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July 10, 2017

via E-MAIL and OVERNIGHT MAIL

David Foster, Chief – Utilities Division
c/o Sharla Dillon
Dockets and Records Manager
Tennessee Public Utility Commission
502 Deaderick St.
Nashville, TN 37243

In Re: PETITION OF KINGSPORT POWER COMPANY d/b/a AEP APPALACHIAN POWER FOR APPROVAL OF ITS TARGETED RELIABILITY PLAN, AND ITS TRP & MS RIDER, AN ALTERNATIVE RATE MECHANSIM, AND MOTION FOR PROTECTIVE ORDER (Docket No. 17-00032)

Dear Ms. Dillon:

Enclosed for filing in this docket please find an original and four copies of the direct testimony, exhibits and work papers of Stephen J. Baron submitted on behalf of East Tennessee Energy Consumers, an Intervenor in this matter.

Thank you for your kind attention to this request.

Sincerely yours,

Michael J. Quinan

Enclosures

cc: Ms. Kelly Grams
Mr. James R. Bacha
Mr. William C. Bovender
Mr. Joseph B. Harvey
Ms. Noelle J. Coates
Mr. William K . Castle
Mr. David Foster
Hon. Herbert H. Slatery, III
Mr. Wayne M. Irvin

CERTIFICATE OF SERVICE

I hereby certify that, on May 4, 2017, the foregoing direct testimony, exhibits and workpapers of Stephen J. Baron were served by hand-delivery, facsimile, overnight delivery service, or first class mail, postage prepaid, to all parties of record at their addresses shown below

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This 10th day of July, 2017.

Michael J. Quinan

BEFORE THE

TENNESSEE PUBLIC UTILITY COMMISSION

NASHVILLE, TENNESSEE

PETITION OF **KINGSPORT POWER COMPANY** **d/b/a AEP Appalachian Power** **For Approval of its Targeted Reliability Plan,** **And its TRP & MS Rider, An Alternative Rate Mechanism**	**Docket No. 17-00032**

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

EAST TENNESSEE ENERGY CONSUMERS

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

July 2017

BEFORE THE

TENNESSEE PUBLIC UTILITY COMMISSION

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PETITION OF **KINGSPORT POWER COMPANY** **d/b/a AEP Appalachian Power** **For Approval of its Targeted Reliability Plan,** **And its TRP & MS Rider, An Alternative Rate** **Mechanism.**	**Docket No. 17-00032**

DIRECT TESTIMONY OF STEPHEN J. BARON

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

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

A. I am testifying on behalf of East Tennessee Energy Consumers ("ETEC"), a group of large industrial customers taking service from Kingsport Power Company ("Kingsport" or the "Company").

Q. What is your occupation and by whom are you employed?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Roswell, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions and industrial consumer groups throughout the United States.

Q. Please state your educational background.

A. I graduated from the University of Florida in l972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which I received a grant from the Public Utility Research Center of the University of Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

Q. Please describe your professional experience.

A. I have more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity I was responsible for the operation and management of the Atlanta office.

My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to numerous industrial, commercial, public service commission and utility clients, including international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." My article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming. I have also presented testimony as an expert before the Federal Energy Regulatory Commission ("FERC") and in United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Baron Exhibit ____ (SJB-1).

Q. Have you previously testified in rate proceedings involving operating utilities of American Electric Power Company, Inc. ("AEP Operating Companies")?

A. Yes. I have testified in numerous AEP Operating Company rate proceedings in Virginia (Appalachian Power Company), West Virginia (Appalachian Power Company), Kentucky (Kentucky Power Company), Ohio (Ohio Power Company, Columbus and Southern Power Company), Indiana (Indiana Michigan Power Company), and Louisiana (Southwest Electric Power Company). I have also testified before FERC in the AEP and Central and Southwest merger case. These cases have included a range of issues, including issues associated with demand response tariffs.

Finally, I presented testimony before the Tennessee Regulatory Authority in Kingsport's 2012 case regarding PJM Demand Response rate issues (Docket No. 12-00012) and in Kingsport's 2016 general rate case (Docket No. 16-00001).

Q. What is the purpose of your testimony?

A. My testimony responds to the Direct Testimony of Kingsport witnesses William Castle, Philip Wright and Wayne Allen regarding the Company's proposal to implement a Targeted Reliability Plan ("TRP") and to recover costs through an Alternative Rate Mechanism ("ARM"). The proposed ARM would recover the costs of both the TRP and major storms ("MS") through a "TRP & MS Rider."

I will address two issues raised by the Company's filing. The first issue concerns whether the proposed rider should be approved. In my view, recovering these TRP and MS costs through a rider, rather than through base rates, is not a reasonable ratemaking approach. Unlike fuel costs, which have significant volatility and can materially impact a utility's financial results, the TRP and MS costs proposed for rider recovery can be reasonably recovered through base rates using a deferral mechanism. The Commission should reject the proposed rider.

The second issue concerns the allocation of the TRP & MS costs to customer rate classes if the rider is approved. I strongly disagree with Kingsport's proposed methodology for allocating rider costs to rate classes. Kingsport's proposed method uses the same allocation as the one that was agreed among the Parties for assigning the revenue increase to rate classes in the settlement of Kingsport's recent general rate case. As I will explain, the rider costs at issue in the instant case are directly related to providing *distribution* service on the Kingsport system. Larger customers that take service on Kingsport's Industrial Power *Transmission* ("IP-Transmission") rate schedule, however, do not utilize the Company's distribution facilities. Accordingly, such customers should not be charged for any rider costs associated with maintaining distribution facilities, such as overhead primary and secondary distribution lines.

II. KINGSPORT'S PROPOSED ALTERNATIVE RATE MECHANISM ("RIDER") SHOULD BE REJECTED

Q. Have you reviewed the Company's request to implement an ARM to recover a proposed vegetation management program, a distribution system improvement program and major storm costs?

A. Yes. As described in the testimony of Company witnesses William Castle, Philip Wright and A. Wayne Allen, Kingsport is seeking Commission approval for a new, four-year, cycle-based vegetation management program that would recover vegetation management program ("VMP") costs in excess of the amounts included in base rates. In addition, the Company requests authority to implement other distribution system improvement projects, such as improved inspections and maintenance of distribution system lines and other facilities, designed to reduce distribution system outages. (The Company calls its program to accomplish these other system improvements its System Improvement Program, or "SIP.") The Company's request covers a 10-year period during which Kingsport now expects to spend over $90 million on VMP and SIP projects that are designed to improve distribution system reliability.[1] The Company also requests recovery of incremental MS costs, although the Company has provided no estimate of such costs. All three sets of costs – VMP, SIP, and MS costs – would be recovered through an ARM, outside of a base rate case.

Q. What is the estimated revenue requirement impact on Kingsport's customers from the ARM proposal?

A. Based on Mr. Wright's projections (Wright Figure 7), the first-year revenue requirement impact on customers would be an increase of $3.3 million (not including any costs for major storms). Over the full 10-year period, customer charges are expected to increase by $52.5 million.[2] If the proposed ARM is approved by the Commission, the Company initially would defer its expenditures. After one year, the Company would begin charging customers via the ARM. Subsequently, the Company would adjust and true-up the ARM annually, as new expenditures are made.

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[1] See testimony of Mr. Wright at page 16, Figure 7 (new capital of $54.5 million, total O&M of $36.3 million).

[2] See Table 4 in the next section of my testimony. This 10-year revenue requirement amount of $52.5 million reflects the 10-year new capital expenditures and O&M expenses shown in Mr. Wright's Figure 7 and does not include any incremental major storm costs.

Q. Do you oppose the underlying vegetation management and distribution system improvement programs requested by the Company?

A. No. However, as I will discuss, I do oppose the Company's basic proposal to recover the costs of those programs through an ARM, rather than through a base rate case, and, if the Commission approves an ARM, I also oppose Kingsport's proposed allocation to customer rate classes of the TRP and major storm revenue requirements. I will discuss the rate class allocation issue in the next section of my testimony.

Q. What is your concern with the recovery of the TRP and MS costs through an ARM?

A. My primary objection to the Company's ARM proposal is that it represents what is sometimes called single issue ratemaking. Single issue ratemaking occurs when only one item of cost – in this case TRP and MS distribution costs – is considered in a utility revenue requirement analysis but the other components of the revenue requirement are ignored. Thus, the utility's net plant in service or other expense items, which may be declining over time, are ignored. The utility's revenues, which may be increasing over time, are also ignored. As a general matter, a utility's customers are potentially disadvantaged with single issue ratemaking approaches, such as Kingsport's proposal here, because the Commission does not examine potential offsetting changes in other expenses, revenues or net plant in service that might mitigate the impact of an increase in the single item of cost. From Kingsport's standpoint, under its ARM proposal, it will recover all of its increased costs associated with the TRP and MS expenditures, but it will not be subjecting the other components of its revenue requirement to regulatory review.[3] If other costs are decreasing, Kingsport will not be passing on to customers the offsetting, net effect of such decreases, yet Kingsport will impose any higher costs associated with the TRP and MS on its customers. Similarly, if Kingsport's revenues are increasing, it will not pass on to customers the offsetting, net effect of such increases. Yet Kingsport will impose any higher costs associated with the TRP and MS on its customers. Kingsport may be overearning on its total investment (including on its TRP and MS-related investment), yet it will simply retain such over-earnings while separately increasing its rates through the ARM to recover increased TRP and/or MS costs.

Q. In a full base rate proceeding, would the other parties and the Commission have an opportunity to evaluate all of Kingsport's costs and revenues to determine whether any potential reductions could offset increased TRP and MS costs?

[3] Fuel and purchased power costs, historically both significant and volatile, are, of course, subject to separate review and recovery through the Company's Fuel and Purchased Power Adjustment Rider.

A. Yes. This is the primary reason why a base rate case is the most reasonable ratemaking approach. In such a case, a complete review of all of Kingsport's costs, including its reasonable TRP and MS costs, would be considered, and, if there are legitimate offsets to the TRP and MS cost increases, the offsets would be reflected in the overall, Commission-approved revenue requirement. Only a full base rate case provides reasonable assurance that the Company will not be placed in an overearning position as a result of the TRP and MS cost recovery. While TRP and MS costs will increase as a result of the Company's proposed programs, the Commission cannot assess, under the Company's single-issue ARM proposal, whether *other* costs included in the Company's recent base rate case (and currently being recovered from customers in base rates) will decrease, or other revenues (currently being collected from customers in base rates) will increase, to prevent Kingsport's rates from producing excess earnings. Only in a full base rate case can an analysis be undertaken to determine the overall reasonable level of Kingsport's costs to be recovered from its customers in its rates.

Q. Has the Company confirmed this result in any data responses?

A. Yes. In response to the Consumer Protection and Advocate Division of the Attorney General's Office ("CPAD") First Set-Informal data request CPAD-1-24, the Company confirmed that there would be no offset to the ARM costs through the TRP & MS Rider in the event that Kingsport is overearning. In its response, Kingsport stated "The TRP&MS Rider is intended to recover costs related only to distribution reliability and major storms as described in this Petition and provided for in Tennessee Code Annotated Section 65-5-103 (d) (2) (A)." This means that there would be no offsets in the event of overearning by the Company. A copy of the data response is attached as Baron Exhibit__(SJB-2).

