COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

ELECTRONIC TARIFF FILING OF KENTUCKY	**)**	
POWER COMPANY FOR APPROVAL OF A	**)**	
SPECIAL CONTRACT WITH EBON	**)**	**CASE NO. 2022-0387**
INTERNATIONAL, LLC	**)**	

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

OFFICE OF THE ATTORNEY GENERAL OF THE COMMONWEALTH OF KENTUCKY

AND

THE KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

February 2023

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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. 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 Atlanta, Georgia.

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

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

Q. Please state your educational background and experience.

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida.

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

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

Q. Have you previously presented testimony before the Kentucky Public Service Commission?

A. Yes. I have testified before the Kentucky Public Service Commission ("Commission") in 32 cases over the past forty years, including numerous Kentucky Power Company ("Kentucky Power, "KPCo" or the "Company") cases. I have also testified in numerous American Electric Power ("AEP") cases in other jurisdictions, including Ohio, West Virginia, Virginia, Indiana, Louisiana, Tennessee, and before the FERC.

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

A. I am testifying on behalf of the Office of the Attorney General of the Commonwealth of Kentucky ("AG") and the Kentucky Industrial Utility Customers, Inc. ("KIUC").

Q. What is the purpose of your testimony?

A. I provide testimony on the reasonableness of KPCo's proposed Special Contract with Ebon International, LLC ("Ebon"). My testimony responds to the testimony of Company witness Brian West and the Company's economic analysis that purports to demonstrate that the proposed contract terms and rates do not result in economic harm to the Company's other customers. I will discuss the Company's study (referred to as a "marginal cost study" in Mr. West's testimony) and identify a number of flaws that result in an incorrect conclusion regarding the impact on

KPCo and its other customers from the addition of the 250 MW and 2 billion kWh (annual) Ebon load pursuant to the Special Contract. I will discuss each of these problems and present a corrected analysis that shows that the Ebon load addition, under the terms and rates of the Special Contract will very likely result in significant harm to other customers.

II. SUMMARY AND CONCLUSIONS

Q. Would you summarize your conclusions and recommendations?

A. The Ebon Special Contract is not in the Public Interest and should not be approved because the revenues that will be paid by Ebon over the life of the contract (10-years) are likely to be significantly below the incremental costs incurred by KPCo in serving Ebon. This means that the Company's customers will pay millions of dollars in higher rates as a result of the contract. In light of my conclusion that the Special Contract will result in net harm to customers, I am recommending that the Commission reject the Company's request for approval.

The Ebon contract, parts of which are confidential, includes rate provisions that are based on three public KPCo tariffs and some additional non-public provisions. The three KPCo tariffs are: Rate IGS, Tariff E.D.R. (Economic Development Rider) and Rider D.R.S. (Demand Response Service, which is an interruptible rate credit mechanism).

The primary issue in this case is whether the rates and revenues paid by Ebon will be sufficient to cover the expected incremental costs imposed on KPCo from serving Ebon. My analysis shows that this not the case with the Ebon contract.

Over the 10-year contract term, KPCo's customers will pay an extra $69 million in electric rates on a net present value basis ($93 million on a nominal basis), in exchange for the promised creation of 100 jobs. These jobs are not guaranteed to be created – rather, they are expected jobs.

There are significant additional risks that KPCo and its customers will face that could raise the harm from the contract to $209 million or more on an NPV basis. These risks are associated with the Company's assumptions that it will be able to interrupt Ebon down to 25 MW 1) during each of the PJM 5 CP hours used to determine KPCo's generation capacity obligation; 2) during the AEP Zonal Network Service Peak Load hour (NSPL); and 3) during 5 of the 12 AEP East Company monthly coincident peak hours (12 CP). The Company's analysis assumes success in interrupting Ebon during 11 of the 18 critical hours each year, even though there are only 20 opportunities under the contract for the Company to call for an interruption.

The PJM 5 CP hours can occur any time across all of PJM during the four summer months. If KPCo fails to interrupt Ebon during any of the PJM 5 CP hours used to determine the KPCo PJM capacity obligation, then KPCo and its customers will incur millions of dollars of additional costs. The NSPL hour in the AEP East Zone is used to assign transmission costs among the AEP East Companies and non-affiliate transmission customers in the AEP Zone. The NSPL hour can occur at any time during the year, winter or summer. The AEP East Companies' 12 CP factor is used to allocate transmission costs among the AEP Operating Companies, including KPCo. If KPCo fails to interrupt Ebon during the monthly peak in only 4 of these 12 months, instead of the 5 months as the Company assumes, then the incremental transmission costs will increase by $23 million (NPV). Hitting all of the PJM 5 CP hours, the single NSPL hour and 5 of the 12 CP hours with only 20 chances appears to be very risky.

Q. At page 8 of KPCo witness Brian West's testimony, he states that the Ebon Special Contract produces "rates sufficient to cover all marginal cost associated with Ebon's proposed load." Is Mr. West's conclusion that the contract will cover incremental costs, correct?

A. No. The Company's marginal cost analysis is flawed. The analysis includes incorrect Ebon revenues in year 5. The analysis fails to to reflect the Incremental Discount. The Company's analysis incorrectly assumes that it will not incur any incremental generating costs associated with the 25 MW of Ebon's load that is firm. The Company unreasonably assumed a constant price for energy purchased from the PJM market to serve Ebon over the entire 10-year period. For transmission expenses, the Company unreasonably assumed that transmission costs will increase at 5% per year, when actual transmission costs have been increasing at 12% per year for the last 6 years. When these corrections are properly reflected in the marginal cost/economic analysis, the Company's net benefits of $96 million[1] ($65 million on an NPV basis) turn into <u>net costs to KPCo's customers of $93 million ($69 million NPV).</u>

Q. Based on your analysis, what is the of the impact of the Ebon contract on a typical residential customer?

A. A typical residential customer would pay an additional $33 per year in KPCo electric charges for each year of 10-year Ebon contract. This is based on my base case analysis that shows a total 10-year harm of $69 million (NPV). If the harm increased to $209 million (NPV) due to failures to interrupt Ebon during the critical

[1] See KPCo ERRATA BKW-Exhibit 2.

11 hours discussed earlier, a typical residential customer could experience an annual bill increase of $103 per year.

Q. Would you summarize the results of your economic analysis?

A. Table 1 below summarizes the corrections/revisions that I have made to the Company's analysis that was presented in ERRATA BKW-Exhibit 2. I will explain these results in the remainder of my testimony.

Table 1
Summary of Corrected Ebon 10-Year Economic Analysis Results

	Benefits/(Costs) $Millions Nominal	Benefits/(Costs) $Millions NPV
Company ERRATA BKW-Exhibit 2	96.0	64.6
Correction to Include Generation Capacity Costs	76.8	51.1
Correction to Fix Year 5 Revenue, Incorrect EDR Discounts	62.6	39.7
Revision to Reflect PJM Market Energy Price	-42.3	-36.5
Revision to Reflect Correct Transmission Costs	**-92.9**	**-68.8**

III. EBON SPECIAL CONTRACT ECONOMIC ANALYSIS

Q. Please describe your understanding of the proposed Special Contract with Ebon?

A. The key provisions of the 10-year Ebon Special Contract are:

1. KPCo will provide, after the first transition year, service to Ebon at a transmission voltage to serve a load of 250 MW at an expected 90% load factor. This produces an annual energy requirement of almost 2 billion kWh.

