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June 20, 2018

**via E-MAIL and OVERNIGHT MAIL**

David Foster, Chief – Utilities Division  
c/o Sharla Dillon  
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Tennessee Public Utility Commission  
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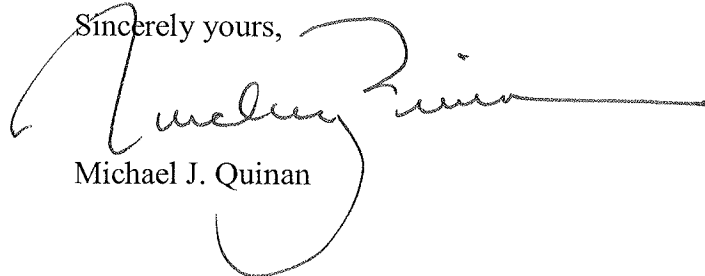
In Re: PETITION OF KINGSPORT POWER COMPANY d/b/a AEP  
APPALACHIAN POWER FOR APPROVAL OF A STORM DAMAGE RIDER  
TARIFF (Docket No. 17-00143)

Dear Ms. Dillon:

Enclosed please find an original and 4 copies of East Tennessee Energy Consumers' *Testimony and Exhibits of Stephen J. Baron* to be filed on behalf of East Tennessee Energy Consumers in the above-referenced docket.

Thank you for your kind attention to this request.

Sincerely yours,



Michael J. Quinan

MJQ  
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  
Ms. Karen H. Stachowski

**BEFORE THE  
TENNESSEE PUBLIC UTILITY COMMISSION  
NASHVILLE, TENNESSEE**

**PETITION OF  
KINGSPORT POWER COMPANY  
d/b/a AEP Appalachian Power  
For Approval of a Storm Damage Rider  
Tariff (SDR)**

**Docket No. 17-00143**

**DIRECT TESTIMONY  
AND EXHIBITS  
OF  
STEPHEN J. BARON**

**ON BEHALF OF  
EAST TENNESSEE ENERGY CONSUMERS  
J. KENNEDY AND ASSOCIATES, INC.  
ROSWELL, GEORGIA**

**June 20, 2018**

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**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.

*J. Kennedy and Associates, Inc.*

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

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

8  
9       **Q.     Please state your educational background.**

10      A.     I graduated from the University of Florida in 1972 with a B.A. degree with high honors  
11      in Political Science and significant coursework in Mathematics and Computer  
12      Science. In 1974, I received a Master of Arts Degree in Economics, also from the  
13      University of Florida. My areas of specialization were econometrics, statistics, and  
14      public utility economics. My thesis concerned the development of an econometric  
15      model to forecast electricity sales in the State of Florida, for which I received a grant  
16      from the Public Utility Research Center of the University of Florida. In addition, I  
17      have advanced study and coursework in time series analysis and dynamic model  
18      building.

19  
20      **Q.     Please describe your professional experience.**

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

3  
4             Following the completion of my graduate work in economics, I joined the staff of the  
5             Florida Public Service Commission in August of 1974 as a Rate Economist. My  
6             responsibilities included the analysis of rate cases for electric, telephone, and gas  
7             utilities, as well as the preparation of cross-examination material and the preparation  
8             of staff recommendations.

9  
10            In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services,  
11            Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received  
12            successive promotions, ultimately to the position of Vice President of Energy  
13            Management Services of Ebasco Business Consulting Company. My responsibilities  
14            included the management of a staff of consultants engaged in providing services in  
15            the areas of econometric modeling, load and energy forecasting, production cost  
16            modeling, planning, cost-of-service analysis, cogeneration, and load management.

17  
18            I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of  
19            the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this  
20            capacity I was responsible for the operation and management of the Atlanta office.  
21            My duties included the technical and administrative supervision of the staff,

1 budgeting, recruiting, and marketing as well as project management on client  
2 engagements. At Coopers & Lybrand, I specialized in utility cost analysis,  
3 forecasting, load analysis, economic analysis, and planning.

4  
5 In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice  
6 President and Principal. I became President of the firm in January 1991.

7  
8 During the course of my career, I have provided consulting services to numerous  
9 industrial, commercial, public service commission and utility clients, including  
10 international utility clients.

11  
12 I have presented numerous papers and published an article entitled "How to Rate Load  
13 Management Programs" in the March 1979 edition of "Electrical World." My article  
14 on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public  
15 Utilities Fortnightly." In February of 1984, I completed a detailed analysis entitled  
16 "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute,  
17 which published the study.

18  
19 I have presented testimony as an expert witness in Arizona, Arkansas, Colorado,  
20 Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan,  
21 Minnesota, Maryland, Missouri, Montana, New Jersey, New Mexico, New York,

1 North Carolina, Ohio, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia,  
2 Wisconsin, and Wyoming. I have also presented testimony as an expert before the  
3 Federal Energy Regulatory Commission ("FERC") and in United States Bankruptcy  
4 Court. A list of my specific regulatory appearances can be found in Baron Exhibit  
5 \_\_\_\_ (SJB-1).  
6

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

9 A. Yes. I have testified in numerous AEP Operating Company rate proceedings in  
10 Virginia (Appalachian Power Company), West Virginia (Appalachian Power  
11 Company), Kentucky (Kentucky Power Company), Ohio (Ohio Power Company,  
12 Columbus and Southern Power Company), Indiana (Indiana Michigan Power  
13 Company), and Louisiana (Southwest Electric Power Company). I have also testified  
14 before FERC in the AEP and Central and Southwest merger case. These cases have  
15 included a range of issues, including issues associated with demand response tariffs.  
16

17 Finally, I presented testimony before the Tennessee Regulatory Authority in  
18 Kingsport's 2012 case regarding PJM Demand Response rate issues (Docket No. 12-  
19 00012), in Kingsport's 2016 general rate case (Docket No. 16-00001) and in  
20 Kingsport's Alternative Rate Mechanism ("ARM") case (Docket No. 17-00032).  
21

1       **Q.     What is the purpose of your testimony?**

2       A.     My testimony responds to the Direct Testimony of Kingsport witness Garry Simmons  
3             regarding the Company's proposal to implement a Storm Damage Rider ("SDR")  
4             tariff to recover previously deferred 2013 and unrecovered 2009 storm damage costs.  
5             My testimony focuses on the design of the Company's proposed rider, specifically the  
6             allocation of costs to each rate class. I have not analyzed, and I do not address, the  
7             reasonableness of the costs that the Company requests for recovery in its proposed  
8             SDR.

