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Via Overnight Mail

RECEIVED
OCT 29 2013
PUBLIC SERVICE COMMISSION

October 28, 2013

Mr. Jeff Derouen, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

Re: Case No. 2013-00199

Dear Mr. Derouen:

Please find enclosed the original and ten (10) copies each of the **PUBLIC VERSION** of KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.'s DIRECT TESTIMONY/EXHIBITS of the following witnesses: BILL CUMMINGS, KELLY THOMAS, STEVE HENRY, STEVE BARON, LANE KOLLEN and PHIL HAYET for filing in the above-referenced matter. I also enclose a copy of the CONFIDENTIAL pages to be filed under seal.

The information filed under seal is information that Big Rivers sought confidential treatment through a Petition for Confidential Treatment dated September 3, 2013. KIUC redacted this information in order to protect Big River's interests in keeping this information confidential.

By copy of this letter, all parties listed on the Certificate of Service have been served. Please place these documents of file.

Very Truly Yours,

Michael L. Kurtz

Michael L. Kurtz, Esq.
Kurt J. Boehm, Esq.
Jody Kyler Cohn, Esq.
BOEHM, KURTZ & LOWRY

MLKkew
Attachment
cc: Certificate of Service
Quang Nyugen, Esq.
Richard Raff, Esq.
Jeff Cline (cover ltr only)

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served by electronic mail (when available) and by Overnight Mail, unless other noted, this 28th day of October, 2013 to the following:

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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
OCT 29 2013
PUBLIC SERVICE
COMMISSION

In The Matter Of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT OF RATES	**) CASE NO. 2013-00199**

PUBLIC VERSION

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

OCTOBER 28, 2013

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT OF RATES	**) CASE NO. 2013-00199**

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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

APPLICATION OF BIG RIVERS ELECTRIC	**)**
CORPORATION FOR A GENERAL ADJUSTMENT	**) CASE NO. 2013-00199**
OF RATES	**)**

DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

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

Q. Please state your occupation and your position with Kennedy and Associates.

A. I am a utility rate and planning consultant. I am a principal and the Vice President of Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Business Administration in Accounting degree and a Master of Business Administration degree from the University of Toledo. I also earned a Master of Arts degree in theology from Luther Rice University. I am a Certified

Public Accountant ("CPA"), with a practicing license, a Certified Management Accountant ("CMA"), and a Chartered Global Management Accountant ("CGMA").

I have been an active participant in the utility industry for more than thirty years, initially as an employee of The Toledo Edison Company from 1976 to 1983 and thereafter as a consultant in the industry since 1983. I have testified as an expert witness on planning, ratemaking, management, accounting, finance, and tax issues in proceedings before federal and state regulatory commissions and courts on hundreds of occasions.

I have testified before the Kentucky Public Service Commission ("Commission") on dozens of occasions, including numerous cases involving Big Rivers Electric Corporation ("BREC" or the "Company") and the complex interrelationships among the Company's creditors, the former owners and present owner of the Sebree and Hawesville Smelters, and the Company's other Rural and Large Industrial customers. I was personally involved in and provided expert testimony in Case Nos. 9613 and 9885, on behalf of the Attorney General regarding the Workout Plan in 1986 and 1987, respectively; Case No. 10217, on behalf of Alcan Aluminum and National Southwire regarding the Workout Plan in 1988; Case No. 92-490 on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC") and the Attorney General regarding fuel costs; Case No. 96-327 on behalf of KIUC regarding environmental costs; Case No. 97-204 on behalf of Alcan and Southwire regarding Restructuring; Case No. 2009-00040 on behalf of KIUC regarding emergency rate relief and cash requirements; Case No. 2011-00036 on behalf of KIUC regarding a base rate increase; Case No. 2012-00535 on behalf of KIUC, the pending base rate increase ("Century rate case" or "Century increase"); and Case No. 2012-00063 on behalf of KIUC regarding environmental retrofits.

I also have testified before the Commission on numerous occasions in other utility base rate cases, environmental rate cases, and fuel adjustment cases on behalf of KIUC involving Kentucky Power Company, Louisville Gas and Electric Company, Kentucky Utilities Company, and East Kentucky Power Cooperative. My qualifications and regulatory appearances are further detailed in my Exhibit___ (LK-1).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of KIUC, a group of large customers taking electric service on the Big Rivers Electric Corporation system. The members of KIUC participating in this case are Aleris, Inc., Domtar, Inc., and Kimberly-Clark Corporation. These members of KIUC are the three largest customers in the Large Industrial class served by Big Rivers.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address and make recommendations in response to the Company's request for a base rate increase of $70.397 million, the entirety of which is attributable to the loss of the Alcan Primary Products Corporation ("Alcan") load upon termination of its contract for service on January 31, 2014 and the Company's inability to economically sell the resulting excess energy into a depressed energy market, according to Mr. Bailey's Direct Testimony at pages 5-6.

II. SUMMARY OF KIUC'S RECOMMENDATIONS

Q. Please summarize your testimony.

A. This is the third Big Rivers base rate increase request in the last three years. In addition to this request, the Century rate increase is still pending, although it was implemented on August 20, 2013 subject to refund. The Company's requests in the two pending Smelter termination driven rate cases, along with the actual base rate increase in Case No. 2011-00 and increases in other tariff components, sum to all-in rate increases at wholesale of 168% for Rural customers and 135% for Large Industrial customers. The Company's request in this case, along with the pending Century base rate increase and the increases in other tariff components compared to the base year in the Century case sum to all-in increases of 115% at wholesale and 72% at retail for Rural customers and 112% at wholesale for Large Industrial customers.

The sheer magnitude of the series of rate increases sought by the Company is staggering and will have a profound and lasting effect on the economy in Western

Kentucky. In addition, there likely will be additional base rate increases due to the loss of existing customers and other reductions in load due to conservation as customers respond to these rate increases.

The Commission should act decisively in this proceeding to ensure that the Company finally resolves its underlying and ongoing problems of excess physical generating capacity and the related excessive fixed costs and that it does so while setting rates at just and reasonable levels.

The Commission should adopt an approach that is balanced and equitable in order to achieve its statutory mandate to set rates at fair, just, and reasonable levels. The Commission has no similar statutory obligation to set rates sufficient to satisfy the creditors who knowingly accepted the risks and should share in the stranded fixed costs of the Smelter terminations.

The Company's approach is unbalanced and inequitable, and is based on an unrealistic view of the future and its ability to successfully implement its so-called load mitigation plan. The Company's approach results in massive rate increases, but does not resolve the underlying problems of excess physical generating capacity and the related excessive fixed and stranded costs. The Company's approach forces the remaining non-Smelter customers to pay for the entirety of the excess capacity and costs stranded by the Smelter terminations and relieves the creditors from sharing any of these costs. The Commission must weigh the Company's "moral obligation" to its customers against its "moral obligation" to repay its creditors.

Throughout this process, the Company's management has acted and continues to act against the interests of the very customers who own the Member cooperatives, which in turn own the Company. The Company has actively opposed any realistic efforts to resolve the Company's problems through restructuring or liquidation of the Company and/or restructuring its debt, and instead has focused on obtaining massive rate increases, at least for the next several years. The Company refuses to retain experts or counsel to assist it in evaluating its restructuring alternatives, including, but not limited to, the merger or sale of all or portions of the Company or its assets to another utility. The Company refuses to offer its power plants for sale at market value and instead insists that it will sell the plants only if it can do so at a premium. The Company refuses to discuss debt restructuring with its creditors.

The Company is determined to retain the entirety of its generation assets and position itself longer-term as a merchant generator, all while forcing customers to carry the cost of this strategy through massive upfront customer rate increases. The claim that such increases will be temporary is based on an unrealistic view of the future and its ability to successfully implement its load mitigation plan. The Company has resorted to using unsupported and unrealistic projections of new replacement loads at high load factors and at prices substantially in excess of market, but substantially below tariffed rates. In addition, these assumptions are completely at odds with the Company's intractable unwillingness to negotiate similar rates with the Smelters prior to their terminations. The Commission must step in and address this tragic situation and the failure of the Company's management to act in the interest of its customers.

Instead of the Company's approach, the Commission should adopt the KIUC Rate Plan proposed in the Century rate case and that I propose again in this case, modified only to include the KIUC recommendation for a reasonable increase in this case, as follows:

- Approve a reasonable base rate increase in the Century case of $21.7 million that will be in effect for the five months prior to the Commission's order in this case (from September 1, 2013 through January 31, 2014);
- Approve a reasonable base rate increase in this case of $8.559 million that will be in effect starting on February 1, 2014.
- Use the $131.5 million[1] in the ratepayer Reserve Funds to provide the additional revenues necessary for the Company to meet its 1.24 TIER target on a monthly basis;
- Use the Reserve funds for the benefit of both Rural and Large Industrial customers on a non-discriminatory basis;
- Direct Big Rivers to work with all stakeholders to achieve a reasonable negotiated solution to the Company's excess capacity and related fixed costs prior to the depletion of the Reserve Funds.

The KIUC Rate Plan provides the Company a reasonable time to finally resolve its problems under the direction of the Commission. It ensures that the Company will remain financially viable during this period and that its will earn a 1.24 TIER. It will provide the Company more than a year, or until February 2015, to

[1] The balance of the Economic Reserve ("ER") at August 31, 2013 was $66.130 million, according to the Company's response to Staff 3-3. The balance of the Rural Economic Reserve at August 31, 2013 was $65.350 million, according to the same response.

resolve the underlying problems before the Reserve funds are depleted.

I also recommend that the Commission direct the Company to retain professional advisers and counsel to identify and pursue options that will benefit customers, including, but not limited to, asset sales, corporate restructuring, corporate liquidation, and creditor concessions. The Commission should retain jurisdiction and supervise this process to ensure that it accomplishes the Commission's objectives. This step is consistent with the decisive action taken by the Commission several years ago when East Kentucky Power Cooperative ("EKPC") faced financial distress and a management crisis. In that case, the Commission directed a focused management audit to address the EKPC's problems, the EKPC Board of Directors ("BOD") replaced the senior management, and the EKPC BOD cancelled a new coal-fired unit midway through construction. That utility now is financially healthy and stable.

Finally, I recommend that the Commission adopt numerous adjustments to the Company's claimed revenue requirement, which are summarized on the following table.

Summary of KIUC Adjustments to Big Rivers Revenue Requirement Case No. 2103-00199 $ Million		
Big Rivers Requested Increase		$70.397
KIUC Adjustments		
Cease Depreciation Expense - Wilson and Coleman Stations	(26.644)	
Include Transmission Revenue from Century Hawesville and Sebree Smelters	(12.781)	
Reduce Non-Recurring Coleman Lay Up Expenses	(1.600)	
Remove MATS 2014 Capital Expenditures for Wilson and Coleman Stations	(0.694)	
Reduce Allocation of ACES Fees to be Paid By Century	(1.333)	
Share Fixed Costs Due to Excess Capacity with Creditors	(18.786)	
Total KIUC Adjustments		(61.838)
Big Rivers Increase after KIUC Adjustments		$8.559

III. THE COMPANY'S REQUESTS IN THE CENTURY AND ALCAN CASES, ALONG WITH CHANGES IN OTHER RATE COMPONENTS, WILL RESULT IN ALL-IN RATE INCREASES OF 72% FOR RURAL CUSTOMERS AND 112% FOR LARGE INDUSTRIAL CUSTOMERS

Q. What is the "all-in" rate impact of the Smelter terminations?

A. The Company estimates that the "all-in" rate impact of the Smelter terminations for the Century and Alcan base rate cases combined together with the increases in other rate components, including the FAC and ECR, will be 115% at wholesale for the Rural customers, 72% at retail for the Member Cooperative residential, commercial and small industrial customers, and 112% for the Large Industrial customers as shown in the following table. The increase to the average residential customer using 1300 kWh per month will be nearly $900 each year. The sources for the data used in the following tables are indicated on the tables.