2. The 250 MW Ebon load consists of 25 MW of firm load and 225 MW of interruptible load, pursuant to the provisions of the Company's standard interruptible load tariff, Rider D.R.S. Rider D.R.S. provides a monthly credit of \$5.50/kW for each kW of billing demand subject to interruption. Based on an expected 225 MW of interruptible load, Ebon will receive an annual interruptible credit on its electric bill of \$14.85 million, the cost of which will be recovered from the Company's other customers through Rider PPA. There is no penalty if Ebon curtails only 90% of its 225 MW of interruptible load.

4. In addition to the D.R.S. interruptible credit, the Special Contract provides for Ebon to receive significant discounts for the first 5 contract years based on the provisions of the Company's Economic Development Rate ("EDR").

5. The Contract includes an Incremental Discount tied to the number of jobs created.

6. Ebon will be billed on the Company's standard IGS tariff, subject to reductions based on the EDR tariff and Rider D.R.S. and other contract provisions.

7. Ebon will construct a distribution substation that will permit interconnection of the Ebon load to the Company's transmission system. Ebon will pay for the substation and all required interconnection costs to tie the substation

into the transmission system. In year 1 of the contract, KPCo will provide approximately 80 MW of mobile skid mounted transformers to serve Ebon's first year, 80 MW load. Ebon will pay for the rental of these transformers, pursuant to a separate contract, which has not yet been presented in this case. It is assumed that after year 1, Ebon will utilize its own distribution substation.

Q. The Company filed an analysis of the economic impact of the Ebon Special Contract, which Mr. West referred to as a marginal cost analysis. Would you describe the Company's analysis?

A. As discussed by KPCo witness Brian West, the Company has developed an economic analysis that compares the incremental cost of serving Ebon's expected load over the 10-year contract period with the revenues that Ebon is expected to pay each year. The original version of this analysis was filed with Mr. West's testimony as BKW-Exhibit 2. That analysis showed that the incremental Ebon revenues exceeded the estimated incremental costs of serving Ebon by a net $18.95 million, for a single year. The Company subsequently filed an ERRATA to BKW-Exhibit 2 that calculated a 10-year net revenue amount, which is shown to be a $96 million benefit (revenues exceed costs) on a nominal basis. Based on Mr. West's analysis, the Special Contract would be economically beneficial. However, as I will discuss in the remainder of my testimony, the Company's analysis is flawed and does not represent a reasonable estimate of the net revenues under the contract.

Q. Does the Company's ERRATA BKW-Exhibit 2 analysis assume that there will be any incremental costs over the life of the contract to provide generation capacity to serve the 25 MW of firm Ebon load?

A. No. KPCo did not include any incremental generation capacity cost for either the 25 MW of firm Ebon load or for any of the 225 MW of Ebon interruptible load. However, the Company has included a scenario wherein incremental generation capacity costs are included for the 25 MW of firm Ebon load in a version of the economic analysis filed in response to KPSC 1-9(f). However, based on the data response, there is no indication that the Company supports this version of its analysis. The Company continues to argue that there is no incremental generation capacity cost incurred to serve 25 MW of firm load that is expected to operate at a 90% load factor (almost 24/7 hours each week of the year for 10 years). When generation capacity costs are included in the analysis, the net benefit is reduced to $77 million on a 10-year nominal basis in the Company's marginal cost analysis.

Q. Is there any reasonable basis to ignore the incremental costs of providing 25 MW of generating capacity plus reserves (28.75 MW) to serve the Ebon firm load over the life of the contract?

A. No. It is particularly inappropriate and incorrect to ignore this component of incremental cost in a situation, as exists with KPCo, in which the Company is purchasing capacity to meet its load obligations under the PJM FRR election without any Ebon load addition. Even if the Company had excess capacity exceeding the 28.75 MW Ebon firm load capacity obligation, the incremental cost associated with this load is not $0, but rather is the opportunity cost of forgoing the revenues that could be obtained by selling the excess capacity off-system. It is simply not credible to argue, as the Company does,[2] that there is no cost to provide 25 MW plus reserves (28.75 MW) of capacity for 10-years.[3] As such, the alternative analysis included in the response to KPSC 1-9(f), which includes a generation capacity cost for the 25 MW of firm Ebon load is more appropriate. Though, as I will discuss subsequently, this analysis [KPSC 1-9(f)] continues to have significant flaws.

Q. Based on your review of the Company's economic analysis, is the Ebon Special Contract likely to produce benefits to the KPCo system?

A. No. Contrary to the results shown in ERRATA BKW-Exhibit 2, even with additional costs for generation capacity [KPSC 1-9(f)], the Company's analysis is flawed. Rather than provide a net benefit to the KPCo system, the Ebon contract will cause net harm to KPCo and its customers. Based on my corrected economic analysis, the Ebon contract will likely result in a minimum of $93 million of net harm (disbenefits) to the KPCo system and its customers on a nominal basis and $69 million of net harm

[2] See Mr. West's testimony at pages 8 and 9 and also see the Company's response to KPSC 1-9 a-b.
[3] KPCo would not likely be willing to sell 28.75 MW of firm capacity to another party for $0 over a 10-year period.

on an NPV basis over its 10-year term. Furthermore, if KPCo is not successful in interrupting the 225 MW of Ebon's interruptible load at 1) the time of the PJM 5 CP hours; 2) at the time of the AEP Zonal peak load hour (NSPL); and 3) at the time of at least 5 of KPCo's 12 CP hours each year, the harm would be significantly worse.

Q. Why is an economic analysis of the Special Contract important in this case?

A. First, under the guidelines established by the Commission in Administrative Order No. 327, an essential element of the Commission's consideration of an EDR contract is whether the customer's expected revenues that will be paid under the contract will exceed the expected incremental costs. I will discuss this Order later in my testimony.

Because the Ebon Special Contract involves a 250 MW load addition on a 1,000 MW system (about a 25% increase in load) and would also increase KPCo's energy requirements by 1.9 billion kWh per year (about a 36% increase in kWh sales levels), it is particularly important for the Commission to consider the impact of the contract on the rates paid by KPCo's customers.

Q. Please summarize the problems that you have identified with the Company's economic analysis?

A. In addition to the failure to include any generation cost needed to serve the 25 MW of firm Ebon load, I have identified the following problems with the Company's analysis:

1. A failure to reflect the correct Ebon revenues in year 5 of the contract.
2. A failure to include the Incremental Discount in the calculation of Ebon revenues, thus overstating these revenues.
3. A failure to present the results of the 10-year economic analysis on a net present value basis.
4. A failure to properly reflect PJM market energy prices expected over the 10-year contract term. This includes both the impact on incremental costs and the impact on incremental Ebon revenues via the Company's Fuel Adjustment Clause ("FAC").
5. A failure to properly reflect expected PJM transmission cost increases in the calculation of incremental transmission costs.

In addition, the Company's analysis did not consider the risks that are associated with the assumed ability of KPCo to interrupt Ebon's 225 MW of interruptible load during each of the PJM 5 CP hours and during the AEP Zonal NSPL hour. The Company also assumed that it could successfully interrupt Ebon's 225 MW of interruptible load at the time of the AEP East Operating Companies' monthly CP hour for 5 of the 12 months each year.[4]

Q. Would you please explain the first problem that you have identified with the Company's analysis, the use of an incorrect Ebon revenue value in year 5 of the analysis?

