer Install Expense-Labor | $ 6,930.09 | $ - | $ 6,930.09 |
| 56 | 587 | 5870002 | Customer Install Expense-Benefits | $ 3,673.98 | $ - | $ 3,673.98 |
| 57 | 587 | 5870004 | Customer Install Expense-Transportation | $ 822.98 | $ - | $ 822.98 |
| 58 | | | Total Customer Install Expense | $ 11,427.05 | $ - | $ 11,427.05 |
| 59 | 588 | 5880000 | Miscellaneous Distribution Expense | $ 11,139.14 | $ - | $ 11,139.14 |
| 60 | 588 | 5880001 | Miscellaneous Distribution Expense-Labor | $ 151,872.22 | $ - | $ 151,872.22 |
| 61 | 588 | 5880002 | Miscellaneous Distribution Expense-Benefits | $ 86,878.69 | $ - | $ 86,878.69 |
| 62 | | | Total Miscellaneous Distribution Expense | $ 249,890.05 | $ - | $ 249,890.05 |
| 63 | 590 | 5900001 | Maintenance Superv & Engineering-Labor | $ 31,881.18 | $ - | $ 31,881.18 |
| 64 | 590 | 5900002 | Maintenance Superv & Engineering-Benefits | $ 17,280.95 | $ - | $ 17,280.95 |
| 65 | 590 | 5900004 | Maintenance Superv & Engineering-Transportation | $ 3,790.91 | $ - | $ 3,790.91 |
| 66 | | | Total Maintenance Superv & Engineering | $ 52,953.04 | $ - | $ 52,953.04 |
| 67 | 591 | 5910000 | On Call Pay -Primary/Secondary | $ 28,781.75 | $ - | $ 28,781.75 |
| 68 | 591 | 5910002 | On Call Pay-Primary/Secondary Benefits | $ 20,336.60 | $ - | $ 20,336.60 |
| 69 | | | Total On Call Pay | $ 49,118.35 | $ - | $ 49,118.35 |
| 70 | 592 | 5920000 | Maintenance Station Equipment | $ 1,387.19 | $ - | $ 1,387.19 |
| 71 | 592 | 5920001 | Maintenance Station Equipment-Labor | $ 16,605.63 | $ - | $ 16,605.63 |
| 72 | 592 | 5920002 | Maintenance Station Equipment-Benefits | $ 14,463.32 | $ - | $ 14,463.32 |
| 73 | 592 | 5920004 | Maintenance Station Equipment-Transportation | $ 1,681.07 | $ - | $ 1,681.07 |
| 74 | | | Total Maintenance Station Equipment | $ 34,137.21 | $ - | $ 34,137.21 |
| 75 | 593 | 5930000 | Maintenance Overhead Lines | $ 157,519.39 | $ - | $ 157,519.39 |
| 76 | 593 | 5930001 | Maintenance Overhead Lines-Labor | $ 114,174.34 | $ - | $ 114,174.34 |
| 77 | 593 | 5930002 | Maintenance Overhead Lines-Benefits | $ 64,744.30 | $ - | $ 64,744.30 |
| 78 | 593 | 5930004 | Maintenance Overhead Lines-Transportation | $ 12,906.93 | $ - | $ 12,906.93 |
| 79 | | | Total Maintenance Overhead Lines | $ 349,344.96 | $ - | $ 349,344.96 |
| 80 | 594 | 5940000 | Maintenance Underground Lines | $ 6,217.67 | $ - | $ 6,217.67 |
| 81 | 594 | 5940001 | Maintenance Underground Lines-Labor | $ 18,617.78 | $ - | $ 18,617.78 |
| 82 | 594 | 5940002 | Maintenance Underground Lines-Benefits | $ 14,395.81 | $ - | $ 14,395.81 |
| 83 | 594 | 5940004 | Maintenance Underground Lines-Transportation | $ 1,988.46 | $ - | $ 1,988.46 |
| 84 | | | Total Maintenance Underground Lines | $ 41,219.72 | $ - | $ 41,219.72 |
| 85 | 595 | 5950000 | Maintenance Line Transformers | $ 16,118.58 | $ - | $ 16,118.58 |
| 86 | 595 | 5950001 | Maintenance Line Transformers-Labor | $ 782.85 | $ - | $ 782.85 |
| 87 | 595 | 5950002 | Maintenance Line Transformers-Benefits | $ (511.13) | $ - | $ (511.13) |
| 88 | 595 | 5950004 | Maintenance Line Transformers-Transportation | $ 61.35 | $ - | $ 61.35 |
| 89 | | | Total Maintenance Line Transformers | $ 16,451.65 | $ - | $ 16,451.65 |
| 90 | 596 | 5961000 | Maintenance Street Lights | $ 16,178.95 | $ - | $ 16,178.95 |

**Docket No. E-34, Sub 46**
**Appalachian State University**
**d/b/a New River Light and Power Company**
**Proforma Adjusted Revenue Requirement**
**For Twelve Months Ended December 31, 2016**

| Line | Main | GL# | Description | Revenue Requirement | Proforma Adjustment | Adjusted Revenue Requirement |
|---|---|---|---|---|---|---|
| 91 | 596 | 5961001 | Maintenance Street Lights-Labor | $ 17,761.21 | $ - | $ 17,761.21 |
| 92 | 596 | 5961002 | Maintenance Street Lights-Benefits | $ 8,362.53 | $ - | $ 8,362.53 |
| 93 | 596 | 5961004 | Maintenance Street Lights-Transportation | $ 2,374.77 | $ - | $ 2,374.77 |
| 94 | | | Total Maintenance Street Lights | $ 44,677.46 | $ - | $ 44,677.46 |
| 95 | 597 | 5970000 | Maintenance-Meters | $ 6,430.85 | $ - | $ 6,430.85 |
| 96 | 597 | 5970001 | Maintenance-Meters-Labor | $ 52,484.69 | $ - | $ 52,484.69 |
| 97 | 597 | 5970002 | Maintenance-Meters-Benefits | $ 30,227.17 | $ - | $ 30,227.17 |
| 98 | 597 | 5970004 | Maintenance-Meters-Transportation | $ 5,451.07 | $ - | $ 5,451.07 |
| 99 | | | Total Maintenance-Meters | $ 94,593.78 | $ - | $ 94,593.78 |
| 100 | 598 | 5980000 | Maintenance Misc Distribution Plant | $ 681.13 | $ - | $ 681.13 |
| 101 | 598 | 5980001 | Maintenance Misc Distribution Plant-Labor | $ 56,861.66 | $ - | $ 56,861.66 |
| 102 | 598 | 5980002 | Maintenance Misc Distribution Plant-Benefits | $ 15,618.32 | $ - | $ 15,618.32 |
| 103 | 598 | 5980004 | Maintenance Misc Distribution Plant-Transportation | $ 5,984.86 | $ - | $ 5,984.86 |
| 104 | | | Total Maintenance Misc Distribution Plant | $ 79,145.97 | $ - | $ 79,145.97 |
| 105 | 901 | 9010001 | Supervision Customer Accounts-Labor | $ 30,857.59 | $ - | $ 30,857.59 |
| 106 | 901 | 9010002 | Supervision Customer Accounts-Benefits | $ 16,768.29 | $ - | $ 16,768.29 |
| 107 | 901 | 9010004 | Supervision Customer Accounts-Transportation | $ 3,681.39 | $ - | $ 3,681.39 |
| 108 | | | Total Supervision Customer Accounts | $ 51,307.27 | $ - | $ 51,307.27 |
| 109 | 902 | 9020000 | Meter Reading Expense | $ 1,454.79 | $ - | $ 1,454.79 |
| 110 | 902 | 9020001 | Meter Reading Expense-Labor | $ 20,742.10 | $ - | $ 20,742.10 |
| 111 | 902 | 9020002 | Meter Reading Expense-Benefits | $ 11,789.96 | $ - | $ 11,789.96 |
| 112 | 902 | 9020004 | Meter Reading Expense-Transportation | $ 2,237.73 | $ - | $ 2,237.73 |
| 113 | | | Total Meter Reading Expense | $ 36,224.58 | $ - | $ 36,224.58 |
| 114 | 903 | 9030000 | Customer Records & Collections Expense | $ 144,195.09 | $ - | $ 144,195.09 |
| 115 | 903 | 9030001 | Customer Records & Collections Expense-Labor | $ 173,670.50 | $ - | $ 173,670.50 |
| 116 | 903 | 9030002 | Customer Records & Collections Expense-Benefits | $ 94,798.10 | $ - | $ 94,798.10 |
| 117 | 903 | 9031000 | Postage | $ 4,976.38 | $ - | $ 4,976.38 |
| 118 | 903 | 9032000 | Customer Records Cash Over/Short | $ 13.05 | $ - | $ 13.05 |
| 119 | 903 | 9033000 | Customer Records - Bank Service Fees | $ 17,907.53 | $ - | $ 17,907.53 |
| 120 | 903 | 9034000 | Customer Records - Credit Card Fees | $ 35,612.20 | $ - | $ 35,612.20 |
| 121 | | | Total Customer Records | $ 471,172.85 | $ - | $ 471,172.85 |
| 122 | 910 | 9100000 | Customer Assistance Expense | $ 3,379.32 | $ - | $ 3,379.32 |
| 123 | 911 | 9110000 | Informational Advertising Expense | $ 4,572.31 | $ - | $ 4,572.31 |
| 124 | 920 | 9200001 | Administrative & General-Salaries | $ 251,152.98 | $ 55,505.21 | $ 306,658.19 |
| 125 | 920 | 9200002 | Administrative & General-Benefits | $ 136,259.69 | $ 15,877.62 | $ 152,137.31 |
| 126 | | | Total Administrative & General | $ 387,412.67 | $ 71,382.83 | $ 458,795.50 |
| 127 | 921 | 9210000 | Office Supplies And Expenses | $ 26,862.16 | $ - | $ 26,862.16 |
| 128 | 923 | 9230000 | Consulting Fees | $ 97,087.28 | $ - | $ 97,087.28 |
| 129 | 923 | 9230001 | Investment Management Expense | $ 23,887.58 | $ - | $ 23,887.58 |
| 130 | | | Total Consulting & Investment Management Fees | $ 120,974.86 | $ - | $ 120,974.86 |
| 131 | 924 | 9240000 | Property Insurance | $ 6,190.26 | $ - | $ 6,190.26 |

**Docket No. E-34, Sub 46**
**Appalachian State University**
**d/b/a New River Light and Power Company**
**Proforma Adjusted Revenue Requirement**
**For Twelve Months Ended December 31, 2016**

| Line | Main | GL# | Description | Revenue Requirement | Proforma Adjustment | Adjusted Revenue Requirement |
|---|---|---|---|---|---|---|
| 132 | 925 | 9250000 | Injuries & Damages Expense | $ 134,939.72 | $ (67,200.00) | $ 67,739.72 |
| 133 | 925 | 9250001 | Injuries & Damages Expense-Labor | $ 5,905.44 | $ - | $ 5,905.44 |
| 134 | 925 | 9250002 | Injuries & Damages Expense-Benefits | $ 3,353.50 | $ - | $ 3,353.50 |
| 135 | 925 | 9250004 | Injuries & Damages Expense-Transportation | $ 828.51 | $ - | $ 828.51 |
| 136 | | | Total Injuries & Damages Expense | $ 145,027.17 | $ (67,200.00) | $ 77,827.17 |
| 137 | 930 | 9301000 | Institutional Advertising Expense | $ 10,456.85 | $ - | $ 10,456.85 |
| 138 | 930 | 9302000 | Miscellaneous General Expense | $ 53,958.25 | $ - | $ 53,958.25 |
| 139 | | | Total Institutional And Miscellaneous | $ 64,415.10 | $ - | $ 64,415.10 |
| 140 | 932 | 9320000 | Maintenance Of General Plant | $ 69,681.46 | $ - | $ 69,681.46 |
| 141 | 932 | 9320001 | Maintenance Of General Plant-Labor | $ 2,284.23 | $ - | $ 2,284.23 |
| 142 | 932 | 9320002 | Maintenance Of General Plant-Benefits | $ 1,108.78 | $ - | $ 1,108.78 |
| 143 | 932 | 9320004 | Maintenance Of General Plant-Transportation | $ 149.47 | $ - | $ 149.47 |
| 144 | | | Total Maintenance Of General Plant | $ 73,223.94 | $ - | $ 73,223.94 |
| 145 | | | *ASU Administrative Support Costs:* | | | |
| 146 | 920 | | Legal | $ 106,501.00 | $ - | $ 106,501.00 |
| 147 | 920 | | Human Resources | $ 17,351.00 | $ - | $ 17,351.00 |
| 148 | 920 | | Information Technology | $ 16,788.00 | $ - | $ 16,788.00 |
| 149 | 920 | | Administrative Supervision | $ 60,940.00 | $ - | $ 60,940.00 |
| 150 | | | Total ASU Administrative Support Costs | $ 201,580.00 | $ - | $ 201,580.00 |
| 151 | | | *Increase in General Salary and Benefits:* | | | |
| 152 | | | A&G Related | $ - | $ 29,531.46 | $ 29,531.46 |
| 153 | | | Customer Service Related | $ - | $ 18,823.08 | $ 18,823.08 |
| 154 | | | Distribution Related | $ - | $ 32,942.87 | $ 32,942.87 |
| 155 | | | Contract Related | $ - | $ 903.04 | $ 903.04 |
| 156 | | | Total Increase in Salary and Benefits | $ - | $ 82,200.44 | $ 82,200.44 |
| 157 | | | **Total Operating Expenses** | **$ 16,488,460.19** | **$ 402,056.14** | **$ 16,890,516.33** |
| 158 | | | **Rate Base Calculation:** | | | |
| 159 | | | Electric Plant In Service | $ 28,495,777.63 | | $ 28,495,777.63 |
| 160 | | | New AMI Meters | | $ 2,101,589.03 | $ 2,101,589.03 |
| 161 | | | Remove Old Meters | | $ (940,426.72) | $ (940,426.72) |
| 162 | | | General Office Building Renovation | | $ 939,185.62 | $ 939,185.62 |
| 163 | | | New Trucks | | $ 80,346.00 | $ 80,346.00 |
| 164 | | | Remove Old Trucks | | $ (55,756.93) | $ (55,756.93) |
| 165 | | | Adjusted Electric Plant In Service | $ 28,495,777.63 | $ 2,124,936.99 | $ 30,620,714.62 |
| 166 | | | Accumulated Depreciation (per books at 12/31/2016) | $ (13,029,169.91) | | $ (13,029,169.91) |
| 167 | | | Remove Accumulated Depreciation on Old Meters | | $ 785,195.18 | $ 785,195.18 |
| 168 | | | Remove Accumulated Depreciation on Old Trucks | | $ 49,146.75 | $ 49,146.75 |
| 169 | | | Average B/E Balance for first year of new AMI meters | | $ (52,539.73) | $ (52,539.73) |
| 170 | | | Average B/E Balance for first year of General Office Building Renovation | | $ (12,076.05) | $ (12,076.05) |
| 171 | | | Average B/E Balance for first year of new trucks | | $ (3,805.86) | $ (3,805.86) |
| 172 | | | Adjusted Accumulated Depreciation | $ (13,029,169.91) | $ 765,920.29 | $ (12,263,249.62) |