RATE INCREASES TO RURAL CLASS FROM CENTURY AND ALCAN TERMINATIONS
AFTER RESERVES ARE DEPLETED

RURAL	CENTURY BASE PERIOD [1]		ALCAN TEST YEAR [2]		CENTURY AND ALCAN INCREASES	
	Rural Rate	Rural Revenues	Rural Rate	Rural Revenues	Rural Rate Increases	Percent Increases
Base Rate - Demand		$ 51,194,845		$126,899,244	$ 75,704,400	147.9%
Base Rate - Energy		$ 71,988,650		$ 80,799,320	$ 8,810,670	12.2%
Non-Smelter Non-FAC PPA		$ (3,006,790)		$ (826,876)	$ 2,179,914	-72.5%
FAC		$ 8,424,822		$ 13,737,782	$ 5,312,960	63.1%
Environmental Surcharge		$ 6,134,626		$ 14,168,287	$ 8,033,661	131 0%
Smelter Surcredit		$ (9,950,005)		$ (308,324)	$ 9,641,681	-96.9%
MRSM (Economic Reserve)		$(15,595,604)		$ -	$ 15,595,604	-100 0%
Totals	$0 0451	$109,190,543	$0 1016	$234,469,433	$ 125,278,890	114 7%
Avg Monthly Residential Bill @ 1300 kWh [1]		$ 101 53		$ 174 94	$73 40	
Avg Annual Residential Increase					$880 82	

[1] Includes $0 033/kWh for Member Cooperative Charges As Shown On Ex Wolfram-7.
[2] Base Rates and Revenues From Tab 59 in Case No 2012-00535.
[2] Test Year Rates and Revenues From Tab 56 in Case No. 2013-00199.

RATE INCREASES TO LARGE INDUSTRIAL CLASS FROM
CENTURY AND ALCAN TERMINATIONS
AFTER RESERVES ARE DEPLETED

LARGE INDUSTRIAL	CENTURY BASE PERIOD [1]		ALCAN TEST YEAR [2]		CENTURY AND ALCAN INCREASES	
	Large Ind Rate	Large Industrial Revenues	Large Ind Rate	Large Industrial Revenues	Large Ind Rate Increases	Percent Increases
Base Rate		$ 41,207,958		$ 65,809,791	$ 24,601,833	59 7%
Non-Smelter Non-FAC PPA		$ (1,190,863)		$ (356,508)	$ 834,355	-70 1%
FAC		$ 3,326,542		$ 5,843,877	$ 2,517,335	75.7%
Environmental Surcharge		$ 2,252,893		$ 4,608,733	$ 2,355,840	104 6%
Smelter Surcredit		$ (3,961,493)		$ (134,005)	$ 3,827,488	-96 6%
Power Factor Penalty/Adjustments		$ 111,014		$ -	$ (111,014)	-100 0%
MRSM (Economic Reserve)		$ (5,948,917)		$ -	$ 5,948,917	-100 0%
Totals	$0 0376	$ 35,797,133	$0 0782	$ 75,771,888	$ 39,974,755	111 7%

[1] Base Rates and Revenues from Tab 59, Adjusted to Reflect Amounts Reflected in Response to KIUC 1-30 c, In Case No 2012-00535.
[2] Test Year Rates and Revenues From Tab 56 in Case No 2013-00199.

Q. The increases shown in the preceding tables are greater than the amounts and percentages that the Company noticed in the Century case (as adjusted in the Company's Rebuttal Testimony) and in this case. Please explain.

A. The primary reason that the rate increases shown on the preceding table are greater is that they include *all* of the increases across *all* tariff components in the test year, whereas the Company's Applications reflect *only* the *base* rate increases sought by the Company while holding all of the other tariff components constant. In reality and in addition to the base rate increases, the Century and Alcan terminations will result in FAC rate increases due mostly to the increases in average fuel cost per kWh from the shutdowns of the Wilson and Coleman plants. The terminations also will result in ECR rate increases to all customer classes due mostly to the fixed costs that must be recovered from the remaining customers. In addition, the terminations will result in increases due to the loss of the Smelter surcredit because there no longer will be any Smelter surcharge revenue from Century or Alcan to fund the surcredit. Further, there will be increases when the Reserve funds are depleted and the surcredits through the MRSM and RER tariffs drop to zero.

Q. Why are the "all-in" rate increases relevant in this proceeding?

A. The Commission must set rates at "fair, just, and reasonable" levels. By including the impacts across all tariff components, the Commission can assess the full magnitude of the increases on the households and businesses in Western Kentucky and make informed judgments regarding an equitable sharing of excess capacity costs between customers and creditors in setting just and reasonable rates. The full rate impact across all tariff components of the Century and the Alcan terminations is what customers pay, not only the base rate impact in isolation.

Q. What factors should the Commission consider in determining whether Big Rivers' proposed rates are fair, just and reasonable?

A. There is no single test for this determination. The particular facts and circumstances of each case are different. However, one fundamental ratemaking principle is that just and reasonable rates should not include the costs of facilities that are not "used and useful" in providing electric service. This is an important principle in a ratemaking environment because the regulator must protect the economic interests of customers who must buy electricity from a single monopoly supplier and have no other options simply because they live or operate their businesses in the utility's service territory. The Commission relied on this ratemaking principle, i.e., that the costs of the facilities must be used and useful in providing electric service, when it initially considered the rate increases for the Wilson plant sought by Big Rivers and for the Trimble County 1 plant sought by Louisville Gas and Electric Company.

The Wilson and Coleman plants will not be used and useful to customers in the test year and may never again be used and useful to customers. The plants represent excess capacity caused by the Smelter terminations and the related costs should not be included in costs recoverable from customers. Despite the loss of both the Century and Alcan loads, the Company, nevertheless, has included the fixed costs related to that excess capacity in its revenue requirement.

Another factor that should be considered is the impact of the proposed increase on customers. The Commission should consider the sheer magnitude of the increases as well as the underlying reasons for the increases and the possibility and likelihood of resolution through means other than the increases.

IV. THE KIUC RATE PLAN PROVIDES AN EQUITABLE AND BALANCED APPROACH THAT SETS RATES AT JUST AND REASONABLE LEVELS, USES THE RESERVE FUNDS TO MITIGATE RATE INCREASES, ENSURES THE COMPANY'S FINANCIAL METRICS, AND PROVIDES THE COMPANY AND ITS STAKEHOLDERS A REASONABLE TIME PERIOD TO RESOLVE THE UNDERLYING PROBLEMS

Q. Please describe the KIUC Rate Plan as proposed in the Century rate case.

A. The KIUC Rate Plan provides a balanced approach that sets rates at fair, just, and reasonable levels, provides the Company a reasonable opportunity and time period to resolve its problems, and preserves the Company's financial metrics during that time period. The KIUC Rate Plan from the Century rate case includes the following elements:

- Approve a reasonable base rate increase of \$21.7 million for Big Rivers' remaining customers for the five months prior to the Commission's order in the pending Alcan rate case (September 1, 2013 through January 31, 2014);
- Use the \$131.5 million in the ratepayer Reserve Funds to provide the additional revenues necessary for the Company to meet its 1.24 TIER target on a monthly basis;

- Use the Reserve funds for the benefit of both Rural and Large Industrial customers on a non-discriminatory basis;
- Direct Big Rivers to work with all stakeholders to achieve a reasonable negotiated solution to the Company's excess capacity and related fixed costs prior to the depletion of the Reserve Funds.

Q. Is there an additional element to the KIUC Rate Plan that you propose in this proceeding?

A. Yes. I recommend that the Commission approve a reasonable rate increase of no more than $8.559 million in this proceeding.

Q. What are the benefits of the KIUC Rate Plan?

A. There are many benefits to KIUC's approach, including:

- avoiding rate shock to customers;
- achieving an equitable sharing of the excess capacity costs resulting from the Century and Alcan terminations rather than forcing Big Rivers' remaining customers to take on 100% of the burden of the stranded generating capacity and the related fixed costs;
- maintaining and improving the Company's credit metrics until February 2015 due to the use of the Economic Reserve and Rural Economic Reserve funds while the Company works with its stakeholders to resolve its problems of excess capacity and the related fixed costs;
- providing a reasonable incentive for the creditors to work with Big Rivers in a cooperative manner prior to the depletion of the ratepayer Reserve Funds;
- providing additional time for resolution of the significant uncertainties surrounding the Century and Alcan terminations departure, including, but not limited to, the impacts of MISO's "must run" ("SSR") decision on Coleman;
- providing additional time to comprehensively study and address the Company's future and structure; and
- providing additional time to sell or otherwise dispose of the Company's excess

generating capacity and to reduce its related fixed costs.

Q. In this case, the Company proposes that the Commission use the Reserve funds to temporarily mitigate the full impact of the rate increase in this proceeding. How does this proposal differ from the KIUC Rate Plan?

A. The Company's proposal is significantly different because it does not require and will not result in a resolution of the underlying problems, fails to limit the time frame to achieve such a resolution, and engages no stakeholders in the resolution other than imposing massive rate increases on its customers. Indeed, under the Company's proposal, it will have no incentive to resolve the underlying problems if the Commission approves the entirety of the requested increases. The Company's proposal to use the Reserve funds in this case only provides a short-term respite before the rate increase time-bomb explodes and customers are struck with the full impact of the increases when the Reserve funds are depleted. Under the Company's proposal, the customers are the only party that will be harmed by this explosion, and yet they will have no control over the length of the fuse or the force of the explosion.

In stark contrast to the Company's plan, the KIUC Rate Plan provides a reasonable and limited time frame for the Company and its stakeholders to resolve the problems. There is an incentive for the Company and its stakeholders to resolve the underlying problems because there will be no automatic rate increase when the Reserve funds are depleted. If the Company fails to resolve its problems, it must come before the Commission and attempt to justify another rate increase. Under the KIUC Rate Plan, the Company and its creditors also have an economic stake in the resolution and outcome, not only the Company's customers. In this manner, the KIUC Rate Plan provides the Commission with stronger and more direct involvement and greater leverage to ensure that the Company and all stakeholders are sufficiently incentivized to resolve the problems, not ignore them and simply hope for a better future after the massive rate increases are imposed. The Company will have until February 2015 to resolve the problems before the Reserve funds are depleted and further action by the Commission may be required.

Q. **Does the Company now agree that the Commission has the flexibility to modify its Order from the Unwind Case and expand the use of the Reserve funds to mitigate base rate increases in addition to mitigating FAC and ECR rate increases?**

A. Yes. The Company and KIUC now are in agreement on this point. However, the Company and KIUC disagree on how the Reserve funds should be used. The Company proposes a time-bomb approach with only a temporary respite and no resolution of the underlying problems. KIUC proposes an hourglass approach that is focused on achieving a permanent resolution of the underlying problems.

Q. **Please describe the Company's proposed modifications to the MRSM and RER tariffs.**

A. The Company proposes that the MRSM tariff be modified so that it offsets the Rural and Large Industrial rate increases sought in this proceeding in addition to the increases in the FAC and ECR until the Economic Reserve is depleted. The Company estimates this will occur in July 2014, according to Ms. Richert in her Direct Testimony at 14. At that time and once the Economic Reserve is depleted, the full impact of the rate increase sought in this proceeding will be imposed on the Large Industrial customers. Also at that time, the full impact of the FAC and ECR rate increases since they were implemented after the Unwind Transaction will be imposed on the Large Industrial Customers.

Similarly, the Company proposes that the RER tariff be modified so that it offsets the Rural rate increases sought in this proceeding in addition to the increases in the FAC and ECR until the Rural Economic Reserve is depleted. The Company estimates this will occur in April 2015, according to Ms. Richert in her Direct Testimony at 14. At that time, the full impact of the rate increase sought in this proceeding will be imposed on the Rural customers. Also, at that time, the full impact of the FAC and ECR rate increases since they were implemented after the Unwind Transaction will be imposed on the Rural customers.