9  
10       **Q.     What types of costs are included in the Company's proposed SDR tariff?**

11       A.     The Company is requesting a total of \$1,505,354 in deferred 2013 and unrecovered  
12             2009 storm damage expenses. Over 95% of these costs are associated with a major  
13             storm in 2013, which resulted in significant outages and damage to the Company's  
14             distribution system. As described by Company witnesses Phillip Wright, the 2013  
15             deferred costs were associated with repairing and replacing distribution facilities. The  
16             2009 costs also were associated with damage to Kingsport's distribution system.  
17             None of the costs at issue are associated with the Appalachian Power Company's  
18             ("APCo's") transmission system, which serves Kingsport's customers. Any  
19             transmission related storm damage costs are charged to Kingsport by APCo through  
20             purchased power charges from APCo. Such purchased power costs are passed



1 through to Kingsport's customers through the Fuel and Purchased Power Adjustment  
2 ("FPPA") Rider.  
3

4 **Q. Have you reviewed the Company's proposed SDR tariff?**

5 A. Yes. The SDR is designed to recover the \$1.505 million in previously incurred and  
6 deferred 2013 and 2009 major storm costs from customers served on the Kingsport  
7 distribution system. These customers take service at secondary and primary  
8 distribution voltages. None of the SDR charges would be assigned or recovered from  
9 customers taking service at transmission voltages. As discussed by Mr. Simmons,  
10 such transmission voltage customers do not utilize the Kingsport distribution system  
11 facilities, so such customers are not responsible for these strictly distribution related  
12 costs.  
13

14 **Q. Do you support the Company's proposal to exclude transmission voltage rate**  
15 **schedules from the SDR charges?**

16 A. Yes. The Company properly excludes transmission voltage customers from paying  
17 the SDR because the costs being recovered through the SDR are distribution related  
18 costs. Transmission voltage customers do not use the distribution system. To the  
19 extent that the distribution system required restoration due to the 2009 and 2013  
20 storms, the associated costs are properly charged to distribution related plant and  
21 O&M expenses that are not allocable to transmission customers on a cost of service

1 basis. In other words, there is no basis for assigning transmission voltage customers  
2 the costs of replacing secondary and primary voltage lines, poles and other distribution  
3 facilities because such facilities are not used to serve transmission voltage customers.  
4 As I noted above, Kingsport's transmission voltage customers pay for transmission  
5 service, as do all other Kingsport customers, through the FPPA Rider. Major Storm  
6 costs associated with transmission facilities would be included in APCo's wholesale  
7 charges to Kingsport that are recovered through the FPPA rider.

8  
9 **Q. Does any ratemaking principle support charging transmission voltage customers**  
10 **for storm restoration costs associated with repairing distribution facilities?**

11 A. No. Because these customers do not use such facilities, there is no reasonable  
12 argument for imposing the costs of restoring such facilities on transmission voltage  
13 customers. The Company has properly recognized this important cost causation  
14 principle in its design of the SDR tariff.

15  
16 **Q. Is the Company's proposed SDR cost allocation consistent with prior**  
17 **Commission approved recovery methodologies for distribution related storm**  
18 **damage costs?**

19 A. Yes. As discussed by Company witness Simmons at page 4 of his Direct Testimony,  
20 the Commission previously approved the recovery of 2009 storm damage costs using  
21 the same methodology as the Company is now proposing for its Rider SDR. In Docket

1 No. 12-00051, the Commission's order approved Kingsport's proposed allocation of  
2 storm damage costs to all rate schedules except Industrial Power ("IP") Transmission  
3 because such costs were distribution related costs and were therefore not attributable  
4 to customers taking service directly from the Company's transmission system. All  
5 costs were allocated to rate classes (other than IP-Transmission) using a demand  
6 allocation factor and recovered from customers on a kWh or kW demand basis,  
7 depending on the rate class. The Company follows the same approach in this case  
8 because the costs at issue are similarly distribution related.  
9

10 **Q. Is the Company's proposed methodology consistent with the methodology that**  
11 **Kingsport uses in its fully allocated class cost of service studies to assign cost**  
12 **responsibility for distribution related facilities, including storm related**  
13 **maintenance and replacements?**

14 A. Yes. The Company's class cost of service study presented in Docket No. 16-00001  
15 clearly shows that no distribution costs are assigned to the IP-Transmission rate class.  
16 Baron Exhibit\_\_(SJB-2), which is attached to this testimony, is an excerpt from that  
17 study. The excerpt shows the distribution revenue requirements for each rate class.  
18 These distribution revenue requirements represent the cost of Kingsport's distribution  
19 facilities (lines, poles, transformers) assigned to each rate class.  
20

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

9  
10      **Q. Is the Company's proposed treatment of such costs also consistent with their**  
11      **treatment by other AEP Operating Companies?**

12      A. Yes. I have participated in many AEP rate proceedings over the past 40 years. AEP  
13      affiliates, such as Appalachian Power Company, Kentucky Power Company and Ohio  
14      Power Company, consistently follow this cost causation principle – distribution  
15      related costs, such as secondary and primary lines and poles are not assigned to  
16      transmission voltage customer rate classes.