**Docket No. E-34, Sub 46**
**Appalachian State University**
**d/b/a New River Light and Power Company**
**Proforma Adjusted Revenue Requirement**
**For Twelve Months Ended December 31, 2016**

| Line | Main | GL# | Description | Revenue Requirement | Proforma Adjustment | Adjusted Revenue Requirement |
|---|---|---|---|---|---|---|
| 173 | | | Net Plant in Service | $ 15,466,607.72 | $ 2,890,857.28 | $ 18,357,465.00 |
| 174 | | | Construction Work in Progress | $ 893,581.76 | | $ 893,581.76 |
| 175 | | | Less Amounts Earning AFUDC and Closed to Plant | | $ (831,289.38) | $ (831,289.38) |
| 176 | | | Net Construction Work in Progress | $ 893,581.76 | $ (831,289.38) | $ 62,292.38 |
| 177 | | | Investments - Blue Ridge Electric Membership Corporation | $ 6,973,505.98 | $ - | $ 6,973,505.98 |
| 178 | | | Investments - North Carolina Electric Membership Corporation | $ 407,837.00 | $ - | $ 407,837.00 |
| 179 | | | Regulatory Asset (Unamortized Old Meters) | $ - | $ 139,708.39 | $ 139,708.39 |
| 180 | | | Regulatory Asset (Hydro Removal and Clean-up) | $ - | $ 52,500.00 | $ 52,500.00 |
| 181 | | | Regulatory Liabililty on Gain from Old Trucks | $ - | $ 18,792.29 | $ 18,792.29 |
| 182 | | | Prepayments | $ 29,823.80 | $ 4,749.42 | $ 34,573.22 |
| 183 | | | Cash Working Capital | $ 861,023.89 | $ 29,899.97 | $ 890,923.86 |
| 184 | | | Total Rate Base | $ 24,632,380.15 | $ 2,305,217.97 | $ 26,937,598.12 |
| 185 | | | Rate of Return | 6.97% | 6.97% | 6.97% |
| 186 | | | **Return on Rate Base** | **$ 1,715,645.28** | **$ 160,558.43** | **$ 1,876,203.71** |
| 187 | | | **Revenue Requirement** | **$ 18,099,924.40** | **$ 562,614.57** | **$ 18,662,538.97** |
| 188 | | | Plus Uncollectible Accounts | $ 18,200.18 | $ 2,985.02 | $ 21,185.20 |
| 189 | 928 | 9280000 | Regulatory Commission Expense | $ 30,094.45 | $ (3,900.56) | $ 26,193.89 |
| 190 | | | **Total Revenue Requirement to be Recovered from Rates** | **$ 18,148,219.03** | **$ 561,699.03** | **$ 18,709,918.06** |
| 191 | | | **Rate Revenues:** | | | |
| 192 | | | Residential | $ 4,965,837.46 | $ 167,430.24 | $ 5,133,267.70 |
| 193 | | | Commercial | $ 7,088,874.87 | $ 406,388.81 | $ 7,495,263.68 |
| 194 | | | ASU Campus | $ 3,683,516.56 | $ 179,865.30 | $ 3,863,381.86 |
| 195 | | | Security Lighting | $ 335,437.47 | $ 8,230.77 | $ 343,668.24 |
| 196 | | | **Total Rate Revenues** | $ 16,073,666.36 | $ 761,915.12 | $ 16,835,581.48 |
| 197 | | | **Revenue Deficiency at Present Rates** | | | |
| 198 | | | Amount | $ 2,074,552.67 | | $ 1,874,336.58 |
| 199 | | | Less: Revenue from Proposed Fee Changes | | | $ (119,304.00) |
| 200 | | | Adjusted Amount to Recover from Base Rates or PPAC | | | $ 1,755,032.58 |
| 201 | | | Increase Required with No PPAC adjustment | 12.91% | | 10.42% |
| 202 | | | Adjustment for Purchased Power Revenue Recovered through PPA | | | $ 298,693.47 |
| 203 | | | Less Additional Uncollectible Accounts and Regulatory Fee | | | $ 756.38 |
| 204 | | | Net Revenue from PPA Adjustment | | | $ 297,937.09 |
| 205 | | | Net Increase Required | | | $ 1,457,095.49 |
| 206 | | | Revenues at Present Rates Plus PPAC Adjustment | | | $ 17,133,518.57 |
| 207 | | | Percent Increase Requested above Present Revenues with PPAC Adjustment | | | 8.50% |
| 208 | | | Revised Base Purchased Power Factor | | | $0.0635 |

NOW THEREFORE, in consideration of the premises and the mutual representations, warranties and covenants set forth in this Agreement, and for other good and valuable consideration, the receipt and adequacy of which is hereby acknowledged, the Parties, each intending to be legally bound, hereby agree as follows:

## Article 1

## Definitions

1.1 Definitions. Defined terms in this Agreement are capitalized. The defined terms used in this Agreement have the following meanings:

"Accounting Requirements" shall have the meaning specified in Section 16.7.

"Additional Fuel Savings" shall have the meaning specified in Section 17.32.5.1.

"Administrator" shall mean the RUS Administrator.

"Affiliate" means, with respect to any person, any other person directly or indirectly controlling or controlled by, or under direct or indirect common control with, such person. For purposes of this definition, "control" when used with respect to any person means the power to direct the management and policies of such person, directly or indirectly, whether through the ownership of voting securities, by contract or otherwise, and the terms "controlling" and "controlled" have meanings correlative to the foregoing.

"Aggregate Demand Reduction Cap" means: (a) from the Commencement Date until December 31, 2021, two (2) MW; (b) on the effective date of an extension of the Initial New River Term, if applicable, and for as long and the New River Term remains in effect, three (3) MW; or (c) after December 31, 2021, if the Initial New River Term is not extended, or upon the subsequent termination of the New River Term, two and one-half (2.5) MW.

"Agreement" means this Fifth Amended and Restated Electric Full Requirements Power Purchase and REPS Compliance Service Agreement, together with each Schedule and Attachment, each as amended from time to time.

"Ancillary Services" mean any and all ancillary services provided by the Transmission Provider in connection with any Transmission Service arranged by EMC for the delivery of electric energy provided under this Agreement from the Delivery Points.

"Annual Percentage" shall be calculated as shown on Attachment 7-9.

"Annual Planning Period" means, the period (either May through September or October through April) designated in the then-most recent Duke Annual Plan (or the successor thereto) that Duke files with the NCUC as the period during which Duke's annual peak load is projected to occur; provided, that in the event that NCUC ceases to require Duke to file or filing becomes voluntary and Duke ceases to file the Duke Annual Plan (or a successor thereto) with the NCUC, "Annual Planning Period" shall mean the period (either May through September or October through April) in which Duke's annual peak load is projected to occur under the generation planning criteria for Duke's Generation System used by Duke to meet Duke's Native Load.

"Appalachian State University" or "ASU" shall mean the educational institution and electric customer of New River that purchases electric energy as an end use retail consumer within the New River Service Area.

"Annual REPS Surcharge" shall have the meaning specified in Section 13.3.2.

"Assignment for Security" shall have the meaning specified in Section 17.2.2.

"ASU's Renewable Energy Cap" means four (4) MW during the New River Term for ASU purchases and generation of Renewable Energy as long as ASU is treated by New River as a retail customer. ASU's treatment as a

New River retail customer shall be conclusively evidenced by New River maintaining books and records in accordance with FERC requirements which are separate from those maintained by ASU. If ASU is no longer treated by New River as a retail customer, then ASU's purchases and generation of Renewable Energy shall be included with New River's purchases and generation of EMC Renewable Energy for the purpose of calculating the Aggregate Demand Reduction Cap under Section 11.2.

"Authorized CCR Retail Return" means the total return applicable to any deferred CCR Costs authorized by the NCUC, whether as cost of debt, return on equity, a stated interest rate, weighted average cost of capital, or otherwise.

"Balancing Authority Area" means an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to match the power output of the generators within the electric power system and electric energy imported into the electric power system, with the load located within the electric power system.

"Balancing Authority Load Signal" shall have the meaning specified in Section 8.4.

"Bankrupt" means that the Defaulting Party or any guarantor of such Party:

(i) is dissolved (other than pursuant to a consolidation, amalgamation or merger);

(ii) becomes insolvent or is unable to pay its debts or fails or admits in writing its inability generally to pay its debts as they become due;

(iii) makes a general assignment, arrangement or composition with or for the benefit of its creditors;

(iv) institutes or has instituted against it a proceeding seeking a judgment of insolvency or bankruptcy or any other relief under any bankruptcy or insolvency law or other similar law affecting creditor's rights, or a petition is presented for its winding-up or liquidation;

(v) has a resolution passed for its winding-up, official management or liquidation (other than pursuant to a consolidation, amalgamation or merger);

(vi) seeks or becomes subject to the appointment of an administrator, provisional liquidator, conservator, receiver, trustee, custodian or other similar official for it or substantially all of its assets;

(vii) has a secured party take possession of all or substantially all of its assets, or has a distress, execution, attachment, sequestration or other legal process levied, enforced or sued on or against all or substantially all of its assets;

(viii) causes or is subject to any event with respect to it which, under the applicable Laws of any jurisdiction, has an analogous effect to any of the events specified in clauses (i) to (vii) inclusive; or

(ix) takes any action in furtherance of, or indicating its consent to, approval of, or acquiescence in, any of the foregoing acts.

"Bankruptcy Code" means Title 11 of the United States Code or any successor thereto.

"Beneficial Reuse" means any beneficial uses of coal combustion residuals made by non-affiliated third parties in connection with construction projects, mining reclamation projects, and any other beneficial uses that may be made by such non-affiliated third parties.

"Beneficial Reuse Costs" mean Duke's Generation System costs incurred or credits earned by Duke arising from the transfer of title of quantities of coal combustion residuals to non-affiliated third parties for their Beneficial Reuse.

"Beneficial Reuse Disallowance" means Beneficial Reuse Costs that are properly recorded in Account No. 501 which the NCUC does not permit Duke to recover from North Carolina retail customers pursuant to an applicable Retail Rate Order.

"Billing Dispute Notice" shall have the meaning specified in Section 14.5.

"Billing Period" means the period beginning on the Commencement Date and ending on the last Day of the Month in which the Commencement Date occurred, and each succeeding Month thereafter.

"Blue Ridge" shall have the meaning specified in the first paragraph of this Agreement.

"Broyhill Wind Turbine" means that certain 100 kW Northwind turbine located at the Broyhill Inn and Conference Center on Bodenheimer Drive in Boone, North Carolina.

"Business Day" means any Day other than Saturday, Sunday, or any Day on which the Federal Reserve member banks are not open for business.

"CAMA" means the North Carolina Coal Ash Management Act 2014 N.C. Sess. Laws 122; 2014 N.C. Ch. 122; 2013 N.C. SB 729, as amended June 2015 by the Mountain Energy Act, N.C. SB 716, as further amended by the Drinking Water Protection/Coal Ash Cleanup Act, House Bill 630/S.L. 2016-95.

"Catawba Nuclear Station" means that certain nuclear power plant located near Rock Hill in York County, South Carolina.

"Catawba Up-Rate" means an increase in the electric capacity of the Catawba Nuclear Station with EMC's entitlement to such increased electric capacity being determined and made available pursuant to the terms of the WPSA.

"CCR Demand Costs" mean CCR Costs including Beneficial Reuse Costs; provided however, CCR Demand Costs shall not include Beneficial Reuse Costs that are properly recorded in Account No. 501.

"CCR Disallowance" means CCR Demand Costs for which Duke does not seek recovery in a retail rate proceeding for any reason or CCR Costs which the NCUC does not permit Duke to recover through the issuance of a Retail Rate Order. Any billing credit associated with a CCR Disallowance shall include any rate of return previously charged on such amount by Duke as well as interest computed in accordance with Section 7.3.2.2 of this Agreement.

"CCR Insurance Proceeds" means payments received by Duke from insurance companies that recover CCR Costs which EMC has paid under this Agreement.

"CCR Rule" means the Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities promulgated by the United States Environmental Protection Agency and published on April 17, 2015, 80 Fed. Reg. 21302, as may be amended from time to time.

"CFC" shall have the meaning specified in Section 16.7.

"Claiming Party" shall have the meaning specified in Section 17.4.

"Claims" mean all third party claims or actions, threatened or filed, and whether groundless, false, or fraudulent, that directly or indirectly relate to the subject matter of an indemnity, and the resulting losses, damages, expenses, attorneys' fees, and court costs, whether incurred by settlement or otherwise, and whether such claims or actions are threatened or filed prior to or after the termination of this Agreement.

"Coal Combustion Residual Costs" or "CCR Costs" mean costs incurred by Duke to satisfy the various requirements of CAMA, the CCR Rule, and consent and/or settlement agreements/orders concerning the treatment, management and remediation of coal combustion residuals. CCR Costs shall not include any of the following:

(i) Requirements or obligations imposed on Duke to treat, manage or remediate coal combustion residuals by new legislation or regulations promulgated after December 31, 2016;

(ii) Dan River Incident Repair and Remediation Costs; and

(iii) Settlement Costs.

"CoBank" shall have the meaning specified in Section 16.7.

"Cogeneration Facility" means a facility that meets the criteria for a qualifying cogeneration facility under 18 C.F.R. § 292.205, as amended from time to time.

"Commencement Date" shall have the meaning specified in Section 2.1.1.

"Commercially Reasonable Efforts" mean efforts which are reasonably within the contemplation of the Parties at the Effective Date which require the performing Party that is acting in good faith to take action or expend funds reasonably in relation to the benefit to be obtained by the other Party, and that require a level of effort which would be devoted by an independent entity reasonably in the electric utility industry in light of all of the relevant circumstances.

"Confidential Information" means any documents, analyses, compilations, studies, or other materials prepared by a Party or its Representatives that contain or reflect either (a) any costs of Duke's Generation System and/or any costs associated with Duke's provision of REPS Compliance Service, including system average costs, or (b) written or oral data or information that is privileged, confidential, or proprietary and is marked as "Confidential." "Confidential Information" shall also mean all subsequently prepared documents, analyses, compilations, studies, or other materials by a Party or its Representatives that are derived from previously marked "Confidential" data or information. Notwithstanding the foregoing, information shall not be deemed Confidential Information if it:

(i) is a matter of public knowledge at the time of its disclosure or is thereafter published in or otherwise ascertainable from any source available to the public without breach of this Agreement,

(ii) constitutes information which is obtained from a third party (who or which is not an Affiliate of one of the Parties) other than by or as a result of unauthorized disclosure, or

(iii) prior to the time of disclosure had been independently developed by the receiving Party or its Affiliates not utilizing improper means.