Q. Do you agree with the Company's proposed modifications to the MRSM and RER tariffs?

A. No. The Company's proposed modifications substantially ratchet up the explosive impact of the time-bomb rate increases once each of the Reserve funds are depleted because the MRSM and RER riders are surcredit riders that only reduce rates temporarily. When each of the Reserve funds are depleted, the MRSM and RER surcredit riders will be reset to $0 so that the full impact of the rate increases will be imposed immediately, initially on the Large

Industrial customers and then on the Rural customers. The KIUC Rate Plan provides the Commission another opportunity to assess the Company's progress in resolving its problems prior to imposing yet another base rate increase.

Q. **Does the Company's proposed modification to the RER tariff address the discrimination against the industrial customers in the Large Industrial class and the preferential access to the Rural Economic Reserve Fund afforded the commercial and industrial customers in the Rural class?**

A. No. As I previously discussed, without the adoption of the KIUC Rate Plan or the adoption of the RER tariff modification proposed by KIUC, none of the Rural Economic Reserve fund will be provided to Large Industrial customers. This results in disparate rate treatment between the Rural and Large Industrial customers, discrimination against the Large Industrial customers, and preferential treatment for the Rural customers, including the 16,000 commercial and industrial business customers that are classified as Rural. Many business customers that are classified as Rural actually have larger loads than some of the business customers that are classified as Large Industrial. KIUC witness Mr. Stephen Baron addresses these issues further in his testimony and recommends that the Rural Economic Reserve fund be applied to all customers, both residential and business customers, regardless of the customer class in which they are classified and in a consistent and non-discriminatory manner.

Q. **How should the KIUC Rate Plan be implemented so that it avoids the explosive effect of the Company's time-bomb approach and resolves the discriminatory application of**

the Rural Economic Reserve fund?

A. As a practical matter, there are two steps. The first step is necessary to maintain the surcredit rate effects of the MRSM and to correct the discrimination in the allocation of the RER going forward. The second step is necessary to protect the Company's financial metrics until the Reserve funds are depleted.

In the first step, I recommend that the Commission eliminate the MRSM and RER tariffs and roll-in the test year effects of the present MRSM into base rates on a non-discriminatory basis. This roll-in should not include the Company's proposed offset to the base rate increases in this case because I don't recommend that the Commission adopt the Company's proposal to modify the MRSM and RER tariffs. This roll-in will maintain the surcredit effects of the present MRSM on customer rates by incorporating those effects in base rates. After the MRSM is rolled-in to base rates, the rolled-in rates will not change in the future when the Reserve fund is depleted, or for that matter, when the Rural Economic Reserve fund is depleted unless and until the Company files for another base rate increase if it is not otherwise able to resolve the underlying problems.

The roll-in of the present MRSM to base rates and the elimination of the MRSM and RER tariffs automatically will correct the disparity between Rural and Large Industrial customers in the application of the RER and will ensure that those funds are applied to both classes on a non-discriminatory basis. As a practical matter, this roll-in will convert the Company's time-bomb approach into the KIUC hourglass approach. The FAC and ECR tariffs and rates will not be affected and will continue to operate as they do presently.

After the effective date of the Order in this case, the Company will draw down the Reserve funds each month to match the amount of the MRSM rolled-in to base rates, first from the Economic Reserve until it is depleted, and thereafter from the Rural Economic Reserve until it is depleted. The draws on the Reserve funds will be included in revenues, according to Mr. Christopher Warren at 7. In terms of accounting entries, the Company will debit the Reserve funds and credit revenues. This is the same accounting process presently employed by the Company for the use of the Reserve funds.

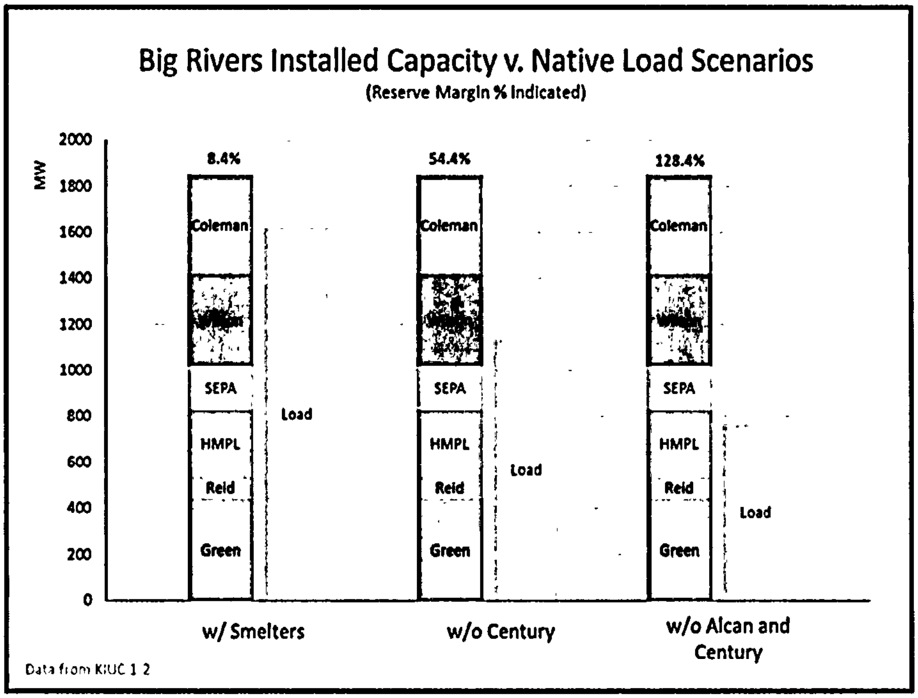
In the second step, I recommend that the Commission direct the Company to debit the Reserve funds and credit revenues for the additional amount necessary to achieve a 1.24 TIER each month. This second step will have no rate effect on customers, but it will provide the Company with revenues sufficient to meet the 1.24 TIER and it will provide the Company with cash equivalent to the draws on the Reserve funds.

V. THE COMPANY HAS SUBSTANTIAL EXCESS CAPACITY THAT IS NOT USED AND USEFUL DUE TO THE SMELTER TERMINATIONS AND THE RELATED STRANDED COSTS ARE THE PRIMARY DRIVERS OF THE CENTURY AND ALCAN RATE INCREASES

Q. Is the Company's generation capacity properly sized to meet the load of its remaining customers after the Smelter terminations?

A. No. The Company has significantly more generation capacity than it needs to serve its present load due to the Smelter terminations as shown on the following graph. The Company's plan to shutdown the Wilson and Coleman plants is not a long-term solution to this extreme excess capacity situation for the reasons that I subsequently address and that Mr. Hayet addresses. The data for the graph below is stated on a

MISO installed capacity basis. I provide the data for the MISO installed capacity and the unforced capacity in my Exhibit___(LK-2).



Q. Have the Company's actions sufficiently downsized or "right-sized" the Company to meet the load requirements of its remaining customers?

A. No. To date, the Company has not sufficiently downsized by divesting or otherwise selling its capacity, although it plans to temporarily shut down the Wilson and Coleman plants for the next 4 to 5 years. The Company estimates that it will restart the plants in 2018 and 2019, respectively, based on its estimates of market prices and its plans to somehow acquire substantial replacement load. However, these assumptions of future market prices and the success of the Company's plans to acquire replacement load are unrealistic. The Commission should not conclude that the Company's problems are only temporary on the basis of these uncertain assumptions.

Q. Will the Company's approach relieve the Company and its customers of the fixed costs of the Wilson and Coleman plants?

A. No. Regardless of the Company's plans and estimates for the future and the uncertainty of the future, the reality is that the shutdown of the plants, temporarily or otherwise, does not relieve the Company or its customers of the fixed costs associated with the ownership of the plants. Under the Company's approach, all of the fixed costs related to the excess generation capacity still are included in the Company's claimed revenue requirement and will continue to be included in the revenue requirement regardless of whether market prices increase or the Company is successful in acquiring replacement load. The only certain way to relieve the Company of some or all of the fixed costs is for it to sell the plants, sell the output of the plants, retire them, or obtain concessions from its creditors either voluntarily or involuntarily.

Q. Please quantify the fixed costs for the Wilson and Coleman plants that still are included in the Company's claimed revenue requirement.

A. The Company's claimed revenue requirement still includes [redacted] million in fixed costs for these plants, consisting of [redacted] million for the Wilson plant and [redacted] million for the Coleman plant. These annual costs could be avoided in whole or part if the Company sold or otherwise divested these power plants. The fixed costs include O&M expense, property insurance expense, property tax expense, depreciation expense, interest expense, and the TIER margin. These amounts were provided by the Company in its Confidential responses to AG 1-105 and AG 1-106, which I have replicated as my Confidential Exhibit___(LK-3) and Confidential Exhibit___(LK-4), respectively.

Q. Are the Company's attempts to sell the ownership or output of the Wilson and Coleman plants serious offers to divest these assets and reduce its excess capacity?

A. No. The Company has submitted bids in response to numerous requests for proposal issued by other utilities, according to its Confidential responses to PSC 2-15 and PSC 2-16. However, these bids are not serious offers to sell. Rather, they are a collective exercise in futility because they reflect the fact that the Company has decided that it will not sell the plants unless it can sell them at [redacted] Not surprisingly, the Company's bids not been competitive and have not been accepted, as described in greater detail in its Confidential responses to PSC 2-15 and 2-16, copies of which are attached as my Confidential Exhibit___(LK-5) and Confidential Exhibit___(LK-6).

Q. Please address the Company's forecast of replacement load in this case.

A. In its production cost modeling and financial forecast used in this case, the Company fabricated and included new ("replacement") loads in addition to its native load projections starting in 2016. These replacement loads represent increments to its native load projections and displace market sales that otherwise would clear the MISO market. The Company fabricated these replacement loads to justify the retention of the power plants and its decision not to sell them at market. The Company now claims that all of its power plants will be necessary to serve these new loads and that the Wilson and Coleman plants will be economic based on the replacement load assumptions, even though the Company projects that market prices will remain depressed for many years into the future.

The replacement load assumptions are altogether new in this case. The Company did not include this replacement load in the production cost modeling or the financial forecast provided in the Century rate case. In the Century rate case, the Company assumed that its native load would remain relatively unchanged, but that market prices would escalate dramatically. In the Century case, the Company argued that operating as a merchant generator and selling into the market in future years provided sufficient margins and economic value to justify retaining the plants. However, that no longer is the case. The Company's projections of market prices in this case now are less than in the Century case and the Company no longer can use the escalation of market prices to justify its decision to retain ownership of the plants. The following chart compares the Company's market price projections in the Century case to its market price and replacement load price projections in this case.

[redacted]

Unable to rely on market sales to justify retention of the power plants again in this case as it had in the Century case, the Company decided to take a different approach. It decided to fabricate and overlay a "replacement load" forecast on top of its native load forecast. In the replacement load forecast, the Company simply assumed that it would add 800 mW of load in 100 to 200 mW annual increments starting in 2016 and continuing through 2021. It further assumed that this load would operate at a 75% load factor. And, it further assumed that this load could be acquired at a price substantially discounted from the tariff rates requested in this proceeding, but at a premium of 25% to the market.

The following chart graphically portrays the Company's replacement load forecast compared to the negligible growth in its existing native load.

[redacted]

Q. What analytical support does the Company have for these replacement load assumptions?

A. Absolutely none. The Company admits that it has no analytical support for these replacement load assumptions, according to its responses to KIUC 2-32 and KIUC 2-35. The replacement load, load factor, and pricing assumptions were completely fabricated to buttress the Company's decision to retain the power plants and support its narrative. I have replicated the Company's response to KIUC 2-32 as my Exhibit___(LK-7) and the Company's response to KIUC 2-35 as my Exhibit___(LK-8).

Q. Is the Company's replacement load forecast credible?

A. No. The Company's projection of replacement load is unrealistic and is not credible, particularly when considered in comparison to its existing load and to the load growth for the entire country projected by the Energy Information Administration ("EIA"). The Company assumes that it will acquire replacement load, i.e., new load exceeding its *entire Rural* load by 2019 and exceeding its *entire Rural and Large Industrial* load by 2021. It assumes that it will acquire replacement load that will more than *quintuple* its existing Large Industrial load by 2021. That simply is not credible on its face.