17  
18      **Q. Is Kingsport's demand allocation methodology consistent with the methods**  
19      **discussed in the National Association of Regulatory Utility Commission Electric**  
20      **Utility Cost Allocation Manual ("NARUC Manual")?**

1       A.     Yes. The NARUC Manual discusses methodologies that are appropriate for the  
2             allocation to customer rate classes of distribution substations, poles, lines,  
3             transformers and meters booked in FERC Accounts 360 to 373. Baron  
4             Exhibit \_\_ (SJB-3) contains an excerpt from Chapter 6 of the NARUC Manual. As can  
5             be seen on page 5 of 17 of that exhibit, all distribution related costs are allocated on  
6             either a demand basis or a customer basis. The Company's proposed demand  
7             allocation of SDR costs to all rate classes, except IP-Transmission, is consistent with  
8             the NARUC methodologies.

9  
10       **Q.     Would there be any basis to allocate storm damage costs on an energy usage (per**  
11             **kWh) basis?**

12       A.     No. Distribution related costs, including storm damage costs associated with repairing  
13             distribution lines, poles and other equipment, are demand related, not energy related.  
14             The NARUC Manual clearly spells this out. So does Kingsport's class cost of service  
15             study. Distribution facilities are planned and installed to meet the maximum kW  
16             demand that might be placed on them. The fact that a rate class might use more energy  
17             (kWh) than another rate class has no bearing on the distribution facilities (lines,  
18             substations, poles, transformers) needed to serve these two rate classes if their  
19             respective kW demands are the same. The fact that one rate class uses more kWh  
20             energy than another during an off-peak period would not impact the size of the  
21             distribution facilities needed to serve that class. As the NARUC Manual discusses, it

1 is the kW demand of the rate class that determines the cost. As such, it would be  
2 unreasonable to assign distribution costs, including storm damage costs, to rate classes  
3 on the basis of such classes' energy usage.  
4

5 **Q. Would there be any basis to allocate the SDR costs to rate classes using the**  
6 **allocation of the revenue increase agreed upon by parties in the Settlement of the**  
7 **Company's recent base rate case (Docket No. 16-00001)?**

8 A. No. First, the Settlement revenue increase allocation applied only to that base rate  
9 case. Second, the Settlement is not based on cost causation. In fact, given the  
10 substantial subsidies that were continuing to be paid in the Settlement rates, it would  
11 be entirely unreasonable to allocate the SDR revenues at issue in this case on the same  
12 basis as the base rate related revenue increases in the Settlement. In particular, using  
13 the Settlement revenue increases to assign distribution related storm damage costs  
14 would result in the IP-Transmission rate class paying for these distribution related  
15 costs; a result contrary to cost responsibility and cost causation.  
16

17 Finally, the Settlement specifically states that the agreed-upon allocation to rate  
18 classes of the overall approved revenue increase in that case is *not* a precedent for  
19 future cost recovery in another case. Specifically, Paragraph 15 of the Stipulation and  
20 Settlement Agreement states: "The Parties agree that the agreed-upon deficiency shall  
21 be allocated to the customer classes as set forth on Schedule 12 and 13 of Attachment

1           A and the Parties agree that the results of such allocations are fair and reasonable *for*  
2           *the limited purpose of resolving this Docket.*” (Emphasis added.) More broadly,  
3           Paragraph 19 states, in part, “that the settlement of an issue provided for herein shall  
4           *not* be cited a precedent by any of the Parties or any other entity in any unrelated or  
5           separate proceeding or docket before the Authority.” (Emphasis added.) Similarly,  
6           Paragraphs 20 and 21 state clearly that the settlement is not precedential.

7  
8       **Q.     Does that complete your testimony?**

9       **A.     Yes.**

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**ON BEHALF OF**  
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**J. KENNEDY AND ASSOCIATES, INC.**  
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**EXHIBIT \_\_ (SJB-1)**  
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**ROSWELL, GEORGIA**

**June 20, 2018**

**Expert Testimony Appearances  
of  
Stephen J. Baron  
As of May 2018**

<b>Date</b>	<b>Case</b>	<b>Jurisdic.</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
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 Intervenor	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 Intervenor	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7	NC	Carolina	Duke Power Co.	Cost-of-service, rate design,

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<b>Date</b>	<b>Case</b>	<b>Jurisdct.</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
	Sub 391		Industrials (CIGFUR III)		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 Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit

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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 Intervenor	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenor	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenor		Proposed rules for cogeneration, avoided cost, rate recovery.
10/87	E-015/GR-87-223	MN	Taconite Intervenor	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.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.

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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.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.

**Expert Testimony Appearances  
of  
Stephen J. Baron  
As of May 2018**

<b>Date</b>	<b>Case</b>	<b>Jurisdic.</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
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 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 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.

**Expert Testimony Appearances  
of  
Stephen J. Baron  
As of May 2018**

<b>Date</b>	<b>Case</b>	<b>Jurisd.</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
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 Intervenor	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenor	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 Intervenor	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 Intervenor	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO <sub>2</sub> 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 (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92	Federal	Louisiana Public	Gulf States	Merger of GSU into Entergy

**Expert Testimony Appearances  
of  
Stephen J. Baron  
As of May 2018**

<b>Date</b>	<b>Case</b>	<b>Jurisdic.</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
	21000 ER92-806- 000 (Rebuttal)	Energy Regulatory Commission	Service Commission Staff	Utilities/Entergy agreement.	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 Intervenor	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 Intervenor	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 Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided 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 &	Proposals to address competition in telecommunication markets.



**Expert Testimony Appearances  
of  
Stephen J. Baron  
As of May 2018**

Date	Case	Jurisdct.	Party	Utility	Subject
				Telegraph Co.	
11/94	EC94-7-000 FERC ER94-898-000		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 PA C-00946104		Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.
8/95	ER95-112 FERC -000		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 FERC -000		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 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	US Bank- ruptcy	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths

**Expert Testimony Appearances  
of  
Stephen J. Baron  
As of May 2018**

<b>Date</b>	<b>Case</b>	<b>Jurisdic.</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
	No. 94-11474	Court Middle District of Louisiana			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 Intervenor	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenor	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	LA	Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735	LA	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.

**Expert Testimony Appearances  
of  
Stephen J. Baron  
As of May 2018**

<b>Date</b>	<b>Case</b>	<b>Jurisdic.</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross- 40-000 Answering Testimony)	EC-98-	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.	Analysis 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.