Q. You indicated that you do not oppose the underlying TRP and MS expenditures that the Company seeks to recover in an ARM. How would the Company be assured of having an opportunity to actually recover these expenditures in a future base rate case if there is no ARM?

A. Assuming that the Commission approves the TRP and MS programs, I would recommend permitting the Company to continue to defer Commission-approved TRP and MS costs that exceed the levels included in base rates until the Company's next base rate case. In that case, the Company would have the opportunity to recover in its rates its reasonable deferred costs on a prospective basis. Since the Company already proposes to defer the TRP and MS costs for a one-year period, my recommendation would simply extend the deferral period until the next base rate case.

Q. Has the Company presented any analysis demonstrating a financial need for an ARM to recover its proposed TRP and MS costs?

A. No. Since a deferral approach would provide the Company a full opportunity to recover all of its TRP and MS expenditures, there is no compelling reason to approve an ARM in this case. A rider mechanism, which would provide cash on a current basis to Kingsport, should only be required if there is a demonstrated financial need. Absent such a demonstration, a deferral approach would provide the Company the opportunity to recover all of its reasonable costs for these programs.

III. IF THE ARM RIDER IS APPROVED, COSTS SHOULD BE ALLOCATED BASED ON COST OF SERVICE

Q. How does the Company propose to allocate the TRP and MS costs that will be recovered in the ARM?

A. Kingsport proposes to allocate the total amount of TRP and MS costs each year to each rate class on the same basis as the revenue increase was allocated to rate classes in the settlement of the Company's 2016 base rate case (Docket No. 16-00001). For example, in the 2016 base rate case, the overall revenue increase agreed to in the settlement was $8.62 million. Of this total increase, $1.37 million, or 15.9% was allocated to the IP-Transmission rate class. Kingsport now proposes to allocate 15.9% of the annual ARM Rider costs to the IP-Transmission rate class, using the same allocation percentages from the base rate case.

Q. Is it reasonable to allocate the Rider costs to rate classes on the same basis used to assign the revenue increase to rate classes and agreed to by Parties in the settlement of Kingsport's recent base rate case?

A. No. Such an allocation would be unfair and unreasonable, and the Commission should reject it. Kingsport witness Wright makes clear that the proposed TRP is associated only with the Company's distribution facilities. He states on page 9 of his testimony: "The Company's proposed TRP would implement two key changes to its current *distribution* operations in order to improve reliability, as measured by SAIDI and SAIFI, and provide benefits to its customers." (Wright testimony at page 3; emphasis added). He defines the distribution system as "1,570 circuit miles of lines operating at nominal voltages of 34.5 kV or less." (Id.)

Q. Do customers taking service at transmission voltages utilize distribution facilities operating at nominal voltages of 34.5 kV or less?

A. No. Customers taking service at transmission voltage – IP Transmission customers -- utilize the AEP transmission system, not the Kingsport distribution system. It would be unreasonable and unfair to allocate vegetation management, distribution system improvement and major storm costs incurred to maintain or improve the reliability of primary and secondary facilities to the IP-Transmission rate class when that class of customers does not even utilize those facilities.

Q. Does AEP or Appalachian Power Company incur vegetation management costs associated with transmission voltage circuits?

A. Yes. However, these expenses are included in separate transmission charges imposed by Appalachian Power Company through the AEP FERC transmission tariff and paid for separately in Kingsport's rates through its Fuel and Purchased Power Adjustment Rider. Kingsport's IP-Transmission customers fully pay for their share of these costs.

Q. What about major storm expenses that the Company proposes to recover through the Rider? Are they incurred to maintain the Company's distribution facilities, such as its overhead lines?

A. Yes. Company witness Allen states on page 7 of his testimony as follows: "For major storm costs that are charged to O&M expense, the Company will record such costs on its books to the appropriate FERC account based on the work involved, with almost all such major storm O&M expense expected to be recorded in Account 593, Maintenance of Overhead Lines, based on past experience."

Q. Is FERC Account 593 a distribution account?

A. Yes. None of the expenses booked to that account would be assigned to Rate IP-Transmission on a cost of service basis.

Q. Does the Settlement of the Company's recent base rate case (Docket No. 16-00001) reflect an agreement among the parties that Kingsport could recover future, incremental vegetation management, distribution system improvement and major storm costs, such as those that Kingsport seeks to collect through its proposed Rider, from the same rate classes and on the same basis as the revenue increase in that case was allocated to rate classes?

A. No. The settlement reflects no such agreement. Nor would any such agreement have been justified, given the substantial subsidies that were continuing to be paid in the Settlement rates. IP-Transmission customers continue to pay substantial subsidies in those rates.

Moreover, the Settlement specifically states that the agreed-upon allocation to rate classes of the overall approved revenue increase is *not* a precedent for future cost recovery. More specifically, Paragraph 15 of the Stipulation and Settlement Agreement states: "The Parties agree that the agreed-upon deficiency shall be allocated to the customer classes as set forth on Schedule 12 and 13 of Attachment A and the Parties agree that the results of such allocations are fair and reasonable *for the limited purpose of resolving this Docket*." (Emphasis added.) More broadly, Paragraph 19 contains a provision stating, in part, "that the settlement of an issue provided for herein shall *not* be cited a precedent by any of the Parties or any other entity in any unrelated or separate proceeding or docket before the Authority."

(Emphasis added.) Similarly, Paragraphs 20 and 21 state clearly that the settlement is not precedential.

Q. If the Rider is approved, how should its costs be allocated to rate classes?

A. The incremental vegetation management costs, distribution system improvement costs and major storm costs should be assigned to rate classes consistent with how and why these costs are incurred. As fully explained by Company witness Wright, these costs are associated with maintaining the Kingsport's primary and secondary distribution lines and other distribution facilities. These costs are not incurred to serve customers taking service on Kingsport's IP-Transmission rate. IP-Transmission customers do not utilize the distribution system. They are directly connected into the transmission system. To the extent that vegetation management and storm damage costs are associated with maintaining or repairing the transmission system, such costs are reflected in the transmission charges that Kingsport pays to Appalachian Power, and Kingsport already passes those costs through its Fuel and Purchased Power Adjustment Rider to all of its customers, including its IP-Transmission customers.

Q. Can you cite additional the evidence that supports your statement that the IP-Transmission rate class does not use Kingsport's distribution facilities?

A. Yes. The Company's class cost of service study presented in Docket No. 16-00001 clearly shows that no distribution costs are assigned to the IP-Transmission rate class. Baron Exhibit__(SJB-3), which is attached to this testimony, is an excerpt from that study. The excerpt shows the distribution revenue requirements for each rate class. (The calculation of the revenue requirement for each class is, of course, based on an equal rate of return for each class.) These distribution revenue requirements represent the cost of Kingsport's distribution facilities (lines, poles, transformers) assigned to each rate class.

The top portion of the exhibit shows the allocation factors for each rate class associated with distribution lines. As can be seen, no costs associated with distribution accounts 365 (overhead lines, plant-in-service), 583 (overhead line operations expense), 593 (overhead line maintenance expense), and 594 (underground line maintenance expense) are assigned to the IP-Transmission class. This means that customers in the IP-Transmission class are not responsible for the Company's distribution costs, which include the maintenance and repair of distribution facilities, such as overhead distribution lines. The TRP and MS Rider costs are all associated with these distribution facilities.

Q. Have you compared the Company's proposed Rider allocation factors for each rate class to alternative distribution allocation factors using those in the class

cost of service study filed by the Company in the recent base rate case, Docket 16-00001?

A. Yes. Table 1 below compares the Company's proposed Rider allocation factors for each rate class to three alternative distribution allocation factors using the data shown in Exhibit__(SJB-3).

Table 1
Comparison of Alternative Rider Cost Allocation Factors

	Kingsport Proposed	Distribution OH Lines (Acct 365)	Total OH Lines (Accts 583&593)	Distribution Rev Req as filed
Residential (RS/EMP/TOD)	28.27%	69.96%	70.78%	68.59%
SGS (Fixed/Measured/NM)	3.12%	1.35%	1.36%	1.52%
MGS Secondary	14.27%	7.63%	7.49%	8.07%
GS-TOD	0.02%	0.03%	0.03%	0.03%
MGS Primary	0.17%	0.03%	0.02%	0.02%
LGS Secondary	24.27%	12.15%	11.81%	13.09%
LGS Primary	1.48%	0.77%	0.66%	0.80%
IP Primary	1.88%	2.47%	2.13%	2.05%
IP Sub/Transmission	15.89%	0.00%	0.00%	0.00%
Church Service	1.24%	0.87%	0.90%	0.97%
Public Schools	2.78%	2.33%	2.34%	2.20%
Electric Heating General	3.24%	2.06%	2.07%	2.22%
Outdoor Lighting	0.97%	0.12%	0.15%	0.16%
Street Lighting	2.40%	0.22%	0.25%	0.28%
Total	100.00%	100.00%	100.00%	100.00%

As can be seen, the Company's proposed Rider allocation would assign 15.89% of the costs to the IP-Transmission rate class, even though that class does not use Kingsport's distribution system. However, because the IP-Transmission rate class does not use Kingsport's distribution system, the class cost of service study allocates no such distribution costs to that class.

Q. Which of the distribution allocation factors shown in your Table 1 would be appropriate to allocate Rider costs to rate classes?

A. While any of the three sets of allocation factors could reasonably be used to allocate Rider costs, I have used the Total Distribution Revenue Requirement ("Distribution Rev Req") factors as a reasonable measure of TRP and MS Rider cost responsibility in this case. Each of the three sets of distribution allocation factors produces relatively similar Rider cost allocations to each rate class. However, I believe that the Total Distribution Revenue Requirement allocators are the "most" reasonable to use in this case because they reflect an overall blended cost responsibility for distribution facilities. While overhead line maintenance is the likely expense category for these TRP and MS costs, use of overall distribution revenue requirement allocators captures the full complement of distribution costs that could be impacted by the ARM. So, use of such allocators are, in my view, the "most" reasonable to use here. I note that the Total Distribution Revenue Requirement allocators assign slightly lower costs to the residential class.

Q. Has the Company confirmed that its Rider costs at issue in this case are distribution-related costs?

A. Yes. In response to data requests ETEC-4 and ETEC-5, the Company provided a breakdown, by type of distribution circuit, of the estimated Rider costs for the TRP (Vegetation Management and System Improvement) presented in Mr. Wright's Figure 7. The Company's response to ETEC-7 shows a breakdown of historic major storm expense by circuit voltage. Baron Exhibit__(SJB-4) contains copies of these responses, including the attachments.

Q. What do these Kingsport data responses show?

A. These responses confirm that all of the costs that will be recovered through the Rider will be distribution costs to maintain and/or repair primary and secondary distribution facilities. Such costs include both new capital costs and O&M expenses. None of the costs are associated with providing service to customers taking service on the IP-Transmission rate. Such customers do not use Kingsport's distribution system.

Q. Has the Company confirmed that none of the Rider costs (TRP and MS) would be assigned to the IP-Transmission class in the Company's class cost of service study?