To provide some further context to assess the credibility of the replacement load assumptions, the Company presently represents only 0.09% of the entire load of all utilities across the country. Yet, to achieve its replacement load assumptions, the Company will have to acquire 1.3% to 4.5% of all the load growth each year projected by the Energy Information Administration ("EIA") for the entire country. In other words, the Company's assumption is that it will succeed in acquiring an outsized and disproportionate share of the entire country's load growth. This simply is not credible on its face.

Further, the Company is engaged in energy efficiency and demand response programs to reduce its load, which, if these programs are successful, will reduce its load and cause its rates to rise even further, all else equal. Thus, the Company will be required to acquire even more replacement load at even greater discounts.

In summary, the Company's replacement load projection is not credible and it will not resolve its problems through outsized and disproportionate growth. Mr. Hayet also addresses the Company's replacement load and provides additional evidence that the projection is not credible.

The Commission must deal with the Company's problems now. They are not temporary.

Q. Do you have any additional comments regarding the Company's replacement load assumptions?

A. Yes. First, any new large industrial loads that may choose to locate in the Company's service territory or new municipal loads that may choose the Company as their supplier likely will be price sensitive. The Company assumes that will require substantial discounts from the tariffed rates in this proceeding. The

Company assumes that it will discount the average member tariff rates by *nearly* [redacted] in 2016 through 2018 in order to attract these loads, according to the confidential financial model provided in response to PSC 1-57. The Company assumes that the average price paid by the replacement load will not reach parity with the average member tariff rates until 2022, or 10 years after Century provided its notice of termination. And this assumption is based solely on the unrealistic assumption that member tariff rates will drop starting in 2019 due to margins from the replacement load. In other words, the entire set of assumptions is circular. The average price paid by the replacement load never reaches the average member tariff rates that will result from this proceeding if the Company's Century and Alcan rate increases are granted in full.

The following graph portrays the Company's projection of average member tariff rates as the top line, market prices as the bottom line, and the replacement load prices as the middle line. It should be noted that the declining average tariff rates drop starting in 2019 only because of the Company's unrealistic assumptions that: 1) it will acquire massive new replacement loads that will pay a substantial premium over market; 2) it will be able to charge the replacement loads a premium over tariff rates after market prices rise starting in 2022; 3) it will incur no CO_2 capital expenditures or operating expenses for its power plants; 4) it will not incur other capital expenditures or operating expenses to meet other evolving environmental requirements for its power plants, and 5) it then will use its enhanced financial position to reduce the tariff rates for all members except for the replacement load.

[redacted]

The Company plans to justify these discounts on the basis of "economic development," according to its response to KIUC 2-36. However, the result of this strategy will be a multi-tier pricing structure where all the present customers will pay full embedded cost for capacity that is excess, while all the new customers will pay less than full embedded cost. At the same time, the Company assumes that it will be able to price such loads at a premium to the market. The Company assumed a 25% premium, but could offer no analytical support for this assumption, according to its response to KIUC 2-35. I have attached a copy of the company's response to KIUC 2-36 as my Exhibit___(LK-9).

Second, the Company now assumes that it will acquire new loads starting in 2016 at the same average price that it rejected for the Sebree Smelter when it was negotiating with Alcan. To put this in context, the Company refused to supply the Sebree Smelter at a price that would have provided some contribution to fixed costs on the basis of principle, i.e., that it would not sell to the Smelters below full embedded cost. The Company now is willing to sell to other potential and unknown loads for the same price that it previously rejected. This is inexplicable.

Third, the Company has made offers or held discussions to acquire loads presently served by TVA, according to its response to PSC 2-16. However, TVA is a low-cost producer and acts aggressively to retain and attract customer loads. The Company is not likely to be successful in acquiring such loads. The Commission may recall that several years ago, EKPC was forced to cancel a power plant that was under construction when it ultimately was unsuccessful in acquiring a load that was served by TVA. EKPC's customers still are paying for that misstep. The Company is not aware of any other utility that has ever successfully poached customer loads from TVA, according to its response to KIUC 2-36(g).

Fourth, the Company assumed that the replacement load would be priced above tariff rates after 2021, as shown on the preceding chart. On this basis, the Company assumed that it would apply these premium revenues to reduce tariff rates for native load. This assumption is not credible. While the Company may have to discount tariff rates to acquire the replacement load, there is no logical support for the premise that replacement load prices would exceed tariff rates and then continue to escalate so that tariff rates will be reduced even further.

Q. What is the harm to customers over the next five years if the Company retains the Wilson and Coleman power plants rather than selling or otherwise divesting them?

A. In the absence of a sale or other divestiture of the plants, the certain harm to customers of "holding-on," or the cost of the Company's bet on its unrealistic view of the future, is at least [redacted] million annually based on the fixed costs included in the Company's claimed revenue requirement in this case. The harm in the test year will increase in subsequent years to reflect escalation in property tax and insurance expenses, the interest and TIER on additional debt to fund capital expenditures necessary to comply with MATS and other environmental requirements, and the expenses that will be incurred to shut down and subsequently restart the units. This is a permanent harm to customers if the Company's view of the future does not materialize.

VI. THE RESPONSIBILITY FOR PAYING FOR BIG RIVERS' EXCESS CAPACITY SHOULD BE SHARED BETWEEN BIG RIVERS' CUSTOMERS AND ITS CREDITORS

Q. How should the Commission treat the costs associated with Big Rivers' excess capacity for recovery purposes?

A. I recommend that the Commission balance the cost burden associated with Big Rivers' excess capacity, which no longer is used and useful, by equitably sharing that burden between the Company's customers and its creditors. To do so, the Commission should disallow a percentage of the revenue requirement caused by the Century and Alcan terminations and the excess capacity resulting from the loss of these loads on the Big Rivers' system. This recommendation will require customers to bear a portion of the cost of the excess capacity, but also will require that creditors bear a portion of the cost, consistent with the fact that both customers and creditors have an economic interest in the impacts resulting from the Century and Alcan terminations. I address my recommendation and the effects on the Company's revenue requirement later in my testimony.

Q. Why do you recommend that the Commission balance the cost burden of Big Rivers' excess capacity, rather than imposing 100% of the costs associated with that capacity onto customers?

A. Assets that once were used and useful can be rendered no longer used and useful in two general ways. The first is through regulatory changes and the second is through market changes. Utilities generally are protected from stranded costs associated with regulatory changes. For example, one regulatory change would be deregulation. In that case, stranded costs resulting from deregulation would be the responsibility of the shopping customers. In contrast, the stranded costs resulting from market changes typically are shared among impacted parties.

In this case, market changes have rendered a significant amount of Big Rivers' generating capacity as excess and unnecessary to meet the needs of its remaining customers. This is the reason why Big Rivers plans to shut down the Wilson and Coleman plants. Those plants no longer will be used or useful. The market changes include the loss in value of coal-fired generation and the reduction in wholesale market prices from levels that Big Rivers assumed when it agreed to the one-year notice provision in the Smelter contracts. These market changes have resulted in excess capacity that is no longer physically or economically used and useful.

Since Big Rivers' capacity has been rendered no longer used and useful because of market changes, not regulatory changes, it is reasonable to equitably share the resulting stranded cost burden between the Company's customers and its creditors. What is not reasonable is forcing customers to pay 100% of the costs associated with that excess capacity. Instead, the Commission should balance the interests of the Company's customers and creditors by sharing the cost burden associated with the Company's excess capacity among the parties. My recommendation achieves that equitable balance.

Q. Why else does it make sense to share the costs of Big Rivers' excess capacity between the Company's customers and its creditors?

A. The Commission has a statutory mandate to set rates at just and reasonable levels for Big Rivers and its customers; however, there is no statutory requirement that the Commission set rates at levels sufficient to pay off all creditors, without regard for the rate impact on customers. In other words, the statutory requirement serves to protect customers from serving as the guarantor of the utility's obligations to creditors and establishes the Commission as the arbiter of the conflicting demands of customers and creditors.

Q. Has the Commission relied on this principle in prior Big Rivers' proceedings?

A. Yes. In Big Rivers' financial workout plan case, Case No. 9613, the Commission determined that customers should not be held responsible for 100% of Big Rivers' debts. Specifically, the Commission "*emphatically*" declared:

> We emphatically reject the claims of REA, the banks, and Big Rivers that the members of the cooperative ultimately bear the total risk and responsibility for the utility's debts. The distribution cooperatives and their members do not stand in the same position as shareholders of an investor-owned company. The REA, with its oversight and monitoring responsibility, bears a substantial amount of the risk associated with Big Rivers' actions. The creditor banks are compensated for the risks they take. Cooperative members must shoulder a portion of the risk, too, since they have a say in the affairs of the utility. Nor are the aluminum companies exempt from responsibility. Until the downturn of recent years, these companies or their predecessors were in frequent contact with Big Rivers' management. Rather than allocate

> the risk among all parties now, we have chosen to give the participants an opportunity to discuss the allocation among themselves as a revised workout plan is negotiated.[2]

The Commission also concluded that the application of the "used and useful" standard involves a balancing of interests, stating:

> The establishment of fair, just and reasonable rates involves a balancing of utility and ratepayer interests. After balancing these interests, the Commission may conclude in a given case that rates should be based upon prudent investments even where facilities are cancelled prior to completion of construction. On the other hand, in considering the need for facilities on an economic basis, the Commission may decide that it is not in the customers' interest to pay rates that include the cost of unneeded facilities.[3]

The Commission concluded that in applying the "used and useful" standard, it "must carry out a complex balancing of equities and allocation of risk."[4] The Commission ordered the parties to develop a workout plan that "must offer an equitable balance among all interests"[5] (the utility, customers, and creditors).

The Commission should apply the same reasoning and establish such an equitable balancing of all interests in this case.

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[2] 1987 BREC Order at 19.
[3] 1987 BREC Order at 37.
[4] 1987 BREC Order at 39.
[5] 1987 BREC Order at 43.

Q. Is it equitable to impose the entirety of the costs associated with the Company's excess capacity solely on customers?

A. No. The Rural and Large Industrial customers did not cause Big Rivers' financial problems resulting from the Century and Alcan terminations. Wholesale market prices and the value of the coal generating assets are now lower than Big Rivers assumed when it agreed to the one-year notice provision in the Smelter contracts as part of the Unwind transaction. This was a risk that Big Rivers and its creditors undertook when the Company entered into the Smelter contracts.

Further, Big Rivers' creditors were fully informed of the Smelter termination risk when they loaned money to the Company and when they consented to the Unwind transaction. Most recently, CoBank and CFC, as well as the rating agencies, were fully informed and well aware of the possibility of the Smelter terminations as a risk factor when the creditors negotiated the terms of their loans and before they actually loaned $537 million to Big Rivers in mid-2012. In fact, the Company provided a Disclosure Statement dated July 12, 2012 to these creditors prior to obtaining the loan proceeds in which it warned them of the risk of the Smelter terminations. In that Disclosure Statement, Big Rivers stated:

> The Smelters intervened in the Company's last rate case, and pressed their case by saying that keeping the Smelter rates low and predictable was important to reduce the risk that the Smelters would have to cease operations upon the next downward cycle in the world price of aluminum. The Smelters say that they are very sensitive to the price they pay for electricity because the cost of electricity is approximately one-third of the cost of the aluminum smelting process.

* * *

The Smelters have made public statements that the unanticipated magnitude of the current and future rate increases projected by Big Rivers as well as Big Rivers' recent evaluation of the impact of environmental legislation is what drives the current need for a statewide solution to the Smelters' increasing utility costs. Local representatives of Alcan informed economic development officials in state government in February of this year that projected power rates in 2013-2015 make it difficult for Alcan to envision a long-term future for the Sebree plant.