**Expert Testimony Appearances  
of  
Stephen J. Baron  
As of May 2018**

<b>Date</b>	<b>Case</b>	<b>Jurisdic.</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
08/00	98-0452 E-GI	WV	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	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
09/00	00-1178-E-T	WV	West Virginia Energy Users Group	Appalachian Power Co. Wheeling Power 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.

**Expert Testimony Appearances  
of  
Stephen J. Baron  
As of May 2018**

<b>Date</b>	<b>Case</b>	<b>Jurisdic.</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
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 Intervenor	Duquesne Light Company	Provider of last resort issues.
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybdenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.

**Expert Testimony Appearances  
of  
Stephen J. Baron  
As of May 2018**

<b>Date</b>	<b>Case</b>	<b>Jurisd.</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
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	WV	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.
03/06	05-1278-E-PC -PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. Wheeling Power Co.	Retail cost of service, rate design.
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.

**Expert Testimony Appearances  
of  
Stephen J. Baron  
As of May 2018**

<b>Date</b>	<b>Case</b>	<b>Jurisdic.</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
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 allocation, 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	Environmental Surcharge Rate Design Southern Power
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 Intervenor	West Penn Power Co.	Default Service Plan issues.
3/08	Doc No. E-01933A-05-0650	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design

**Expert Testimony Appearances  
of  
Stephen J. Baron  
As of May 2018**

<b>Date</b>	<b>Case</b>	<b>Jurisdct.</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
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. OH 08-124-EL-ATA		Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Recovery of Deferred Fuel Cost
7/08	Docket No. UT 07-035-93		Kroger Company	Rocky Mountain Power Co.	Cost of Service, Rate Design
08/08	Doc. No. WI 6680-UR-116		Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Doc. No. WI 6690-UR-119		Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Case No. OH 08-936-EL-SSO		Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Competitive Solicitation
09/08	Case No. OH 08-935-EL-SSO		Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
09/08	Case No. OH 08-917-EL-SSO 08-918-EL-SSO		Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Provider of Last Resort Rate Plan
10/08	2008-00251 KY 2008-00252		Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
11/08	08-1511 WV E-GI		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 -00016	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Fuel Cost Recovery Rider



**Expert Testimony Appearances  
of  
Stephen J. Baron  
As of May 2018**

<b>Date</b>	<b>Case</b>	<b>Jurisd.</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
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 Intervenor	Minnesota Power Co.	Cost of Service, rate design
4/10	EL09-61	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to off-system sales
4/10	2009-00459	KY	Kentucky Industrial	Kentucky Power Company	Cost of service, rate design,

**Expert Testimony Appearances  
of  
Stephen J. Baron  
As of May 2018**

Date	Case	Jurisd.	Party	Utility	Subject
			Utility Customers, Inc.		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. 11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Electric Security Rate Plan, Stipulation Support Testimony
10/11	11-0452	WV	West Virginia	Mon Power Co.	Energy Efficiency/Demand Reduction

**Expert Testimony Appearances  
of  
Stephen J. Baron  
As of May 2018**

<b>Date</b>	<b>Case</b>	<b>Jurisd.</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
	E-P-T		Energy Users Group	Potomac Edison Co.	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	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
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	Entergy Services, Inc.	System Agreement Issues

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<b>Date</b>	<b>Case</b>	<b>Jurisd.</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
			Service Commission	and the Entergy Operating Companies	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/11-1775-E-P	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-GI	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-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Right-of-Way, Vegetation Control Cost 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

**Expert Testimony Appearances  
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As of May 2018**

<b>Date</b>	<b>Case</b>	<b>Jurisdic.</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
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-GI	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-SSO	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 Companies	System Agreement Issues Related to Interruptible load
5/15	15-0301- E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
5/15	15-0303-	WV	West Virginia Energy	Appalachian Power	Energy Efficiency/Demand Response

**Expert Testimony Appearances  
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As of May 2018**

<b>Date</b>	<b>Case</b>	<b>Jurisdic.</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
	E-P		Users Group	Company, Wheeling Power Co.	
6/15	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
06/16	15-1734-E- T-PC	WV	West Virginia Energy Users Group	Appalachian Power Company, Wheeling Power Co.	Demand Response Rider
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

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As of May 2018**

<b>Date</b>	<b>Case</b>	<b>Jurisdic.</b>	<b>Party</b>	<b>Utility</b>	<b>Subject</b>
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- Service, Rate Design 16-0036	AZ	Kroger		Arizona Public Service Co. Cost of
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
7/17	17-00032	TN	East Tennessee Energy Consumers	Kingsport Power Co.	Vegetation Management Cost Recovery
8/17	17-0631- E-P	WV	West Virginia Energy Users Group	Monongahela Power Co.	Electric Energy Purchase Agreement
8/17	17-0296- E-PC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation Resource Asset Transfer
9/17	2017-0179	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission cost recovery.
9/17	17-0401 E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Issues
12/17	17-0894- E-PC	WV	West Virginia Energy Users Group	Appalachian Power Co.	Wind Project Asset Purchase
5/18	1150/ 1151	D.C.	Healthcare Council of the National Capital Area	Potomac Electric Power Co.	Cost of Service, Rate Design Tax Cut and Jobs Act Issues

**BEFORE THE**  
**TENNESSEE PUBLIC UTILITY COMMISSION**  
**NASHVILLE, TENNESSEE**

**PETITION OF**  
**KINGSPORT POWER COMPANY**  
**d/b/a AEP Appalachian Power**  
**For Approval of a Storm Damage Rider**  
**Tariff (SDR)**