A. Baron Exhibit__(SJB-2), page 1 of 2 contains the summary schedule from the Company's response to KPSC 1-9(e)(f). This schedule shows the Company's ERRATA BKW-Exhibit 2 [KPSC 1-9(e)] and the version that includes generation capacity cost [KPSC 1-9(f)]. As can be seen in both schedules, the assumed Ebon revenues in year 5 are identical to the revenues in years 6 through 10, a value of $125,834,226. [redacted]

Q. Please explain the error in the Company's analysis associated with the Incremental Discount.

A. The Ebon Special Contract incorporates the discounts consistent with Tariff E.D.R. These include both Billing Demand Discounts and Incremental Billing Demand

[4] The AEP East Transmission Agreement uses a 12 CP allocator to assign PJM Network Integrated Transmission Service ("NITS") costs to each of the participating Operating Companies.

Discounts (Incremental Discounts). The Company's analysis (ERRATA BKW-Exhibit 2) failed to reflect these Incremental Discounts. In Tariff E.D.R., these Incremental Billing Demand Discounts are tied to the number of jobs created by the EDR customer. The effect of failing to include this Incremental Discount in the Company's economic analysis results in an overstatement of Ebon revenues during each of the first 5 years of the contract. This, in turn, results in an overstatement of the net economic benefits of the contract in the Company's analysis.[5]

Q. Please discuss the next problem, the Company's failure to present the results on a net present value ("NPV") basis.

A. An NPV economic analysis is a fundamental requirement in a life of contract economic analysis to measure the net benefits or net costs. A dollar of net benefits or costs (incremental Ebon revenues compared to incremental costs of serving the Ebon load) that occurs in year 10 does not have the same economic benefit (or harm if costs exceed revenues) as a dollar of net benefits in year 1. In a properly conducted analysis, net benefits or net costs each year must be adjusted to a net present value in order to accumulate these benefits and costs over the 10-year period. For example, as is the case of the Ebon analysis, benefits that occur in the later years of a contract cannot be used to offset costs that might occur in the early years, without adjusting for the time

[5] The economic analysis compares incremental costs to Ebon revenue under the contract. If the net amount (revenues minus costs) is positive, there is a net economic benefit. If the net amount is negative (costs exceed revenues), this means that there is a net economic harm from the contract.

value of money (NPV). The Company's analysis (ERRATA BKW-Exhibit 2), which is presented on a nominal basis simply assumes that you can offset early year costs with later year benefits without recognizing the time value of money (NPV).[6]

Baron Exhibit__(SJB-2), page 2 of 2 shows the correction to the year 5 revenue value and the EDR discounts and presents the results on an NPV basis using a discount rate of 5.9%, which is the after-tax weighted average cost of capital equivalent to the 6.29% used by the Company in its analysis. Correcting for these two errors reduces the net benefit from the $65 million (NPV) based on Mr. West's ERRATA BKW-Exhibit 2 to $40 million (NPV).[7]

Q. What is the next problem that you have identified in your review of the Company's economic analysis?

A. A major element in the Company's economic analysis is the incremental energy cost incurred by KPCo to serve Ebon's 2 billion kWh per year. While the Company's analysis states that it is based on Day Ahead PJM market energy prices (Locational Marginal Prices), the values for the DA LMP's are held constant for the entire 10 years. This is not consistent with any reasonable expectations. While it is also true

[6] In addition, by presenting its economic results on a nominal basis only, the Company's analysis places equal weight on benefits that might occur in the later years of the 10-year contract with benefits in the early years of the contract. These future benefits, if any, may or may not materialize, depending on whether Ebon actually remains a customer through year 10 of the contract.

[7] The results shown on page 2 of 2 of Exhibit__(SJB-2) assume an incremental cost for the capacity needed to serve Ebon's 25 MW of firm load. This is based on the analysis provided in the Company's response to KPSC 1-9(f).

that the analysis assumes that the FAC rate paid by Ebon will be constant during that period, the Company's analysis creates a bias because it does not reflect the likely incremental costs associated with serving Ebon's load.

As can be seen in Exhibit__(SJB-2), page 1 of 2, the KPCo analysis assumed a constant $43.05/MWh Day-Ahead PJM LMP at the AEP Dayton Hub for each hour of each year of the 10-year study.[8]

Q. Have you developed an alternative, more reasonable, estimate of the incremental energy cost associated with Ebon's two billion kWh of incremental energy annually?

A. Yes. I have used recent projections of futures prices for the AEP-Dayton Hub on and off-peak day-ahead prices. These futures prices, based on S&P Global data, project composite on/off-peak, annual day-ahead LMP prices higher than those assumed in the Company's analysis. Table 2 below shows a comparison of the Company's assumed DA LMPs by year and the annualized S&P Global future prices.[9]

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[8] See Baron Exhibit__(SJB-2), page 1 of 2.
[9] The S&P Global futures prices for the AEP-Dayton Hub extends through December 2028. I assumed that the prices for the next 4 years grew at 0.31% per year, the percentage change in the annualized 2027 to 2028 growth rate.

Table 2
KPCo DA LMPs vs. S&P Global Futures ($/MWh)

Year	KPCo	S&P*	% Difference
2023	43.05	46.54	8.1%
2024	43.05	47.10	9.4%
2025	43.05	45.59	5.9%
2026	43.05	45.49	5.7%
2027	43.05	44.75	3.9%
2028	43.05	44.89	4.3%
2029	43.05	45.03	4.6%
2030	43.05	45.17	4.9%
2031	43.05	45.31	5.2%
2032	43.05	45.45	5.6%

* Source: S&P Global Futures Prices, January 23, 2023

Q. In the Company's analysis, the FAC rate was held constant for the entire 10-year analysis. Is this a reasonable assumption?

A. No. First, the Company's analysis assumed that the FAC rate plus base fuel ($0.02612/kWh) was exactly equal to the day-ahead LMP rate each year. This is incorrect. As I will explain, the FAC + Base Fuel charge includes generation fuel costs associated with KPCo generation, PJM market revenues produced by the sales of the Company's generation into the PJM market (a credit to fuel costs) and the cost of PJM market energy purchases at LMP. This (FAC + Base Fuel) is not equal to the PJM market day-ahead LMP rate as assumed by the Company in its analysis.

Q. How would an increase in PJM purchased power costs associated with the Ebon energy usage impact the FAC revenues paid by Ebon?

A. First, it is important to understand that all of the energy (100%) from KPCo's generation resources (Mitchell, Big Sandy) is sold into the PJM energy market. This occurs whether or not there is additional Ebon load and is unaffected by the Ebon load. The revenues from these sales into the PJM market are used to offset KPCo fuel costs and PJM energy market purchases. As a member of PJM, KPCo must purchase 100% of its customer load requirements from the PJM market based on day ahead and real time Locational Marginal Costs ("LMP"). With the addition of Ebon's load, these PJM market energy purchases simply increase. However, the generation revenues from Mitchell and Big Sandy stay the same, with or without Ebon. As such, the incremental cost of energy to serve Ebon is determined by the PJM market energy price (LMP). This is the approach used by the Company to estimate incremental energy costs for Ebon. However, because KPCo's fuel and purchased power costs (base fuel plus FAC) are comprised of 1) PJM purchased energy costs to serve all of the Company's load, 2) the fuel expenses associated with Mitchell and Big Sandy, and 3) the revenues received from the sales of the Company's generation into the PJM market, the total fuel charges paid by Ebon will not be equivalent to its incremental costs. Essentially, items (2) and (3) together form the net margins associated with the Company's generation that is sold into the PJM market. These "margins," which benefited the Company's existing customers will now be shared with Ebon and it's 2.0 billion kWh.

Another way to think about these impacts is to view the transactions from the perspective of a traditional standalone utility that is not part of an RTO like PJM. In that case, it is reasonable to assume that KPCo's Mitchell and Big Sandy generation first serve KPCo customer load, with any excess sold off-system and any deficiency (KPCo generation is less than its load in an hour) is purchased from the market. The addition of Ebon's load will either result in additional market energy purchases or will result in a reduction in off-system sales – either way, the incremental cost of serving Ebon's load is the market energy cost, which for KPCo is the day-ahead LMP.