"Contract Price for Capacity" shall be calculated as shown on Attachment 4-3 for each EMC Contract Resource.

"Consolidated Stipulation" shall have the meaning specified in Section 17.32.5.1.

"Contract Price for Energy" shall be calculated as shown on Attachment 4-3 for each EMC Contract Resource.

"Cover Costs" shall have the meaning specified in Section 6.4.

"CPR" means the International Institute for Conflict Prevention & Resolution or any successor thereto.

"Credit Amount" means the costs for which Duke is obligated to credit EMC under Section 7.1.1, excluding the costs set forth in Section 7.1.2.

"Dan River Incident" means the failure of the storm water pipe under an ash basin at the Dan River Steam Station that occurred on February 2, 2014, which resulted in the release of coal ash into the Dan River.

"Dan River Incident Repair and Remediation Costs and Credits" mean (i) costs incurred by Duke that are directly related to (A) pipe repair that limits or prevents further release of coal ash into the Dan River, (B) impoundment repair that restores the Dan River Steam Station's ash basin and related infrastructure to its intended operating state, (C) remediation of the Dan River from the effects of the Dan River Incident, and (D) litigation setting forth causes of action directly involving or directly related to the Dan River Incident whether or not related to a violation(s) specified in the Judgment in United States v. Duke Energy Carolinas, LLC, Case Nos. 5:15-CR-67 & 68 (E.D.N.C. May 14, 2015), Additional Probation Term 16 (Page 6 of 10); and (ii) any credits for amounts recovered by Duke for such costs, including, but not limited to, insurance payments for such costs.

"Dan River Steam Station" means an approximately 320 MW power plant comprised of coal fired steam generating units and natural gas/oil fired combustion turbine units owned by Duke and located in Eden, North Carolina which was retired from service in 2012.

"Day" means a day, commencing at 00:00:00 Eastern Time of such calendar day and ending 23:59:59 Eastern Time of the same calendar day.

"Debt Service Coverage Ratio" shall have the meaning specified in Section 16.7.

"Defaulting Party" shall have the meaning specified in Section 17.5.1.

"Delivery Points" mean any available points on the Transmission System where electric energy is delivered for Transmission Service.

"Demand Rate Adjustment Percentage" shall be calculated as shown on Attachment 7-9.

"Depreciation and Amortization Expense" shall have the meaning specified in Section 16.7.

"Disputed Amount" shall have the meaning specified in Section 14.5.

"Duke" shall have the meaning specified in the first paragraph hereof, provided that for purposes of this Agreement, "Duke" shall not include Duke Transmission.

"Duke Annual Plan" means the Annual Report Duke is required to file with the NCUC in accordance with NCUC Rule R8-60 or successor thereto. In the event Duke is no longer required to file the Annual Report with the NCUC or filing becomes voluntary, "Duke Annual Plan" shall mean the generation planning criteria for Duke's Generation System used by Duke to meet Duke's Native Load.

"Duke-Blue Ridge Agreement" means this Agreement.

"Duke Demand Response Programs" mean the demand response programs that Duke makes available to Duke's Native Load retail customers within the State of North Carolina under riders approved and on file with the NCUC, as such riders may be amended from time to time.

"Duke Energy" means Duke Energy Corporation, a Delaware corporation.

"Duke Monthly CCR Demand Rate" shall have the meaning specified in Section VI of Schedule 1.

"Duke Native Load" or "Duke's Native Load" means the electric capacity and energy demands imposed on Duke by its retail customers located within Duke's Service Area, as such Service Area may be amended from time to time in accordance with Laws or pursuant to the requisite approvals of the Governmental Authorities that have jurisdiction to regulate retail electric service within such Service Area, including by merger or acquisition, plus the demands of Duke's wholesale power sales customers served under contracts with a firmness of supply equal to such retail customers.

"Duke Schedule 1 Demands" shall have the meaning specified in Schedule 1, Section I.B.

"Duke Transmission" means Duke Electric Transmission, a division of Duke, or any successor thereto.

"Duke's Average Peak Hour Load" shall have the meaning specified in Schedule 1, Section I.B.

"Duke's Generation Planning Practices" mean the then-current generation planning practices of Duke that are reflected in the Duke Annual Plan.

"Duke's Generation System" means Duke's owned or leased electric generating facilities and purchased power resources the output of which are used to serve Duke's Native Load located within the State of North Carolina, as such system may be amended from time to time by any means including by merger or acquisition, but does not include any RECs.

"Eastern Time" means the time in effect in Charlotte, North Carolina, whether Eastern Standard Time or Eastern Daylight Saving Time.

"Effective Date" shall have the meaning specified in Section 2.1.1.

"Electric Full Requirements Service" shall have the meaning specified in Section 4.3.

"EMC" or "Blue Ridge" shall have the meaning specified in the first paragraph of this Agreement.

"EMC Allocable Share of Beneficial Reuse Disallowances" mean (a) if the Retail Rate Order specifies a Beneficial Reuse Disallowance for any Year, the Beneficial Reuse Disallowance(s) for such Year times the EMC Energy Allocation Factor; and/or (b) if the Retail Rate Order does not specify a Year for all or any portion of the Beneficial Reuse Disallowance(s) set forth in a Retail Rate Order, the average of the EMC Energy Allocation Factors for the Years subject to the Retail Rate Order times the Beneficial Reuse Disallowance(s) set forth in such Retail Rate Order that are not specified for any particular Year.

"EMC Allocable Share of CCR Disallowances" means (a) if the Retail Rate Order specifies CCR Disallowances for any Year, the CCR Disallowances for such Year times the EMC Production Demand Allocation Factor for that Year and/or (b) if the Retail Rate Order does not specify a Year for all or any portion of the CCR Disallowances set forth in a Retail Rate Order, the average of the EMC Production Demand Allocation Factors for the Years subject to the Retail Rate Order times the CCR Disallowances set forth in such Retail Rate Order that are not specified for any particular Year.

"EMC CCR Costs" mean CCR Costs multiplied by the EMC Production Demand Allocation Factor.

"EMC CCR Demand Costs" shall have the meaning specified in Section VI of Schedule 1.

"EMC Contract Resources" shall have the meaning specified in Section 5.2.1.

"EMC Credit Amount" shall have the meaning specified in Section 7.1.1.

"EMC Deferred CCR Costs" shall have the meaning specified in Section 7.4.2.5(b)(ii).

"EMC Demand Response Programs" mean demand response programs developed and implemented by EMC which are made available to EMC's Native Load customers or made available to New River to offer to New River's Native Load customers during the New River Term.

"EMC Energy Allocation Factor" means the sum of the EMC Native Load in each Hour (kW) for the Year divided by S. "S" for each Year shall be defined in accordance with Section IV of Schedule 1.

"EMC Group" means collectively Piedmont, Blue Ridge, Haywood, and Rutherford.

"EMC Maximum Annual CCR Billing Amount" shall be the annual values as stipulated in Attachment 7-4.

"EMC Monthly CCR Demand Costs" shall have the meaning specified in Section VI of Schedule 1.

"EMC Native Load" or "EMC's Native Load" means the electric capacity and energy demands imposed on EMC by its retail customers located within EMC's Service Area, excluding any such demands that constitute Non-Conforming Load, plus New River Native Load during the New River Term.

"EMC Peak Hour Billing Demand" shall have the meaning specified in Section 7.3.2.2.

"EMC Production Demand Allocation Factor" means the Monthly Billing Demand divided by Duke's Average Peak Hour Load.

"EMC Renewable Energy" means Renewable Energy purchased or generated by EMC from facilities located in the EMC Service Area or Renewable Energy purchased or generated by New River facilities located in New River's Service Area or ASU's campus within New River's Service Area.

"EMC's Ancillary Service Credit" means the credit set forth in Section 7.3.2.5.

"EMC's REPS Account" means a retail customer account of EMC used for the purpose of calculating EMC's requirements under the REPS.

"EMC's Share of CCR Insurance Proceeds" mean the share of CCR Insurance Proceeds that are allocable to EMC: (a) if the CCR Insurance Proceeds specifies a Year(s) and/or specific costs identifiable in a specific Year(s), then EMC's Share of CCR Insurance Proceeds shall be the CCR Insurance Proceeds times the EMC Production Demand Allocation Factor for demand related charges and/or the EMC Energy Allocation Factors for fuel related charges for the Year(s) to which such proceeds apply, or (b) if the CCR Insurance Proceeds do not specify a Year(s) nor specify costs, the EMC's Share of the CCR Insurance Proceeds shall equal the ratio of the EMC CCR Costs to total CCR Costs incurred from January 1, 2015 through December 31st of the Year prior to the Year in which the CCR Insurance Proceeds are received times the CCR Insurance Proceeds.

"Energy Costs" shall have the meaning specified in Section 7.1.1.2.

"Energy Efficiency Programs" mean programs or activities implemented by an electric system or its customers that results in less electric energy being used to perform the same function. Energy Efficiency Programs include Voltage Management Programs, but do not include Duke Demand Response Programs or EMC Demand Response Programs.

"Equitable Defenses" mean, with respect to a proceeding involving this Agreement, the discretion of a Governmental Authority to make or enter an order of bankruptcy, insolvency, reorganization, or other ruling affecting creditors' rights generally, or exercising other discretion committed to the court's or agency's equitable powers.

"Equity" shall have the meaning specified in Section 16.7.

"Event of Default" shall have the meaning specified in Section 17.5.1.

"Extension New River Term" shall have the meaning specified in Section 4.7.

"Extension Term" shall have the meaning specified in Section 2.2.2.

"Federal Power Act" means the Federal Power Act, 16 U.S.C. §§791a-828c, as amended from time to time.

"Federal REPS" shall mean a standard or requirement established by the Government which specifies a percentage of electricity generated by eligible renewable or alternative energy resources that a seller of electric energy is required to generate or procure.

"FERC" means the Federal Energy Regulatory Commission or any successor agency that administers the Federal Power Act.

"FERC Hold Harmless Commitment" shall have the meaning specified in Section 17.32.1.

"FERC Merger Application" shall have the meaning specified in Section 17.32.1.

"Fitch Rating" means Fitch Ratings, Inc., a jointly owned subsidiary of the Hearst Corporation and Fimalac, S.A.

"Force Majeure" shall have the meaning specified in Section 17.4.

"Fuel Rate" shall have the meaning specified in Section 7.3.3.1.

"GHG" means carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride and such other similar emissions as may be regulated under Law.

"Government" means the United States government.

"Governmental Authority" means any federal, state, local or other governmental, regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, court, tribunal, arbitrating body, government-owned corporation or other governmental authority or department thereof.

"Governmental Charges" mean all taxes, fees, assessments and other charges imposed by any Governmental Authority.

"GSU Loss Factor" shall have the meaning specified in Section 7.6.2.

"Haywood" means Haywood Electric Membership Corporation.

"Hold Harmless Period" shall have the meaning specified in Section 17.32.2.

"Hour" means one of the twenty-four (24) clock hours in a Day.

"Hourly" shall have the meaning correlative to that of Hour.

"Hourly Fuel Charge" shall have the meaning specified in Section 7.3.3.1.

"Hourly Variable O&M Charge" shall have the meaning specified in Section 7.3.3.2.

"Hydro RECs" mean any REC related to a hydroelectric generation facility owned by Duke and allocated pursuant to the REPS to Duke as a result of the generation of electric energy from such facility that is purchased by EMC pursuant to a separate contract.

"Impasse Notice" shall have the meaning specified in Section 15.2.

"Initial New River Term" means the period commencing on January 1, 2011, and continuing through 23:59:59 Eastern Time on December 31, 2021.

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"Initial Term" shall have the meaning specified in Section 2.2.1.

"Interest Expense" shall have the meaning specified in Section 16.7.

"Interest Rate" means either (i) the Prime Rate plus two (2%) percent, or (ii) the maximum lawful rate permitted by applicable Law, whichever is less.

"ISO" means an independent system operator.

"ITC" means an independent transmission company.

"Joint Dispatch Agreement" means that certain Joint Dispatch Agreement entered into between Duke and PEC dated as of July 2, 2012, as approved by FERC in FERC Docket No. EC11-60.

"kWh" means kilowatt-hour, a unit of electric energy.

"kW" means kilowatt.

"Law" means any law, rule, regulation, order, writ, judgment, decree, or other legal or regulatory determination by a court, regulatory agency, or other Governmental Authority of competent jurisdiction.

"Legal Proceeding" means any suit, hearing, or proceeding by or before any court or any Governmental Authority.

"Material Adverse Change" or "MAC" shall have the meaning specified in Section 16.2.

"Material Adverse Ruling" shall have the meaning specified in Section 2.3.2.2(c).

"Material Adverse Ruling Termination Date" shall have the meaning specified in Section 2.3.2.2.

"Merger" shall have the meaning specified in Section 17.32.1.

"Merger-Related Costs" shall have the meaning specified in Section 17.32.2.

"Minimum Availability Requirement" means the New River Peaking Resource is available at least eighty percent (80%) of the Hours that Duke, as scheduling agent or Purchasing – Selling Agent for Blue Ridge, directs New River to operate the New River Peaking Resource during any rolling twenty four (24) Month period.

"Month" means a calendar month, commencing at one (1) minute prior to 12:01 a.m. Eastern Time on one of January 1, February 1, March 1, April 1, May 1, June 1, July 1, August 1, September 1, October 1, November 1 or December 1 and ending at one (1) minute after 11:59 p.m. Eastern Time of the succeeding January 31, February 28 or 29 (during a leap Year), March 31, April 30, May 31, June 30, July 31, August 31, September 30, October 31, November 30 or December 31.

"Monthly" shall have a meaning correlative to that of Month.

"Monthly Billing Demand" shall have the meaning specified in Section 7.3.2.2.

"Monthly Capacity Credit" shall have the meaning specified in Section 7.1.1.1.

"Monthly Demand Charge" shall have the meaning specified in Section 7.3.2.

"Monthly Demand Rate" shall have the meaning specified in Section 7.3.2.1.

"Monthly Energy Charge" shall have the meaning specified in Section 7.3.3.

"Monthly Energy Credit" shall have the meaning specified in Section 7.1.1.2.

"Monthly Fuel Charge" shall have the meaning specified in Section 7.3.3.1.

"Monthly Variable O&M Charge" shall have the meaning specified in Section 7.3.3.2.

"Moody's" means Moody's Investors Services, Inc.

"MWh" means megawatt-hour, a unit of electric energy.

"MW" means megawatt.

"NCEMC" shall have the meaning specified in the Recitals of this Agreement.

"NCEMC Budget" means the budget approved by the NCEMC board of directors in the Year preceding the Year of the projected NCEMC expenditures and revenues.

"NCEMC Policies" shall have the meaning specified in Section 8.1.1.