A. Yes. In response to data request ETEC-10, Kingsport confirmed that none of these capital costs and O&M expenses, which are all distribution costs, would be allocated to the IP-Transmission rate class based on cost of service principles. The

Company's response to ETEC-11 confirms that no Rider costs would be allocated to transmission voltage customers on the IP-Transmission rate based on Kingsport's cost of service methodology that it filed and supported in the recent base rate case (Docket No. 16-00001). Baron Exhibit__(SJB-5) contains copies of the Company's responses to ETEC-10 and ETEC-11. There would be no reasonable basis to assign these costs to a rate class that does not utilize the Kingsport distribution system.

Q. Are you familiar with the allocation of costs to customer rate classes used in calculating the Vegetation Management Surcharge ("VMS") charged by Appalachian Power Company ("APCo"), Kingsport's AEP-affiliated power supplier, in West Virginia?

A. Yes. I participated in the APCo West Virginia proceeding in which the VMS was approved. Both APCo and the Public Service Commission of West Virginia ("West Virginia Commission") agreed with my recommendation to allocate the VMS costs associated with APCo's distribution system on the same basis as FERC Account 593 (Overhead Line Maintenance) was allocated to rate classes in the Company's class cost of service study. Attached as Exhibit__(SJB-6) is an excerpt from the West Virginia Commission's Order in Case No. 14-1152-E-42T, APCo's 2014 base rate case. On page 90 of that order (exhibit page 3), APCo is directed to allocate costs consistent with the allocation of Account 593 expenses. Baron Exhibit__(SJB-7) contains a copy of the Rebuttal Testimony of APCo witness

Charles Gary. Mr. Gary's Rebuttal exhibit CWG-R1, which is referred to in the WVPSC Order (page 4 of my exhibit), confirms that no distribution-related vegetation management costs are allocated to transmission voltage rate classes.

Q. In West Virginia, are any vegetation management costs associated with distribution feeders (primary and secondary lines) allocated to transmission voltage customers?

A. No. The only vegetation management costs that are assigned to transmission voltage customers are costs associated with maintaining transmission lines. Vegetation management costs associated with distribution are not assigned to transmission voltage customers.

Q. How are vegetation management costs recovered from customers in APCo's Virginia jurisdiction?

A. Currently, these costs are recovered in base rates, not through a rider. However, in a pending proceeding before the Virginia State Corporation Commission ("VSCC"), APCo is seeking approval of a rider mechanism (rate adjustment clause) to recover vegetation management costs (Case No. PUE 2016-00090).

Q. How does APCo propose to allocate such rider costs to rate classes in Virginia?

A. First, under the Virginia statute that authorizes a utility to seek recovery of vegetation management costs through a rider, no vegetation management costs can be charged to large general service customers taking service at subtransmission or transmission voltages on APCo's system in Virginia. This statute, Va. Code § 56-585.1 A 5 f, permits costs to be recovered through such a rider as follows:

> f. Projected and actual costs, not currently in rates, for the utility to design, implement, and operate programs approved by the Commission that accelerate the vegetation management of distribution rights-of-way. No costs shall be allocated to or recovered from customers that are served within the large general service rate classes for a Phase II Utility or that are served at subtransmission or transmission voltage, or take delivery at a substation served from subtransmission or transmission voltage, for a Phase I Utility.[4]

APCo's witness in PUE-2016-00090, William Castle, confirmed that no rider costs were being allocated to or recovered from subtransmission or transmission voltage customers. At page 7 of his testimony, Mr. Castle testified as follows:

> Q. PLEASE EXPLAIN WHICH CUSTOMERS ARE EXEMPT FROM THE COSTS OF THE ACCELERATED VEGETATION MANAGEMENT PROGRAM.
>
> A. Consistent with Subsection A 5 f, which requires that, "no costs be allocated to or recovered from customers that are served at subtransmission or transmission voltage or who take delivery at a substation served from subtransmission or transmission voltage," [sic] the billing determinants used to determine the allocation of costs amongst the classes were adjusted to remove all customers at the subtransmission and transmission voltage levels as well as customers who take primary distribution service from, and are metered at, a Company-owned substation served from subtransmission or transmission voltage. (Bracketed portion added).

[4] The reference in the statute to a "Class 1 Utility" is a reference to APCo.

Thus, the result in Virginia is the same as that required by the West Virginia Commission – there is <u>no allocation of distribution system vegetation management costs to transmission voltage rate classes</u>.

Q. How does APCo propose to allocate the rider costs to all other rate classes (other than transmission voltage rate classes) in Virginia?

A. As explained by APCo witness Michael Spaeth in PUE-2016-00090, APCo proposes to allocate vegetation management costs to be recovered through the rider by using the same allocation factor that was used to allocate distribution overhead lines in APCo's 2014 Biennial Review class cost of service study.[5] Mr. Spaeth testified as follows on page 3 of his testimony:

> Q. AFTER CALCULATING THE REVENUE REQUIREMENT, HOW DID YOU DEVELOP RATES FOR TARIFF CLASSES?
>
> A. The Initial VM-RAC Revenue Requirement of $13,801,710 was allocated to each customer class, excluding subtransmission and transmission customers based upon each rate class's distribution overhead line class allocation factor. The distribution overhead line class allocation factor accounts for the weighting of equipment between secondary and primary customers and is based upon Accounts 364 and 365. The distribution overhead line class allocation factors used in this filing are the same 2013 test year data that the Company filed in its 2014 Biennial Review and, consistent with the Company's other RACs and base rates, were developed using a six coincident peak methodology. The

[5] In Virginia, non-fuel, non-rider rates are reviewed by the VSCC in "Biennial Reviews," *i.e.*, in base rate cases.

class allocation factors are shown in Statement 2 of Rate Case Schedule 46N.

Q. PLEASE DESCRIBE WHY THE VM-RAC COST RESPONSIBILITY IS BORNE BY CUSTOMERS AT THE PRIMARY AND SECONDARY VOLTAGE LEVELS.

A. According to § 56-585.l.A.f of the Code of Virginia,

> Projected and actual costs, not currently in rates, for the utility to design, implement, and operate programs approved by the Commission that accelerate the vegetation management of distribution rights-of-way. No costs shall be allocated to or recovered from customers that are served within the large general service rate classes for a Phase II Utility or that are served at subtransmission or transmission voltage, or take delivery at a substation served from subtransmission or transmission voltage, for a Phase I Utility. (Emphasis added).

In order to comply with the Code of Virginia, I adjusted the billing determinants to remove all customers at the subtransmission and transmission voltage levels as well as certain primary voltage customers that take delivery at a substation served from subtransmission or transmission voltage.

Based on Mr. Spaeth's testimony, rider costs were allocated to all other rate classes (other than those with customers taking service at subtransmission or transmission voltages), based on cost of service (the same allocator used by the Company in its class cost of service study to allocate overhead line costs).

Q. Have you developed an alternative set of Year 1 Rider rates for each rate class using your recommended cost of service allocation approach?

A. Yes. Using the distribution revenue requirement allocator (Distribution Rev Req) from my Table 1, I have developed a set of recommended Rider costs for each rate class. These are shown in Table 2, along with Kingsport's proposed Rider rate class cost allocation for comparison purposes.

Table 2
Comparison of Rider Revenue Allocation by Rate Class
Year 1

	Kingsport Power as Filed	Distribution Rev Req Allocation
Residential (RS/EMP/TOD)	941,395	2,283,649
SGS (Fixed/Measured/NM)	104,025	50,487
MGS Secondary	475,135	268,624
GS-TOD	521	1,121
MGS Primary	5,796	729
LGS Secondary	808,016	435,966
LGS Primary	49,353	26,639
IP Primary	62,504	68,352
IP Sub/Transmission	529,069	-
Church Service	41,290	32,374
Public Schools	92,447	73,144
Electric Heating General	107,812	73,812
Outdoor Lighting	32,190	5,404
Street Lighting	79,967	9,217
Total	3,329,520	3,329,520

Table 3 below shows the specific rates for each rate class reflecting the Rider cost allocation shown in my Table 2. These rates produce the same total TRP and MS revenues for Kingsport as the Company's proposed rates.

Table 3 **TRP-MS Rider Rates Based on Distribution Revenue Requirement Allocator** Tariff	Energy Rate (¢) / kWh	Demand Rate ($) / KW or *KVA	Customer Rate ($)/ Month /Customer
Residential			$4.61
Residential Employee			$4.61
Residential Time-of-Day			$4.61
Small General Service (SGS)			$1.16
Medium General Service (MGS) Secondary		$0.63	
General Service Time-of-Day (GS-TOD)	0.23460		
Medium General Service (MGS) Primary		$0.14	
Large General Service (LGS) Secondary*		$0.65	
Large General Service (LGS) Primary*		$0.51	
LGS Subtransmission/Transmission*		$0.50	
Industrial Power (IP) Secondary		$0.48	
Industrial Power (IP) Primary		$0.47	
Industrial Power (IP) Subtransmission/Transmission		$0.00	
Church Service	0.32864		
Public Schools (PS)	0.26682		
Electric Heating General (EHG)		$0.76	
Outdoor Lighting (OL)- (per Lamp)			$0.08

Q. Kingsport proposes in this case to implement a 10-year TRP and MS plan, and it has presented annual expense and capital cost estimates for each year in Mr. Wright's Figure 7. Have you prepared an analysis that shows the impact of your recommended Rider cost allocation methodology for each rate class over the entire 10-year period?

A. Yes. Using the Company's calculation of annual TRP and MS revenue requirements, based on Mr. Wright's Figure 7 expenditures, I have developed a comparison of the Company's Rider cost allocation proposal to my recommended, cost-based allocation. This analysis, which is summarized in Table 4 below, assumes the same rate class allocation factors for each of the 10 years.

Table 4
Comparison of Rider Revenue Allocation by Rate Class
Cumulative Years 1 to 10

	Kingsport Power as Filed	Distribution Rev Req Allocation
Residential (RS/EMP/TOD)	14,840,417	36,000,087
SGS (Fixed/Measured/NM)	1,639,883	795,898
MGS Secondary	7,490,156	4,234,671
GS-TOD	8,216	17,670
MGS Primary	91,363	11,485
LGS Secondary	12,737,795	6,872,693
LGS Primary	778,015	419,952
IP Primary	985,337	1,077,523
IP Sub/Transmission	8,340,385	-
Church Service	650,903	510,354
Public Schools	1,457,358	1,153,068
Electric Heating General	1,699,584	1,163,591
Outdoor Lighting	507,447	85,193
Street Lighting	1,260,627	145,301
Total	52,487,486	52,487,486

Q. What conclusions can be drawn from the comparison in Table 4?

A. Table 4 clearly demonstrates that IP-Transmission customers would be charged over $8 million in unjustified costs over the full 10-year plan period if the Company's allocation proposal is adopted. As I have indicated, these transmission voltage customers do not utilize the Kingsport distribution system, so it would be unreasonable and unfair to assign them $8 million in charges for vegetation management and major storm maintenance costs that are incurred by Kingsport to serve *other* customers. As I noted earlier, all of the non-residential rate classes, except Rate PS (Pubic Schools), were paying substantial subsidies to the residential rate class, based on Kingsport's class cost of service study in Docket No. 16-00001. Ignoring cost of service in the allocation of the Rider costs at issue in this case would further exacerbate this situation. In particular, if the Company's proposed allocation is adopted and millions of dollars of additional costs are allocated to the IP-Transmission class, which is not responsible for these costs, the Company's rates will move further and further from cost of service. Kingsport's response to ETEC-13, which is attached as Baron Exhibit__(SJB-8), confirms this result.