Q. Will the FAC plus base fuel revenues paid by Ebon increase by the same amount as the incremental energy cost incurred to serve the load?

A. No, for these reason that I discussed above. While the costs included in the FAC calculation will increase by the incremental energy cost associated with the Ebon load at LMP, Ebon will only pay a portion of this increase because the FAC is an average cost mechanism incorporating the value of KPCO's owned generation. Essentially, the incremental cost to serve Ebon will be spread to all KPCo customers. As a result, the FAC paid by Ebon will be not reflect the full burden of the incremental energy cost that Ebon is imposing on the system. Another way of looking at this is that the net margins that KPCo receives from its sales of Mitchell and Big Sandy into the PJM energy market will now be spread over two billion additional kWh (the Ebon load). Ebon will benefit from its kWh share of the generation revenue margins produced by Mitchell and Big Sandy.

Q. Have you estimated the impact on the FAC from purchasing an additional two billion kWh from the PJM energy market?

A. Yes. My analysis is based on the relationship between FAC costs and PJM market energy prices for the 12-month period ending April 2022, assuming Ebon load and the loss of Rockport contract. I have developed a percentage factor (87.4%) that I believe is reasonable to use to estimate Ebon FAC revenues over the 10-year contract period that is consistent with the PJM market energy prices I have used to develop incremental cost. Using this factor, I revised the Ebon energy revenues for each year of the analysis.

Q. What is the impact on the economic analysis of using futures prices to estimate the incremental energy cost of Ebon's two billion kWh per year?

A. Baron Exhibit__(SJB-3) shows the summary results of the analysis. <u>The net benefit of the Ebon contract is now a negative $37 million (NPV) over its 10-year term.</u> Based on this adjustment alone, the Ebon Special Contract is harmful to KPCo's other customers and should not be approved, as filed.

Q. What is the next problem that you have identified in your review of the Company's economic analysis?

A. The next problem concerns the Company's assumption regarding incremental transmission costs that will be incurred to serve the Ebon load. KPCo assumed that its PJM Network Integrated Transmission costs (NITS) will increase by 5% per year from the 2022 level. This can be seen on Line 9 of the Company's economic analysis [Baron Exhibit__(SJB-2)].

Q. Have NITS revenue requirements been increasing by 5% per year for the AEP Zone?

A. No. Based on the actual AEP filings in support of its zonal NITS charges, AEP's revenues requirements have been increasing by more than 12% per year for the period 2017 to 2023. Table 3 below summarizes the annual growth in AEP NITS revenue requirements over the period 2017 to 2023. The average annual growth rate is approximately 12%, not the 5% assumption used in the Company's analysis. The NITS revenue requirements shown in Table 3 are calculated in the same manner as used by the Company in its transmission cost analysis (AEP Operating Company revenue requirements plus AEP Transmission Company revenue requirements, less any true-ups, plus PJM Schedule 12 RTEP revenue requirements).

Table 3
AEP Zone NITS Revenue Requirements (2017 - 2023)*

	OpCo PTRR	Transco PTRR	Schedule 12 Expense (RTEP)	Total Zonal PTRR	Percent Change
2017 PTRR	827,202,202	440,613,008	184,908,438	1,452,723,648	
2018 PTRR	882,030,590	594,166,885	200,688,696	1,676,886,170	15.4%
2019 PTRR	809,314,974	724,665,303	179,720,803	1,713,701,080	2.2%
2020 PTRR	856,434,690	918,994,737	175,155,813	1,950,585,241	13.8%
2021 PTRR	964,119,865	1,132,336,245	189,895,185	2,286,351,295	17.2%
2022 PTRR	1,060,007,136	1,324,725,753	191,147,425	2,575,880,314	12.7%
2023 PTRR	1,190,113,047	1,480,285,114	193,924,473	2,864,322,633	11.2%
			Average Annual Growth Rate		12.1%

* Source: Response to AG-KIUC 2-3.

Based on this history, I have revised the Company's assumed 5% annual escalation factor for incremental Ebon transmission costs to a conservative 10% escalation factor. Baron Exhibit__(SJB-4) shows the summary results of my transmission adjustment to incremental cost. The net present value benefit of the Ebon Special Contract, reflecting my prior adjustments and the transmission cost adjustment is a negative $69 million (i.e., a harm to other customers of $69 million on an NPV basis). On a nominal basis, the 10-year harm is $93 million. The results shown in Exhibit__(SJB-4) include the cumulative impact of the following corrections that I have discussed:

1) Incorrect year 5 revenue,
2) Inclusion of the Incremental Discount,
3) Inclusion of incremental capacity costs to serve 25 MW of firm Ebon load,

4) Correction to reflect DA LMP futures prices and FAC revenues,
5) Correction to reflect historic NITS transmission cost increases.

Table 4 below summarizes the impacts of these changes on the Special Contract net economic analysis results (Ebon revenues minus incremental costs). The first column shows the 10-year results on a nominal basis. The second column shows these results on an NPV basis. The third column shows the change in the NPV results due to each correction.

Table 4
Corrections to KPCo Ebon Economic Analysis

Case Adjustment	Net Revenue/(Cost) Nominal $M	Net Revenue/(Cost) NPV $M	Incremental Impact on Net Revenue/(Cost) NPV $M
KPSC 1-9e	96.0	64.6	0.0
KPSC 1-9f (adds Generation Capacity Cost)	76.8	51.1	-13.4
+ Corrected Yr 5 Revenue, Corrected EDR Discount	62.6	39.7	-11.5
+ Replacement LMP and FAC Projection	-42.3	-36.5	-76.2
+ Corrected NITS Escalation Factor	-92.9	-68.8	-32.3

Q. Have you estimated the impact of the harm to a typical residential customer?

A. Yes. Based on an average $9.29 million net harm each year over the 10-year contract period, the average annual additional charge to a typical residential customer would be about $33 per year. Over the full 10-year period, this would amount to $330 per residential customer.

Q. Based on the corrections that you have made to the Company's analysis, what do you conclude about the economic impact of the Ebon Special Contract?

A. The contract, as proposed, will very likely result in millions of dollars of additional costs to KPCo that will be paid for by its customers. Contrary to KPCo's position that the revenues paid by Ebon under the contract terms and rates will exceed the incremental costs of serving its 250 MW of demand and two billion annual kWh of energy, the reverse is true: Ebon's revenues will likely fall short of its incremental costs by $69 million on an NPV basis over the 10-year contract period ($93 million nominal).

Q. Your analysis relied on AEP-Dayton Hub market energy costs (day-ahead LMP) based on the futures prices as of January 23, 2023. Have you performed a similar analysis using AEP-Dayton Hub futures prices on August 23, 2022, the day that the Ebon Special Contract was signed by KPCo?

A. Yes. I used the identical model and assumptions that I used to develop my corrected analysis, which I presented in Exhibit__(SJB-4), except for the projected DA-LMP values used to calculate incremental energy costs and the FAC, which uses August 23, 2022 prices instead of January 23, 2023 futures prices. The result of this alternative analysis shows a net cost to customers from the Ebon contract of $83 million on an NPV basis. Had the Company performed a reasonable analysis of the Ebon contract costs and benefits on the day that the contract was signed, the resulting harm to customers would have been $83 million (NPV), about $14 million higher than the results I presented in my Exhibit__(SJB-4) and Tables 1 and 4.