"NCUC" means the North Carolina Utilities Commission or any successor agency with jurisdiction to regulate retail electric service in the State of North Carolina.

"NCUC Settlement Agreement" shall have the meaning specified in Section 17.32.5.

"Negotiation Period" shall have the meaning specified in Section 15.2.

"Neighbor Compensation Costs" mean costs incurred by Duke that are not required by Law and that are incurred under a program voluntarily implemented by Duke and publicly announced by Duke in December 2016 under which Duke provides to eligible property owners located within a certain proximity to Duke coal ash basins goodwill cash payments, compensation for reduction in property values, and compensation for water bills.

"NERC" means the North American Electric Reliability Council.

"Network Integration Transmission Service" means Network Integration Transmission Service provided under the OATT.

"Network Integration Transmission Service Agreement" or "NITSA" means that certain agreement for Network Integration Transmission Service, as amended from time to time, executed by EMC and Transmission Provider.

"Network Operating Agreement" or "NOA" means that certain agreement, as amended from time to time, executed by EMC and Transmission Provider in conjunction with the Network Integration Transmission Service Agreement.

"Network Resource" shall have the meaning specified in the OATT.

"Neutral Auditors" shall have the meaning specified in Section 2.3.2.2(e).

"New River" means New River Light & Power Company, the utility division of Appalachian State University.

"New River Agreement" means the Electric Service Agreement by and between EMC and New River dated as of September 1, 2010, as amended from time to time.

"New River Electric Service" means full requirements service, transmission service, distribution service and certain other services provided by Blue Ridge to New River under the terms and conditions of the New River Agreement.

"New River Native Load" or "New River's Native Load" means the electric capacity and energy demands imposed on New River by its retail customers located within New River's Service Area, excluding any such demands that constitute Non-Conforming Load.

"New River Peaking Resource" shall have the meaning specified in Attachment 4-3, page 8.

"New River Peaking Resource Credit Amount" shall have the meaning specified in Section 7.2.

"New River Restructuring" means a transaction whereby all or substantially all of the assets and liabilities associated with New River's business are contributed to (a) a newly formed entity that is a direct, wholly-owned subsidiary of Appalachian State University with such entity solely engaged in the business of providing electric service to retail customers residing within New River's Service Area; or (b) a non-profit corporation with Appalachian State University as the sole beneficiary.

"New River Service Area" means the service area identified on the map which is an attachment to and incorporated by reference into the New River Service Area Agreement.

"New River Service Area Agreement" means that certain agreement entered into between New River and Blue Ridge on April 27, 1965, as amended on October 7, 1985.

"New River Term" shall have the meaning specified in Section 4.7.

"Non-Claiming Party" shall have the meaning specified in Section 17.4.

"Non-Conforming Load" shall have the meaning specified in Section 4.4.

"Non-Conforming Retail Load" shall have the meaning specified in Section 4.4.

"Non-Defaulting Party" shall have the meaning specified in Section 17.5.1(1).

"Notice of Termination" means a written notice to terminate this Agreement under Sections 2.2 or 2.3 that conforms to the requirements set forth in Section 2.3.3.

"OATT" means the Open Access Transmission Tariff of the Transmission Provider on file with FERC, or the successor transmission tariff (including the Open Access Transmission Tariff of an RTO, ITC or ISO that is applicable to the Transmission System), as either may be amended from time to time.

"Operating Committee" shall have the meaning specified in Section 10.1.

"Operating Company Merger" shall have the meaning specified in Section 17.32.3.

"Original Notice" shall have the meaning specified in Section 15.2.

"Operating Protocols" mean the written protocols and procedures developed and maintained by the Parties in accordance with Section 8.3.

"Parity Savings" shall have the meaning specified in Section 17.32.5.1.

"Party" and "Parties" shall have the meanings specified in the preamble of this Agreement.

"Patronage Capital or Margins" shall have the meaning specified in Section 16.7.

"PEC" shall have the meaning specified in Section 17.32.3.

"Piedmont" means Piedmont Electric Membership Corporation.

"Power Rate Schedule" means Schedule 1 to this Agreement.

"Prime Rate" means, for any date, the per annum rate of interest announced from time to time by Citibank, N.A. (or a suitable replacement agreed upon by the Parties) as its "prime" rate for commercial loans, effective on the date payment is due as established from time to time by such bank.

"Principal and Interest Expense" shall have the meaning specified in Section 16.7.

"Prior Agreement" means the Fourth Amended and Restated Electric Full Requirements Power Purchase Agreement and REPS Compliance Service Agreement dated as of March 30, 2017, between Duke Energy Carolinas, LLC and Blue Ridge Electric Membership Corporation.

"Production Investment Base" shall have the meaning specified in Schedule 1, Section III. A.1.

"Progress Energy" means Progress Energy, Inc., a North Carolina corporation.

"Prudent Utility Practice" means any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Prudent Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the electric utility industry.

"PSCSC" means the Public Service Commission of South Carolina, or any successor agency with jurisdiction to regulate retail electric service within the State of South Carolina.

"Purchasing - Selling Entity" means that entity designated to the Transmission Provider by EMC who, upon the effectiveness of such designation, is eligible to purchase and sell energy and/or capacity and reserve transmission services on behalf of EMC.

"PURPA" means the Public Utilities Regulatory Policies Act, 16 U.S.C. §2601 *et seq*. (2005), as amended, including amendments included in the Energy Policy Act of 2005.

"PURPA Resource" shall have the meaning specified in Section 5.6.1.

"Rates" mean collectively, Duke's annual Demand Rates, Fuel Rates, Variable O&M Rate, and CCR Costs charged by Duke under this Agreement and in accordance with the Power Rate Schedule.

"REC" means a "renewable energy certificate" as defined under the REPS.

"Renewable Energy" means electric energy produced by a generating facility which uses fuel that is continuously or cyclically renewed by nature that qualifies to satisfy Laws applicable to EMC, such as but not limited to solar, wind, hydropower, geothermal, ocean current or wave energy, and biomass energy.

"Renewable Energy and Energy Efficiency Portfolio Standard" or "REPS" means the Renewable Energy and Efficiency Portfolio Standards, Section 62-133.8 *et seq*. of the General Statutes of the State of North Carolina, as amended.

"Representatives" mean, with respect to a Party, such Party's officers, directors, employees, advisors, and representatives and such Party's Affiliates and their respective officers, directors, employees, advisors, and representatives.

"REPS Charge" shall have the meaning specified in Section 13.3.1.

"REPS Compliance Service" means the service provided by Duke to EMC as set forth in the provisions of Article 13.

"REPS MAR" shall have the meaning specified in Section 13.4.2.

"REPS Rate" shall have the meaning specified in Section 13.3.1.1.

"REPS Rider" means the then applicable REPS Rider, as filed by Duke and approved by the NCUC, in accordance with the provisions of N.C. Gen. Stat. 62-133.8(h).

"Resolution Period" shall have the meaning specified in Section 2.3.2.2(e).

"Resource Summary Attachments" mean the Resource Summary Attachments as such term is defined in the WPSA.

"Restricted Rentals" shall have the meaning specified in Section 16.7.

"Retail Parity Method" means a method by which Duke may charge EMC for CCR Costs that is consistent with and in accordance with the methodology by which Duke is permitted to charge North Carolina retail customers for such costs pursuant to a Retail Rate Order and under such methodology. EMC's charges for CCR Costs will be calculated on the same basis as Duke charges such North Carolina retail customers, including CCR Disallowances, Beneficial Reuse Disallowances, deferral of CCR Costs, and Authorized CCR Retail Return.

"Retail Rate Order" means a final, non-appealable order issued by the NCUC in (i) a retail rate proceeding; (ii) a proceeding approving Duke's recovery of CCR Costs through Duke's fuel adjustment clause; and/or (iii) any other proceeding in which the NCUC expressly approves Duke's recovery of CCR Costs from North Carolina retail customers.

"Revised and Restated Settlement Agreement" shall have the meaning specified in Section 17.32.1.

"Revised GSU Loss Factor" shall have the meaning specified in Section 7.6.2.

"RTO" means a regional transmission organization as that term is defined by FERC.

"RUS" means the Rural Utilities Service of the United States Department of Agriculture or any agency succeeding to the functions of RUS.

"Rutherford" means Rutherford Electric Membership Corporation.

"Scheduling," "Scheduled" or "Schedule" shall mean or relate to the acts undertaken by Duke of requesting and confirming the quantity(ies) of electric energy to be made available by EMC in each Hour during the Term.

"Scheduling Agent" means Duke acting as agent on behalf of EMC to perform Scheduling Services.

"Scheduling Policies" shall have the meaning specified in Section 8.1.1.

"Selection Date" shall have the meaning specified in Section 15.5.

"SEPA" means the Southeastern Power Administration.

"SEPA Contract" means the Contract Executed by Blue Ridge and the United States of America acting by and through the Southeastern Power Administration as of May 2, 1997, as amended from time to time.

"SEPA Policies" shall have the meaning specified in Section 8.1.1.

"SERC" means the SERC Reliability Corporation.

"Service Area" means the area within a state or states within which an electric utility provides retail electric service as determined under the applicable Laws of such state or states.

"Settlement Costs" mean the burden of, or the costs associated with, compliance with the criminal fines, restitution related to counts of conviction, community service payments, the mitigation obligation, costs of the clean-up in response to the February 2, 2014, release at the Dan River Steam Station, and funding of the environmental compliance plans, as set forth in the Judgment in United States v. Duke Energy Carolinas, LLC, Case Nos. 5:15-CR-67 & 68 (E.D.N.C. May 14, 2015), Additional Probation Term 16. The term "Settlement Costs" also includes the burden of, or costs associated with criminal and/or civil fines, penalties, restitution, community service payments or any mitigation obligation imposed on Duke from its failure to comply with the terms as set forth in the Judgment in United States v. Duke Energy Carolinas, LLC, Case Nos. 5:15-CR-67 & 68 (E.D.N.C. May 14, 2015), Additional Probation Term 16. The Parties acknowledge and agree that the term "Settlement Costs" shall also include the burden of and/or costs associated with CCR Costs and Beneficial Reuse Costs that Duke is prohibited from collecting in Rates pursuant to an agreement reached with a Governmental Authority including "Unallowable Costs" as described in paragraph III.C.16 of the Interim Administrative Agreement between Duke Energy Corporation; Duke Energy Business Services, LLC; Duke Energy Carolinas, LLC; and Duke Energy Progress, Inc. and the United States Environmental Protection Agency (EPA Case Nos. 15-0411-00 thru 15-0411-03 and 15-0411-00A thru 15-0411-02A); provided, however, for purposes of this definition, the phrase "an agreement reached with a Governmental Authority" shall not include nor apply to any agreement, order, and/or finding issued, accepted and/or approved by (i) FERC pertaining to wholesale rates and/or regulation, and/or (ii) the NCUC or PSCSC pertaining to retail rates and/or regulation. In addition, such phrase shall not include nor apply to any CCR Disallowance and any Beneficial Reuse Disallowance.

"Short Term Interest Expense" shall have the meaning specified in Section 16.7.

"S&P" or "Standard & Poor's" means Standard & Poor's Financial Services, LLC.

"Standard Arbitration Process" shall mean the arbitration process described in Section 15.6.1.

"State of North Carolina Settlement Agreement" shall have the meaning specified in Section 17.32.6.

"Streamlined Arbitration Process" shall mean the arbitration process described in Section 15.6.2.

"Submission" or "Submissions" shall have the meaning specified in Section 15.6.1(5).

"Substitute Energy" shall have the meaning specified in Section 6.4.

"Substitute Energy Costs" shall have the meaning specified in Section 6.5.

"Summer Period" means the period (May 1 – September 30) designated as the summer period in the then-most recent Duke Annual Plan.

"Term" means the term of this Agreement determined in accordance with Section 2.2.3.

"Times Interest Earned Ratio" or "TIER" shall have the meaning specified in Section 16.7.

"Time of Use Rate" means a rate structure that charges a higher rate during peak Hours in an effort to shift peak period demand to off-peak Hours.

"Transmission Provider" means any entity transmitting electric energy provided by Duke under this Agreement to the EMC distribution system, and shall include any ISO, RTO, ITC, or other future organization, agency or authority that has been approved by FERC to serve as the Transmission Provider.

"Transmission Service" means the service provided by a Transmission Provider to EMC pursuant to which electric energy provided under this Agreement is delivered from the Delivery Point to EMC's distribution system.

"Transmission System" means the electric transmission system owned or leased and operated by Duke Transmission.

"Twenty CP Hours" shall have the meaning specified in Section 7.3.2.2.

"VAR" means a unit of reactive power of an alternating current, equal to the product of the current measured in amperes and the voltage measured in volts.

"Variable O&M Rate" shall have the meaning specified in Section 7.3.3.2.

"Voltage Management Programs" mean the implementation and operation of field apparatus, controls, software, and communications products to manage distribution system VAR flow to minimize technical losses and to improve energy efficiency and system voltages in EMC's distribution system. Such programs which implement conservation voltage reduction strategies reduce demand and electric energy consumption while maintaining customer voltage power quality and include programs commonly referred to as Volt/Var management programs.

"Winter Period" means the period (October 1 – April 30) designated as the winter period in the then most recent Duke Power Annual Plan.

"WPSA" means the Wholesale Power Supply Agreement by and between North Carolina Electric Membership Corporation and EMC dated as of January 1, 2004, as amended from time to time.

"Year" means a calendar year.

1.2 Interpretation. In this Agreement, unless the context otherwise requires, the singular shall include the plural and any pronoun shall include the corresponding masculine, feminine and neuter forms. The words "hereof," "herein," "hereto" and "hereunder" and words of similar import when used in this Agreement shall, unless otherwise expressly specified, refer to this Agreement as a whole and not to any particular provision of this Agreement. Whenever the terms "include," "includes," or "including" are used herein in connection with a listing of items included within a prior reference, such listing shall be interpreted to be illustrative only, and shall not be interpreted as a limitation on or exclusive listing of the items included within the prior reference. Any reference in this Agreement to "Section," "Article," "Schedule," or "Attachment" shall be references to this Agreement unless otherwise stated, and all such Sections, Articles, Schedules, and Attachments shall be incorporated in this Agreement by reference. In the event that any index or publication referenced in this Agreement ceases to be published, each such reference shall be deemed a reference to a successor or alternate index or publication reasonably agreed to by the Parties. Unless specified otherwise, a reference to a given agreement or instrument, and all schedules and attachments thereto, shall be a reference to that agreement or instrument as modified, amended, supplemented and restated, and in effect from time to time. Unless otherwise stated, any reference in this Agreement to any entity shall include its permitted successors and assignees, and in the case of any Governmental Authority, any person succeeding to its functions and capacities. All dollar amounts referred to in this Agreement shall be in U.S. currency. Unless otherwise stated, any reference in this Agreement to the REPS or any section of the REPS shall include the statute and any related NCUC rules and regulations, as either the statute or the NCUC rules and regulations may be amended from time to time, and any successor North Carolina statute and NCUC rules and regulations.