Q. Let's assume that the Commission – perhaps from a concern about the impact of your proposal on the residential rate class -- decides, contrary to your recommendation, to use the allocation of the revenue increase that was used in the base case settlement as the basis for allocating the revenue requirement in this case. Is there an alternative allocation of the Rider revenue requirement among rate classes that, consistent with such an approach by the Commission, would prevent IP Transmission customers from paying distribution-related Rider costs but also reduce the impact on the residential class of using a cost-based approach for allocating Rider costs?

A. Yes. I continue to believe that any approved Rider costs should be allocated on the basis of cost of service, as is done by APCo in both the Virginia and West Virginia jurisdictions; however, if the Commission were to use the allocation of the base rate revenue increase reflected in the base case settlement as the basis for allocating Rider costs, and if, consistent with that approach, it wished to prevent IP-Transmission customers from paying distribution-related Rider costs, for which they are not responsible, but also reduce the impact of a fully cost-based approach on the residential rate class, the table below would reflect such an alternative approach.

Under that alternative, Rider costs could be allocated to all rate classes, except the IP-Transmission class, using Kingsport's proposal. This Rider allocation would use the Company's proposed class revenue increases from the last base rate case for all distribution rate classes, but it would not allocate any Rider costs to the IP-Transmission rate class. Table 5 shows such an allocation, compared to Kingsport's proposal.

Table 5
Comparison of Rider Revenue Allocation by Rate Class
Year 1

	Kingsport Power as Filed	Alternative Rev Req Allocation	Difference
Residential (RS/EMP/TOD)	941,395	1,119,246	177,851
SGS (Fixed/Measured/NM)	104,025	123,678	19,653
MGS Secondary	475,135	564,898	89,764
GS-TOD	521	620	98
MGS Primary	5,796	6,890	1,095
LGS Secondary	808,016	960,669	152,653
LGS Primary	49,353	58,677	9,324
IP Primary	62,504	74,313	11,808
IP Sub/Transmission	529,069	-	(529,069)
Church Service	41,290	49,090	7,801
Public Schools	92,447	109,912	17,465
Electric Heating General	107,812	128,181	20,368
Outdoor Lighting	32,190	38,271	6,081
Street Lighting	79,967	95,075	15,108
Total	3,329,520	3,329,520	0

The monthly residential ARM Rider charge using this alternative allocation method is \$2.26 per month, which compares to Kingsport's estimated monthly residential charge of \$1.90. Table 6 presents the Year 1 Rider rates for each rate class based on such an alternative allocation.

Table 6
TRP-MS Rider Rates Based on Alternate Revenue Requirement Allocator

Tariff	Energy Rate (¢) / kWh	Demand Rate ($) / KW or *KVA	Customer Rate ($)/ Month /Customer
Residential			$2.26
Residential Employee			$2.26
Residential Time-of-Day			$2.26
Small General Service (SGS)			$2.84
Medium General Service (MGS) Secondary		$1.33	
General Service Time-of-Day (GS-TOD)	0.12969		
Medium General Service (MGS) Primary		$1.28	
Large General Service (LGS) Secondary*		$1.44	
Large General Service (LGS) Primary*		$1.11	
LGS Subtransmission/Transmission*		$1.09	
Industrial Power (IP) Secondary		$0.52	
Industrial Power (IP) Primary		$0.51	
Industrial Power (IP) Subtransmission/Transmission		$0.00	
Church Service	0.49833		
Public Schools (PS)	0.40094		
Electric Heating General (EHG)		$1.32	
Outdoor Lighting (OL)- (per Lamp)			$0.58

Q. Does that complete your testimony?

A. Yes.

BEFORE THE

TENNESSEE PUBLIC UTILITY COMMISSION

NASHVILLE, TENNESSEE

PETITION OF **KINGSPORT POWER COMPANY** **d/b/a AEP Appalachian Power** **For Approval of its Targeted Reliability Plan,** **And its TRP & MS Rider, An Alternative Rate** **Mechanism.**	**Docket No. 17-00032**

EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

EAST TENNESSEE ENERGY CONSUMERS

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

July 2017

BEFORE THE

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EXHIBIT__(SJB-1)

OF

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July 2017

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of
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As of June 2017

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa Clara	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.
6/85	84-768-E-42T	WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.

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6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.

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Date	Case	Jurisdict.	Party	Utility	Subject
			Staff		
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.
10/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Excess capacity, power and cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.

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Date	Case	Jurisdict.	Party	Utility	Subject
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171-EL-AIR 88-170-EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171-EL-AIR 88-170-EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load fore-casting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.
8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air

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Date	Case	Jurisdict.	Party	Utility	Subject
					Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410-EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design

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Date	Case	Jurisdict.	Party	Utility	Subject
					(flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035-E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public	Cajun Electric	Evaluation of appropriate avoided

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Date	Case	Jurisdict.	Party	Utility	Subject
			Service Commission	Power Cooperative	cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital

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					structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bank-ruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues
7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98 (Allocated Stranded Cost Issues)	U-22092	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.
3/98	U-22092		Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.

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9/98	U-17735		Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.
12/98	8794	MD	Maryland Industrial Group and Millennium Inorganic Chemicals Inc.	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross-Answering Testimony)	EC-98-40-000	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.
5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658-EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.

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08/00	98-0452 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
10/00	SOAH 473- 00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66- 000 & ER00-2854 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic .	Independent Transmission Company ("Transco"). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.

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08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and the Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000 ER03-583-001 ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001 ER03-682-002	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345-03-0437	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation rate design.
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.

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04/04	2003-00433 2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service Rate Design
0-6/04	03S-539E	CO	Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co.	Aquila, Inc.	Cost of Service, Rate Design Interruptible Rates
06/04	R-00049255	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
10/04	04S-164E	CO	CF&I Steel Company, Climax Mines	Public Service Company of Colorado	Cost of service, rate design, Interruptible Rates.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
07/05	U-28155	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Independent Coordinator of Transmission – Cost/Benefit
09/05	Case Nos. 05-0402-E-CN 05-0750-E-PC	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Environmental cost recovery, Securitization, Financing Order
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses. Congestion Cost Recovery Mechanism
03/06	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Transmission Prudence Investigation
06/06	R-00061346 C0001-0005	PA	Duquesne Industrial Intervenors & IECPA	Duquesne Light Co.	Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues
06/06	R-00061366 R-00061367 P-00062213 P-00062214		Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues
07/06	U-22092 Sub-J	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.

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07/06	Case No. 2006-00130 Case No. 2006-00129	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
08/06	Case No. PUE-2006-00065	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Incr, Off-System Sales margin rate treatment
09/06	E-01345A-05-0816	AZ	Kroger Company	Arizona Public Service Co.	Revenue alllocation, cost of service, rate design.
11/06	Doc. No. 97-01-15RE02	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power United Illuminating	Rate unbundling issues.
01/07	Case No. 06-0960-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Implementation of FERC Decision Jurisdictional & Rate Class Allocation
05/07	Case No. 07-63-EL-UNC	OH	Ohio Energy Group	Ohio Power, Columbus Southern Power	Environmental Surcharge Rate Design
05/07	R-00049255 Remand	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
06/07	R-00072155	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues.
07/07	Doc. No. 07F-037E	CO	Gateway Canyons LLC	Grand Valley Power Coop.	Distribution Line Cost Allocation
09/07	Doc. No. 05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
11/07	ER07-682-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Schedule MSS-3. Cost functionalization issues.
1/08	Doc. No. 20000-277-ER-07	WY	Cimarex Energy Company	Rocky Mountain Power (PacifiCorp)	Vintage Pricing, Marginal Cost Pricing Projected Test Year
1/08	Case No. 07-551	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Class Cost of Service, Rate Restructuring, Apportionment of Revenue Increase to Rate Schedules
2/08	ER07-956	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
2/08	Doc No. P-00072342	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Default Service Plan issues.
3/08	Doc No.	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design

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	E-01933A-05-0650				
05/08	08-0278 E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co. American Electric Power Co.	Expanded Net Energy Cost "ENEC" Analysis.
6/08	Case No. 08-124-EL-ATA	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Recovery of Deferred Fuel Cost
7/08	Docket No. 07-035-93	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Rate Design
08/08	Doc. No. 6680-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Doc. No. 6690-UR-119	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Case No. 08-936-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Competitive Solicitation
09/08	Case No. 08-935-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
09/08	Case No. 08-917-EL-SSO 08-918-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Provider of Last Resort Rate Plan
10/08	2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
11/08	08-1511 E-GI	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
11/08	M-2008-2036188, M-2008-2036197	PA	Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Transmission Service Charge
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
01/09	E-01345A-08-0172	AZ	Kroger Company	Arizona Public Service Co.	Cost of Service, Rate Design
02/09	2008-00409	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Cost of Service, Rate Design
5/09	PUE-2009 -00018	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Transmission Cost Recovery Rider
5/09	09-0177-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost "ENEC" Analysis
6/09	PUE-2009	VA	VA Committee For	Dominion Virginia	Fuel Cost Recovery

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Date	Case	Jurisdict.	Party	Utility	Subject
	-00016		Fair Utility Rates	Power Company	Rider
6/09	PUE-2009 -00038	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Fuel Cost Recovery Rider
7/09	080677-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
8/09	U-20925 (RRF 2004)	LA	Louisiana Public Service Commission Staff	Entergy Louisiana LLC	Interruptible Rate Refund Settlement
9/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Energy Cost Rate issues
9/09	Doc. No. 05-UR-104	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
9/09	Doc. No. 6680-UR-117	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
10/09	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Allocation of Rev Increase
10/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Cost of Service, Rate Design
11/09	PUE-2009 -00019	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Cost of Service, Rate Design
11/09	09-1485 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
12/09	Case No. 09-906-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
12/09	ER09-1224	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
12/09	Case No. PUE-2009-00030	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Increase, Rate Design
2/10	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Rate Design
3/10	Case No. 09-1352-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
3/10	E015/ GR-09-1151	MN	Large Power Intervenors	Minnesota Power Co.	Cost of Service, rate design
4/10	EL09-61	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating	System Agreement Issues Related to off-system sales