Q. Are there additional potential net costs that could be caused by the Ebon contract beyond those considered directly in your analysis?

A. Yes. There are two sources of potential additional costs to KPCo and its customers that are associated with the risk that the Company will not succeed in its attempt to interrupt Ebon's 225 MW of interruptible load in during three critical periods. These periods are:

1) during each of the PJM 5 CP hours in the summer that are used to assign generation capacity obligations in PJM,

2) during the AEP Zonal peak CP hour (NSPL) used to assign transmission costs to the AEP East Companies as a group and non-affiliate transmission customers in the AEP zone, and

3) during at least 5 of the 12 CP hours used to allocate the AEP East Company costs to each AEP Operating Company, including KPCo.[10]

Q. Would you explain how interruptible load in each of these critical periods impacts the Ebon Special Contract economic analysis?

A. As a PJM FRR member, KPCo has a generation capacity obligation that is based on its Obligation Peak Load. To the extent that KPCo fails to fully interrupt Ebon's 225 MW of load on each of the PJM summer 5 CP hours, its Obligation Peak Load would

[10] The Company's analysis assumed that Ebon's 225 MW of interruptible load would be fully interrupted in 5 of the 12 monthly hours forming the 12 CP allocation factor.

be increased, resulting in an increase in its FRR capacity obligation, which in turn would result in increased capacity costs beyond the amount needed to supply Ebon's 25 MW's of firm load. This is a risk that has not been factored into the Company's economic analysis.

Q. What is the potential impact of this risk on the Ebon economic analysis results?

A. To illustrate the potential impact, I assumed that KPCo fails to interrupt Ebon during one of the 5 PJM CP hours each year. Under this scenario, KPCo's incremental capacity obligation would increase by 20% of the interruptible load on the system, plus reserves, each year.

In year 1 of the contract, the Company assumes that Ebon will have 8 MW of firm load and 72 MW of interruptible load. In KPCo's economic analysis in which it included generation capacity costs [KPSC 1-9(f)], the Company only included capacity costs for the 8 MW of firm load plus 15% reserves (total of 9.2 MW capacity obligation) because it was assumed that 100% of the interruptible load would be interrupted during each of the PJM 5 CP hours. If KPCo failed to interrupt Ebon's interruptible load for 1 one the 5 hours, this would add another 14.4 MW of load plus reserves to the Company's FRR capacity obligation (total increase in the capacity obligation of 16.56 MW).

In years 2 through 10 of the contract a similar failure to interrupt in 1 of the 5 PJM CP hours would add another 45 MW of Ebon load plus reserves to KPCo's capacity obligation (total annual increase in the FRR capacity obligation of 51.8 MW).[11]

Using the Company's incremental generation capacity cost assumptions, this would increase the 10-year Ebon incremental generation capacity costs by $24 million (NPV) from the level calculated by the Company in response to KPSC 1-9(f) and increase the harm to the Company's other customers by an equal amount. Under this scenario, the total harm to the Company's customers would increase from $69 million to $93 million (NPV).[12] This, of course, assumes that the Company only fails to interrupt Ebon in one of the 5 CP hours. If the interruption failure was in two of the 5 hours, the harm would increase by an additional $24 million (NPV), producing a total harm of $117 million (NPV).[13]

Q. Are there any other risks that would adversely impact the economics of the Ebon contract?

A. Yes. The Company's analysis, and all of my analyses, assumed that Ebon would fully curtail the entirety of its contracted interruptible load during a Rider D.R.S.

[11] In years 2 through 10, the interruptible load is 225 MW. If KPCo fails to interrupt in 1 of the 5 CP hours, this would increase the Company's capacity obligation by 20% X 225 X 1.15 or 51.8 MW each year.
[12] This includes the impact of the corrections summarized in Table 3 plus the additional generation capacity cost of $61 million.
[13] $69 million plus $24 million plus $24 million = $117 million.

Discretionary Interruption event. In year 1 of the contract, this assumes that 72 MW of Ebon's total year 1 load of 80 MW would be interrupted; in years 2 through 10 of the contract, it assumes that 225 MW of Ebon's 250 MW load would be interrupted.

However, pursuant to Section 4.3 of the KPCo/Ebon contract, Ebon does not incur any penalty if it only reduces its interruptible load during a Discretionary Interruption event to 90% of its contractual interruptible capacity level. This means that in year 1, Ebon could operate at 15.2 MW (8 MW firm load and 10% of its 72 MW interruptible load) and it would still meet is contractual obligations without any penalty. In years 2 through 10, Ebon could operate at 47.5 MW (25 MW firm load and 10% of its 225 MW interruptible load) and it would still meet is contractual obligations without any penalty.[14] If Ebon only reduced its interruptible load by 90% of the agreed upon level, it would add an additional firm capacity obligation in year 1 of 7.2 MW and in years 2 through 10 of 22.5 MW. The additional incremental generation capacity cost associated with this additional load would be $12 million (NPV) over the 10-year contract. This would increase the $69 million of harm shown in Table 4 to $81 million (NPV). In addition, there would also be

[14] Section 4.3 of the contract states as follows: "The Customer will be determined to have failed a Discretionary Interruption event and to be liable for the DRS Event Failure Charge if the Customer has not achieved at least ninety percent (90%) of their agreed upon Interruptible Capacity reservation during the duration of a Discretionary Interruption."

incremental transmission costs associated with this additional load, which I have not calculated at this time.

Because Ebon's crypto mining operations would be more profitable if it only curtailed 90% of its interruptible load, which it can do without penalty, this is a possible if not likely outcome.

Q. The Company's analysis also assumes that Ebon's full 225 MW load will be interrupted during the AEP Zonal peak (NSPL). Is this an additional risk that has not been accounted for in the study?

A. Yes. The AEP Zonal NSPL is used to assign transmission costs (NITS costs) among the AEP East and non-affiliates transmission users in the AEP Zone. The KPCo study assumed that 100% of Ebon's interruptible load would always be fully interrupted during the annual AEP Zonal NSPL. The Company also assumed that Ebon's load would be fully interrupted in 5 of the monthly CP demand hours used to allocate transmission costs per the AEP East Transmission Agreement, which uses a 12 CP allocator to assign NITS costs to each AEP Company. These 5 hours are not necessarily the same 5 hours used by PJM to determine KPCo's FRR capacity obligation. The PJM 5 CP hours are based on the entire PJM RTO summer system peak (about 149,000 MW)[15], while the Transmission Agreement 12 CPs are based on the AEP East Companies coincident peak (about 16,000 MW).

Q. Is the 12 CP allocation important in the calculation of incremental transmission costs?

A. Yes. It is the most important factor that impacts the transmission cost associated with Ebon is the impact on KPCo's 12 CP, not the AEP Zonal NSPL. This occurs because as KPCo's 12 CP increases due to Ebon's load, it is allocated a larger share of the entire AEP East Companies' NITS revenue requirement, not just the incremental increase due to Ebon. For example, in years 2 through 10 of the Company's analysis, which assumes that 100% of Ebon's interruptible load of 225 MW is interrupted, the total increase in the AEP East Companies' total NITS costs due to Ebon load is $451,546, while the increase in KPCo's share of this cost is $19,804,193 due to its larger 12 CP allocation. Almost all of the Ebon incremental transmission cost increase is due to the increase in its 12 CP allocation.