**Docket No. 17-00143**

**EXHIBIT \_\_ (SJB-2)**  
**OF**  
**STEPHEN J. BARON**

**ON BEHALF OF**  
**EAST TENNESSEE ENERGY CONSUMERS**  
**J. KENNEDY AND ASSOCIATES, INC.**  
**ROSWELL, GEORGIA**

**June 20, 2018**



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

Allocation Factor	Total Retail 1	RS 2	SGS 3	MGS-SEC 4	MGS-PRI 5	MGS-SUB 6	LGS-SEC 7	LGS-PRI 8	LGS-SUB 9
<b>Allocator for Account 365</b>									
DIST_OH LINES DISTPRI	0.74910000	0.50903264	0.00994903	0.06011799	0.00026527	-	0.09730199	0.00769274	-
DIST_OH LINES DISTSEC	0.25090000	0.19057884	0.00358693	0.01652522	-	-	0.02418453	-	-
<b>Allocator for Accounts 583 and 593</b>									
TOTOH LINES DISTPRI	0.64673877	0.43947556	0.00858954	0.05190313	0.00022902	-	0.08400610	0.00664156	-
TOTOH LINES DISTSEC	0.35326123	0.26833047	0.00505032	0.02326711	-	-	0.03405124	-	-
<b>Allocator for Account 594 (Maint. of UG Lines)</b>									
TOTUG LINES DISTPRI	0.71110000	0.48321067	0.00944434	0.05706835	0.00025181	-	0.09236610	0.00730250	-
TOTUG LINES DISTSEC	0.28890000	0.21944291	0.00413019	0.01902804	-	-	0.02784739	-	-
<b>Proposed Revenue at Equal ROR (including SL)</b>									
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
<b>Allocator for Account 365</b>								
DIST_OH LINES DISTPRI	0.02467896	-	-	0.00603406	0.01720575	0.01526046	0.00052139	0.00103972
DIST_OH LINES DISTSEC	-	-	-	0.00271237	0.00608805	0.00537861	0.00071249	0.00113296
<b>Allocator for Accounts 583 and 593</b>								
TOTOH LINES DISTPRI	0.02130669	-	-	0.00520953	0.01485466	0.01317519	0.00045014	0.00089765
TOTOH LINES DISTSEC	-	-	-	0.00381895	0.00857183	0.00757296	0.00100317	0.00159518
<b>Allocator for Account 594 (Maint. of UG Lines)</b>								
TOTUG LINES DISTPRI	0.02342706	-	-	0.00572796	0.01633295	0.01448634	0.00049494	0.00098698
TOTUG LINES DISTSEC	-	-	-	0.00312317	0.00701011	0.00619323	0.00082040	0.00130455
<b>Proposed Revenue at Equal ROR (including SL)</b>								
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 a Storm Damage Rider**  
**Tariff (SDR)**

**Docket No. 17-00143**

**EXHIBIT \_\_ (SJB-3)**  
**OF**  
**STEPHEN J. BARON**

**ON BEHALF OF**  
**EAST TENNESSEE ENERGY CONSUMERS**  
**J. KENNEDY AND ASSOCIATES, INC.**  
**ROSWELL, GEORGIA**

**June 20, 2018**

# ELECTRIC UTILITY COST ALLOCATION MANUAL



NATIONAL ASSOCIATION OF REGULATORY UTILITY  
COMMISSIONERS

January, 1992

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# PREFACE

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**T**his project was jointly assigned to the NARUC Staff Subcommittees on Electricity and Economics in February, 1985. Jack Doran, at the California PUC had led a task force in 1969 that wrote the original **Cost Allocation Manual**; the famous "Green Book". I was asked to put together a task force to revise it and include a Marginal Cost section.

I knew little about the subject and was not sure what I was getting into so I asked Jack how he had gone about drafting the first book. "Oh" he said, "There wasn't much to it. We each wrote a chapter and then exchanged them and rewrote them." What Jack did not tell me was that like most NARUC projects, the work was done after five o'clock and on weekends because the regular work always takes precedence. It is a good thing we did not realize how big a task we were tackling or we might never have started.

There was great interest in the project so when I asked for volunteers, I got plenty. We split into two working groups; embedded cost and marginal cost. Joe Jenkins from the Florida PSC headed up the Embedded Cost Working Group and Sarah Voll from the New Hampshire PUC took the Marginal Cost Working Group. We followed Jack's suggestions but, right from the beginning, we realized that once the chapters were technically correct, we would need a single editor to cast them all "into one hand" as Joe Jenkins put it. Steven Mintz from the Department of Energy volunteered for this task and has devoted tremendous effort to polishing the book into the final product you hold in your hands. Victoria Jow at the California PUC took Steven's final draft and desktop published the entire document using Ventura Publisher.

We set the following objectives for the manual:

- It should be simple enough to be used as a primer on the subject for new employees yet offer enough substance for experienced witnesses.
- It must be comprehensive yet fit in one volume.
- The writing style should be non-judgmental; not advocating any one particular method but trying to include all currently used methods with pros and cons.

It is with extreme gratitude that I acknowledge the energy and dedication contributed by the following task force members over the last five years.

Steven Mintz, Department of Energy, Editor; Joe Jenkins, Florida PSC, Leader, Embedded Cost Working Group; Sarah Voll, New Hampshire PUC, Leader, Marginal Cost Working Group; Victoria Jow, California PUC; John A. Anderson, ELCON; Jess Galura, Sacramento MUD; Chris Danforth, California PUC; Alfred Escamilla, Southern California Edison; Byron Harris, West Virginia CAD; Steve Houle, Texas Utility Electric Co.; Kevin Kelly, formally NRRI; Larry Klapow California PUC; Jim Ketter P.E., Missouri PSC; Ed Lucero, Price Waterhouse; J. Robert Malko, Utah State University; George McCluskey, New Hampshire PUC; Marge Meeter, Florida PSC; Gordon Murdock, The FERC; Dennis Nightingale, North Carolina UC; John Orecchio, The FERC; Carl Silsbee, Southern California Edison; Ben Turner, North Carolina UC; Dr. George Parkins, Colorado PUC; Warren Wendling, Colorado PUC; Schef Wright, formally Florida PSC; **IN MEMORIAL** Bob Kennedy Jr., Arkansas PSC.

Julian Ajello  
California PUC

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## CHAPTER 6

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### CLASSIFICATION AND ALLOCATION OF DISTRIBUTION PLANT

**D**istribution plant equipment reduces high-voltage energy from the transmission system to lower voltages, delivers it to the customer and monitors the amounts of energy used by the customer.