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				Companies	
4/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses.
4/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
7/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Cost of Service, Rate Design
09/10	2010-00167	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Cost of Service, Rate Design
09/10	10M-245E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Economic Impact of Clean Air Act
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Cost of Service, Rate Design, Transmission Rider
11/10	Doc. No. 4220-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Northern States Power Co. Wisconsin	Cost of Service, rate design
12/10	10A-554EG	CO	CF&I Steel Company Climax Molybdenum	Public Service Company	Demand Side Management Issues
12/10	10-2586-EL-SSO	OH	Ohio Energy Group	Duke Energy Ohio	Provider of Last Resort Rate Plan Electric Security Plan
3/11	20000-384-ER-10	WY	Wyoming Industrial Energy Consumers	Rocky Mountain Power Wyoming	Electric Cost of Service, Revenue Apportionment, Rate Design
5/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Cost of Service, Rate Design
6/11	Docket No. 10-035-124	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
6/11	PUE-2011-00045	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Fuel Cost Recovery Rider
07/11	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Entergy System Agreement - Successor Agreement, Revisions, RTO Day 2 Market Issues
07/11	Case Nos. 11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Electric Security Rate Plan, Provider of Last Resort Issues
08/11	PUE-2011-00034	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Rate Recovery of RPS Costs
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility	Louisville Gas & Electric Co. Kentucky Utilities Company	Environmental Cost Recovery
09/11	Case Nos.	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan,

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	11-346-EL-SSO 11-348-EL-SSO			Columbus Southern Power Co.	Stipulation Support Testimony
10/11	11-0452 E-P-T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Energy Efficiency/Demand Reduction Cost Recovery
11/11	11-1272 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis
11/11	E-01345A- 11-0224	AZ	Kroger Company	Arizona Public Service Co.	Decoupling
12/11	E-01345A- 11-0224	AZ	Kroger Company	Arizona Public Service Co.	Cost of Service, Rate Design
3/12	Case No. 2011-00401	KY	Kentucky Industrial Utility Consumers	Kentucky Power Company	Environmental Cost Recovery
4/12	2011-00036 Rehearing Case	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Cost of Service, Rate Design
5/12	2011-346 2011-348	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Interruptible Rate Issues
6/12	PUE-2012 -00051	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Fuel Cost Recovery Rider
6/12	12-00012 12-00026	TN	Eastman Chemical Co. Air Products and Chemicals, Inc.	Kingsport Power Company	Demand Response Programs
6/12	Docket No. 11-035-200	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
6/12	12-0275- E-GI-EE	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Rider
6/12	12-0399- E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
7/12	120015-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
7/12	2011-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Environmental Cost Recovery
8/12	Case No. 2012-00226	KY	Kentucky Industrial Utility Consumers	Kentucky Power Company	Real Time Pricing Tariff
9/12	ER12-1384	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement, Cancelled Plant Cost Treatment
9/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
11/12	12-1238 E-GI	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost Recovery Issues

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12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana	Purchased Power Contracts
12/12	EL09-61	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to off-system sales Damages Phase
12/12	E-01933A-12-0291	AZ	Kroger Company	Tucson Electric Power Co.	Decoupling
1/13	12-1188 E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Securitization of ENEC Costs
1/13	E-01933A-12-0291	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
4/13	12-1571 E-PC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Generation Resource Transition Plan Issues
4/13	PUE-2012 -00141	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Generation Asset Transfer Issues
6/13	12-1655 E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Generation Asset Transfer Issues
06/13	U-32675	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	MISO Joint Implementation Plan Issues
7/13	130040-EI	FL	WCF Health Utility Alliance	Tampa Electric Company	Cost of Service, Rate Design
7/13	13-0467-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost (“ENEC”)
7/13	13-0462-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Issues
8/13	13-0557-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Right-of-Way, Vegetation Control Cost Recovery Surcharge Issues
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Ratemaking Policy Associated with Rural Economic Reserve Funds
10/13	13-0764-E-CN	WV	West Virginia Energy Users Group	Appalachian Power Company	Rate Recovery Issues – Clinch River Gas Conversion Project
11/13	R-2013-2372129	PA	United States Steel Corporation	Duquesne Light Company	Cost of Service, Rate Design
11/13	13A-0686EG	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Demand Side Management Issues
11/13	13-1064-	WV	West Virginia Energy	Mon Power Co.	Right-of-Way, Vegetation Control Cost

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2017

Date	Case	Jurisdict.	Party	Utility	Subject
	E-P		Users Group	Potomac Edison Co.	Recovery Surcharge Issues
4/14	ER-432-002	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Union Pacific Railroad Litigation Settlement
5/14	2013-2385 2013-2386	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Interruptible Rate Issues
5/14	14-0344- E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
5/14	14-0345- E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Issues
5/14	Docket No. 13-035-184	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
7/14	PUE-2014 -00007	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Renewable Portfolio Standard Rider Issues
7/14	ER13-2483	FERC	Bear Island Paper WB LLC	Old Dominion Electric Cooperative	Cost of Service, Rate Design Issues
8/14	14-0546- E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Rate Recovery Issues – Mitchell Asset Transfer
8/14	PUE-2014 -00026	VA	Old Dominion Committee	Appalachian Power Company	Biennial Review Case - Cost of Service Issues
9/14	14-841-EL- SSO	OH	Ohio Energy Group	Duke Energy Ohio	Electric Security Rate Plan Standard Service Offer
10/14	14-0702- E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Cost of Service, Rate Design
11/14	14-1550- E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost ("ENEC")
12/14	EL14-026	SD	Black Hills Power Industrial Intervenors	Black Hills Power, Inc.	Cost of Service Issues
12/14	14-1152- E-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Cost of Service, Rate Design transmission, lost revenues
2/15	14-1297 EI-SS0	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Electric Security Rate Plan Standard Service Offer
3/15	2014-00396	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses.
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
5/15	EL10-65	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating	System Agreement Issues Related to Interruptible load

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2017

Date	Case	Jurisdict.	Party	Utility	Subject
				Companies	
5/15	15-0301-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
615	14-1580-EL-RDR	OH	Ohio Energy Group	Duke Energy Ohio	Energy Efficiency Rider Issues
7/15	EL10-65	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Off-System Sales and Bandwidth Tariff
8/15	PUE-2015 -00034	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Renewable Portfolio Standard Rider Issues
8/15	87-0669-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Cost of Service, Rate Design
11/15	D2015-6.51	MT	Montana Large Customer Group	Montana Dakota Utilities Co.	Class Cost of Service, Rate Design
11/15	15-1351-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost ("ENEC")
3/16	EL01-88 Remand	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Bandwidth Tariff
5/16	16-0239-E-ENEC	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
6/16	E-01933A-15-0322	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
6/16	16-00001	TN	East Tennessee Energy Consumers	Kingsport Power Co.	Cost of Service, Rate Design
6/16	14-1297 El-SS0-Rehearing	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Electric Security Rate Plan Standard Service Offer
7/16	160021-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
7/16	16AL-0048E	CO	CF&I.Steel LP Climax Molybdenum	Public Service Company of Colorado	Cost of Service, Rate Design
7/16	16-0403-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Energy Efficiency/Demand Response
10/16	16-1121-E-ENEC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost ("ENEC")
11/16	16-0395-EL-SSO	OH	Ohio Energy Group	Dayton Power & Light	Electric Security Rate Plan

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2017

Date	Case	Jurisdict.	Party	Utility	Subject
11/16	EL09-61-004 Remand	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to off-system sales Damages Phase
12/16	1139	D.C.	Healthcare Council of the National Capital Area	Potomac Electric Power Co.	Cost of Service, Rate Design
1/17	E-01345A-16-0036	AZ	Kroger	Arizona Public Service Co.	Cost of Service, Rate Design
2/17	16-1026-E-PC	WV	West Virginia Energy Users Group	Appalachian Power Co.	Wind Project Purchase Power Agreement
3/17	2016-00370 2016-00371	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
5/17	16-1852	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Interruptible Rate Issues

BEFORE THE

TENNESSEE PUBLIC UTILITY COMMISSION

NASHVILLE, TENNESSEE

PETITION OF
KINGSPORT POWER COMPANY **Docket No. 17-00032**
d/b/a AEP Appalachian Power
For Approval of its Targeted Reliability Plan,
And its TRP & MS Rider, An Alternative Rate
Mechanism

EXHIBIT__(SJB-2)

OF

STEPHEN J. BARON

ON BEHALF OF

EAST TENNESSEE ENERGY CONSUMERS

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

July 2017

TENNESSEE PUBLIC UTILITY COMMISSION
PETITION OF KINGSPORT POWER COMPANY
DOCKET NO. 17-00032
Data Requests and Requests for the Production of Documents by The Consumer Protection And Advocate Division of the Attorney General's Office (First Set-Informal) To Kingsport Power Company

Data Request CPAD 1-24:

Assuming a scenario in which the Company's actual rate of return exceeds that authorized by the Commission, does the Company intend to use this over-earnings to reduce the TRP & MS Rider Surcharge? If the Company does so intend, how does the Company plan to incorporate the assumed scenario into the TRP & MS Rider Surcharge and related tariff? If the Company does not so intend, explain the Company's rationale for not using such over-earnings to reduce the TRP & MS Rider Surcharge.

Response CPAD 1-24:

The TRP&MS Rider is intended to recover costs related only to distribution reliability and major storms as described in this Petition and as provided for in Tennessee Code Annotated Section 65-5-103 (d) (2) (A). The Rider is to recover, or refund costs that are incremental to those in base rates, as determined in the Company's last base rate case (Docket No. 16-00001), so that the costs of the program are exactly recovered.

BEFORE THE

TENNESSEE PUBLIC UTILITY COMMISSION

NASHVILLE, TENNESSEE

PETITION OF **KINGSPORT POWER COMPANY** **d/b/a AEP Appalachian Power** **For Approval of its Targeted Reliability Plan,** **And its TRP & MS Rider, An Alternative Rate** **Mechanism**	**Docket No. 17-00032**

EXHIBIT__(SJB-3)

OF

STEPHEN J. BARON

ON BEHALF OF

EAST TENNESSEE ENERGY CONSUMERS

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

July 2017

DISTRIBUTION ALLOCATION FACTORS (FROM KINGSPORT DOCKET NO. 16-00001 CLASS COST OF SERVICE STUDY)

Allocation Factor	Total Retail	RS	SGS	MGS-SEC	MGS-PRI	MGS-SUB	LGS-SEC	LGS-PRI	LGS-SUB
	1	2	3	4	5	6	7	8	9
Allocator for Account 365									
DIST_OHLINES DISTPRI	0.74910000	0.50903264	0.00994903	0.06011799	0.00026527	-	0.09730199	0.00769274	-
DIST_OHLINES DISTSEC	0.25090000	0.19057884	0.00358693	0.01652522	-	-	0.02418453	-	-
Allocator for Accounts 583 and 593									
TOTOHLINES DISTPRI	0.64673877	0.43947556	0.00858954	0.05190313	0.00022902	-	0.08400610	0.00664156	-
TOTOHLINES DISTSEC	0.35326123	0.26833047	0.00505032	0.02326711	-	-	0.03405124	-	-
Allocator for Account 594 (Maint. of UG Lines)									
TOTUGLINES DISTPRI	0.71110000	0.48321067	0.00944434	0.05706835	0.00025181	-	0.09236610	0.00730250	-
TOTUGLINES DISTSEC	0.28890000	0.21944291	0.00413019	0.01902804	-	-	0.02784739	-	-
Proposed Revenue at Equal ROR (including SL)									
DISTPRI	10,903,334	7,134,508	159,784	943,303	3,834	-	1,574,637	140,198	-
DISTSEC	6,619,275	4,883,889	105,922	476,314	-	-	719,767	-	-
Total DISTPRI + DISTSEC	17,522,609	12,018,397	265,705	1,419,616	3,834	-	2,294,404	140,198	-
% of Total	100.0%	68.59%	1.52%	8.10%	0.02%	0.00%	13.09%	0.80%	0.00%
KPCo Proposed ARM Allocation	100.0%	28.3%	3.1%	14.3%	0.2%		24.3%	1.5%	