Q. Is this a risky assumption?

A. Yes, I believe that it is. The Company assumes that it can interrupt all of Ebon's load annually during each of the critical hours that will determine the amount of additional transmission charges that will be paid by KPCo due to Ebon. As an example of the

[15] Weather Normalized Summer peak, 2022. Source: PJM Load Forecast Report, January 2023.

dispersion of the peak hours over the year, Table 5 below shows the date and time of historic occurrences of the annual AEP Zonal NSPL. As can be seen, the NSPL can occur in either the summer months or the winter months. Given that the Company only has 20 opportunities to call for an Ebon interruption, and that the primary focus is to curtail Ebon's 225 MW of interruptible load during all 5 of the PJM 5 CP hours, there is little leeway left to achieve an interruption during the one hour that forms the AEP Zonal NSPL and during the 5 monthly peaks that are included in the 12 CP calculation.[16]

Table 5
AEP Zonal NSPL Occurrence 2014 - 2023*

	NSPL	Date	Hour	Summer/Winter
2014	22,846	7/18/2013	15	S
2015	24,408	1/30/2014	8	W
2016	24,725	2/20/2015	8	W
2017	22,476	8/11/2016	15	S
2018	22,739	7/19/2017	17	S
2019	22,739	1/3/2018	8	W
2020	22,498	1/31/2019	8	W
2021	21,615	7/9/2020	17	S
2022	21,925	8/24/2021	17	S
2023	21,717	6/22/2022	16	S

* Source: AG-KIUC 2-1.

[16] See response to AG-KIUC 2-19, attached as Baron Exhibit__(SJB-5), that confirms that the purpose of the D.R.S. interruptions is not to interrupt load to avoid KPCo's 12 CP demands associated with the AEP East Transmission Agreement ("Generally, it is not the main purpose of the program").

Q. The Company's analysis assumed that it could fully interrupt Ebon's interruptible load at the time of 5 of the 12 monthly CPs used to allocate transmission costs among the AEP East Companies. If KPCo was only able to interrupt Ebon in 4 of those months, instead of 5, what would the impact be on the economic results?

A. If it is assumed that the Company can only fully interrupt Ebon's interruptible load in 4 of the 12 months, the incremental cost increases by $23 million over the 10-year period.[17] If the Company was not able to interrupt Ebon during any of the 12 months, the resulting impact is an increase the 10-year incremental transmission costs of $113 million over the Company's assumed 5 months of interruption.

IV. EVALUATION OF ECONOMIC DEVELOPMENT CONTRACTS

Q. What is your understanding of the standard that the Commission uses to evaluate Economic Development Rate contracts?

A. My understanding, which is not a legal analysis, is that the Commission's Order in Administrative Case No. 327 provides the criteria used by the Commission to assess the reasonableness of an Economic Development Contract ("EDR"). While the Company has asserted that the Ebon Special Contract is not an EDR arrangement ("the

[17] For comparison purposes, this assumes that Ebon's load in the NSPL hour is fully interrupted, as in the Company's analysis.

Company is not seeking approval of the Special Contract under the terms of Tariff E.D.R"),[18] the Ebon Special Contract specifically incorporates the relevant provisions of Tariff E.D.R. Moreover, from a policy perspective, the Commission's Order in Administrative Case 327 directly applies to the issues raised in this case, specifically the requirement to demonstrate that the contract is not economically harmful to the Company's other customers. In fact, the Company implicitly recognizes this requirement through the inclusion of a marginal cost analysis in its filing. Regardless of the legal issues, which I am not addressing, the Commission's consideration of the Ebon contract should include an evaluation of the economic impact of the contract terms and rates on other customers.

I have reviewed the Commission's Order in Case No. 327 and believe that the Company's proposed contract with Ebon does not satisfy a number of the Commission's requirements for an EDR contract. Guideline No. 2 states:

> "Each utility should be required to demonstrate that all variable costs associated with the transaction during each year that the contract is in effect will be recovered and that the transaction makes some contribution to fixed costs. Furthermore, the customer-specific fixed costs associated with adding an economic development/incentive customer should be recovered either up front or as a part of the minimum bill over the life of the contract."

The Commission Order goes on to state:

> the Commission finds that variable cost recovery is a fundamental requirement of EDRs. Therefore, each time an EDR contract is submitted for approval, utilities should demonstrate that the discounted rate exceeds

[18] KPCo response to Joint Intervenors 1-15.

> the total short-run marginal (variable) costs associated with serving that customer for each year of the discount period. Short-run marginal costs will include both marginal capacity costs and marginal energy costs. (Order at page 7).

As I have discussed, the Ebon Special Contract revenues are likely to be lower than the expected incremental (marginal) costs to serve Ebon under the contract terms and rates, and therefore the contract is harmful to the Company's other customers.

Q. Are there other provisions of the Commission's Order that are relevant to the consideration of the Ebon Special Contract?

A. Yes. Commission Guideline No. 1 states:

> "Each utility should be required to provide an affirmative declaration and evidence to demonstrate that it has adequate capacity to meet anticipated load growth each year in which an incentive tariff is in effect."

KPCo does not currently have sufficient capacity to meet its existing capacity obligations without the added Ebon load. Clearly, the Company does not meet this Commission's requirements in a number of key areas.[19]

Q. Are there other concerns raised by the Ebon contract beyond the economic harm analysis issue that you will discuss subsequently?

A. Yes. As discussed above, one of the rate provisions of the Special Contract relies on KPCo's Rider D.R.S., which will provide Ebon an interruptible credit of $5.50/kW-

[19] See Direct Testimony of Brian West at page 7.

month for 225 MW of its total 250 MW load. Rider D.R.S. states that it is available to customers that take service from the "Company under a standard demand metered rate schedule …" Ebon will not be taking service under a standard demand metered rate schedule. In response to AG-KIUC 1-12 [attached as Baron Exhibit__(SJB-6)], the Company states that its position is that the Ebon Special Contract meets the standard demand metered rate requirement. Cleary, a Special Contract is not a standard rate.

Q. Does that complete your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

ELECTRONIC TARIFF FILING OF KENTUCKY	**)**	
POWER COMPANY FOR APPROVAL OF A	**)**	
SPECIAL CONTRACT WITH EBON	**)**	**CASE NO. 2022-0387**
INTERNATIONAL, LLC	**)**	

EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

THE KENTUCKY ATTORNEY GENERAL

AND

THE KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

February 2023

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

ELECTRONIC TARIFF FILING OF KENTUCKY POWER COMPANY FOR APPROVAL OF A SPECIAL CONTRACT WITH EBON INTERNATIONAL, LLC	**))))**	**CASE NO. 2022-0387**

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BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

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ELECTRONIC TARIFF FILING OF KENTUCKY	**)**	
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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

ELECTRONIC TARIFF FILING OF KENTUCKY POWER COMPANY FOR APPROVAL OF A SPECIAL CONTRACT WITH EBON INTERNATIONAL, LLC	**))))**	**CASE NO. 2022-0387**

EXHIBIT__(SJB-1)

OF

STEPHEN J. BARON

ON BEHALF OF

THE KENTUCKY ATTORNEY GENERAL

AND

THE KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

February 2023

Professional Qualifications

Of

Stephen J. Baron

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

Mr. Baron has more than forty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

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

In December 1975, he joined the Utility Rate Consulting Division of Ebasco Services, Inc.

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

He joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity he was responsible for the operation and management of the Atlanta office. His duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, he specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

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

He has presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." His article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, he completed a detailed analysis entitled "Load Data

Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

Mr. Baron has presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, South Carolina, Ohio, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, Wyoming, the Federal Energy Regulatory Commission and in United States Bankruptcy Court. A list of his specific regulatory appearances follows.