* * *

Local representatives of Century have told Big Rivers and others in state government that rates at the status quo level are not sustainable for Century's Hawesville smelter even in the short term, and that $50/MWh power puts their smelter's viability at great risk. Century wrote Big Rivers on April 18, 2012, stating that at the current LME prices the Hawesville aluminum smelter cannot sustain operations at Big Rivers' current and projected power rates, and requesting to renegotiate the power rate provisions of its contract. Big Rivers has commenced discussions with Century relating to the sustainability of the Hawesville smelter. Century reported on April 24, 2012, that with the current power price forecast and assuming that the LME remains at its current level, the Hawesville plant is not viable from an economic standpoint.

* * *

On June 14, 2012, at the request of the Governor of Kentucky, representatives of the Commonwealth met with representatives of Big Rivers and the Smelters to discuss ways to reduce the Smelters' costs in order to make them more economically viable. A number of approaches were discussed including, but not limited to, suggestions that Big Rivers reduce rates to the Smelters to a rate averaging about $35/MWh.

* * *

Since the meeting on June 14th, the Smelters have advanced other proposals to Big Rivers requesting significant rate reductions for the Smelters. Big Rivers offered a counterproposal and it has been rejected by the Smelters. On June 25, 2012, Big Rivers advised the Smelters that the gap between their demand and the Big Rivers' proposal is far larger than Big Rivers has the ability to close. There can be no assurances as to the outcome of this situation and as to whether one or both of the Smelters will give one year's notice, terminate its Smelter Agreement and close its smelting operations. (Emphasis added).

In short, when CoBank and CFC loaned $537 million to Big Rivers in mid-2012, they did so fully informed regarding the Smelter termination risk. Thus, they cannot now legitimately claim that they have no responsibility for any of the costs of the excess capacity caused by the Smelter terminations. The creditors knowingly assumed this risk.

VII. THE COMPANY'S REVENUE REQUIREMENT IS EXCESSIVE AND SHOULD BE REDUCED

A. Summary and Determination of Reasonable Rate Increase Under KIUC Rate Plan

Q. Is it still necessary for the Commission to determine the appropriate revenue requirement and deficiency under either the Company's approach or under the KIUC Rate Plan?

A. Yes. The Commission is under a statutory obligation to set rates at fair, just and reasonable levels. The Company's claimed revenue requirement is excessive and should be reduced to correct errors, reflect various other ratemaking adjustments, and reflect an equitable sharing of the costs of excess capacity that no longer is used and useful.

Q. What effect does the pending Century increase have on the increase sought in this proceeding?

A. The Company's claimed revenue deficiency assumes that the Commission will grant the entirety of the increase sought in the Century rate case. To the extent that the Commission does not grant the entirety of the increase sought in the Century rate case, then the Company's approach would require the Commission to add the amount not granted in the Century rate case to the amount requested in this case, all else equal.

Q. How does the KIUC Rate Plan differ from the Company's approach?

A. The KIUC Rate Plan provides a reasonable rate increase in both the Century rate case and in this case and allows the Company to temporarily recover the remaining revenue deficiency through draws on the Reserve funds in order to maintain its financial metrics. However, once the Reserve funds are fully depleted, the Company no longer will be able to use those funds to recover the remaining revenue deficiency and will have to seek another rate increase if it has not resolved the underlying problem of excess capacity and the related costs among all stakeholders. Unlike the Company's proposal, there will be no automatic rate increase when the Reserve funds are depleted. The hourglass approach allows the Commission to be directly involved and to retain direct oversight over the progress of the Company's negotiations with its stakeholders outside of the context of a rate case.

Q. Are there significant known and unknown uncertainties in the Company's

projected test year?

A. Yes. As I discussed in the section of my testimony on the KIUC Rate Plan, the Company's revenue requirement is based on numerous assumptions that include both *known uncertainties* and *unknown uncertainties.* In its requested increase, the Company increased the revenue deficiency by resolving each known uncertainty against customers. In other words, instead of filing a "barebones" request that would have minimized the requested increase, the Company filed an excessive request that maximized its requested increase. This is further evidence of the Company's single-minded determination to retain its power plants regardless of the cost to customers.

Under the KIUC Rate Plan, I recommend that the Commission reduce the Company's claimed revenue deficiency by reversing the Company's systemic bias against customers and resolving each known uncertainty in favor of the customers. As I previously discussed, these known uncertainties include the shut down and/or the timing of the shutdown of the Wilson and Coleman plants and the transmission revenues from the Century Hawesville and Sebree Smelters, among others.

In any event, if the KIUC Rate Plan is adopted, the actual resolution of the known uncertainties, as well as the resolution of any unknown uncertainties and other normal variations between projected and actual revenues and expenses, will be captured and the revenue from the Economic Reserve or the Rural Economic Reserve will be adjusted to ensure that the Company actually earns a 1.24 TIER.

B. There Should Be No Depreciation Expense On the Wilson and Coleman Plants During the Shutdown

Q. Please describe the Company's request to recover depreciation expense on the Wilson and Coleman plants even though they are shut down during the test year.

A. The Company plans to shutdown both the Wilson and Coleman plants during the test year and has removed the variable expenses and avoidable fixed O&M expenses (payroll and related expenses plus avoidable fixed departmental expenses ("FDE")) from the test year expenses and revenue requirement, with certain exceptions that should be corrected and that I subsequently address. The most significant of these exceptions is that the Company failed to remove the depreciation expense on the Wilson and Coleman plants, despite the fact that the RUS Uniform System of Accounts ("USOA") requires that it cease depreciation expense on the plants after they are shutdown. Under the USOA and the circumstances in this case, depreciation is an avoidable fixed expense.

In the Century rate case, the Company argued that depreciation expense should continue on the plants during the shutdown and should be included in the revenue requirement. The Company argues the same position in this case, according to its response to AG 2-89. Thus, the Company included $26.643 million in depreciation expense on the Wilson and Coleman plants in the revenue requirement in this case, consisting of $20.177 million for the Wilson plant and $6.466 million for the Coleman plant. These amounts were provided by the Company in its Confidential responses to AG 1-105 and AG 1-106, which I have replicated as my Confidential Exhibit___(LK-3) and Confidential Exhibit___(LK-4), respectively.

Q. **Does the Company have any valid authoritative support for its argument that the accounting rules require it to continue depreciation on the Wilson and Coleman plants after they are shut down?**

A. No. In response to Staff's cross-examination questions on this issue at the hearing in Case No. 2012-00535, Ms. Billie Richert, the Company's CFO, stated that "*there are no definitive pronouncements or standards*" on whether depreciation should be ceased on an idled plant.[6]

Q. **Is the Company correct on this issue?**

A. No. The RUS USOA requires the utility to cease depreciation on generating assets removed from service until they again are returned to service. The USOA limits depreciation expense to the plant in service recorded in Account 101 *Electric Plant in Service*. Once the Wilson and Coleman plants are shutdown, their costs no longer qualify under the USOA as plant in service and no longer qualify for depreciation expense. In order to be included in plant in service, the USOA requires that the original cost of electric plant included in Account 101 must be "*used by the utility in its electric utility operations.*" Specifically, for Account 101, the USOA states:

6 Tr. July 2, 2013 at 10:48:30.

> ***101 Electric Plant in Service***
> *This account shall include the original cost of electric plant, included in Accounts 301 to 399, prescribed herein, owned and used by the utility in its electric utility operations, and having an expectation of life in service of more than one year from date of installation, including such property owned by the utility but held by nominees.*

Once the Wilson and Coleman plants are shut down, they no longer will be "used by the utility in its electric utility operations" and, thus, the original cost of the plants no longer will qualify for Account 101. Consequently, the Company must remove the cost from Account 101. Pursuant to the USOA, depreciation expense may only be computed on plant in service. Once the cost of the plants is removed from Account 101, there will be no cost to depreciate, and consequently, the Company cannot record depreciation expense on the plants in Account 403 *Depreciation Expense*. For Account 403, the USOA states:

> ***403 Depreciation Expense***
> *A. This account shall include the amount of depreciation expense for all classes of depreciable electric plant in service except such depreciation expense as is chargeable to clearing accounts or to Account 416, Costs and Expenses of Merchandising, Jobbing and Contract Work.*

In addition to removing the cost of the plants from Account 101, the USOA directs that the cost of the plants be transferred to and recorded in Account 105 *Electric Plant Held for Future Use*, as long as the utility has a definite plan to use the plants in the future. Big Rivers claims to have a definite plan to use the Wilson and Coleman plants in the future if they become economic again. For Account 105, the USOA states:

> ***105 Electric Plant Held for Future Use***
>
> *A. This account shall include the original cost of electric plant (except land and land rights) owned and held for future use in electric service under a definite plan for such use, to include: (1) Property acquired (except land and land rights) but never used by the utility in electric service, but held for such service in the future under a definite plan, and (2) property (except land and land rights) previously used by the utility in service but retired from such service and held pending its reuse in the future, under a definite plan, in electric service.*

Once the original cost of the Wilson and Coleman plants is transferred from Account 101 to Account 105, depreciation ceases for accounting purposes. If and when the plants are returned to service, the original cost of the plants will be transferred from Account 105 back to Account 101 and depreciation again will commence for accounting purposes.

Q. Is the cessation of depreciation on plants that are shutdown consistent with the definition of depreciation set forth in the USOA?

A. Yes. In order to record depreciation expense, there must be a loss in service value, not restored by current maintenance. However, during the period when the plants are shutdown, there will be no loss in service value. The USOA provides the following definition of depreciation:

> *Depreciation, as applied to depreciable electric plant, is the loss in service value, not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.*

Thus, the USOA is internally consistent on the depreciation issue. The definition of depreciation is consistent with the other requirements related to depreciation found in Account 101 and Account 403. The cessation of depreciation once the Wilson and Coleman plants are shut down is consistent with the fact that the plants no longer will incur a "loss in service value" or "wear or tear" because they will not be operated. After the plants are shut down, there will be no operating hours and, to the extent that a plant's operating hours are a relevant indicator of expected service life, then the plants will have roughly the same remaining operating hours of depreciable life left after they are returned to service than if they had remained in service.

Q. Is the RUS USOA view of depreciation expense supported by the Company's own depreciation studies and its depreciation witness in Case Nos. 2011-00036 and 2012-00535?

A. Yes. This view of depreciation expense also is supported by the depreciation studies and testimony of Big Rivers' depreciation witness, Mr. Ted Kelly of Burns & McDonnell, in Case No. 2011-00036 and in Case No. 2012-00535. In both proceedings, Mr. Kelly's depreciation studies indicate that he based the estimated remaining lives of the Wilson and Coleman plants (and other plants) on the expected typical operating hours and maintenance experience of the plants.[7]

At the hearing in Case No. 2012-00535, Mr. Kelly confirmed that "*the expected useful life of the plant*" was "*based on typical operating hours.*"[8] During the period that the

[7] Depreciation Report at II-4 to II-7.
[8] Tr. July 2, 2013 at 20:49:10.

Wilson and Coleman plants are shut down, they no longer will accrue operating hours against the typical operating hours for the plants. Therefore, the expected remaining operating hours will not be depleted during the shutdown and will remain available in future years. Mr. Kelly agreed with this premise, stating: "*when these units are laid-up and they're not operating, they will have less operating hours, less wear and tear, less mileage.*"[9]

At the hearing in Case No. 2012-00535, the Commission Staff explored this concept further with Ms. Richert. Ms. Richert confirmed that suspending depreciation while a plant is shut down does not deprive the utility from fully recovering its investment if the depreciation expense after the plant is returned to service is sufficient to recover the investment in the asset.[10]

Q. Has the Company cited any provision of the RUS USOA that is contrary to your testimony that the USOA requires the cessation of depreciation?

A. No. Although the Company opposed my recommendation in Case No. 2012-00535 and also opposes it in this proceeding, the Company cited no provision of the RUS USOA that either requires or allows it to continue depreciation during the shutdown period.

Q. Please respond to the Company's claims that depreciation should continue on the Wilson and Coleman plants during the shutdown period.