DISTRIBUTION ALLOCATION FACTORS

Allocation Factor	IP-PRI 10	IP-SUB 11	IP-TRA 12	CS 13	PS 14	EHG 15	OL 16	SL 17
Allocator for Account 365								
DIST_OHLINES DISTPRI	0.02467896	-	-	0.00603406	0.01720575	0.01526046	0.00052139	0.00103972
DIST_OHLINES DISTSEC	-	-	-	0.00271237	0.00608805	0.00537861	0.00071249	0.00113296
Allocator for Accounts 583 and 593								
TOTOHLINES DISTPRI	0.02130669	-	-	0.00520953	0.01485466	0.01317519	0.00045014	0.00089765
TOTOHLINES DISTSEC	-	-	-	0.00381895	0.00857183	0.00757296	0.00100317	0.00159518
Allocator for Account 594 (Maint. of UG Lines)								
TOTUGLINES DISTPRI	0.02342706	-	-	0.00572796	0.01633295	0.01448634	0.00049494	0.00098698
TOTUGLINES DISTSEC	-	-	-	0.00312317	0.00701011	0.00619323	0.00082040	0.00130455
Proposed Revenue at Equal ROR (including SL)								
DISTPRI	359,724	-	-	93,349	233,877	235,849	8,106	16,166
DISTSEC	-	-	-	77,030	151,067	152,608	20,335	32,342
Total DISTPRI + DISTSEC	359,724	-	-	170,378	384,944	388,457	28,441	48,508
% of Total	2.05%	0.00%	0.00%	0.97%	2.20%	2.22%	0.16%	0.28%
KPCo Proposed ARM Allocation	1.9%		15.9%	1.2%	2.8%	3.2%	1.0%	2.4%

BEFORE THE

TENNESSEE PUBLIC UTILITY COMMISSION

NASHVILLE, TENNESSEE

PETITION OF **KINGSPORT POWER COMPANY** **d/b/a AEP Appalachian Power** **For Approval of its Targeted Reliability Plan,** **And its TRP & MS Rider, An Alternative Rate Mechanism**	**Docket No. 17-00032**

EXHIBIT__(SJB-4)

OF

STEPHEN J. BARON

ON BEHALF OF

EAST TENNESSEE ENERGY CONSUMERS

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

July 2017

TENNESSEE PUBLIC UTILITY COMMISSION
PETITION OF Kingsport Power Company
DOCKET NO. 17-00032
Data Requests and Requests for the Production of Documents by the East Tennessee Energy Consumers (First Set) To Kingsport Power Company

Data Request ETEC-4:

With regard to the vegetation management program, please provide, for each planned expenditure included in the Company's 10-year cost projection presented in Mr. Wright's testimony (Figure 7), an estimated breakdown of such expenditure by circuit voltage (secondary, primary), by year.

Response ETEC-4:

Please see ETEC-1-004, Attachment 1, for vegetation management planned expenditures based on circuit voltage by year.

Vegetation Management				
TRP Asset Program	**New Capital**		**Total O&M**	
Year	**Overhead Primary**	**Overhead Secondary**	**Overhead Primary**	**Overhead Secondary**
Year 1	$1,408,747	$351,315	$2,951,661	$736,089
Year 2	$1,436,922	$358,342	$3,010,694	$750,811
Year 3	$1,465,661	$365,508	$3,070,908	$765,827
Year 4	$1,494,974	$372,819	$3,132,326	$781,144
Year 5	$670,832	$167,293	$2,012,496	$501,879
Year 6	$684,249	$170,639	$2,052,746	$511,916
Year 7	$697,934	$174,052	$2,093,801	$522,155
Year 8	$711,892	$177,533	$2,135,677	$532,598
Year 9	$536,666	$133,834	$2,178,391	$543,250
Year 10	$547,399	$136,511	$2,221,958	$554,115
Total Spend	**$9,655,275**	**$2,407,845**	**$24,860,658**	**$6,199,783**

TENNESSEE PUBLIC UTILITY COMMISSION
PETITION OF Kingsport Power Company
DOCKET NO. 17-00032
Data Requests and Requests for the Production
of Documents by the East Tennessee Energy Consumers (First Set)
To Kingsport Power Company

Data Request ETEC-5:

With regard to the system improvement program, please provide, for each planned expenditure included in the Company's 10-year cost projection presented in Mr. Wright's testimony (Figure 7), an estimated breakdown of such expenditure by circuit voltage (secondary, primary), by year.

Response ETEC-5:

Please see ETEC-1-005, Attachment 1, for system improvement planned expenditures based on circuit voltage by year.

System Improvement				
TRP Asset Program	**New Capital**		**Total O&M**	
Year	**Primary**	**Secondary**	**Primary**	**Secondary**
Year 1	$921,349	$296,508	$181,168	$58,303
Year 2	$941,045	$302,846	$181,338	$58,358
Year 3	$949,947	$305,711	$181,478	$58,403
Year 4	$960,033	$308,957	$181,625	$58,450
Year 5	$4,719,353	$1,518,779	$536,561	$172,676
Year 6	$4,719,353	$1,518,779	$536,561	$172,676
Year 7	$4,719,353	$1,518,779	$536,561	$172,676
Year 8	$4,719,353	$1,518,779	$536,561	$172,676
Year 9	$4,719,353	$1,518,779	$536,561	$172,676
Year 10	$4,719,353	$1,518,779	$536,561	$172,676
Total Spend	**$32,088,494**	**$10,326,696**	**$3,944,976**	**$1,269,569**

**TENNESSEE PUBLIC UTILITY COMMISSION
PETITION OF Kingsport Power Company
DOCKET NO. 17-00032
Data Requests and Requests for the Production
of Documents by the East Tennessee Energy Consumers (First Set)
To Kingsport Power Company**

Data Request ETEC-7:

With regard to the Major Storm Expenses for the years 2009 to 2016 shown in Mr. Wright's Figure 8, please provide an estimated breakdown of these expenses by distribution voltage (secondary, primary).

Response ETEC-7:

Please see ETEC-1-007, Attachment 1, for the requested information.

Major Storm Expense				
Year	Total Primary		Total Secondary	
2009	$	1,461,943	$	470,481
2010	$	438,089	$	140,986
2011	$	675,402	$	217,357
2012	$	307,246	$	98,878
2013	$	1,087,592	$	350,008
2014	$	63,510	$	20,439
2015	$	-	$	-
2016	$	150,370	$	48,392

BEFORE THE

TENNESSEE PUBLIC UTILITY COMMISSION

NASHVILLE, TENNESSEE

PETITION OF	
KINGSPORT POWER COMPANY	**Docket No. 17-00032**
d/b/a AEP Appalachian Power	
For Approval of its Targeted Reliability Plan,	
And its TRP & MS Rider, An Alternative Rate	
Mechanism	

EXHIBIT__(SJB-5)

OF

STEPHEN J. BARON

ON BEHALF OF

EAST TENNESSEE ENERGY CONSUMERS

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

July 2017

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR data is current as of June 16, 2017

Title 18 → Chapter I → Subchapter C → Part 101

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Title 18: Conservation of Power and Water Resources

PART 101—UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR PUBLIC UTILITIES AND LICENSEES SUBJECT TO THE PROVISIONS OF THE FEDERAL POWER ACT

365 Overhead conductors and devices.

This account shall include the cost installed of overhead conductors and devices used for distribution purposes.

ITEMS

1. Circuit breakers.
2. Conductors, including insulated and bare wires and cables.
3. Ground wires, clamps, etc.
4. Insulators, including pin, suspension, and other types, and tie wire or clamps.
5. Lightning arresters.
6. Railroad and highway crossing guards.
7. Splices.
8. Switches.
9. Tree trimming, initial cost including the cost of permits therefor.
10. Other line devices.

NOTE: The cost of conductors used solely for street lighting or signal systems shall not be included in this account but in account 373, Street Lighting and Signal Systems.

366 Underground conduit.

This account shall include the cost installed of underground conduit and tunnels used for housing distribution cables or wires.

ITEMS

1. Conduit, concrete, brick and tile, including iron pipe, fiber pipe, Murray duct, and standpipe on pole or tower.
2. Excavation, including shoring, bracing, bridging, backfill, and disposal of excess excavated material.
3. Foundations and settings specially constructed for and not expected to outlast the apparatus for which constructed.
4. Lighting systems.
5. Manholes, concrete or brick, including iron or steel frames and covers, hatchways, gratings, ladders, cable racks and hangers, etc., permanently attached to manholes.
6. Municipal inspection.
7. Pavement disturbed, including cutting and replacing pavement, pavement base, and sidewalks.
8. Permits.
9. Protection of street openings.
10. Removal and relocation of subsurface obstructions.
11. Sewer connections, including drains, traps, tide valves, check valves, etc.
12. Sumps, including pumps.
13. Ventilating equipment.

583 Overhead line expenses (Major only).

584 Underground line expenses (Major only).

Accounts 581.1 through 584 shall include, respectively, the cost of labor, materials used and expenses incurred in the operation of overhead and underground distribution lines and stations.

ITEMS

Line Labor:

1. Supervising line operation.
2. Changing line transformer taps.
3. Inspecting and testing lightning arresters, line circuit breakers, switches and grounds.
4. Inspecting and testing line transformers for the purpose of determining load, temperature or operating performance.
5. Patrolling lines.
6. Load tests and voltages surveys of feeders, circuits and line transformers.
7. Removing line transformers and voltage regulators with or without replacements.
8. Installing line transformers or voltage regulators with or without change in capacity provided that the first installation of these items is included in account 368, Line transformers.
9. Voltage surveys, either routine or upon request of customers, including voltage tests at customers' main switch.
10. Transferring loads, switching and reconnecting circuits and equipment for operation purposes.
11. Electrolysis surveys.
12. Inspecting and adjusting line testing equipment.

Line Supplies and Expenses:

13. Tool expenses.
14. Transportation expenses.
15. Meals, traveling and incidental expense.
16. Operating supplies, such as instrument charts, rubber goods, etc.

Station Labor:

1. Supervising station operation.
2. Adjusting station equipment where such adjustment primarily affects performance, such as regulating the flow of cooling water, adjusting current in fields of a machine, changing voltage of regulators or changing station transformer taps.
3. Keeping station log and records and preparing reports on station operation.
4. Inspecting, testing and calibrating station equipment for the purpose of checking its performance.
5. Operating switching and other station equipment.
6. Standing watch, guarding and patrolling station and station yard.
7. Sweeping, mopping and tidying station.
8. Care of grounds, including snow removal, cutting grass, etc.