Distribution facilities provide service at two voltage levels: primary and secondary. Primary voltages exist between the substation power transformer and smaller line transformers at the customer's points of service. These voltages vary from system to system and usually range between 480 volts to 35 KV. In the last few years, advances in equipment and cable technology have permitted the use of higher primary distribution voltages. Primary voltages are reduced to more usable secondary voltages by smaller line transformers installed at customer locations along the primary distribution circuit. However, some large industrial customers may choose to install their own line transformers and take service at primary voltages because of their large electrical requirements.

In some cases, the utility may choose to install a transformer for the exclusive use of a single commercial or industrial customer. On the other hand, in service areas with high customer density, such as housing tracts, a line transformer will be installed to serve many customers. In this case, secondary voltage lines run from pole-to-pole or from handhole-to-handhole, and each customer is served by a drop tapped off the secondary line leading directly to the customer's premise.

#### I. COST ACCOUNTING FOR DISTRIBUTION PLANT AND EXPENSES

**T**he Federal Energy Regulatory Commission (FERC) Uniform System of Accounts requires separate accounts for distribution investment and expenses. Distribution plant accounts are summarized and classified in Table 6-1. Distribution expense accounts are summarized and classified in Table 6-2. Some utilities may choose to establish subaccounts for more detailed cost reporting.

TABLE 6-1  
CLASSIFICATION OF DISTRIBUTION PLANT<sup>1</sup>

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Distribution Plant <sup>2</sup>		
360	Land & Land Rights	X	X
361	Structures & Improvements	X	X
362	Station Equipment	X	-
363	Storage Battery Equipment	X	-
364	Poles, Towers, & Fixtures	X	X
365	Overhead Conductors & Devices	X	X
366	Underground Conduit	X	X
367	Underground Conductors & Devices	X	X
368	Line Transformers	X	X
369	Services	-	X
370	Meters	-	X
371	Installations on Customer Premises	-	X
372	Leased Property on Customer Premises	-	X
373	Street Lighting & Signal Systems <sup>1</sup>	-	-

<sup>1</sup> Assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

<sup>2</sup> The amounts between classification may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.



TABLE 6-2  
CLASSIFICATION OF DISTRIBUTION EXPENSES<sup>1</sup>

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Operation <sup>2</sup>		
580	Operation Supervision & Engineering	X	X
581	Load Dispatching	X	-
582	Station Expenses	X	-
583	Overhead Line Expenses	X	X
584	Underground Line Expenses	X	X
585	Street Lighting & Signal System Expenses <sup>1</sup>	-	-
586	Meter Expenses	-	X
587	Customer Installation Expenses	-	X
588	Miscellaneous Distribution Expenses	X	X
589	Rents	X	X
	Maintenance <sup>2</sup>		
590	Maintenance Supervision & Engineering	X	X
591	Maintenance of Structures	X	X
592	Maintenance of Station Equipment	X	-
593	Maintenance of Overhead Lines	X	X
594	Maintenance of Underground Lines	X	X
595	Maintenance of Line Transformers	X	X
596	Maint. of Street Lighting & Signal Systems <sup>1</sup>	-	-
597	Maintenance of Meters	-	X
598	Maint. of Miscellaneous Distribution Plants	X	X

<sup>1</sup>Direct assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

<sup>2</sup>The amounts between classifications may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

To ensure that costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst's evaluation of how the costs in these accounts were incurred. In making this determination, supporting data may be more important than theoretical considerations.

Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses. This will ensure that costs are assigned to the correct functional groups for classification and allocation. As indicated in Chapter 4, all costs of service can be identified as energy-related, demand-related, or customer-related. Because there is no energy component of distribution-related costs, we need consider only the demand and customer components.

To recognize voltage level and use of facilities in the functionalization of distribution costs, distribution line costs must be separated into overhead and underground, and primary and secondary voltage classifications. A typical functionalization and classification of distribution plant would appear as follows:

Substations: Distribution:	Demand
	Overhead Primary
	Demand
	Customer
	Overhead Secondary
	Demand
	Customer
	Underground Primary
	Demand
	Customer
	Underground Secondary
	Demand
	Customer
	Line Transformers
	Demand
	Customer
Services:	Overhead
	Demand
	Customer
	Underground
	Demand
	Customer
Meters:	Customer
Street Lighting:	Customer
Customer Accounting:	Customer
Sales:	Customer

From this breakdown it can be seen that each distribution account must be analyzed before it can be assigned to the appropriate functional category. Also, these accounts must be classified as demand-related, customer-related, or both. Some utilities assign distribution to customer-related expenses. Variations in the demands of various customer groups are used to develop the weighting factors for allocating costs to the appropriate group.

## **II. DEMAND AND CUSTOMER CLASSIFICATIONS OF DISTRIBUTION PLANT ACCOUNTS**

When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs.

Classifying distribution plant as a demand cost assigns investment of that plant to a customer or group of customers based upon its contribution to some total peak load. The reason is that costs are incurred to serve area load, rather than a specific number of customers.

Distribution substations costs (which include Accounts 360 -Land and Land Rights, 361 - Structures and Improvements, and 362 -Station Equipment), are normally classified as demand-related. This classification is adopted because substations are normally built to serve a particular load and their size is not affected by the number of customers to be served.

Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system. As shown in Table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.

### **A. The Minimum-Size Method**

Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines

the price of all installed units. Once determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and customer-related costs. Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method (to be discussed). The following describes the methodologies for determining the minimum size for distribution plant Accounts 364, 365, 366, 367, 368, and 369.

**1. Account 364 - Poles, Towers, and Fixtures**

- Determine the average installed book cost of the minimum height pole currently being installed.
- Multiply the average book cost by the number of poles to find the customer component. Balance of plant account is the demand component.

**2. Account 365 - Overhead Conductors and Devices**

- Determine minimum size conductor currently being installed.
- Multiply average installed book cost per mile of minimum size conductor by the number of circuit miles to determine the customer component. Balance of plant account is demand component. (Note: two conductors in minimum system.)