A. In a Commission Staff Post-Hearing Data Request in Case No. 2012-00535, Big Rivers was given yet another opportunity to "*[p]rovide documentation in support of Big Rivers' position*

[9] Tr. July 2, 2013 at 20:50:00.
[10] Tr. July 2, 2013 at 10:56:10.

that depreciation expense should continue on idled plant."[11] In response to that request, the Company simply declared that "*[d]epreciation expense should continue on idled plant based on accounting standards and guidance by the various authoritative accounting sources and agencies including the Financial Accounting Standards Board ("FASB"), the United States Code of Federal Regulations ("CFR"), the International Accounting Standards Board ("IASB"), the Internal Revenue Service ("IRS"), and the Rural Utilities Service ("RUS").*" The Company made a similar declaration in this proceeding in response to AG 2-89.

Despite the Company's declarations and apparent reliance on these general references to various accounting standards and their alleged requirements, the Company failed to provide any specific analyses of any actual requirements set forth in these standards or their applicability to the Company on this issue, with one exception. The exception was a citation to an excerpt from the "Basis for Conclusions" issued by the IASB, an international accounting standards organization.

Q. Is the Company subject to the accounting standards issued by the IASB?

A. No. The Company is *not* subject to the requirements of the IASB. The IASB does not set accounting standards in this country and any IASB standard or any basis for conclusion for any IASB standard is not applicable to the Company or this depreciation issue even for *accounting* purposes, let alone *ratemaking* purposes. The Company is subject only to the *accounting* requirements of the FASB, which sets U.S. Generally Accepted Accounting Principles ("GAAP"), but does not set *rates*; the RUS, which is responsible for the USOA

[11] Commission Staff Post-Hearing Data Request, Item 4.

and other accounting guidance for utilities subject to the RUS, but does not set *rates*; and the Commission, which does set *rates* for the Company and determines the *accounting* treatment for many of the Company's revenues, expenses, assets, and liabilities, such as the Reserve funds and regulatory assets.

There are significant differences between U.S. GAAP, applicable in this country, and the standards adopted by IASB, applicable in certain other countries, on many accounting issues, including depreciation. Thus, while the Basis for Conclusions issued by the IASB may be interesting as an academic matter, it is contrary to U.S. GAAP and the RUS USOA and it is completely irrelevant to the depreciation issue in this proceeding.

Q. In its response to the post-hearing data request in Case No. 2012-00535 and in response to AG 2-89 in this proceeding, the Company also cited the requirements of the Internal Revenue Service. Please respond.

A. The federal tax laws are completely irrelevant to the depreciation issue in this case. The IRS implements and enforces federal tax laws. The IRS does not promulgate accounting standards and has no ratemaking authority. The Company's depreciation rates are based on depreciation studies that rely on engineering estimates and analyses. They do not rely in any respect on federal tax laws or the tax lives or depreciation methodologies allowed for income tax purposes.

Q. Is there additional authoritative support for the cessation of depreciation on the Wilson and Coleman plants when they are shut down?

A. Yes. In my experience, all legitimate utility depreciation experts recognize the NARUC Depreciation Manual entitled "Public Utility Depreciation Practices" ("NARUC Manual") as an authoritative and primary reference source for both depreciation theory and application. The NARUC Depreciation Manual directs that depreciation expense be recognized in the "periods during which the related assets are expected to provide benefits . . . " and "in which the property is providing utility service," not the periods in which it provides no benefits and is not providing utility service. The NARUC Manual states:

> Generally accepted accounting principles require expenses, such as depreciation, to be allocated by systematic and rational procedures to the periods during which the related assets are expected to provide benefits. The simplest and most logical way to accomplish this is to use a method that distributes the cost of property in a reasonable and consistent manner to all the accounting periods in which the property is providing utility service.[12]

Q. If the RUS does not agree that the Company can cease depreciation on the Wilson and Coleman plants during the shutdown, does that preclude the Commission from setting depreciation rates to 0% and depreciation expense to $0 for ratemaking purposes?

A. No. The Commission should not be misled by any claims that the Commission cannot independently set depreciation rates for intrastate wholesale ratemaking purposes or that it must adopt depreciation rates approved by the RUS. The Commission is the only regulatory body with the statutory authority to set intrastate wholesale rates in Kentucky. The RUS does not have statutory authority to set intrastate wholesale rates or set depreciation rates for that purpose in Kentucky.

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12 NARUC Depreciation Manual at 17 (footnote omitted).

Q. **What if the Commission determines that depreciation expense should cease on the Wilson and Coleman plants while they are shut down and adopts a 0% depreciation rate for that purpose, but the RUS refuses to agree with that determination.**

A. That is a distinct possibility given that the RUS has a dual role as both a creditor and as the overseer of the USOA. In its role as a creditor, the RUS may attempt to coerce the Commission and may require the Company to continue depreciation expense on the Wilson and Coleman plants during the shutdown, in effect overruling or reinterpreting the USOA. Regardless of the propriety of such actions, this would result in a difference in the timing of the depreciation expense for accounting purposes and the depreciation expense for ratemaking purposes.

The USOA anticipates such timing differences and directs that the two different expense amounts be reconciled through deferred expense accounting and the recording of regulatory assets. In this case, the Company first would compute depreciation expense using the RUS-approved depreciation rates and then would compute depreciation expense using the Commission-approved depreciation rates. The Company would record the difference as a negative depreciation expense and then defer the difference as a regulatory asset or as a contra-liability. The deferred expense amounts would be accumulated so that the total deferral would effectively reduce the accumulated depreciation using the RUS-approved depreciation rates. In this manner, the depreciation expense on the Wilson and Coleman plants reported on the income statement would be equal to the amount allowed in the Company's revenue requirement, or $0. However, the difference between the depreciation expense for RUS accounting purposes and the depreciation expense for ratemaking purposes would be tracked through the regulatory asset account. The net of the regulatory asset and the accumulated depreciation would be equivalent to the accumulated depreciation for ratemaking purposes.

Q. Please describe the accounting for such a timing difference in greater detail.

A. The Company would defer the depreciation expense through a credit to account 403 *Depreciation Expense* and a debit to account 182.3 *Other Regulatory Assets* or to account 108 *Accumulated Provision for Depreciation.* The RUS USOA describes account 182.3 as follows:

> *A. This account shall include the amounts of regulatory-created assets, not includable in other accounts, resulting from the ratemaking actions of regulatory agencies. (See the definition of regulatory assets and liabilities.)*
>
> *B. The amounts included in this account are to be established by those charges which would have been included in net income, or accumulated other comprehensive income, determinations in the current period under the general requirements of the Uniform System of Accounts but for it being probable that such items will be included in a different period(s) for purposes of developing the rates that the utility is authorized to charge for its utility services. When specific identification of the particular source of a regulatory asset cannot be made, such as in plant phase-ins, rate moderation plans, or rate levelization plans, Account 407.4, Regulatory Credits, shall be credited. The amounts recorded in this account are generally to be charged, concurrently with the recovery of the amounts in rates, to the same account that would have been charged if included in income when incurred, except all regulatory assets established through the use of Account 407.4 shall be charged to Account 407.3, Regulatory Debits, concurrent with the recovery of the amounts in rates.*

Q. Are you aware of another utility that addressed similar timing differences between depreciation expense for accounting purposes and depreciation expense for ratemaking purposes in the manner that you described?

A. Yes. Another utility, Northern States Power Company ("NSP," a subsidiary of Xcel Energy), recently proposed a similar deferral of the depreciation expense on Sherco 3, one of its coal-fired units, which was idled for an extended period due to a catastrophic equipment failure.[13] In that proceeding, NSP offered to defer the depreciation expense associated with Sherco 3, amortize that deferral over the remaining life of the unit, and essentially suspend and restart the remaining life when the unit was placed back in service. The Administrative Law Judge accepted the Company's offer to defer the depreciation expense for the test year.

Although NSP is subject to the FERC USOA, and not the RUS USOA, the accounting requirements for plant that is temporarily shut down are the same for the two USOAs. Instead of setting the depreciation rate to 0%, the NSP approach was to continue to compute the depreciation expense for accounting purposes, but to include $0 in the revenue requirement, defer the difference by recording negative depreciation expense, and record the difference as a regulatory asset. The net effect was the same for ratemaking purposes as if the Company had used a 0% depreciation rate for both accounting and ratemaking purposes.

Q. Is the cash flow generated by depreciation alone, excluding the depreciation on the Wilson and Coleman plants, sufficient for the Company to make its debt principal repayments during the shutdown period?

A. Yes. The Company included $49.138 million in depreciation and amortization expense in the test year. The depreciation expense on the Wilson and Coleman plants comprises $26.643 million of this total amount. If the Commission directs the Company to cease

13 Minnesota Public Utilities Commission, Docket No. OAH 68-2500-30266 PUC E-002/GR-12-961.

depreciation on the plants while they are shut down, then the remaining depreciation expense included in the revenue requirement will be $22.495 million, all else equal. This amount equals or exceeds the Company's debt principal repayments in each year reflected in the Company's corporate financial model forecast through 2017, the year prior to the projected restart of the Wilson plant. In addition, the lower cash flow resulting from the cessation of depreciation on the Wilson and Coleman plants during the shutdown period will be offset by the elimination of the capital expenditures for MATS compliance during that same period (or at least until one year before the plants are returned to service) and the reduction or elimination of other capital expenditure during that same period. The Company provided its financial model forecast in response to PSC 1-57.

Q. **Do you have additional comments regarding the Company's cash flow if depreciation is ceased on the Wilson and Coleman plants during the shutdown period?**

A. Yes. The minimal reduction in cash flow from ceasing depreciation on the plants, net of the offsetting reductions in MATS and other capital expenditures on the plants, during the shutdown period, will not cause liquidity problems. Among other sources of financing, the Company presently has and projects that it will maintain extremely high levels of cash and short-term investments, according to its response to KIUC 2-39. I have attached a copy of the response to KIUC 2-39 as my Exhibit___(LK-10).

The Company projects that the short term investments will exceed $100 million in some months and that these investments will average $85 million during the test year. The Company maintains these short term investments in a Fidelity Prime Money Market Portfolio account that it assumes will earn only 0.10% annually. This earnings rate is much less than the 5.84% interest rate on its RUS Series A Note debt outstanding.

Most utilities maintain minimal levels of short-term investments and draw on short-term financing if and when their cash outflows exceed cash inflows. Instead, the Company decided to boost its cash and short-term investments and thus, its liquidity, by retaining a portion of the proceeds from the CFC and CoBank financings earlier this year rather than paying down more of the RUS Series A Note. If it had paid off an additional amount of the RUS Series A Note, then it would have reduced the interest expense and TIER margin included in the revenue requirement in this proceeding.

The Company's level of short-term investments adds $6.2 million to the revenue requirement, assuming that it could have reduced the RUS Series A Note by $85 million and avoided the interest at 5.84% and the 1.24 TIER margin in addition to the interest.

Although it is questionable whether the Company needs this level of liquidity or whether customers should bear this cost, it does provide the Company the liquidity to offset any net reductions in cash flow resulting from the cessation of depreciation.

Q. If the Company cannot shut down the Wilson and Coleman plants because MISO determines that one or both are must run units because of the Smelter load and for that reason cannot cease depreciation, then what effect will this have on the KIUC Rate Plan?

A. If MISO determines that either Wilson or Coleman is must run because of the Smelter load at either Hawesville or Sebree, then there will be an increase in the revenue requirement, all else equal. This increase should be recovered directly from Century or, if that is not possible, then it should be equitably shared between the Company's customers and creditors.

As I previously discussed, depreciation is an avoidable expense during a temporary shutdown, similar to payroll expense and other fixed departmental expenses. If the Smelters cease operating, then the Company will not incur the depreciation expense. However, if the plants are not shut down and are required to operate for reliability purposes to allow the Smelters market access, then this expense should be charged to and recovered from Century. The market-based rates paid by Century remain regulated by the Commission and still are subject to the "fair, just and reasonable" and nondiscrimination standards. Costs caused by Century, including depreciation expense that otherwise could be avoided, should be paid by the cost causer. Otherwise, the other customers will be required to inappropriately subsidize the Smelters for this component of the cost to serve them even with market access.