Expert Testimony Appearances
of
Stephen J. Baron
As of January 2023

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

Expert Testimony Appearances
of
Stephen J. Baron
As of January 2023

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

Expert Testimony Appearances
of
Stephen J. Baron
As of January 2023

Date	Case	Jurisdict.	Party	Utility	Subject
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.
10/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Excess capacity, power and cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.

Expert Testimony Appearances
of
Stephen J. Baron
As of January 2023

Date	Case	Jurisdict.	Party	Utility	Subject
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.

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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

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					Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410-EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.

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

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Date	Case	Jurisdict.	Party	Utility	Subject
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.

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

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

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08/00	98-0452 E-GI	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.

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

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Date	Case	Jurisdict.	Party	Utility	Subject
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.

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07/06	Case No. 2006-00130 Case No. 2006-00129	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
08/06	Case No. PUE-2006-00065	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Incr, Off-System Sales margin rate treatment
09/06	E-01345A-05-0816	AZ	Kroger Company	Arizona Public Service Co.	Revenue 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 Southern Power	Environmental Surcharge Rate Design
05/07	R-00049255 Remand	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
06/07	R-00072155	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues.
07/07	Doc. No. 07F-037E	CO	Gateway Canyons LLC	Grand Valley Power Coop.	Distribution Line Cost Allocation
09/07	Doc. No. 05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
11/07	ER07-682-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Schedule MSS-3. Cost functionalization issues.
1/08	Doc. No. 20000-277-ER-07	WY	Cimarex Energy Company	Rocky Mountain Power (PacifiCorp)	Vintage Pricing, Marginal Cost Pricing Projected Test Year
1/08	Case No. 07-551	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Class Cost of Service, Rate Restructuring, Apportionment of Revenue Increase to Rate Schedules
2/08	ER07-956	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
2/08	Doc No. P-00072342	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Default Service Plan issues.
3/08	Doc No. E-01933A-05-0650	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design

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05/08	08-0278 E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co. American Electric Power Co.	Expanded Net Energy Cost "ENEC" Analysis.
6/08	Case No. 08-124-EL-ATA	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Recovery of Deferred Fuel Cost
7/08	Docket No. 07-035-93	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Rate Design
08/08	Doc. No. 6680-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Doc. No. 6690-UR-119	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Case No. 08-936-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Competitive Solicitation
09/08	Case No. 08-935-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
09/08	Case No. 08-917-EL-SSO 08-918-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Provider of Last Resort Rate Plan
10/08	2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
11/08	08-1511 E-GI	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
11/08	M-2008-2036188, M-2008-2036197	PA	Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Transmission Service Charge
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
01/09	E-01345A-08-0172	AZ	Kroger Company	Arizona Public Service Co.	Cost of Service, Rate Design
02/09	2008-00409	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Cost of Service, Rate Design
5/09	PUE-2009 -00018	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Transmission Cost Recovery Rider
5/09	09-0177-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost "ENEC" Analysis
6/09	PUE-2009 -00016	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Fuel Cost Recovery Rider

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6/09	PUE-2009 -00038	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Fuel Cost Recovery Rider
7/09	080677-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
8/09	U-20925 (RRF 2004)	LA	Louisiana Public Service Commission Staff	Entergy Louisiana LLC	Interruptible Rate Refund Settlement
9/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Energy Cost Rate issues
9/09	Doc. No. 05-UR-104	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
9/09	Doc. No. 6680-UR-117	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
10/09	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Allocation of Rev Increase
10/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Cost of Service, Rate Design
11/09	PUE-2009 -00019	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Cost of Service, Rate Design
11/09	09-1485 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost “ENEC” Analysis.
12/09	Case No. 09-906-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
12/09	ER09-1224	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy’s Compliance Filing System Agreement Bandwidth Calculations.
12/09	Case No. PUE-2009-00030	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Increase, Rate Design
2/10	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Rate Design
3/10	Case No. 09-1352-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
3/10	E015/ GR-09-1151	MN	Large Power Intervenors	Minnesota Power Co.	Cost of Service, rate design
4/10	EL09-61	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to off-system sales
4/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses.

Expert Testimony Appearances
of
Stephen J. Baron
As of January 2023

Date	Case	Jurisdict.	Party	Utility	Subject
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 E-P-T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Energy Efficiency/Demand Reduction Cost Recovery

Expert Testimony Appearances
of
Stephen J. Baron
As of January 2023

Date	Case	Jurisdict.	Party	Utility	Subject
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 Service Commission	Entergy Services, Inc. and the Entergy Operating	System Agreement Issues Related to off-system sales

Expert Testimony Appearances
of
Stephen J. Baron
As of January 2023

Date	Case	Jurisdict.	Party	Utility	Subject
				Companies	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
5/14	2013-2385 2013-2386	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Interruptible Rate Issues

Expert Testimony Appearances
of
Stephen J. Baron
As of January 2023

Date	Case	Jurisdict.	Party	Utility	Subject
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-SS0	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Electric Security Rate Plan Standard Service Offer
3/15	2014-00396	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses.
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
5/15	EL10-65	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating 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- E-P	WV	West Virginia Energy Users Group	Appalachian Power Company, Wheeling Power Co.	Energy Efficiency/Demand Response

Expert Testimony Appearances
of
Stephen J. Baron
As of January 2023

Date	Case	Jurisdict.	Party	Utility	Subject
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
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

Expert Testimony Appearances
of
Stephen J. Baron
As of January 2023

Date	Case	Jurisdict.	Party	Utility	Subject
12/16	1139	D.C.	Healthcare Council of the National Capital Area	Potomac Electric Power Co.	Cost of Service, Rate Design
1/17	E-01345A-16-0036	AZ	Kroger	Arizona Public Service Co.	Cost of Service, Rate Design
2/17	16-1026-E-PC	WV	West Virginia Energy Users Group	Appalachian Power Co.	Wind Project Purchase Power Agreement
3/17	2016-00370 2016-00371	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
5/17	16-1852	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Interruptible Rate Issues
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 recover.
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
6/18	17-00143	TN	East Tennessee Energy Consumers	Kingsport Power Co.	Storm Damage Rider Cost Recovery
7/18	18-0503-E-ENEC	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
7/18	18-0504-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Vegetation Management Cost Recovery
7/18	G.O.236.1	WV	West Virginia Energy Users Group	Appalachian Power Company	Tax Cut and Jobs Act Issues
7/18	G.O.236.1	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Tax Cut and Jobs Act Issues
10/18	18-0646-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Cost of Service, Rate Design TCJA issues
10/18	18-00038	TN	East Tennessee Energy Consumers	Kingsport Power Co.	Tax Cut and Jobs Act Issues

Expert Testimony Appearances
of
Stephen J. Baron
As of January 2023

Date	Case	Jurisdict.	Party	Utility	Subject
11/18	18-1231- E-ENEC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost ("ENEC")
11/18	2018-00054	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Tax Cut and Jobs Act Issues
12/18	2018-00134	VA	Collegiate Clean Energy	Appalachian Power Company	Competitive Service Provider Issues
1/19	2018-00294 2018-00295	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
1/19	2018-00101	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Cost of Service
2/19	UD-18-07	City of New Orleans	Crescent City Power Users Group	Entergy New Orleans	Cost of Service, Rate Design
4/19	42310	GA	Georgia Public Service Commission Staff	Georgia Power Company	2019 Integrated Resource Plan Optimal Reserve Margin Issues
7/19	19-0396 E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Issues
10/19	19-0387 E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Economic Development Fund
10/19	19-0564 E-T	WV	West Virginia Energy Users Group	Appalachian Power Company	Mitchell Generating Plant Surcharge
10/19	E-01933A- 19-0028	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
11/19	19-0785 E-ENEC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost ("ENEC")
11/19	2018-00101	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Cost of Service
11/22	2019-00170 -UT	NM	COG Operating, LLC	Southwestern Public Service Co.	Cost of Service, Rate Design
12/19	19-1028 E-PC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	PURPA Contract Buy-out
4/20	20-00064	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Cooperative, Inc.	Rate Design
7/20	2019-226-E	SC	The South Carolina Office of Regulatory Staff	Dominion Energy South Carolina	2020 Integrated Resource Plan Load Forecasting, Reserve Margin Issue
7/20	2020-00015	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	2020 Triennial Review Case - Cost Allocation, Revenue Apportionment
8/20	E-01345A- 19-0236	AZ	Kroger Company	Arizona Public Service Co	Cost of Service, Rate Design