**3. Accounts 366 and 367 - Underground Conduits, Conductors, and Devices**

- Determine minimum size cable currently being installed.
- Multiply average installed book cost per mile of minimum size cable by the circuit miles to determine the customer component. Balance of plant Account 367 is demand component. (Note: one cable with ground sheath is minimum system.) Account 366 conduit is assigned, based on ratio of cable account.
- Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component. Balance of plant account is demand component.

**4. Account 368 - Line Transformers**

- Determine minimum size transformer currently being installed.

- Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component.

#### 5. Account 369 - Services

- Determine minimum size and average length of services currently being installed.
- Estimate cost of minimum size service and multiply by number of services to get customer component.
- If overhead and underground services are booked separately, they should be handled separately. Most companies do not book service by size. This requires an engineering estimate of the cost of the minimum size, average length service. The resultant estimate is usually higher than the average book cost. In addition, the estimate should be adjusted for the average age of service, using a trend factor.

### **B. The Minimum-Intercept Method**

The minimum-intercept method seeks to identify that portion of plant related to a hypothetical no-load or zero-intercept situation. This requires considerably more data and calculation than the minimum-size method. In most instances, it is more accurate, although the differences may be relatively small. The technique is to relate installed cost to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no-load intercept. The cost related to the zero-intercept is the customer component. The following describes the methodologies for determining the minimum intercept for distribution-plant Accounts 364, 365, 366, 367, and 368.

#### 1. Account 364 - Poles, Towers, and Fixtures

- Determine the number, investment, and average installed book cost of distribution poles by height and class of pole. (Exclude stubs for guying.)
- Determine minimum intercept of pole cost by creating a regression equation, relating classes and heights of poles, and using the Class 7 cost intercept for each pole of equal height weighted by the number of poles in each height category.
- Multiply minimum intercept cost by total number of distribution poles to get customer component.

- Balance of pole investment is assigned to demand component.
- Total account dollars are assigned based on ratio of pole investment. (Transformer platforms in Account 364 are all demand-related. They should be removed before determining the account ratio of customer- and demand-related costs, and then they should be added to the demand portion of Account 364.)

## 2. Account 365 - Overhead Conductors and Devices

- If accounts are divided between primary and secondary voltages, develop a customer component separately for each. The total investment is assigned to primary and secondary; then the customer component is developed for each. Since conductors generally are of many types and sizes, select those sizes and types which represent the bulk of the investment in this account, if appropriate.
- When developing the customer component, consider only the investment in conductors, and not such devices as circuit breakers, insulators, switches, etc. The investment in these devices will be assigned later between the customer and demand component, based on the conductor assignment.
  - Determine the feet, investment, and average installed book cost per foot for distribution conductors by size and type.
  - Determine minimum intercept of conductor cost per foot using cost per foot by size and type of conductor weighted by feet or investment in each category, and developing a cost for the utility's minimum size conductor.
  - Multiply minimum intercept cost by the total number of circuit feet times 2. (Note that circuit feet, not conductor feet, are used to get customer component.)
  - Balance of conductor investment is assigned to demand.
  - Total primary or secondary dollars in the account, including devices, are assigned to customer and demand components based on conductor investment ratio.

## 3. Accounts 366 and 367 - Underground Conduits, Conductors, and Devices

- The customer demand component ratio is developed for conductors and applied to conduits. Underground conductors are generally booked by type and size of conductor for both one-conductor (1/c) cable and three-conductor (3/c) cables. If conductors are booked by voltage, as between primary and secondary, a customer component is

developed for each. If network and URD investments are segregated, a customer component must be developed for each.

- The conductor sizes and types for the customer component derivation are restricted to I/c cable. Since there are generally many types and sizes of I/c cable, select those sizes and types which represent the bulk of the investment, when appropriate.
  - Determine the feet, investment, and average installed book cost per foot for I/c cables by size and type of cable.
  - Determine minimum intercept of cable cost per foot using cost per foot by size and type of cable weighted by feet of investment in each category.
  - Multiply minimum intercept cost by the total number of circuit feet (I/c cable with sheath is considered a circuit) to get customer component.
  - Balance of cable investment is assigned to demand.
  - Total dollars in Accounts 366 and 367 are assigned to customer and demand components based on conductor investment ratio.

#### 4. Account 368 - Line Transformers

- The line transformer account covers all sizes and voltages for single- and three-phase transformers. Only single-phase sizes up to and including 50 KVA should be used in developing the customer components. Where more than one primary distribution voltage is used, it may be appropriate to use the transformer price from one or two predominant, selected voltages.
  - Determine the number, investment, and average installed book cost per transformer by size and type (voltage).
  - Determine zero intercept of transformer cost using cost per transformer by type, weighted by number for each category.
  - Multiply zero intercept cost by total number of line transformers to get customer component.
  - Balance of transformer investment is assigned to demand component.
  - Total dollars in the account are assigned to customer and demand components based on transformer investment ratio from customer and demand components.

### C. The Minimum-System vs. Minimum-Intercept Approach

When selecting a method to classify distribution costs into demand and customer costs, the analyst must consider several factors. The minimum-intercept method can sometimes produce statistically unreliable results. The extension of the regression equation beyond the boundaries of the data normally will intercept the Y axis at a positive value. In some cases, because of incorrect accounting data or some other abnormality in the data, the regression equation will intercept the Y axis at a negative value. When this happens, a review of the accounting data must be made, and suspect data deleted.

The results of the minimum-size method can be influenced by several factors. The analyst must determine the minimum size for each piece of equipment: "Should the minimum size be based upon the minimum size equipment currently installed, historically installed, or the minimum size necessary to meet safety requirements?" The manner in which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs.

Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.

When allocating distribution costs determined by the minimum-size method, some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs.

Advocates of the minimum-intercept method contend that this problem does not exist when using their method. The reason is that the customer cost derived from the minimum-intercept method is based upon the zero-load intercept of the cost curve. Thus, the customer cost of a particular piece of equipment has no demand cost in it whatsoever.