1.3 Construction. The Parties acknowledge that each was actively involved in the negotiation and drafting of this Agreement and that no Law or rule of construction shall be raised or used in which the provisions of this Agreement shall be construed in favor of or against either Party because one is deemed to be the author thereof.

6.3 Emergency Load Curtailment Program. EMC agrees to implement an emergency load curtailment program for the curtailment of EMC's Native Load in the event a load curtailment order is made by Duke. EMC shall comply with its obligation to implement and maintain an emergency load curtailment program and to curtail EMC's Native Load in the manner specified by Section 6.2.

6.4 Substitute Energy. In the event that Duke fails to deliver a sufficient quantity of electric energy to meet its obligations to provide Electric Full Requirements Service and Duke's failure to deliver such electric energy is not pursuant to a curtailment permitted under Section 6.2 of this Agreement, or is otherwise not excused under this Agreement, Duke shall pay to EMC an amount equal to EMC's Cover Costs, if any, incurred for the electric energy that EMC obtained to replace such electric energy ("Substitute Energy") Duke failed to supply. EMC's "Cover Costs" shall be equal to Substitute Energy Costs incurred by EMC for the Substitute Energy minus the costs that EMC would have incurred had Duke supplied the electric energy to EMC. EMC shall bill its Cover Costs to Duke in accordance with the provisions of Article 14. In the event that EMC incurs Cover Costs for Substitute Energy over a period that extends past the Month in which Duke's failure to deliver electric energy occurs, then Duke shall pay the Cover Costs incurred in the following Month(s) in accordance with the billing and payment provisions of Article 14.

6.5 Substitute Energy Costs. "Substitute Energy Costs" shall be equal to (i) in the case in which EMC contracts with an energy supplier to provide Substitute Energy to EMC, the cost that EMC, acting in a commercially reasonable manner, incurs to purchase such Substitute Energy, or (ii) in the case in which Substitute Energy is provided to EMC by the Balancing Authority Area operator, system operator, or similar entity providing such service on behalf of load (or load serving entities), the cost to EMC imposed on EMC by such Balancing Authority Area operator, system operator, or other entity providing such Substitute Energy. In either case, Substitute Energy Costs shall include ancillary services charges, if any, reasonably incurred by EMC to the point where electric energy is delivered to the Transmission System or imposed to the point where electric energy is delivered to the Transmission System by the Balancing Authority Area operator, system operator, or other entity providing Substitute Energy, including congestion charges, energy imbalance charges, backup capacity charges, replacement capacity charges, deficient capacity charges, commitment fees, ratcheted demand and similar charges incurred by EMC in obtaining such Substitute Energy.

## Article 7

## Charges, Credits and Reimbursements for Electric Capacity, Energy and CCR Costs

7.1 Duke's Credit Obligation to EMC for Electric Capacity and Energy Made Available.

7.1.1 Amount of Credit. Each Month during the Term, Duke shall credit or reimburse EMC an amount equal to EMC's Credit Amount. The EMC "Credit Amount" is the amount of costs associated with EMC's entitlement to electric capacity and energy from the EMC Contract Resources made available to Duke pursuant to this Agreement that EMC is obligated to pay NCEMC under the WPSA, and SEPA under the SEPA Contract. The amount of the EMC Credit Amount shall be the sum of the Monthly Capacity Credit and the Monthly Energy Credit.

7.1.1.1 Monthly Capacity Credit. The "Monthly Capacity Credit" shall equal the sum of the Contract Prices for Capacity for each of the EMC Contract Resources as calculated in accordance with Attachment 4-3. If applicable for an EMC Contract Resource, the Monthly Capacity Credit may be initially calculated by EMC based on estimated data provided by NCEMC or SEPA and such estimated data shall be subject to Monthly and/or annual true-up(s) after actual data become available to EMC. The true-up shall appear on the statement EMC delivers to Duke for the Billing Period immediately following the Month in which the true-up is reflected on NCEMC's or SEPA's billing statement to EMC.

7.1.1.2 Monthly Energy Credit. The "Monthly Energy Credit" shall be the sum of the Contract Prices for Energy calculated for each of the EMC Contract Resources as set forth in Attachment 4-3. "Energy Costs" shall mean with respect to each EMC Contract Resource, the variable costs associated with the production of electric energy, including but not limited to costs of fuel, start charges, and any variable charges incurred by EMC under the WPSA, and the SEPA Contract in connection with electric energy Scheduled by Duke from the EMC Contract Resources set forth in Attachment 4-3. If applicable for an EMC Contract Resource, the Monthly Energy Credit may be initially calculated by EMC based on estimated data provided by NCEMC or SEPA and such estimated data shall be subject to Monthly and/or annual true-up(s) after actual data become available to EMC. The true-up shall appear on the statement EMC delivers to Duke for the Billing Period immediately following the Month in which the true-up is reflected on NCEMC's or SEPA's billing statement to EMC.

7.1.2 Amounts Not Included in the Calculation of the EMC Credit Amount.

7.1.2.1 Specific Exclusions. The Credit Amount shall not include: (a) interest income earned on amounts paid by EMC to NCEMC for periods prior to February 1, 2008, to fund the decommissioning trust fund for the Catawba Nuclear Station, but shall include credits to Duke for interest income earned on amounts paid by EMC to NCEMC for the period beginning on February 1, 2008, and ending with the termination date hereof to fund such decommissioning trust fund; (b) costs paid by EMC to NCEMC associated with the management of the nuclear decommissioning trust fund for the Catawba Nuclear Station, (c) costs paid by EMC associated with the actual decommissioning of Catawba Nuclear Station at the end of its useful life, (d) any amount paid, credited or reimbursed by NCEMC to EMC determined by the positive difference of depreciation expense collected by NCEMC from EMC with respect to the Catawba Nuclear Station and the principal payments on indebtedness incurred by NCEMC to finance its ownership interest in the Catawba Nuclear Station, including any fee associated with such amount, (e) charges for additional services billed under Section 5.1(b) of the WPSA unless Duke has given prior consent to such charges, (f) charges for stranded costs incurred by NCEMC and billed under Section 5.1(e) of the WPSA, (g) charges for EMC's share of unrecovered costs billed under Section 5.1(f) of the WPSA, and (h) charges for EMC's share of revenue shortfall billed under Section 5.1(g) of the WPSA.

7.1.2.2 Cost of EMC Contract Resources Incurred After the Term. The Credit Amount shall not include any costs for electric capacity and energy, including true-ups, refunds, or corrections, from the EMC Contract Resources if such electric capacity and energy was delivered after the termination of this Agreement. However, true-ups, credits, refunds, or corrections made after the termination of this Agreement which relate to costs for electric capacity and energy made available after the Commencement Date and before the termination of this Agreement shall be subject to credit or reimbursement to EMC by Duke or credit or reimbursement to Duke by EMC.

7.2 New River Peaking Resource Credit Amount. Each Month during the New River Term to the extent that the New River Peaking Resource is made available to Duke, Duke shall credit or reimburse EMC an amount equal to the New River Peaking Resource Credit Amount. The New River Peaking Resource Credit Amount is equal to the sum of (i) the Monthly Capacity Credit which is equal to the Contract Price for Capacity for the New River Peaking Resource as calculated in accordance with Attachment 4-3 and (ii) the Monthly Energy Credit which is equal to the Contract Price for Energy for the New River Peaking Resource as calculated in accordance with Attachment 4-3. The New River Peaking Resource Credit Amount may be initially calculated by EMC based on estimated data provided by New River and such estimated data shall be subject to Monthly and/or annual true-up(s) after actual data becomes available to EMC. The true-up shall appear on a statement that EMC delivers to Duke for the Billing Period immediately following the Month in which the true-up is reflected on New River's billing statement to EMC. The New River Peaking Resource Credit Amount shall not include any costs for electric capacity and energy, including true-ups, refunds, or corrections, from the New River Peaking Resource if such electric capacity and energy was delivered after the New River Term. However, true-ups, credits, refunds, or corrections made after the termination of the New River Term which relate to costs for electric capacity and energy made available after the commencement date of the Initial New River Term and before the end of the New River Term shall be subject to credit or reimbursement to EMC by Duke or credit or reimbursement to Duke by EMC.

7.3 Duke Charges to EMC for Electric Full Requirements Service.

7.3.1 General. For Electric Full Requirements Service provided beginning on the Commencement Date through the termination of this Agreement, EMC shall pay to Duke the Monthly Demand Charge set forth in Section 7.3.2, the Monthly Energy Charge set forth in Section 7.3.3, and the EMC Monthly CCR Demand Costs set forth in Section 7.4. The charges set forth in this Section 7.3 and Section 7.4 are in addition to the other charges set forth in other sections of this Agreement.

7.3.2 Monthly Demand Charge. The "Monthly Demand Charge" for a Month shall be equal to the product of (i) the Monthly Billing Demand for the Month (kW) and (ii) the Monthly Demand Rate for the Year ($/kW-Month), minus EMC's Ancillary Services Credit for such Month.

7.3.2.1 Monthly Demand Rate. The "Monthly Demand Rate" for each Year shall be calculated in accordance with the formula rate set forth in Schedule 1. The Monthly Demand Rate shall initially be calculated based on estimated data, and shall be subject to true-up after actual data become available. The true-up shall be provided to EMC no later than June 30 following the Year in which Electric Full Requirements Service was provided, and shall include interest on any refunds or surcharges calculated in accordance with Section 35.19a of FERC's regulations.

7.3.2.2 Monthly Billing Demand. The "Monthly Billing Demand" for each Month of a Year shall be equal to the average of the twenty (20) EMC Peak Hour Billing Demands coincident with the twenty (20) highest Hourly (integrated sixty-minute) Duke Schedule 1 Demands during the Annual Planning Period for such Year (as determined in Section 7.3.2.3) ("Twenty CP Hours"). The "EMC Peak Hour Billing Demand" for an Hour shall be equal to the integrated sixty (60) minute EMC Native Load demand (kW) for the Hour. The Monthly Billing Demand shall initially be calculated based on estimated data, and shall be subject to true-up after actual data become available. The true-up shall be provided to EMC no later than June 30 following the Year in which service was provided, and shall include interest on any refunds or surcharges calculated in accordance with Section 35.19a of FERC's regulations. Examples showing the calculation of the Monthly Billing Demand are shown in Attachment 7-8.

7.3.2.3 Determination of Annual Planning Period. If the then-effective Annual Planning Period is the Summer Period, the Annual Planning Period for purposes of determining the Monthly Billing Demand for the Year under Section 7.3.2.2 shall be the Summer Period that occurs within such Year (for example, if the Annual Planning Period in 2016 is the Summer Period, and the Summer Period is May - September, the Annual Planning Period for purposes of determining the Monthly Billing Demand for 2016 under Section 7.3.2.2 is May 2016 - September 2016). If the then-effective Annual Planning Period is the Winter Period, the Annual Planning Period for purposes of determining the Monthly Billing Demand for the Year under Section 7.3.2.2 shall be the Winter Period that ends in such Year (for example, if the Annual Planning Period in 2016 is the Winter Period, and the Winter Period is October - April, the Annual Planning Period for purposes of determining the Monthly Billing Demand for 2016 under Section 7.3.2.2 is October 2015 - April 2016).

7.3.2.4 Annual Percentage. Each June 30 during the Term, Duke shall calculate the Annual Percentage for the immediately preceding Year using the formula set forth in Attachment 7-9, and shall provide such calculation to EMC, together with supporting information. The Annual Percentage may be a positive or negative value. In the event that the Annual Percentage for such Year is greater than positive four percent (4%), the Monthly Demand Rate for such Year calculated pursuant to Section 7.3.2.1 shall be reduced by the percentage equal to the Demand Rate Adjustment Percentage. This reduction shall only apply to the Year for which it is calculated. This reduction shall be reflected in the true-up provided to EMC pursuant to Section 7.3.2.1. In the event that the Annual Percentage for such Year is a positive four percent (4%) or less, or is negative, there shall be no adjustments to the Monthly Demand Rate under this Section 7.3.2.4 for such Year. Illustrative examples showing the calculation of the Annual Percentage and Demand Rate Adjustment Percentage and the resulting reduction, if any, to the Monthly Demand Rate are set forth in Attachment 7-10.

7.3.2.5 EMC's Ancillary Service Credit. "EMC's Ancillary Service Credit" for a Month shall be equal to (a) the sum of the charges paid by EMC to the Transmission Provider under the OATT for Reactive Supply and Voltage Control from Generation Sources Service (OATT Schedule 2), Regulation and Frequency Response Service (OATT Schedule 3), Operating Reserve – Spinning Reserve Service (OATT Schedule 5) and Operating Reserve – Supplemental Reserve Service (OATT Schedule 6) for the Month, multiplied by (b) the Duke Supply Ratio for the Month, and further multiplied by (c) the Billing Determinant Ratio for the Month. The Duke Supply Ratio for the Month shall be equal to the ratio (not to exceed 1.0) of (a) the Duke-Supplied Load for the Month to (b) EMC's Monthly Network Load (as such amount is determined under the OATT) for the Month. The Billing Determinant Ratio for a Month shall be equal to the ratio (not to exceed 1.0) of (a) EMC's Monthly Billing Demand for the Month divided by the Duke Average Peak Hour Load for the Year that includes such Month to (b) the Duke-Supplied Load for the Month divided by the Transmission Provider's Monthly Transmission System Peak (as such amount is determined under the OATT) for the Month. The Duke-Supplied Load for a Month shall be equal to the portion of the EMC's Network Load (as such amount is determined under the OATT) for the Month that is served under this Agreement. Example: If the sum of the charges under part (a) for the Month is $70,000, the Duke-Supplied Load for the Month is 200 MW, EMC's Monthly Network Load for the Month is 230 MW, EMC's Monthly Billing Demand for the Month is 210 MW, the Duke Average Peak Hour Load for the Year that includes the Month is 19,000 MW, and the Transmission Provider's Monthly Transmission System Peak for the Month is 22,000 MW, EMC's Ancillary Service Credit for the Month would be equal to $70,000 * (200/230) * (210/19,000) / (200/22,000), or $70,000 * .87 * 1.2 limited to 1, or $60,900.

7.3.3 Monthly Energy Charge. The "Monthly Energy Charge" for a Month shall be equal to the sum of the Monthly Fuel Charge and Monthly Variable O&M Charge for the Month.

7.3.3.1 Monthly Fuel Charge. The "Monthly Fuel Charge" for a Month shall be equal to the sum of the Hourly Fuel Charges for the Month. The "Hourly Fuel Charge" for an Hour shall be equal to the product of (i) EMC's Native Load demand during the Hour (kW) and (ii) the Fuel Rate for the Year ($/kWh). The "Fuel Rate" for each Year shall be calculated in accordance with the formula rate set forth in Schedule 1. The "Fuel Rate" shall initially be calculated based on estimated data, and shall be subject to true-up after actual data become available. The true-up shall be provided to EMC no later than June 30 following the Year in which service was provided, and shall include interest on any refunds or surcharges calculated in accordance with Section 35.19a of FERC's regulations. Duke will keep EMC informed of the true-up subtotal on a semi-annual basis during a Year.