Expert Testimony Appearances
of
Stephen J. Baron
As of January 2023

Date	Case	Jurisdict.	Party	Utility	Subject
10/20	2020-00174	KY	Kentucky Industrial Utility Customers, Inc., KY AG	Kentucky Power Company	Cost of service, net metering, transmission costs.
11/20	20-0665 E-ENEC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co	Expanded Net Energy Cost ("ENEC")
2/21	2019-224-E 2019-225-E	SC	The South Carolina Office of Regulatory Staff	Duke Energy Carolinas Duke Energy Progress	2020 Integrated Resource Plan Load Forecasting, Reserve Margin Issue
3/21	2020-00349 2020-00350	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design. Net Metering issues
3/21	20AL-0432E	CO	Climax Molybdenum	Public Service Company of Colorado	Cost of Service, Rate Design
3/21	20-1476-	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Electric Security Rate Plan Standard Service Offer
5/21	20-1040 E-CN	WV	West Virginia Energy Users Group	Appalachian Power Company	Environmental CCN and Surcharge
5/21	20-1012 E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Infrastructure Investment Tracker and Surcharge
5/21	2020-00238 -UT	NM	COG Operating, LLC	Southwestern Public Service Co.	Cost of Service, Rate Design
6/21	2021-00045	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Coal Combustion Residuals Rider CCR Cost Allocation, Rate Design
7/21	20-1049 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co	Excess Accumulated. Def. Income Tax Rate Treatment
7/21	21-00339 E-ENEC	WV	West Virginia Energy Users Group	Appalachian Power Co. Wheeling Power Co.	Expanded Net Energy Cost ("ENEC")
9/21	2021-00058	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Cost of Service 2020 Triennial Review Case - Cost Allocation, Revenue Apportionment
11/21	21-0658 E-ENEC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co	Expanded Net Energy Cost ("ENEC")
2/22	2021-0481	KY	Kentucky Industrial Utility Customers, Inc., KY AG	Kentucky Power Company Liberty Utilities	Acquisition of Kentucky Power Co. by Liberty Utilities
2/22	21-0813- E-CS	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co	Solar Energy Rate Recovery
3/22	2021-00229	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Nuclear Plant Upgrade Rider SNL
3/22	21-00107	TN	East Tennessee Energy Consumers	Kingsport Power Co.	Cost of Service, Rate Design
3/22	2021-00206	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	2021 RPS Plan

Expert Testimony Appearances
of
Stephen J. Baron
As of January 2023

Date	Case	Jurisdict.	Party	Utility	Subject
5/22	44160	GA	Georgia Public Service Commission Staff	Georgia Power Company	2022 Integrated Resource Plan Optimal Reserve Margin Issues
6/22	2021-00156	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	2021 RPS Cost Allocation
9/22	22-00393 E-ENEC	WV	West Virginia Energy Users Group	Appalachian Power Co. Wheeling Power Co.	Expanded Net Energy Cost ("ENEC") Coal Inventory Prudence Issues
10/22	44280	GA	Georgia Public Service Commission Staff	Georgia Power Company	2022 Rate Case
11/22	22-0793 E-ENEC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co	Expanded Net Energy Cost ("ENEC")
1/23	E-01933A-22-0107	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

ELECTRONIC TARIFF FILING OF KENTUCKY POWER COMPANY FOR APPROVAL OF A SPECIAL CONTRACT WITH EBON INTERNATIONAL, LLC	**))))**	**CASE NO. 2022-0387**

EXHIBIT__(SJB-2)

OF

STEPHEN J. BARON

ON BEHALF OF

THE KENTUCKY ATTORNEY GENERAL

AND

THE KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

February 2023

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

ELECTRONIC TARIFF FILING OF KENTUCKY	**)**	
POWER COMPANY FOR APPROVAL OF A	**)**	
SPECIAL CONTRACT WITH EBON	**)**	**CASE NO. 2022-0387**
INTERNATIONAL, LLC	**)**	

EXHIBIT__(SJB-3)

OF

STEPHEN J. BARON

ON BEHALF OF

THE KENTUCKY ATTORNEY GENERAL

AND

THE KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

February 2023

[redacted]

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

ELECTRONIC TARIFF FILING OF KENTUCKY	**)**	
POWER COMPANY FOR APPROVAL OF A	**)**	
SPECIAL CONTRACT WITH EBON	**)**	**CASE NO. 2022-0387**
INTERNATIONAL, LLC	**)**	

EXHIBIT__(SJB-4)

OF

STEPHEN J. BARON

ON BEHALF OF

THE KENTUCKY ATTORNEY GENERAL

AND

THE KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

February 2023

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

ELECTRONIC TARIFF FILING OF KENTUCKY	**)**	
POWER COMPANY FOR APPROVAL OF A	**)**	
SPECIAL CONTRACT WITH EBON	**)**	**CASE NO. 2022-0387**
INTERNATIONAL, LLC	**)**	

EXHIBIT__(SJB-5)

OF

STEPHEN J. BARON

ON BEHALF OF

THE KENTUCKY ATTORNEY GENERAL

AND

THE KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

February 2023

Kentucky Power Company
KPSC Case No. 2022-00387
AG-KIUCs Second Set of Data Requests
Dated January 17, 2023

DATA REQUEST

AG-KIUC 2_19 With regard to Rider DRS, does KPCo currently attempt to interrupt customers for the purpose of avoiding:

a. KPCo's load at the time of the AEP Zonal NSPL?

b. KPCo's 12 CP hours used to allocate transmission costs under the AEP East Transmission Agreement.

RESPONSE

a. Yes.

b. Whether the Company would attempt to interrupt a customer in this instance is situationally dependent. Generally, it is not the main purpose of the program.

Witness: Brian K. West

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

ELECTRONIC TARIFF FILING OF KENTUCKY	**)**	
POWER COMPANY FOR APPROVAL OF A	**)**	
SPECIAL CONTRACT WITH EBON	**)**	**CASE NO. 2022-0387**
INTERNATIONAL, LLC	**)**	

EXHIBIT__(SJB-6)

OF

STEPHEN J. BARON

ON BEHALF OF

THE KENTUCKY ATTORNEY GENERAL

AND

THE KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

February 2023

Kentucky Power Company
KPSC Case No. 2022-00387
AG-KIUC's First Set of Data Requests
Dated December 8, 2022

DATA REQUEST

1_12 Rider D.R.S. states that it is available for customers that take service under a standard demand metered rate schedule. Is it the Company's position that this would also apply to a non-standard special contract like the Ebon contract?

RESPONSE

Yes.

Witness: Brian K. West

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

STEPHEN J. BARON, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Stephen J. Baron

Stephen J. Baron

Sworn to and subscribed before me on this 8th day of February 2023.

Jessica K. Inman

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2023
CHEROKEE COUNTY, GEORGIA