### D. Other Accounts

The preceding discussion of the merits of minimum-system versus the zero-intercept classification schemes will affect the major distribution-plant accounts for FERC Accounts 364 through 368. Several other plant accounts remain to be classified. While the classification of the following distribution-plant accounts is an important step,



it is not as controversial as the classification of substations, poles, transformers, and conductors.

**1. Account 369 - Services**

This account is generally classified as customer-related. Classification of services may also include a demand component to reflect the fact that larger customers will require more costly service drops.

**2. Account 370 - Meters**

Meters are generally classified on a customer basis. However, they may also be classified using a demand component to show that larger-usage customers require more expensive metering equipment.

**3. Account 371 - Installations on Customer Premises**

This account is generally classified as customer-related and is often directly assigned. The kind of equipment in this account often influences how this account is treated. The equipment in this account is owned by the utility, but is located on the customer's side of the meter. A utility will often include area lighting equipment in this account and assign the investment directly to the lighting customer class.

**4. Account 373 - Street Lighting and Signal Systems**

This account is generally customer-related and is directly assigned to the street customer class.

**III. ALLOCATION OF THE DEMAND AND CUSTOMER COMPONENTS OF DISTRIBUTION PLANT**

After completing the classification of distribution plant accounts, the next major step in the cost of service process is to allocate the classified costs. Generally, determining the distribution-demand allocator will require more data and analysis than determining the customer allocators. Following are procedures used to calculate the demand and customer allocation factors.

**A. Development of the Distribution Demand Allocators**

There are several factors to consider when allocating the demand components of distribution plant. Distribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads. Distribution substations are designed to meet the maximum load from the distribution feeders emanating from the substation.

Similarly, when designing primary and secondary distribution feeders, the distribution engineer ensures that sufficient conductor and transformer capacity is available to meet the customer's loads at the primary- and secondary-distribution service levels. Local area loads are the major factors in sizing distribution equipment. Consequently, customer-class noncoincident demands (NCPs) and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of distribution facilities. The customer-class load characteristic used to allocate the demand component of distribution plant (whether customer class NCPs or the summation of individual customer maximum demands) depends on the load diversity that is present at the equipment to be allocated. The load diversity at distribution substations and primary feeders is usually high. For this reason, customer-class peaks are normally used for the allocation of these facilities. The facilities nearer the customer, such as secondary feeders and line transformers, have much lower load diversity. They are normally allocated according to the individual customer's maximum demands. Although these are the methods normally used for the allocation of distribution demand costs, some exceptions exist.

The load diversity differences for some utilities at the transmission and distribution substation levels may not be large. Consequently, some large distribution substations may be allocated using the same method as the transmission system. Before the cost analyst selects a method to allocate the different levels of distribution facilities, he must know the design and operational characteristics of the distribution system, as well as the demand losses at each level of the distribution system.

As previously indicated, the distribution system consists of several levels. The first level starts at the distribution substation, and the last level ends at the customer's meters. Power losses occur at each level and should be included in the demand allocators. Power losses are incorporated into the demand allocators by showing different demand loss factors at each predominant voltage level. The demand loss factor used to develop the primary-distribution demand allocator will be slightly larger than the demand loss factor used to develop the secondary demand allocator. When developing the distribution demand allocator, be aware that some customers take service at different voltage levels.

Cost analysts developing the allocator for distribution of substations or primary demand facilities must ensure that only the loads of those customers who benefit from these facilities are included in the allocator. For example, the loads of customers who take service at transmission level should not be reflected in the distribution substation or primary demand allocator. Similarly, when analysts develop the allocator for secondary demand facilities, the loads for customers served by the primary distribution system should not be included.

Utilities can gather load data to develop demand allocators, either through their load research program or their transformer load management program. In most cases, the load research program gathers data from meters on the customers' premises. A more complex procedure is to use the transformer load management program.

This procedure involves simulating load profiles for the various classes of equipment on the distribution system. This provides information on the nature of the load diversity between the customer and the substation, and its effect on equipment cost. Determining demand allocators through simulation provides a first-order load approximation, which represents the peak load for each type of distribution equipment.

The concept of peak load or "equipment peak" for each piece of distribution equipment can be understood by considering line transformers. If a given transformer's loading for each hour of a month can be calculated, a transformer load curve can be developed. By knowing the types of customers connected to each load management transformer, a simulated transformer load profile curve can be developed for the system. This can provide each customer's class demand at the time of the transformer's peak load. Similarly, an equipment peak can be defined for equipment at each level of the distribution system. Although the equipment peak obtained by this method may not be ideal, it will closely approximate the actual peak. Thus, this method should reflect the different load diversities among customers at each level of the distribution system. An illustration of the simulation procedure is provided in Appendix 6-A.

### **B. Allocation of Customer-Related Costs**

When the demand-customer classification has been completed, most of the assumptions will have been made that affect the results of the completed cost of service study.

The allocation of the customer-related portion of the various plant accounts is based on the number of customers by classes of service, with appropriate weightings and adjustments. Weighting factors reflect differences in characteristics of customers within a given class, or between classes. Within a class, for instance, we may want to give more weighting of a certain plant account to rural customers, as compared to urban customers. The metering account is a clear example of an account requiring weighting for differences between classes. A metering arrangement for a single industrial customer may be 20 to 80 times as costly as the metering for one residential customer.

While customer allocation factors should be weighted to offset differences among various types of customers, highly refined weighting factors or detailed and time consuming studies may not seem worthwhile. Such factors applied in this final step of the cost study may affect the final results much less than such basic assumptions as the demand-allocation method or the technique for determining demand-customer classifications.

Expense allocations generally are based on the comparable plant allocator of the various classes. For instance, maintenance of overhead lines is generally assumed to be directly related to plant in overhead conductors and devices. Exceptions to this rule will occur in some accounts. Meter expenses, for example, are often a function of

maintenance and testing schedules related more to revenue per customer than to the cost of the meters themselves.