7.3.3.2 Monthly Variable O&M Charge. The "Monthly Variable O&M Charge" for a Month shall be equal to the sum of the Hourly Variable O&M Charges for the Month. The "Hourly Variable O&M Charge" for an Hour shall be equal to the product of (i) EMC's Native Load demands during the Hour (kW) and (ii) the Variable O&M Rate for the Year ($/kWh). The Variable O&M Rate for each Year shall be calculated in accordance with the formula rate set forth in Schedule 1. The Variable O&M Rate shall initially be calculated based on estimated data, and shall be subject to true-up after actual data become available. The true-up shall be provided to EMC no later than June 30 following the Year in which service was provided, and shall include interest on any refunds or surcharges calculated in accordance with Section 35.19a of FERC's regulations.

7.4 Duke Charges to EMC for CCR Costs. The EMC Monthly CCR Demand Costs for each Year shall be calculated in accordance with the formula rate set forth in Section VI of Schedule 1. The EMC Monthly CCR Demand Costs shall initially be calculated based on estimated data, and shall be subject to true-up after actual data become available. The true-up calculations shall be provided to EMC no later than June 30 following the Year in which Electric Full Requirements Service was provided, and shall include interest on any refunds or surcharges calculated in accordance with Section 35.19a of FERC's regulations.

7.4.1 Exclusions. The Parties agree that EMC shall not be responsible for paying, Duke shall not recover from EMC, and EMC's CCR Costs shall not include payments ordered in a final, non-appealable order, agreed upon in a final, non-appealable settlement, or sought by any third party and which Duke by a final, non-appealable settlement expressly agrees to assume or pay for third-party personal injury or property damage caused or alleged to have been caused by either: (a) Duke's activities in complying with the requirements of CAMA, the CCR Rule, and consent and/or settlement agreements/orders concerning the treatment, management and remediation of coal combustion residuals or (b) the release or threatened release to the environment of any of Duke's coal combustion residuals under 42 U.S.C. § 9607 or 9613 (or any substantively similar state law), whether such payment liability for either (a) or (b) results from litigation or settlement.

7.4.2 Methodology for EMC Maximum Annual CCR Billing Amount.

7.4.2.1 EMC Maximum Annual CCR Billing Amount. The Parties agree to adjust the billing and payment provisions set forth in Article 14 of this Agreement to permit EMC to defer the payment of EMC CCR Demand Costs to the extent that such EMC CCR Demand Costs exceed in any Year the EMC Maximum Annual CCR Billing Amount as set forth in Attachment 7-4. The deferral of any EMC CCR Demand Costs shall be calculated in the following manner.

7.4.2.2 Duke is obligated to provide EMC its estimated EMC CCR Demand Costs for the succeeding Year by December 1st of the current Year pursuant to Section 17.26 of this Agreement.

7.4.2.3 The estimated EMC CCR Demand Costs for a Year shall be compared to the EMC Maximum Annual CCR Billing Amount for such Year.

(a) If the estimated EMC CCR Demand Costs exceed the EMC Maximum Annual CCR Billing Amount, EMC shall be obligated to pay Duke the EMC Maximum Annual CCR Billing Amount for the applicable Year.

(b) If the estimated EMC CCR Demand Costs are equal to or less than the EMC Maximum Annual CCR Billing Amount, EMC shall be obligated to pay Duke the amount of estimated EMC CCR Demand Costs.

7.4.2.4 The estimated EMC CCR Demand Costs are trued-up to actual EMC CCR Demand Costs incurred by Duke during the applicable Year by June 30 of the following Year pursuant to Section 7.4 of this Agreement.

7.4.2.5 EMC CCR Demand Costs actually incurred by Duke are compared to the EMC Maximum Annual CCR Billing Amount for the applicable Year.

7.4.2.5.1 If there are no EMC Deferred CCR Costs from previous Years and EMC CCR Demand Costs are equal to or less than the EMC Maximum Annual CCR Billing Amount, then the true-up amount is either paid by or credited to EMC. Interest on the payment or credit is calculated in accordance with Section 7.4 of this Agreement.

7.4.2.5.2 If EMC CCR Demand Costs for the applicable Year exceed the EMC Maximum Annual CCR Billing Amount, then EMC shall elect one of the following payment options: (i) pay the excess amount in accordance with Section 7.4 of this Agreement; or (ii) defer the excess amount ("EMC Deferred CCR Costs") for recovery in succeeding Years. Any EMC Deferred CCR Costs shall accrue interest in accordance with Section 7.4 of this Agreement.

7.4.2.5.3 In any Year in which EMC Deferred CCR Costs are outstanding and EMC CCR Demand Costs are less than the EMC Maximum Annual CCR Billing Amount for such

Year, the difference shall be applied to reduce the amount of such outstanding EMC Deferred CCR Costs.

7.4.2.6 Duke is not permitted to earn the Cost of Capital Rate on EMC Deferred CCR Costs unless the amount of EMC Deferred CCR Costs exceed three million dollars ($3,000,000.00). If EMC Deferred CCR Costs exceed three million dollars ($3,000,000.00), EMC will have the option exercisable within thirty (30) Days of the completion of the true-up process set forth in Section 7.4 of this Agreement to reduce the EMC Deferred CCR Costs to three million dollars ($3,000,000.00) or less. If EMC does not elect the option to pay excess EMC Deferred CCR Costs, Duke shall be permitted to earn interest on the EMC Deferred CCR Costs of three million dollars ($3,000,000.00) or less and the Cost of Capital Rate on any EMC Deferred CCR Costs exceeding three million dollars ($3,000,000.00). Duke's Cost of Capital Rate on such amount shall be computed in accordance with Section III.A.2 of Schedule 1 to this Agreement.

7.4.2.7 EMC will be required to repay any EMC Deferred CCR Costs if EMC informs Duke in writing that (1) EMC elects to convert to the Retail Parity Method in accordance with Section 17.33, or (2) EMC elects to terminate the application of the EMC Maximum Annual CCR Billing Amount provisions and instead assume the obligation to pay Duke EMC CCR Demand Costs on an "as incurred basis" in accordance with Section 7.4 of this Agreement. If EMC elects either one of the foregoing options, then by January 1 of the Year following such election, EMC shall inform Duke in writing of its election: (a) to pay the entire amount of EMC Deferred CCR Costs as a part of the true-up process as set forth in Section 7.4 of this Agreement, or (b) to pay the EMC Deferred CCR Costs in twenty-four (24) equal Monthly installments with interest accruing on the unpaid balance in accordance with Section 7.4 of this Agreement; provided, however, if the EMC Deferred CCR Costs at the time of the EMC election exceed three million dollars ($3,000,000.00), then notwithstanding Section 7.4.2.6, EMC shall be obligated to pay Duke the Cost of Capital Rate on any unpaid balance exceeding three million dollars ($3,000,000.00).

7.4.2.8 If this Agreement expires or terminates, EMC shall be responsible for the payment of all EMC Deferred CCR Costs within ninety (90) Days of such termination or expiration of this Agreement. An amendment and restatement of this Agreement shall not be considered a termination or expiration of this Agreement for purposes of EMC's responsibility to pay all EMC Deferred CCR Costs within the above mentioned ninety (90) day period.

7.4.2.9 Examples showing the calculation of EMC Deferred CCR Costs are shown in Attachment 7-4.

7.4.3 Beneficial Reuse Costs.

7.4.3.1 From January 1, 2015 through December 31, 2016, Beneficial Reuse Costs shall be included as a component of CCR Demand Costs and recovered in accordance with Section VI of Schedule 1. Beginning January 1, 2017 and continuing throughout the Term, Beneficial Reuse Costs that are properly recorded in Account No. 501 shall be recovered as a component of Fuel Rate determined in accordance with Section IV of Schedule 1, and shall not be included in CCR Demand Costs for purposes of applying the methodology set forth in Section VI of Schedule 1.

7.4.3.2 Disallowances. Duke shall provide billing credits for EMC's Allocable Share of Beneficial Reuse Disallowances as a part of the annual true-up performed in accordance with Section 7.3.3.1 of the Agreement and shall include interest computed in accordance with Section 7.3.3.1.

7.5 Payment, Credit or Reimbursement. All charges, payments, credits or reimbursements contemplated by this Article 7 shall be made in accordance with the provisions of Article 14.

7.6 Determination of EMC Capacity and Energy Demands.

7.6.1 General. For purposes of determining the electric capacity and energy charges under Section 7.3 and Section 7.4 of this Agreement, EMC's Native Load demands shall be as determined under the NOA (which demands shall include the adjustments under the NOA for losses between the point of delivery under the NITSA and the point of measurement, and the corrections under the NOA for any metering failures or inaccuracies), and shall be multiplied by (1+LF), in order to reflect such demands at the generation level. Metered receipts used in billings and accounting hereunder will in all cases include adjustments for such losses. LF shall be equal to the sum of (i) the Real Power Loss factor in the DEC Zone as stated in the Transmission Provider's OATT, as it may be amended from time to time, and (ii) the GSU Loss Factor as determined under Section 7.6.2, and shall be expressed as a decimal. For example, if the transmission loss factor in the Transmission Provider's OATT is 2.2% and generator step-up transformer loss factor is .3%, then (1+LF) shall be equal to (1+.022+.003), or 1.025. In the event that the NOA is terminated, or the electric capacity and energy demands measured under the NOA no longer include an adjustment for losses between the point of delivery under the NITSA and the point of measurement or provisions for correcting such demands for metering failures or inaccuracies, then for purposes of determining the capacity and energy charges under this Agreement, EMC's metered electric capacity and energy demands shall be adjusted for losses between the point of delivery under the NITSA and point of measurement and further multiplied by (1+LF), in order to reflect such demands at the generation level, and suitable arrangements shall be made by the Parties for correcting such demands due to metering failures or inaccuracies.

7.6.2 GSU Loss Factor. For the period beginning with the Commencement Date and ending May 31, 2018, the GSU Loss Factor shall be 0.24%. Thereafter, the GSU Loss Factor shall be recalculated and adjusted on an annual basis as follows. After each calendar year, Duke shall calculate the applicable GSU Loss Factor in accordance with the Methodology for Calculation of GSU Loss Factor - Duke set forth in Attachment 7.6.2 hereto. By April 1 of the year immediately succeeding the 12-month loss factor calculation period, Duke shall give notice to EMC stating the revised GSU Loss Factor (the "Revised GSU Loss Factor") along with supporting calculations and documentation in sufficient detail to enable EMC to verify the accuracy of the Revised GSU Loss Factor. The Revised GSU Loss Factor shall be effective June 1 following the giving of such notice. The Revised GSU Loss Factor shall be subject to EMC's audit rights as set forth in Section 14.6.

7.7 Emission Allowances and Credits. In the event a Law is enacted that allocates GHG emission allowances or credits based upon EMC's retail electric service load and the responsibility for costs associated with GHG emissions is assigned to generators of electric energy, the Parties agree to commence good faith negotiations within sixty (60) Days after the enactment of such Law to modify this Agreement in order to fairly and equitably allocate between the Parties the benefits of the allowance or credits or the cost of Duke's compliance with GHG Laws to provide electric energy and capacity to EMC. If the Parties have not reached agreement with respect to such modifications within sixty (60) Days after commencing good faith negotiations, then Duke shall have the right to unilaterally make application to FERC under Section 205 of the Federal Power Act under the provisions of Section 12.3.

## Article 8

## Scheduling Services

8.1 Appointment of Duke as Scheduling Agent. EMC hereby appoints Duke as Scheduling Agent, effective on the Commencement Date, as EMC's limited agent during the Term for the specific and limited purpose of Scheduling the EMC Contract Resources that EMC is making available to Duke under Section 5.2.1 of this Agreement.

8.1.1 Scheduling Policies. When Scheduling EMC Contract Resources hereunder, as applicable, Duke shall comply as applicable with (i) the NCEMC policies set forth in Attachment 8-1 ("NCEMC Policies"), (ii) the Transmission Provider's OATT; and (iii) the SEPA policies set forth in Attachment 8-2 ("SEPA Policies") (collectively, the "Scheduling Policies").

**Schedule 1**
**Annual Production Capacity and Energy Rates**

Schedule 1 Methodology:

This Schedule 1 sets forth the formulas and methods that Duke will use to determine its Rates. The Rates will be annual formula rate calculations. The Rates shall initially be estimated and then shall be trued-up by July 1 of the following Year based on actual costs and loads for the applicable period using the formula rates set forth below. The calculations will be based on Duke's FERC Form 1 data and Duke's company records. The true-up will include interest on any refunds or surcharges calculated in accordance with the methodology set forth in 18 C.F.R. § 35.19a or its successor. The formulas for the Rates were designed to include all costs incurred by Duke to own, operate and maintain Duke's Generation System. The formulas for the Rates may only be amended by the mutual agreement of the Parties or pursuant to Section 12.3 of the Agreement. Disallowance or any other treatment of any such costs by the NCUC or any other Governmental Authority other than FERC will not have any effect on the inclusion of such costs in the formulas for the Rates as set forth below, except as provided in Section 17.32, Section 7.4, Section VI of Schedule 1, and/or the defined term, "Settlement Costs."

General Exclusion of Incremental Renewable Energy Costs:

It is intended that the formulas for the Rates exclude all Incremental Renewable Energy Costs. If any of the cost items as set forth in this Schedule 1 contain Incremental Renewable Energy Costs, then such costs shall be excluded when calculating Electric Rates under this Agreement.

Exclusion of Dan River Incident Repair and Remediation Costs and Credits, Exclusion of Settlement Costs, and Exclusion of Neighbor Compensation Costs:

It is intended that the formulas for Rates exclude all Dan River Incident Repair and Remediation Costs and Credits, all Settlement Costs, and all Neighbor Compensation Costs. If any of the cost items set forth in this Schedule 1 contain Dan River Incident Repair and Remediation Costs and Credits, Settlement Costs, and/or Neighbor Compensation Costs, then such costs or credits shall be excluded when calculating Rates under this Agreement

I. Definitions

Capitalized terms not otherwise defined in the Agreement and as used in this Schedule 1 have the following definitions:

A. Allocation Factors

1. Production Wages and Salaries Allocation Factor shall equal the ratio of the sum of Duke's production-related direct wages and salaries and transmission wages and salaries to Duke's total direct wages and salaries excluding administrative and general wages and salaries, where transmission wages and salaries equals Duke's transmission-related direct wages and salaries multiplied by the TP Plant Allocation Factor.

2. Production Plant Allocation Factor shall equal the ratio of the sum of Duke's investments in Production Plant plus Production Related General Plant plus Production Related Intangible Plant plus TP Plant to investment in Total Plant in Service.