Station Supplies and Expenses:

9. Building service expenses.
10. Operating supplies, such as lubricants, commutator brushes, water and rubber goods.
11. Station meter and instrument supplies, such as ink and charts.
12. Station record and report forms.
13. Tool expenses.
14. Transportation expenses.
15. Meals, traveling and incidental expenses.

BEFORE THE

TENNESSEE PUBLIC UTILITY COMMISSION

NASHVILLE, TENNESSEE

PETITION OF **KINGSPORT POWER COMPANY** **d/b/a AEP Appalachian Power** **For Approval of its Targeted Reliability Plan,** **And its TRP & MS Rider, An Alternative Rate** **Mechanism**	**Docket No. 17-00032**

EXHIBIT__(SJB-6)

OF

STEPHEN J. BARON

ON BEHALF OF

EAST TENNESSEE ENERGY CONSUMERS

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

July 2017

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

Case Nos. 14-1152-E-42T and 14-1151-E-D

APPALACHIAN POWER COMPANY
and WHEELING POWER COMPANY

COMMISSION ORDER ON THE TARIFF FILING
OF APPALACHIAN POWER COMPANY and
WHEELING POWER COMPANY TO INCREASE RATES,
and PETITION TO CHANGE DEPRECIATION RATES.

May 26, 2015

adjustments 14-PE and 29-CI. The Companies did not make an adequate showing in the record that the additional adjustment of $6.736 million for amortization of ENEC carrying cost is required to offset ENEC revenues for the 2013 test year.

VII. RATEMAKING MECHANISMS

A. Vegetation Management Program

The Companies proposed to recover an additional $44.6 million through a new surcharge for the Vegetation Management Program (VMP). The Commission approved the VMP by Commission Order issued March 18, 2014, in Case No. 13-0557-E-P (VMP Case). The Commission deferred the implementation of a cost recovery mechanism for VMP O&M expenses until the conclusion of the current base rate case. In this case, the Companies proposed that all VMP expenses be recovered through a surcharge and none through base rates. Companies Exh. CWG-D at 3.

Mr. Gary and Companies witnesses Wright and Ferguson testified that a VMP surcharge is the fairest and most accurate means of recovering VMP costs. The Companies witnesses stated that, because of the surcharge true-up mechanism, ratepayers will pay the actual costs incurred, no more, no less. Further, interested stakeholders will have the opportunity to review VMP costs. Companies Exh. CWG-D at 3-6; Companies Exh. PAW-D at 12; Companies Exh. SHF-D at 10. Mr. Gary agreed to a correction in the allocation of transmission-related VMP costs as identified by SWVA witness Daniel. Companies Exh. CWG-R1; SWVA Exh. JWD-D at 15-16; Companies Exh. CWG-R at 2. Mr. Gary had no objection to WVEUG witness Baron's alternative method of allocating distribution-related VMP costs among customer classes. WVEUG Exh. SJB-D at 16-19; Companies Exh. CWG-R at 2 and attached Exh. CWG-R1.

In response to the CAD and WVEUG testimony that VMP costs should be recovered through base rates and not through a surcharge, Companies witnesses Gary and Ferguson testified that base rate treatment would deprive the Companies and their customers of the flexibility to match costs and recovery during the implementation years of the VMP and of the protection that only VMP costs actually incurred are recovered. CAD Exh. RCS-D at 99-100; WVEUG Exh. SJB-D at 16. Companies Exh. CWG-R at 1-2; Companies Exh. SHF-D at 10.

CAD opposed the proposal of the Companies to recover VMP through a rate surcharge instead of as an O&M expense included in base rates. CAD Exh. RCS-D at 83-84. Mr. Smith reasserted the concerns of CAD that were expressed in the VMP Case, arguing (i) a surcharge is an extraordinary ratemaking mechanism, (ii) the need to perform vegetation management is not extraordinary, and (iii) the Companies have not shown documentary evidence to support the projected level of expense. The best protection for ratepayers is to maintain VMP costs in base rates. Id.

In the alternative, CAD argued that if the Commission does not agree with the CAD position that VMP costs should be recoverable in base rates, the Commission should adjust the proposed surcharge to reflect Commission determinations on proper return in the current rate case, application of the effective federal income tax rate determined by the Commission in the current rate case, and new depreciation rates approved by the Commission in Case No. 14-1151-E-D.

WVEUG also opposed the imposition of a VMP surcharge for the reasons stated by WVEUG witness Baron. Mr. Baron argued that the Companies failed in this case, as they did in the VMP Case, to demonstrate that the surcharge is necessary to deliver safe, reliable service. Mr. Baron testified that base rate proceedings are the preferred ratemaking approach to vegetation management because the Commission has the opportunity to review all costs and expenses, some of which decrease over time. WVEUG Exh. SJB-D at 16. WVEUG argued in its brief that the Companies did not cite any regulatory requirement mandating the surcharge and failed to show that a surcharge is of such necessity to forgo cost recovery through traditional means. WVEUG argued that the Companies have an opportunity to recover the full costs of their VMP in a traditional Rule 42 base rate proceeding. WVEUG questioned why the Commission should relieve the Companies from bearing the cost-related risks incident to the VMP, such as regulatory lag, and instead require ratepayers to bear those risks. WVEUG argued that the Companies did not justify a departure from traditional ratemaking.

Mr. Baron testified that to the extent the Commission approves implementation of the VMP surcharge in this case, it should require the Companies to allocate the distribution-related vegetation management expenses among applicable rate classes using the same allocation methodology employed by the Companies for their base rate calculations. Specifically, the Companies should allocate these distribution expenses in accordance with the approach used for Federal Energy Regulatory Commission (FERC) Account No. 593 for "overhead maintenance expenses." WVEUG Exh. SJB-D at 17-18. The Companies did not object to this allocation. Companies Exh. CWG-R at 2 and attached Exh. CWG-R1.

Staff witness Melton testified that Staff does not oppose the proposed VMP surcharge because the surcharge will be subject to true-up on an annual basis. Staff Exh. EEM-D at 6. Staff witness Melton testified that he recommends that the Commission require the Companies to file certain information with its yearly true-up filing, including:

(a) All contractual performance measures contractually required by the Companies.
(b) Miles of single phase lines to be cleared in the forecast period.
(c) Miles of three phase lines to be cleared in the forecast period.
(d) Miles of single phase lines cleared in the previous period.
(e) Miles of three phase lines cleared in the previous period.

(f) Miles of single phase lines where the ROW was widened.
(g) Miles of three phase lines where the ROW was widened.

Id.

Mr. Melton requested that the Commission direct the Companies to make the yearly filings as formal case filings or part of the ENEC by a date certain every year in order to ensure there is no confusion as to when and how the yearly formal review/ true-up filing will occur.

The Commission understands that, following a series of cases, including cases specifically focusing on vegetation management, we are initiating a significant change. The Commission will authorize the Companies to recover the vegetation management costs associated with the cycle-based VMP authorized by the Commission in the VMP Case through a surcharge mechanism. The Commission stated in the VMP Case that it would in the next base rate case consider a rate recovery mechanism not tied to traditional base rate standards. Commission Order March 18, 2014 at 14-15. The Commission determines that it is reasonable to approve a surcharge for the VMP because VMP surcharge annual review will assure that only the actual cost of the VMP will be recovered in rates, and the annual VMP review will assure that the VMP will be implemented as intended.

In the past, base rates included provisions for ongoing costs related to vegetation management, however, that type of rate recovery did not assure sufficient revenue to carry-out a cycle-based end-to-end VMP or a means for the Commission to assess the extent and effectiveness of such vegetation management efforts. The Commission understood that a cycle-based end-to-end VMP would result in increased rates when it authorized the VMP program, but determined that such an increase in cost was warranted in order to address the service related issues experienced from the lack of a focused VMP. The Commission believes that authorizing a VMP surcharge with annual reviews, that include annual rate true-ups, is the best way to assure the service related benefits related to the VMP are achieved and appropriate rate recovery is afforded that substantial increase in VMP effort and cost.

The VMP has been in effect since March 18, 2014, and is currently in the initial six-year transition period. The evidence presented in the VMP Case was that after the six-year transition period, the VMP will maintain vegetation along all distribution and transmission lines on a four-year cycle. After the VMP is well-established and the costs well defined, the Commission may find it appropriate to remove the VMP surcharge and roll the VMP costs into base rates in a future base rate case.

The initial VMP surcharge will be set to produce $44.472 million annually, allocated to the various customer tariff classifications as indicated in Mr. Gary's rebuttal testimony, including the modifications to the tariff allocation suggested by both Mr. Baron and Mr. Daniel. Companies Exh. CWG-R at 2-3. In order to avoid multiple rate changes regarding ENEC and VMP filings, the Companies will file their annual ENEC and the VMP review cases at the beginning of March of each year, and the revised ENEC rates and VMP surcharge revisions will take effect at the same time. The Commission will require, therefore, that the Companies file a formal petition for annual review and true-up of the VMP surcharge on or before the first business day of March 2016, and for each year thereafter, until further order of the Commission. As argued by the intervenors, the VMP surcharge review filing true-ups will be determined using the (i) RoE, (ii) federal and state income tax rates, (iii) tariff allocations and (iv) new depreciation rates approved in this Order.

B. PJM OATT Revenues.

The Companies proposed a shift of PJM Open Access Transmission Tariff (OATT) revenues from ENEC proceedings to base rate proceedings. Companies Exh. JJS-D at 6-11; Companies Exh. CRP-R at **3;** Companies Exh. SHF-D at 11-12; Tr. 1/20 at 50-55. Staff witness Eads and WVEUG witness Baron both opposed the shift. Staff Exh. TRE-D at 21-24; WVEUG Exh. SJB-D at 21-24; Tr. 1/22 at 146-149. The Companies stated in their initial brief that they decided to withdraw the proposed shift of PJM OATT revenues in this case. The Companies stated that although they continue to think that a shift of PJM OATT revenues to base rates is a sound concept, they have come to the conclusion that they can improve upon their proposal in a fashion that will permit PJM OATT revenues to continue to be handled in ENEC proceedings. Accordingly, the Companies presented their new proposal in their ENEC filing on March 2, 2015, in Case No. 15-0303-E-P. The issue will not, therefore, be considered in this case.

C. Major Storm Expense Tracker

Companies witness Scalzo testified that the Companies proposed implementation of a new tracker for major storm restoration expenses would allow the Commission and the Companies to true-up the storm expenses embedded in rates with those actually incurred. Companies Exh. JJS-D at 4-6. Mr. Scalzo stated in his rebuttal testimony, in response to WVEUG witness Kollen, that a major storm is one with severe weather where assistance is secured from outside of the affected district and restoration efforts last longer than twenty-four hours. The major costs are typically labor, contractor costs, fleet cost, materials and supplies. Under the proposed approach, capital costs associated with major storms would continue to be recovered in base rates. Companies Exh. JJS-R at 5. In response to Staff witness Melton, Mr. Scalzo stated that the storm tracker would assign the overall benefits of the VMP, which is expected to result in lower storm restoration costs in the future, to the customers who are paying for the VMP. The three-year average of major storm restoration costs, or $6.7 million, will be included in the 2012 Storm deferral. Then, if future major storm costs are less than $6.7 million annually, the difference would be used to reduce the 2012 storm deferral balance.