If that is not possible for whatever reason, then the increase in the revenue requirement should be shared 31.3% to customers and 68.7% to creditors. Under the KIUC Rate Plan, this would add $8.339 million ($26.443 million in depreciation expense on the Wilson and Coleman plants times 31.3% customer share of stranded fixed costs) to the rate increase in this proceeding, all else equal.

Q. Please summarize your recommendation to cease depreciation expense on the Wilson and Coleman plants while they are shut down.

A. The Commission should set the depreciation rate to 0% for the Wilson and Coleman plants for *ratemaking* purposes while they are shut down. This *ratemaking* is consistent with the *accounting* requirements set forth in U.S. GAAP and the RUS USOA. There is no relevant and authoritative accounting guidance to the contrary. Nevertheless, if the RUS does not authorize a deprecation rate of 0%, then the Commission still should set the depreciation rate to 0% for *ratemaking* purposes and, in addition, authorize the Company to defer the timing difference as a regulatory asset in accordance with the requirements set forth in the RUS USOA for such *accounting* and *ratemaking* timing differences.

Only the Commission has the *ratemaking* authority to set depreciation rates for intrastate wholesale *ratemaking* purposes. The RUS does not have this *ratemaking* authority. The RUS has a fundamental conflict on this issue as both a creditor and overseer of the USOA and depreciation rates, but it does not have the authority to overrule or impose its approved depreciation rates on this Commission for intrastate wholesale *ratemaking* purposes.

C. There Will Be Transmission Revenues from the Hawesville and Sebree Smelters If They Continue to Operate

Q. Please describe the transmission revenues that the Company will receive from

the Century Hawesville and Sebree Smelters.

A. The Company will receive transmission revenues from the Hawesville Smelter pursuant to the Century transaction approved in Case No. 2013-00221, although if Century is required to pay for the SSR costs to continue operating the Coleman plant for MISO reliability purposes, then the transmission revenues will be used to offset the SSR revenues. However, if the Coleman plant is shut down, as expected, and the Hawesville Smelter continues to operate, then Big Rivers will receive the transmission revenues. Thus, this issue is a known uncertainty.

If the Company enters into a transaction with Century for the Sebree Smelter similar to that it entered into for the Hawesville Smelter, then it also will receive transmission revenues from the Sebree Smelter. However, unlike the circumstances with the Hawesville Smelter and the MISO designation of the Coleman plant as an SSR, there does not appear to be an SSR issue related to the Sebree Smelter transaction. The issue with the Sebree Smelter is whether or not the Company will enter into a transaction similar to that it entered into with Hawesville Smelter. This also is a known uncertainty, but it is not dependent on the shutdown of either the Wilson or Coleman plants. To the extent that the Company and Century enter into a transaction for the Sebree Smelter similar to that between the Company and Century for the Hawesville Smelter, then the Company will receive transmission revenues and the revenues will not be used to offset any SSR revenues.

Q. Did the Company include the transmission revenues from the Hawesville Smelter in the claimed revenue requirement?

A. No. As I previously discussed, the Company reflected the effects of all known uncertainties against customers when it quantified the test year revenue requirement. In this case, the Company assumed that the Coleman plant would be shut down for all other purposes, including all variable O&M expenses, all avoidable fixed O&M expenses, severance expenses, replacement capacity expenses, and capital expenditures, *except* for the Hawesville Smelter transmission revenues. Contrary to the assumption that Coleman would be shut down for all other purposes, the Company inexplicably assumed that Coleman would continue in operation and that it would not receive any incremental transmission revenues from the Hawesville Smelter. Obviously, the Coleman plant cannot both be shut down and continue in operation at the same time.

Q. If the Coleman plant is shut down during the test year, will the Hawesville Smelter transmission revenues be offset against the SSR revenues?

A. No. Consequently, the Hawesville Smelter transmission revenues should be reflected in the revenue requirement and reduce the revenue deficiency.

Q. Did the Company include the transmission revenues from the Sebree Smelter in the claimed revenue requirement?

A. No. Although no Big Rivers witness addressed the issue and the Company and Century have begun negotiations, the Company simply assumed that it would not receive transmission revenue from the Sebree Smelter. That would only be the case if the Sebree Smelter actually ceases smelting operations.

Q. If the Company enters into a similar transaction for the Sebree Smelter, will it receive transmission revenues?

A. Yes. Consequently, the Sebree Smelter transmission revenues should be included in the revenue requirement.

Q. Has the Company quantified the transmission revenues that it will receive from the Hawesville Smelter if the Coleman plant is shut down and the Company and Century enter into a transaction for the Sebree Smelter similar to that between the Company and Century for the Hawesville Smelter?

A. Yes. The Company quantified the Hawesville Smelter transmission revenues at $7.513 million using 482 mW as the load and rates published by MISO effective July 1, 2013. The Company quantified the Sebree Smelter transmission revenues at $5.268 million 338 MW as the load and the same MISO rates. The Company provided these amounts in response to SC 1-12 (c) and (d), a copy of which is attached as Exhibit___(LK-11).

Q. What is your recommendation?

A. I recommend that the Commission include these transmission revenues as a reduction in the revenue requirement. If the Commission adopts the KIUC Rate Plan, then the actual transmission revenues received by the Company will be trued-up to the amounts reflected in the revenue requirement used to set base rates in this proceeding. If, for example, the actual Hawesville Smelter transmission revenues are \$8.513 million instead of the \$7.513 million that I recommend be reflected in the revenue requirement, and these transmission revenues are not used to offset SSR expenses, then the Company will need to draw down \$1.0 million less from the Reserve funds to achieve the 1.24 TIER over a twelve month period, all else equal.

D. Coleman Layup Expenses Are Nonrecurring and Should Be Deferred and Amortized

Q Please describe the Company's request to recover the Coleman layup expenses.

A. The Company included [redacted] million in Coleman layup expenses in the revenue requirement as recurring expenses, according to its Confidential response to AG 2-8.

Q. Are the layup expenses recurring?

A. No. They are similar to the Coleman severance expenses, which the Company acknowledges are nonrecurring.

Q. How should the Commission treat these nonrecurring expenses?

A. The Commission should treat all nonrecurring revenues and expenses in the same manner. I recommend that the Commission defer the Coleman layup expenses and amortize them over five years, the same treatment as the Company proposes for the Coleman severance expenses.

Q. What is the effect of your recommendation?

A. The effect of my recommendation is a reduction of $1.600 million in the revenue requirement.

<u>E. Mercury and Air Toxics Standards ("MATS") Capital Expenditures Will Not Be Incurred for the Wilson and Coleman Plants In the Test Year</u>

Q. Did Big Rivers include MATS compliance capital expenditures for the Wilson and Coleman plants in the test year?

A. Yes. The Company included [redacted] million for the Wilson plant and [redacted] million for the Coleman plant for MATS compliance in capital expenditures and plant additions in the test year, according to its Confidential response to KIUC 2-42. These costs were included in the worksheet tab labeled "ECP" (environmental compliance plan) in the financial model. The capital expenditures were assumed to be in-service by September 1, 2014. These amounts are direct expenditures only and do not include capitalized interest during construction.

Q. Does Big Rivers still plan to install the MATS compliance equipment on the Wilson and Coleman plants during the test year?

A. No. Big Rivers does not intend to install the MATS compliance equipment or make the capital expenditures for these plants unless they are returned to service, according to its Confidential response to KIUC 2-42. I have attached a copy of this response as my Confidential Exhibit___(LK-12), which confirms this plan.

Q. Should the Commission remove the effects of the MATS capital expenditures for the Wilson and Coleman plants from the Company's revenue requirement?

A. Yes. The Company does not plan to install the MATS equipment or incur the capital expenditures during the test year. As I previously noted, this partially offsets the reduction in cash flow from ceasing depreciation on the Wilson and Coleman plants during the shutdown period.

Q. What is the effect on the revenue requirement of removing the MATS capital expenditures from the test year?

A. The effect is to reduce the revenue requirement by $0.682 million dollars. The revenue requirement includes the interest expense, related margin using a 1.24 TIER, depreciation expense, property tax expense, and property insurance expense. The Company included interest expense using a 3.0% ECP financing interest rate. The

Company included depreciation expense based on the depreciation rates that it proposed in the Century rate case and that are reflected in its request in this case. I have attached the calculation of the effect on the revenue requirement as my Confidential Exhibit___(LK-13).

F. MISO Capacity Charges and Severance Expense Will Not Be Incurred if Coleman Is Not Shut Down

Q. Please describe the Company's request to defer and amortize MISO capacity charges that it will incur from February 2014 to May 2014 if Coleman is shut down.

A. The Company assumed that it will incur $0.511 million in MISO capacity charges if Coleman is shutdown contemporaneous with the Alcan termination on January 31, 2014. The Company seeks to defer this amount and recover $0.102 million in amortization expense based on a five year amortization period.

Q. Please describe the Company's request to recover Coleman plant severance expenses.

A. The Company estimates that it will incur $3.713 million in labor severance costs to shutdown of the Coleman plant contemporaneous with the Alcan termination on January 31, 2014. The Company proposes to defer this amount and recover $0.743 million in amortization expense based on a five year amortization period. The estimated severance costs were provided in Exhibit Haner-2.

Q. Should the Commission allow these deferrals and the amortization expenses?

A. It depends. First, the Company may not incur these costs. The Company will incur some or all of the MISO capacity charges expenses only if the Coleman plant is shutdown prior by May 31, 2014. The Company will incur the severance expenses only if the Coleman plant is shutdown prior to the end of the test year and it does not continue to operate as an SSR.

Second, the Commission should treat all nonrecurring revenues and expenses the same: either they all should be removed as nonrecurring and ignored in the revenue requirement or they all should be removed, deferred and amortized in the revenue requirement. The Company has proposed deferral and amortization of the MISO capacity charges, Coleman severance expense, and other expenses in the revenue requirement on the basis that these expenses are nonrecurring. At the same time, the Company simply removed the Smelter surcredit revenues in the test year, thereby increasing the revenue requirement, even though it too is nonrecurring.

Q. What is your recommendation?

A. I recommend that the Commission adopt the Company's proposal to defer and amortize the MISO capacity charges and the Coleman severance expenses, but only if they are incurred. These issues are known uncertainties, but the Commission may not know whether these costs will be incurred prior to the date at which the record closes in this proceeding. Thus, these issues highlight the importance of the KIUC Rate Plan, which will capture the deferral and amortization expense if the cost is incurred or the savings if the cost is not incurred.

G. ACES Fees Expense Should Be Reduced to Reflect An Allocation to Century

Q. Please describe the ACES fees expense included in the revenue requirement.

A. The Company included $2.272 million in ACES fees expense. Big Rivers has been a member-owner of ACES since 2003. ACES acts as an agent to assist the Company, as well as the other members, in managing its energy portfolio while also providing a suite of support services such as energy risk management, portfolio modeling, contract administration, and regulatory services. All members of ACES share in its costs and reimburse ACES based on their relative load allocations. In other words, the allocation to Big Rivers will be reduced due the Smelter load terminations, although on a two year lagged basis.

Q. Does Big Rivers agree that a portion of the ACES fees should be removed from the revenue requirement due to the Hawesville Smelter load termination and the Century contracts approved in Case No. 2013-00221?

A. Yes. The Company agrees that $0.784 million of the ACES fees should be removed from the revenue requirement, according to its response to KIUC 1-57. The Company plans to allocate 34.5% of the ACES fees to Century for the Hawesville Smelter pursuant to Exhibit A of the Direct Agreement approved in the Century Contracts Case, according its responses to KIUC 1-57 and PSC 3-10. I have attached a copy of the response to KIUC 1-57 as my Exhibit___(LK-14) and the response to PSC 3-10 as my Exhibit___(LK-15).