3. TP Plant Allocation Factor shall equal the ratio of Duke's investments in TP Plant to Duke's investments in Transmission Plant.

B. Terms

Accumulated Deferred Income Taxes shall equal the net of Duke's electric deferred tax balances as recorded in FERC Account Nos. 281-283 and Duke's electric deferred tax balance as recorded in FERC Account No. 190.

Administrative and General Expense shall equal Duke's expenses as recorded in FERC Account Nos. 920-935 excluding FERC Account Nos. 924, 928 and 930.1, and less EPRI dues as recorded in FERC Account No. 930.2.

Avoided Costs of Renewable Energy shall equal the avoided cost of Renewable Energy purchased or generated by Duke as calculated by Duke for the purposes of the REPS.

Contra AFUDC shall equal the reduction in amount of AFUDC recorded in FERC Account No. 107 due to recovery of construction period financing costs from customers resulting from inclusion of construction work in progress in rate base in any of Duke Power's retail or wholesale rate jurisdictions.

Demand Rate means the Demand Rate calculated in Part II below.

Depreciation Expense for Production Plant shall equal Duke's production expense as recorded in FERC Account No. 403 plus an adjustment to increase depreciation expense to eliminate any reduction in depreciable base for Contra AFUDC related to production plant construction work in progress included in rate base.

Depreciation Expense for Transmission Plant shall equal Duke's transmission expense as recorded in FERC Account No. 403 plus an adjustment to increase depreciation expense to eliminate any reduction in depreciable base for Contra AFUDC related to transmission plant construction work in progress included in rate base.

Duke Interconnection Facilities shall mean the Transmission Provider's Interconnection Facilities, as that term is defined in Attachment J of the OATT, that were placed in service on or after March 15, 2000, and that are associated with Duke's generating units.

Duke Interconnection Plant shall equal Duke's gross plant balance as recorded in FERC Balance Sheet Account No. 101, FERC Electric Plant Account Nos. 350-359 and Balance Sheet Account Nos. 102 and 106 tentatively classified to FERC Electric Plant Account Nos. 350-359 for Duke Interconnection Facilities, plus an adjustment to add Contra AFUDC related to Duke Interconnection Facilities construction work in progress included in rate base.

Duke Schedule 1 Demands mean Duke's Native Load demands excluding (a) non-requirements wholesale sales, as listed in Duke's FERC Form 1, and (b) wholesale sales with duration of one year or less, to the extent that the demands and sales described in (a) and (b) are served by Duke's Generation System the cost of which is included in Schedule 1. Such demands and sales shall be compensated for all transmission and generator step-up transformer losses using the same loss factors that are used in the calculation of capacity and energy charges as described in Section 7.6.

Duke's Average Peak Hour Load for a year shall equal the average of the twenty highest hourly (integrated sixty minute) Duke Schedule 1 Demands during the Annual Planning Period of the year.

FAS 106 Regulatory Assets and Liabilities shall equal the net of Duke's FAS 106 balance as recorded in FERC Account No. 182.3 and any Duke FAS 106 balance as recorded in FERC Account No. 254.

FAS 109 Regulatory Assets and Liabilities shall equal the net of Duke's FAS 109 balance as recorded in FERC Account No. 182.3 and any Duke FAS 109 balance as recorded in FERC Account No. 254.

General Plant shall equal Duke's gross plant balance as recorded in FERC Balance Sheet Account No. 101, FERC Electric Plant Account Nos. 389-399, and amounts in FERC Balance Sheet Account Nos. 102 and 106 tentatively classified to FERC Electric Plant Account Nos. 389-399, plus an adjustment to add Contra AFUDC related to general plant construction work in progress included in rate base.

General Plant Depreciation Expense shall equal Duke's general plant expenses as recorded in FERC Account No. 403 plus an adjustment to increase depreciation expense to eliminate any reduction in depreciable base for Contra AFUDC related to general plant construction work in progress included in rate base.

General Plant Depreciation Reserve shall equal Duke's general plant reserve balance as recorded in FERC Account No. 108 plus an adjustment to increase the reserve to equal accumulated depreciation for depreciable base without reduction for Contra AFUDC related to production plant construction work in progress included in rate base.

General Tax Expense shall equal Duke's expenses as recorded in FERC Account No. 408.1.

GSU Transformer Plant shall equal Duke's gross plant balance as recorded in FERC Balance Sheet Account No. 101, FERC Electric Plant Account No. 353 and Balance Sheet Account Nos. 102 and 106 tentatively classified to FERC Electric Plant Account No. 353 for generator step-up facilities, plus an adjustment to add Contra AFUDC related to generator step-up transformer plant construction work in progress included in rate base.

Incremental Renewable Energy Costs shall equal the cost of purchasing or generating Renewable Energy minus the Avoided Cost of Renewable Energy plus the total cost of RECs.

Intangible Plant shall equal Duke's gross plant balance as recorded in FERC Balance Sheet Account No.101, FERC Electric Plant Account Nos. 301-303, and amounts in FERC Balance Sheet Account Nos. 102 and 106 tentatively classified to FERC Electric Plant Account Nos. 301-303, plus an adjustment to add Contra AFUDC related to intangible plant construction work in progress included in rate base.

Intangible Plant Amortization Expense shall equal Duke's intangible plant expenses as recorded in FERC Account No. 404 plus an adjustment to increase depreciation expense to eliminate any reduction in depreciable base for Contra AFUDC related to intangible plant construction work in progress included in rate base.

Intangible Plant Amortization Reserve shall equal Duke's intangible plant reserve balance as recorded in FERC Account No. 111 plus an adjustment to increase the reserve to equal accumulated depreciation for depreciable base without reduction for Contra AFUDC related to intangible plant construction work in progress in rate base.

Net Asset Retirement Cost shall equal Duke's asset retirement costs recorded in FERC Account No. 101, less the associated accumulated depreciation included in FERC Account No. 108.

Other Amortization shall equal Duke's amortization expense recorded in FERC Account Nos. 406 and 407 that is related to production plant.

Other Regulatory Assets/Liabilities shall equal the net of Duke's regulatory assets and liabilities in FERC Account Nos. 182, 228 and 254, excluding FAS 109 Regulatory Assets and FAS 106 Regulatory Assets that are production related.

Payroll Taxes shall equal Duke's payroll tax expenses as recorded in FERC Account No. 408.1.

Plant Held for Future Use shall equal Duke's balance in FERC Account No. 105.

Prepayments shall equal Duke's prepayment balance as recorded in FERC Account No. 165.

Production Depreciation Reserve shall equal Duke's production reserve balance as recorded in FERC Account No. 108 plus an adjustment to increase the reserve to equal accumulated depreciation for depreciable base without reduction for Contra AFUDC related to production plant construction work in progress included in rate base.

Production Operation and Maintenance (O&M) Expense shall equal Duke's expenses as recorded in FERC Account Nos. 500-557.

Production Plant shall equal Duke's gross plant balance as recorded in FERC Balance Sheet Account No. 101, FERC Electric Plant Account Nos. 310-347 and Balance Sheet Account Nos. 102 and 106 tentatively classified to FERC Electric Plant Account Nos. 310-347, plus an adjustment to add Contra AFUDC related to production plant construction work in progress included in rate base.

Production Plant Materials and Supplies shall equal (a) Duke's balance as assigned to production as recorded in FERC Account No. 154, plus (b) Duke's balance as assigned to transmission, as recorded in FERC Account No. 154 multiplied by the TP Plant Allocation Factor.

Production Related Amortization of Investment Tax Credits shall equal Duke's credits as recorded in FERC Account No. 411.4 multiplied by the Production Plant Allocation Factor.

Property Insurance shall equal Duke's expenses as recorded in FERC Account No. 924.

Revenue Tax Rate shall equal 1.0 minus the applicable revenue or gross receipts tax rate(s) to which Duke is subject for the revenues or gross receipts that Duke receives under this Agreement

Tax Deduction for Manufacturing Activities shall equal Duke's annual amount of tax deduction under Section 102 of the American Jobs Creation Act of 2004.

Total Plant in Service shall equal Duke's total gross plant balance as recorded in FERC Balance Sheet Account No. 101, Electric Plant Account Nos. 301-399, and amounts in FERC Balance Sheet Account Nos. 102 and 106, plus an adjustment to add Contra AFUDC related to construction work in progress included in rate base.

TP Plant shall equal the sum of Duke Interconnection Plant and GSU Transformer Plant.

Transmission Depreciation Reserve shall equal Duke's transmission reserve balance as recorded in FERC Account No. 108 plus an adjustment to increase the reserve to equal accumulated depreciation for depreciable base without reduction for Contra AFUDC related to transmission plant construction work in progress included in rate base.

Transmission Plant shall equal Duke's total gross plant balance as recorded in FERC Balance Sheet Account No. 101, Electric Plant Account Nos. 350-359, and transmission amounts in FERC Balance Sheet Account Nos. 102 and 106, plus an adjustment to add Contra AFUDC related to transmission construction work in progress included in rate base.

Unamortized Gain on Reacquired Debt shall equal Duke's amounts included in FERC Account No. 257.

Unamortized Loss on Reacquired Debt shall equal Duke's expenses as recorded in FERC Account No. 189.

Variable Non-Fuel Production Operation and Maintenance Expense shall equal Duke's expenses as recorded in FERC Account Nos. 510, 512, 513, 528, 530, 531, and 544.

II. Demand Rate

The Demand Rate shall be the Production Capacity Revenue Requirement as determined in Part III below, divided by Duke's Average Peak Hour Load, and further divided by the Revenue Tax Rate. The Monthly Demand Rate shall be equal to the Demand Rate divided by twelve (12).

III. Production Capacity Revenue Requirement

The Production Capacity Revenue Requirement shall equal the sum of Duke's (A) Return and Associated Income Taxes, (B) Production Depreciation Expense, (C) TP Plant Depreciation Expense (D) Decommissioning Expense, (E) Production Related General Taxes, (F) Fixed Production Operation and Maintenance Expense, (G) TP Plant Operation and Maintenance Expense, (H) Purchased Power Capacity Expenses, (I) Production Related Administrative and General Expense, (J) Production Related Other Amortization Expense and (K) Capacity Credit for Revenue from Non-Associated Utility Sales.

A. Return and Associated Income Taxes shall equal the product of the Production Investment Base and the Cost of Capital Rate.

1. Production Investment Base

The Production Investment Base shall equal the average of the beginning and end-of-year balances of (a) Production Plant, plus (b) Production Related General and Intangible Plant, plus (c) Production Plant Held for Future Use, plus (d) TP Plant, less (e) Production Related Depreciation Reserve, less (f) TP Plant Depreciation Reserve, less (g) Production Related Net Asset Retirement Costs, plus (h) Nuclear Fuel Inventory, plus (j) Fossil Fuel Inventory, plus (j) Allowance Inventory, less (k) Production Related Accumulated Deferred Income Taxes, plus (l) Production Related Loss on Reacquired Debt, (m) less Production Related Gain on Reacquired Debt, plus (n) FAS 106 and FAS 109 Regulatory Assets/Liabilities, plus (o) Other Regulatory Assets/Liabilities, plus (p) Production Prepayments, plus (q) Production Materials and Supplies, plus (r) Production Related Cash Working Capital.

(a) Production Plant shall equal Production Plant as defined in Section I.B.

(b) Production Related General and Intangible Plant shall equal the sum of General Plant plus Intangible Plant multiplied by the Production Wages and Salaries Allocation Factor.

(c) Production Plant Held for Future Use shall equal Plant Held for Future Use multiplied by the Production Plant Allocation Factor.

(d) TP Plant shall equal TP Plant as defined in Section I.B.

(e) Production Related Depreciation Reserve shall equal Production Depreciation Reserve plus Production Related General and Intangible Plant Depreciation Reserve; where Production Related General and Intangible Plant Depreciation Reserve shall equal the sum of General Plant Depreciation Reserve plus Intangible

Plant Amortization Reserve, multiplied by the Production Wages and Salaries Allocation Factor.

(f) TP Plant Depreciation Reserve shall equal Transmission Plant Depreciation Reserve multiplied by the TP Plant Allocation Factor.

(g) Production Related Net Asset Retirement Costs shall equal Duke's asset retirement cost balance as recorded in FERC Account No. 101 for Production Plant less the associated accumulated depreciation balance as recorded in FERC Account No. 108.

(h) Nuclear Fuel Inventory shall equal Duke's balance of investment in nuclear fuel as recorded in FERC Account Nos. 120.2 – 120.6.

(i) Fossil Fuel Inventory shall equal Duke's balance of investment in fossil fuel as recorded in FERC Account No. 151.

(j) Allowance Inventory shall equal the balance in FERC Account No. 158.1 plus the balance in FERC Account No. 158.2.

(k) Production Related Accumulated Deferred Income Taxes shall equal Total Accumulated Deferred Income Taxes multiplied by the Production Plant Allocation Factor.

(l) Production Related Loss on Reacquired Debt shall equal Unamortized Loss on Reacquired Debt multiplied by the Production Plant Allocation Factor.

(m) Production Related Gain on Reacquired Debt shall equal Unamortized Gain on Reacquired Debt multiplied by the Production Plant Allocation Factor.

(n) FAS 106 and FAS 109 Regulatory Assets/Liabilities shall equal Duke's balance of FAS 106 related costs as recorded in FERC Account Nos. 182.3 and 254 multiplied by the Production Wages and Salaries Allocation Factor, plus Duke's balance of FAS 109 related costs as recorded in FERC Account Nos. 182.3 and 254 multiplied by the Production Plant Allocation Factor.

(o) Other Regulatory Assets/Liabilities shall equal Duke's balance of Other Regulatory Assets/Liabilities as appropriate; provided, that in order to include any amounts in this item, Duke shall make a filing with FERC under Section 205 of the Federal Power Act.

(p) Production Prepayments shall equal Duke's Prepayments in FERC Account 165 multiplied by the Production Wages and Salaries Allocation Factor.

(q) Production Materials and Supplies shall equal Production Plant Materials and Supplies as defined above.

(r) Production Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Fixed Production Operation and Maintenance Expense, Variable Production Non-Fuel Operation and Maintenance Expenses, TP Plant Operation and Maintenance Expense, and Production Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) Duke's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital shall be calculated based upon a proxy capital structure of 45% long term debt and 55% common equity and shall equal the sum of:

(i) the long term debt component, which shall equal the product of 45% and Duke's long term debt expenses recorded in FERC Account Nos. 427, 428, 428.1, 429, 429.1, and 430 divided by Duke's long-term debt balance as recorded in FERC Account Nos. 221 through 227, and

(ii) the return on equity component, which shall equal the product of 55% and Duke's return on equity (ROE) of 11.0%.

(b) Federal Income Tax shall equal
[A+(B+C+D)/E] x (FT) / (1-FT)
where FT is the Federal Income Tax Rate and A is the return on equity component, as determined in Sections III.A.2.(a)(ii) above, B is Production Related Amortization of Investment Tax Credits, C is Duke's annual amount of Tax Deduction for Manufacturing Activities, D is the Equity AFUDC component of Production Depreciation Expense as defined in Section III.B below, and E is Production Investment Base as determined in III.A.1 above.