In their initial brief the Companies ask the Commission to consider authorizing the storm tracker on a trial basis. The Companies believe that over time, the tracker will

BEFORE THE

TENNESSEE PUBLIC UTILITY COMMISSION

NASHVILLE, TENNESSEE

PETITION OF **KINGSPORT POWER COMPANY** **d/b/a AEP Appalachian Power** **For Approval of its Targeted Reliability Plan, And its TRP & MS Rider, An Alternative Rate Mechanism**	**Docket No. 17-00032**

EXHIBIT__(SJB-7)

OF

STEPHEN J. BARON

ON BEHALF OF

EAST TENNESSEE ENERGY CONSUMERS

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

July 2017

REBUTTAL TESTIMONY OF
CHARLES W. GARY
ON BEHALF OF APPALACHIAN POWER COMPANY AND
WHEELING POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF
WEST VIRGINIA IN CASE NO. 14-1152-E-42T

Q. PLEASE STATE YOUR NAME.

A. My name is Charles W. Gary.

Q. ARE YOU THE SAME CHARLES W. GARY WHO OFFERED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony responds to concerns raised by CAD witness Smith, West Virginia Energy Users Group ("WVEUG") witness Baron and SWVA, Inc. witness Daniel.

Q. CAD WITNESS SMITH (p. 100) AND WVEUG WITNESS BARON (p. 16) BOTH OPPOSED THE IMPLEMENTATION OF A NEW SURCHARGE FOR THE COMPANIES' RECOVERY OF VEGETATION MANAGEMENT COSTS INCURRED IN THE NEW CYCLE-BASED VEGETATION MANAGEMENT PROGRAM ("VMP"), CLAIMING THAT BASE RATES ARE THE APPROPRIATE RECOVERY AVENUE. DO YOU AGREE WITH THEM?

A. No. While base rate recovery of vegetation management costs may be an appropriate avenue for recovery, provided those vegetation management activities and costs are stable and predictable, it is not appropriate when those costs and activities are changing in a significant manner. As Company witness Wright has addressed in this case and Case No. 13-0557-E-P, the cost estimates provided to implement the new cycle-based VMP are estimates and are expected to grow for the first several years of implementation. No matter how reasonable those estimates may be, they are still estimates. It is the

Companies' position that the best possible way to ensure that customers pay for the exact amount of vegetation management activities, no more and no less, that are actually performed, those costs, and the recovery of those costs, should be included in one mechanism, the VMP Surcharge.

Q. WVEUG WITNESS BARON (p. 16) OFFERS AN ALTERNATIVE METHOD OF ALLOCATING DISTRIBUTION-RELATED VMP COSTS AMONG CUSTOMER CLASSES. DO YOU AGREE THAT HIS METHODOLOGY PROVIDES AN ACCEPTABLE ALTERNATIVE METHOD TO ALLOCATING DISTRIBUTION-RELATED VMP COSTS?

A. Yes. In my direct testimony, I allocated VMP costs, both transmission and distribution, based on a 12-CP methodology. It is the Companies' position that the 12-CP methodology provides a fair way to allocate VMP costs to customer classes. However, the methodology proposed by Mr. Baron also appears to be an acceptable method of allocating those costs.

Q. SWVA, INC. WITNESS DANIEL (p. 16) INDICATED THAT YOU MADE A MISTAKE REGARDING THE ALLOCATION OF TRANSMISSION-RELATED VMP COSTS. DO YOU AGREE WITH HIM?

A. Yes, I do. Mr. Daniel correctly identified an error in Company Exhibit CWG-D3. It was my intent to allocate transmission-related VMP costs to all customer classes and Special Contract customers. I have corrected that error and developed a new Exhibit that shows the corrected values. For the sake of comparison, I have also incorporated Mr. Baron's suggested method of allocating the distribution-related VMP costs on the same Exhibit. The updated version of Company Exhibit CWG-D3 is provided as Company Exhibit CWG-R1.

Q. ARE THERE ANY OTHER ISSUES THAT YOU WANT TO ADDRESS?

A. Yes, there is just one additional issue that I would like to clarify. On page 15 of his direct testimony, SWVA Inc. witness Daniel discusses the fact that I include transmission-related VMP costs in the proposed surcharge even though Company witness Wright indicated in his direct testimony that transmission-related costs will be recovered through the Open Access Transmission Tariff ("OATT"). As a point of clarification, the Companies recover transmission-related costs for those circuits above 200 kV through the OATT. The transmission-related costs that the Companies are proposing to include in the VMP are those transmission-related vegetation management costs for circuits 200 kV and below.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

APPALACHIAN POWER COMPANY / WHEELING POWER COMPANY
ENERGY AND DEMAND FORECAST
FROM STATEMENT D

(1) TARIFF SCH.		(2) ALLOCATION (DISTRIBUTION)	(3) ALLOCATION (TRANSMISSION)	(4) ENERGY FORECAST 6,015,857,883 (KWH)	(5) MONTHLY DEMAND FORECAST (KW)	(6) REVENUE REQUIREMENT ($) T $2,216,136 D $42,255,572	(7) VEGETATION MANAGEMENT PROGRAM SURCHARGE (¢/kWh)	(8) VEGETATION MANAGEMENT PROGRAM SURCHARGE ($/kW)	(9) REVENUE VERIFICATION ($)
RS		0.683679	0.463886	6,015,210,780		29,917,297	0.497		29,917,463
- On-Peak				196,962					
- Off-Peak				450,141					
SWS		0.011635	0.006464	91,016,993		505,965	0.556		505,963
SGS		0.020878	0.016928	246,368,765		919,734	0.373		919,744
SS	-SEC	0.025230	0.021838	340,106,250	95,081	1,114,521		0.977	1,114,521
	-PRI	0.002685	0.003737	60,040,262	12,806	121,738		0.792	121,738
	-AF	0.000000	0.000323	5,146,493		715	0.014		715
GS:TOD ON-PEAK	-SEC	0.000000	0.001227	8,961,530		2,718	0.030		2,718
OFF-PEAK	-SEC			11,758,552					
ON-PEAK	- PRI	0.000000	0.000000	0		0	0.031		0
OFF-PEAK	-PRI			0					
GS	-SEC	0.175209	0.153180	2,570,653,632	688,841	7,743,005		0.937	7,743,005
	-PRI	0.011233	0.016001	275,659,990	72,182	510,134		0.589	510,134
	-SUBT		0.001637	29,675,843	5,429	3,627		0.056	3,627
	-TRANS		0.000051	1,071,000	209	112		0.045	112
	-AF	0.000000	0.000123	2,179,066		272	0.012		272
LCP	-SEC	0.010266	0.009551	174,738,390	30,907	454,966		1.234	457,746
	- PRI	0.049580	0.069873	1,432,015,070	257,823	2,249,889		0.727	2,248,473
	- SUBT		0.073572	1,518,691,667	326,487	163,046		0.044	173,825
	- TRANS		0.044855	945,003,376	205,024	99,404		0.044	107,682
IP	-SEC	0.000678	0.000596	11,271,720	1,836	29,973		1.234	27,192
	- PRI	0.002667	0.003918	81,932,100	14,080	121,374		0.727	122,790
	- SUBT		0.018422	396,743,753	56,432	40,825		0.044	30,045
	- TRANS		0.032909	750,045,254	123,098	72,930		0.044	64,653
OL		0.003734	0.000000	76,357,906		157,785	0.207		157,786
SL		0.001205	0.000000	28,341,114		50,924	0.180		50,923

APPALACHIAN POWER COMPANY / WHEELING POWER COMPANY
ENERGY AND DEMAND FORECAST
FROM STATEMENT D

(1) TARIFF SCH.	(2) ALLOCATION (DISTRIBUTION)	(3) ALLOCATION (TRANSMISSION)	(4) ENERGY FORECAST 6,015,857,883 (KWH)	(5) MONTHLY DEMAND FORECAST (KW)	(6) REVENUE REQUIREMENT ($) T $2,216,136 D $42,255,572	(7) VEGETATION MANAGEMENT PROGRAM SURCHARGE (¢/kWh)	(8) VEGETATION MANAGEMENT PROGRAM SURCHARGE ($/kW)	(9) REVENUE VERIFICATION ($)
SPECIAL CONTRACT A		0.007007					0.018	15,528
FIRM			26,276,988	71,729				
P1			500,535,556					
P2			0					
P2.5			0					
P3			0					
P4			0					
			526,812,544		15,528			
SPECIAL CONTRACT B		0.021339		110,000			0.036	47,291
138 Kv								
P1			461,784,801					
P2			0					
P2.5			0					
P3			0					
P4			0					
			461,784,801		47,291			
462,367,208								
46 Kv								
P1			582,407					
P2			0					
P2.5			0					
P3			0					
P4			0					
			582,407					
SPECIAL CONTRACT C	0.000886	0.000288		0				
P1			1,073,962					
P2			0					
P3			0					
P4			0					
			1,073,962		38,057	3.544		38,057
SPECIAL CONTRACT D		0.008784	219,150,226	37,111	19,467		0.044	19,467
SPECIAL CONTRACT E								
SEC	0.000000	0.000000	0	0	0	0.000		0
PRI	0.000000	0.000000	0	0	0	0.000		0
SPECIAL CONTRACT F	0.000000	0.000000	0	0	0	0.000		0
SPECIAL CONTRACT G FIRM		0.012463	396,096,833	42,019	27,619		0.055	27,619
SPECIAL CONTRACT H		0.000000	0	0	0		0.000	0
SPECIAL CONTRACT I		0.008748	200,510,073	38,833	19,388		0.042	19,388
SPECIAL CONTRACT J	0.000434	0.000174	6,750,412	664	18,737		2.353	18,737
SPECIAL CONTRACT K		0.002107	54,103,400	13,065	4,669		0.030	4,669
TOTALS	1.00000	1.000000	16,940,501,267		44,471,708			44,471,884

BEFORE THE

TENNESSEE PUBLIC UTILITY COMMISSION

NASHVILLE, TENNESSEE

PETITION OF **KINGSPORT POWER COMPANY** **d/b/a AEP Appalachian Power** **For Approval of its Targeted Reliability Plan,** **And its TRP & MS Rider, An Alternative Rate** **Mechanism**	**Docket No. 17-00032**

EXHIBIT__(SJB-8)

OF

STEPHEN J. BARON

ON BEHALF OF

EAST TENNESSEE ENERGY CONSUMERS

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

July 2017

TENNESSEE PUBLIC UTILITY COMMISSION
PETITION OF Kingsport Power Company
DOCKET NO. 17-00032
Data Requests and Requests for the Production
of Documents by the East Tennessee Energy Consumers (First Set)
To Kingsport Power Company

Data Request ETEC-13:

With regard to Mr. Castle's testimony at page 6, lines 15-20, does Mr. Castle agree that the Company's proposal to allocate Rider costs will have the effect of moving the rates of each of the Company's rate classes further away from cost of service? If not, please provide a complete explanation for your response.

Response ETEC-13:

For those classes whose class rate of return was above the average in the Company's last base rate proceeding, the allocation of revenue requirement for costs not attributable to a class would increase the return of that class and drive it further from cost of service, all other things being equal.