(c) State Income Tax shall equal

[A+(B+C+ D)/E + Federal Income Tax] x (ST) / (l -ST)
where ST is the State Income Tax Rate. A is the return on equity component determined in Sections III.A.2.(a)(ii) above, B is the Amortization of Investment Tax Credits, C is Duke's annual amount of Tax Deduction for Manufacturing Activities, D is the equity AFUDC component of Production Depreciation Expense as defined in Section III.B. below, E is the Production Investment Base as determined in III.A.l above and Federal Income Tax is the rate determined in Section III.A.2.(b) above.

B. Production Depreciation Expense shall equal the sum of Depreciation Expense for Production Plant, plus an allocation of General and Intangible Plant Deprecation Expense calculated by multiplying the sum of General Plant Depreciation Expense and Intangible Plant Amortization Expense by the Production Wages and Salaries Allocation Factor, less decommissioning expense recorded in FERC Account No. 403.

C. TP Plant Depreciation Expense shall equal Depreciation Expense for Transmission Plant multiplied by the TP Plant Allocation Factor.

D. Decommissioning Expense shall equal $48,304,000.00 per year for the period January 1, 2013 through September 30, 2013, $20,989,268.00 per year for the period starting October 1, 2013 through December 31, 2014, and $0.00 per year starting January 1, 2015..

E. Production Related General Taxes shall equal the sum of General Tax Expense less revenue related taxes and Payroll Taxes, multiplied by the Production Plant Allocation Factor, and Payroll Taxes multiplied by the Production Wages and Salaries Allocation Factor.

F. Fixed Production Operation and Maintenance Expense shall equal Duke's expenses as recorded in FERC Account Nos. 500, 502, 505-507, 511, 514, 517, 519, 520, 523-525, 529, 532, 535-543, 545, 546, 548-554, 556, and 557.

G. TP Plant Operation and Maintenance Expense shall equal Duke's expenses as recorded in FERC Account Nos. 560, 562-564 and 566-573 multiplied by the TP Plant Allocation Factor.

H. Purchased Power Expenses shall equal Duke's expenses for purchased power recorded in FERC Account No. 555 less purchased power fuel costs included in the Fuel Rate determined in Section IV below.

I. Production Related Administrative and General Expenses shall equal the sum of (1) Administrative and General Expense multiplied by the Production Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Production Plant Allocation Factor, (3) expenses included in FERC Account 928 related to FERC Assessments multiplied by the Production Plant Allocation Factor, (4) any other production related expenses or assessments in FERC Account Nos. 928 or 930.1, and (5) any other transmission related expenses or assessments in FERC Account Nos. 928 or 930.1 multiplied by the TP Plant Allocation Factor.

J. Production Related Other Amortization Expense shall equal Duke's amortization expense recorded in FERC Account Nos. 406 and 407 either directly assigned to production or allocated to production using the Production Plant Allocation Factor or the Production Wages and Salaries Allocation Factor.

K. Credit for Revenue from Non-Associated Utility Sales shall equal Duke's revenues from inter-system sales from Duke's Generation System recorded in FERC Account 447 to the extent such sales are not included in the determination of Duke's Average Peak Hour Load, less fuel recovered from such sales as determined in the Fuel Rate below, multiplied by 2/3.

IV. Fuel Rate

The Fuel Rate shall equal F/S, and further divided by the Revenue Tax Rate, where:

F is the expense of fossil and nuclear fuel and purchased economic power, as defined in 18 C.F.R. § 35.14(a)(2) (2005), for the calendar year period; provided that for purposes of this calculation described in 18 C.F.R. § 35.14(a)(2) (2005) the cost of fossil fuel shall include, in addition to those items set forth in 18 C.F.R. § 35.14(a)(6) (2011), Beneficial Reuse Costs properly recorded in Account No. 501 and expenses recorded in Account No. 509 for the Year.

S is all kWh sold (compensated for all transmission and generator step-up transformer losses using the same loss factors that are used in the calculation of capacity and energy charges as described in Section 7.6), excluding inter-system sales, for the Year.

Duke shall adjust Beneficial Reuse Costs that are properly recorded in Account No. 501 by applying billing credits equal to EMC Allocable Share of Beneficial Reuse Disallowance as part of the annual true-up performed in accordance with Section 7.3.3.1 or Section 7.4.2 of the Agreement, as applicable.

EMC Allocable Share of Beneficial Reuse Disallowances, if any, shall be determined by the issuance of a Retail Rate Order.

V. Variable O&M Rate

The Variable O&M rate shall equal Variable Non-Fuel Production Operation and Maintenance Expense divided by S as determined in Section IV above, and further divided by the Revenue Tax Rate.

VI. Coal Combustion Residuals Demand Costs

A. Definitions

Duke Monthly CCR Demand Rate means the annual calendar year projection of CCR Demand Costs divided by the Duke's Average Peak Hour Load and then divided by 12. The Duke Monthly CCR Demand Rate shall initially be calculated based on estimated data, and shall be subject to true-up after actual data become available. The true-up shall be provided to EMC no later than June 30 following the Year in which Electric Full Requirements Service was provided, and shall include interest on any refunds or surcharges calculated in accordance with Section 35.19a of FERC's regulations.

EMC CCR Demand Costs mean the allocable load ratio share of CCR Demand Costs applicable to EMC. Such allocable load ratio share will be based on recently available actual values, adjusted as appropriate for known changes in system and/or EMC loads during the forecast period, and subject to annual true-up once actual costs and allocable load ratio share is known.

CCR Disallowance means CCR Demand Costs that the NCUC disallows for recovery in a Retail Rate Order. Any billing credit associated with a CCR Disallowance shall include any rate of return previously charged on such amount by Duke as well as interest computed in accordance with Section 7.3.2.2(d) of the Agreement.

EMC Monthly CCR Demand Costs mean the product of the Duke Monthly CCR Demand Rate and the Monthly Billing Demand.

B. Purpose.

The purpose of this Section VI of Schedule 1 to permit Duke to recover through Rates determined in accordance with Schedule 1 the actual CCR Demand Costs incurred by Duke commencing January 1, 2015. Any CCR Demand Costs collected under this Section VI of Schedule 1 will be excluded from the costs that otherwise would have been collected in accordance with Sections I through V of Schedule 1.

From January 1, 2015 through December 31, 2016, Beneficial Reuse Costs shall be recovered as a component of CCR Demand Costs. Beginning January 1, 2017 through the Term, Beneficial Reuse Costs that are properly recorded in Account No. 501 shall be recovered as a component of Fuel Rate determined in accordance with Section IV of Schedule 1, and shall not be included in CCR Demand Costs for purposes of applying the methodology set forth below in Paragraph C of this Section VI of Schedule 1.

C. Methodology:

It is the intent of this Section VI of Schedule 1 to reflect EMC's full allocable share of Duke's Generation System of CCR Demand Costs as such costs are incurred. The annual calendar year projection of CCR Demand Costs will be divided by Duke's Average Peak Hour Load and then divided by 12 to equal Duke Monthly CCR Demand Rate. The Duke Monthly CCR Demand Rate will be multiplied by the Monthly Billing Demand resulting in the EMC Monthly CCR Demand Costs.

D. Calculation:

Duke Monthly CCR Demand Rate = (CCR Demand Costs /Duke's Average Peak Hour Load) / 12.
EMC Monthly CCR Demand Costs = Duke Monthly CCR Demand Rate * Monthly Billing Demand.

The charges calculated above will be based on Duke's actual expenditures per company records.

E. CCR Costs Owed for Compliance from January 1, 2015 through December 31, 2017

The actual EMC CCR Costs for the period from January 1, 2015 through December 31, 2016 and the estimated EMC CCR Demand Costs from January 1, 2017 through and including December 31, 2017 shall be recovered over twenty four (24) Months and billed in equal Monthly installments starting January 1, 2018 and continuing through December 31, 2019, without any interest payable from EMC, unless otherwise mutually agreed to in writing by the Parties. Actual Beneficial Reuse Costs that are properly recorded in Account No. 501 for the period from January 1, 2017 through and including June 30, 2017 will be recovered in six (6) equal Monthly installments as part of the Fuel Rate under Section IV of Schedule 1 starting July 1, 2017 and continuing through December 31, 2017. For the period July 1, 2017 through December 31, 2017, estimated Beneficial Reuse Costs that are properly recorded in Account No. 501 will be recovered as part of the Fuel Rate under Section IV of Schedule 1 through a Monthly charge. These estimated EMC CCR Demand Costs and Beneficial Reuse Costs will not include Duke's Cost of Capital Rate and will be subject to true-up no later than June 30, 2018 in accordance with the true-up provisions in Sections 7.4.2.4 and 7.3.3.1.

F. General Provisions

1. Duke will adjust the EMC CCR Demand Costs by applying billing credits equal to the EMC Allocable Share of CCR Disallowances, as part of the annual true-up performed in accordance with Section 7.4.2.4 of the Agreement. The only CCR Cost disallowances and/or exclusions that EMC shall receive shall be the EMC Allocable Share of CCR Disallowances, the EMC Allocable Share of Beneficial Reuse Disallowances, exclusions as provided in Section 7.4.1, and/or as provided for in the defined term "Settlement Costs."

2. Except with respect to any interest payable in accordance with the Agreement for any invoicing and true-up of any costs that are billed under this Section VI of Schedule 1, Duke shall not earn Cost of Capital Rate on CCR Costs (as set forth in Section III.A.2 of Schedule 1, except as provided for in Section 7.4.2.6 and Section 7.4.2.7 of this Agreement.).

3. EMC shall receive the EMC's Share of CCR Insurance Proceeds within ninety (90) Days subsequent to Duke's receipt of CCR Insurance Proceeds:

   (i) if demand related and an EMC Deferred CCR Costs balance exists, as a reduction to such balance and/or
   (ii) if demand related and no EMC Deferred CCR Costs balance exists or if fuel related, then as a billing credit or a refund.

   Such reductions, billing credits and/or refunds shall survive termination of this Agreement in accordance with Section 17.9.

NEW RIVER LIGHT & POWER COMPANY
COAL ASH COST RECOVERY RIDER
SCHEDULE CACR

New River Light & Power Company ("NRLP") receives wholesale power supply from Blue Ridge Electric Membership Corporation ("BREMCO") which, in turn, receives power supply from Duke Energy Carolinas ("DEC"). The cost of wholesale power from DEC is passed through to NRLP from BREMCO.

Effective July 1, 2017, the power supply agreement between DEC and BREMCO was amended to allow recovery of costs to comply with (i) the North Carolina Coal Ash Management Act 2014 N. C. Sess. Laws 122; 2014 N.C. Ch. 122; 2013 N. C. SB 729, as amended June 2015 by the Mountain Energy Act, N. C. SB716 as further amended by the Drinking Water Protection/Coal Ash Cleanup Act, House Bill 603/S.L. 2016-95, and (ii) The Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities promulgated by the United States Environmental Protection Agency and published on April 17, 2015, 80 Fed. Reg 21302, as may be amended from time to time ("Coal Ash Costs").

This Coal Ash Cost Recovery Rider ("CACR") provides for a monthly charge or credit to NRLP's customers to recover charges from BREMCO for recovery of DEC's Coal Ash Costs. This Schedule CACR is applicable to all NRLP Rate Schedules.

Monthly Rate

The Monthly Rate will be applied to all kilowatt-hours and shall be calculated monthly as follows:

$$CACR = ((TCA_{n-1}/ES)/(1\text{-}RCF\text{-}UA)) + TU_{n-2}/ES$$

Where:

CACR is the monthly rate per kilowatt-hour to be applied to bills rendered from the 15th of the month following service from BREMCO in which Coal Ash Costs are billed to NRLP through the 14th of the following month (the "billing cycle").

$TCA_{n-1}$ is the Total Coal Ash costs billed by BREMCO for service in the prior month.

ES = The Estimated Sales in kilowatt-hours for the current billing cycle.

RCF= The Regulatory Commission Fee assessed by the North Carolina Utilities Commission per dollar of revenues, which is currently .14%.

UA= Uncollectible Accounts rate of .113%.
New River Light & Power Company
Coal Ash Cost Recovery Rider

$TU_{n-2} = (CACRR_{n-2} - ACACR_{n-2})$

Where:

$TU_{n-2}$ is the True-Up for CACR collections in the second preceding billing cycle.

CACRRn-2 is the Coal Ash Cost Recovery Revenue needed in the second billing cycle preceding the current billing cycle. This amount is calculated as CACRxES for the second billing cycle preceding the current billing cycle.

ACACRn-2 is the actual recovery of coal ash costs under this Rider for the second billing cycle preceding the current billing cycle.

Effective Date: ________________________

# Docket No. E-34, Sub 46
# Appalachian State University
# d/b/a New River Light and Power Company
# CACR Example Calculations

| Line | Formula Component | Description | Amount |
|---|---|---|---|
| | | **January Wholesale/Feb 15 to Mar 14 billing cycle** | |
| 1 | TCAn-1 | January Invoice from BREMCO for Coal Ash Costs | $ 100,000.00 |
| 2 | ES | Expected kWh Sales for February 15 through March 14 billing Cycles | 20,000,000 |
| 3 | | Cost/kWh (Line 1/Line 2) | $ 0.00500 |
| 4 | | Adjustment for Regulatory Commission Fee and Uncollectible Accts | (1-0.0014-0.00113) |
| 5 | CACR | CACR to be applied in February 15 through March 14 billing cycle (Line 3/Line 4) | $ 0.00501 |
| | | **March Wholesale/April 15 to May 14 billing cycle** | |
| 6 | TCAn-1 | March Invoice from BREMCO for Coal Ash Costs | $ 225,000.00 |
| 7 | ES | Expected kWh Sales for April 15 through May 14 billing Cycles | 14,200,000 |
| 8 | | Cost/kWh | $ 0.01585 |
| 9 | | Adjusted for Regulatory Commission Fee and Uncollectible Accounts (Line 8/Line4) | $ 0.01589 |
| | | *True-up for the Feb 15 to Mar 14 billing cycle* | |
| 10 | CACRRn-2 | Required Revenue from second preceding billing cycle (Line 5*Line 2) | $ 100,253.64 |
| 11 | ACACRn-2 | Actual revenue received from the second preceding billing cycle | |
| 12 | | Actual kWh Sales 20,800,000 | |
| 13 | | CACR second preceding $0.00501 | $ 104,263.79 |
| 14 | TUn-2 | True-up for second preceding billing cycle (Line 10-Line 13 | $ (4,010.15) |
| 15 | | True-up per kWh (Line 14/Line 7) | $ (0.00028) |
| 16 | CACR | Total CACR for billing cycle from April 15 through May 14 (Line 9 + Line 15) | $ 0.01560 |