Q. Should the Commission also reduce the ACES fees to reflect an allocation to the Sebree Smelter?

A. Yes. If the Company enters into a transaction with Century for the Sebree Smelter similar to the one it entered into for the Hawesville Smelter, then the ACES fees should be reduced by another 24.2%, or $0.550 million. The ACES fees were caused by the Sebree Smelter and should be recovered from Century regardless of whether there is any SSR Agreement.

H. <u>A Portion of the Costs of Excess Capacity That Is Not Used and Useful Should Be Removed From The Revenue Requirement</u>

Q. Does the Company's revenue requirement still include the entirety of the interest expense, Contract TIER, depreciation expense, insurance expense, and property tax expense for the Wilson and Coleman plants even though they represent excess physical capacity and will be shut down?

A. Yes.

Q. Is that appropriate?

A. No. It is not appropriate to impose the entirety of the fixed costs stranded by the Century and Alcan terminations on the Rural and Large Industrial customers without an equitably sharing these impacts with the Company's creditors. After the Century and Alcan terminations, the Company will have significant excess capacity that no longer is used and useful.

Q. Do you recommend that the entirety of the Company's excess generation, which no longer is used and useful, be allocated to the creditors instead of customers?

A. No. Although there are compelling arguments that the excess generation and the related costs should be allocated solely to creditors instead of solely to customers, I nevertheless recommend an equitable sharing of the impact of the Century termination, and subsequently, the Alcan termination, based on the Commission's decisions and directives in the Orders that I previously cited. In addition, I recommend that this sharing be based on the Rural and Large Industrial sales as a percentage of the Company's total sales prior to the Century and Alcan terminations. Thus, I recommend that 31.3% of the net cost of excess capacity resulting from the Century and Alcan terminations be recovered from the Rural and Large Industrial customers and that 68.7% of it ultimately be shared by the Company's creditors.

This sharing is equitable because the Rural and Large Industrial customers did not cause the excess capacity and should not be required to pay for the entirety of the cost. Arguably, they should not be required to pay for any of the cost of capacity that no longer is used and useful in providing utility service. However, the equitable sharing that I propose provides a balanced approach.

I also note that my recommendation applies only to the base rate increase. The remaining customers still will incur the entirety of the FAC and ECR rate increases.

Q. Have you quantified the effect of your recommendation?

A. Yes. The effect is to reduce the Company's revenue requirement by $18.786 million to reflect my recommendation to share 68.7% of the base rate impact of the excess capacity caused by the Century termination with the Company's creditors. To calculate this amount, I multiplied the Company's quantification of the base rate increase caused by the Century termination, net of cost reductions, or $27.345 million, times the 68.7% allocation to the creditors.

Q. What is the net effect of all of your recommendations on the Company's proposed revenue requirement?

A. The net effect is a reduction of $61.838 million in the Company's proposed increase of $70.397 million, or an increase of no more than $8.559 million.

Q. What effect will your recommendations have on depletion of the Reserve funds under the KIUC Rate Plan?

A. The Reserve funds will be depleted in early February 2015 instead of the mid to late February 2015 date calculated by Mr. Baron based on his recommendation to treat all customers equally with respect to the Reserve funds that were created by the Commission. In other words, if the Commission adopts all of the KIUC revenue requirement recommendations, then the reduction in the Company's revenues will accelerate the depletion of the Rural Economic Reserve by approximately two weeks. That is because only one of the KIUC recommendations will affect the depletion of that Reserve fund, i.e., the adjustment to reflect a sharing of the stranded fixed costs associated with excess capacity with the creditors.

None of the other KIUC adjustments affect the Company's margin. For example, if the Commission directs the Company to cease depreciation on the Wilson and Coleman plants, then depreciation expense and the revenue to recover depreciation expense still will match and there will be no reduction in the Company's margins. As another example, if the Commission reflects the Century transmission revenue in the revenue requirement and the Company receives that revenue, then there will be no reduction in the Company's margins. As yet another example, the Company will not make the MATS capital expenditures for the Wilson and Coleman plants in the test year. Thus, removing the effects of these expenditures from the Company's claimed revenue requirement correctly ensures that the Company does not overrecover and that there is no effect on the Company's margins.

This means that adoption of the KIUC Rate Plan will give Big Rivers until early February 2015 to resolve its excess capacity situation and reduce or eliminate the related stranded fixed costs. If a resolution cannot be reached by that time, then the utility will have the right to seek additional rate relief from the Commission.

Q. Does this complete your testimony?

A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

LANE KOLLEN, 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.

Lane Kollen

Sworn to and subscribed before me on this
28th day of October 2013.

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2015
CHEROKEE COUNTY, GEORGIA

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT OF RATES	)) CASE NO. 2013-00199)

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

OCTOBER 28, 2013

EXHIBIT ____ (LK-1)

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

Luther Rice University, MA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

Mr. Kollen has more than thirty years of utility industry experience in the financial, rate, tax, and planning areas. He specializes in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition and diversification. Mr. Kollen has expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

1986 to Present:

J. Kennedy and Associates, Inc.: Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Maryland, Minnesota, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, West Virginia and Wisconsin state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986:

Energy Management Associates: Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983:

The Toledo Edison Company: Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
Gallatin Steel
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Customers, Inc.
Kimberly-Clark Company
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial Energy Consumers
Occidental Chemical Corporation
Ohio Energy Group
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Cities in Texas-New Mexico Power Company's Service Territory
Cities in AEP Texas Central Company's Service Territory
Cities in AEP Texas North Company's Service Territory
Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York State Energy Office
Office of Public Utility Counsel (Texas)

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

**Expert Testimony Appearances
of
Lane Kollen
as of October 2013**

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County, completion.
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.

Expert Testimony Appearances
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as of October 2013

Date	Case	Jurisdict.	Party	Utility	Subject
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric Corp.	Financial workout plan.
5/88	M-87017-1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017-2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.
7/88	M-87017-1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
7/88	M-87017-2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170-EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171-EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	8800-355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71).
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
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.	Recovery of CAAA costs, least cost financing.
9/91	91-231-E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	PUC Docket 10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base.
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
3/93	93-01-EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission	Gulf States Utilities /Entergy Corp.	Merger.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.
11/94	U-19904 Initial Post-Merger Earnings Review (Rebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.
6/95	3905-U Rebuttal	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.

**Expert Testimony Appearances
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Lane Kollen
as of October 2013**

Date	Case	Jurisdict.	Party	Utility	Subject
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co., The Cleveland Electric Illuminating Co.	Competition, asset write-offs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC Docket 14965	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co., and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.

**Expert Testimony Appearances
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as of October 2013**

Date	Case	Jurisdict.	Party	Utility	Subject
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co., Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness.
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.
11/97	U-22491	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.

**Expert Testimony Appearances
of
Lane Kollen
as of October 2013**

Date	Case	Jurisdict.	Party	Utility	Subject
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
4/99	99-02-05	Ct	Connecticut Industrial Utility Customers	Connecticut Light and Power Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.

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5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Co.	Alternative regulation.
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
6/99	U-23358	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, American Electric Power Co.	Merger Settlement and Stipulation.
7/99	97-596 Surrebuttal	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 Surrebuttal	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
8/99	98-474 98-083 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
8/99	98-0452-E-GI Rebuttal	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
10/99	U-24182 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	PUC Docket 21527	TX	The Dallas-Fort Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.

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11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
01/00	U-24182 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
04/00	99-1212-EL-ETP 99-1213-EL-ATA 99-1214-EL-AAM	OH	Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
05/00	2000-107	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 Supplemental Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
05/00	99-1658-EL-ETP	OH	AK Steel Corp.	Cincinnati Gas & Electric Co.	Regulatory transition costs, including regulatory assets and liabilities, SFAS 109, ADIT, EDIT, ITC.
07/00	PUC Docket 22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.
10/00	SOAH Docket 473-00-1015 PUC Docket 22350	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 Affidavit	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009	PA	Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.
12/00	U-21453, U-20925, U-22092 (Subdocket C) Surrebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets.

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01/01	U-24993 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U-20925, U-22092 (Subdocket B) Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy Corp.	Merger, savings, reliability.
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
07/01	U-21453, U-20925, U-22092 (Subdocket B) Transmission and Distribution Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Company	Revenue requirements, Rate Plan, fuel clause recovery.
11/01	14311-U Direct Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/01	U-25687 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.
02/02	PUC Docket 25230	TX	The Dallas-Fort Worth Hospital Council and the Coalition of Independent Colleges and Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.
02/02	U-25687 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02	14311-U Rebuttal Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	14311-U Rebuttal Panel with Michelle L. Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear life extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02	U-25687 (Suppl. Surrebuttal)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 U-22092 (Subdocket C)	LA	Louisiana Public Service Commission	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.
09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.
11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.
04/03	2002-00429 2002-00430	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.

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06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
06/03	2003-00068	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.
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 ER03-744-000, ER03-744-001 (Consolidated)	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc.	Unit power purchases and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
12/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
12/03	2003-0334 2003-0335	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Earnings Sharing Mechanism.
12/03	U-27136	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Purchased power contracts between affiliates, terms and conditions.
03/04	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
03/04	2003-00433	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	SOAH Docket 473-04-2459 PUC Docket 29206	TX	Cities Served by Texas-New Mexico Power Co.	Texas-New Mexico Power Co.	Stranded costs true-up, including valuation issues, ITC, ADIT, excess earnings.
05/04	04-169-EL-UNC	OH	Ohio Energy Group, Inc.	Columbus Southern Power Co. & Ohio Power Co.	Rate stabilization plan, deferrals, T&D rate increases, earnings.

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06/04	SOAH Docket 473-04-4555 PUC Docket 29526	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Stranded costs true-up, including valuation issues, ITC, EDIT, excess mitigation credits, capacity auction true-up revenues, interest.
08/04	SOAH Docket 473-04-4555 PUC Docket 29526 (Suppl Direct)	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Interest on stranded cost pursuant to Texas Supreme Court remand.
09/04	U-23327 Subdocket B	LA	Louisiana Public Service Commission Staff	SWEPCO	Fuel and purchased power expenses recoverable through fuel adjustment clause, trading activities, compliance with terms of various LPSC Orders.
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission Staff	SWEPCO	Revenue requirements.
12/04	Case Nos. 2004-00321, 2004-00372	KY	Gallatin Steel Co.	East Kentucky Power Cooperative, Inc., Big Sandy Recc, et al.	Environmental cost recovery, qualified costs, TIER requirements, cost allocation.
01/05	30485	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric, LLC	Stranded cost true-up including regulatory Central Co. assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
02/05	18638-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements.
02/05	18638-U Panel with Tony Wackerly	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Comprehensive rate plan, pipeline replacement program surcharge, performance based rate plan.
02/05	18638-U Panel with Michelle Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Energy conservation, economic development, and tariff issues.
03/05	Case Nos. 2004-00426, 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, excess common equity ratio, deferral and amortization of nonrecurring O&M expense.
06/05	2005-00068	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, margins on allowances used for AEP system sales.
06/05	050045-EI	FL	South Florida Hospital and Heallthcare Assoc.	Florida Power & Light Co.	Storm damage expense and reserve, RTO costs, O&M expense projections, return on equity performance incentive, capital structure, selective second phase post-test year rate increase.
08/05	31056	TX	Alliance for Valley Healthcare	AEP Texas Central Co.	Stranded cost true-up including regulatory assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
09/05	20298-U	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Revenue requirements, roll-in of surcharges, cost recovery through surcharge, reporting requirements.

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09/05	20298-U Panel with Victoria Taylor	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Affiliate transactions, cost allocations, capitalization, cost of debt.
10/05	04-42	DE	Delaware Public Service Commission Staff	Artesian Water Co.	Allocation of tax net operating losses between regulated and unregulated.
11/05	2005-00351 2005-00352	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Workforce Separation Program cost recovery and shared savings through VDT surcredit.
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	System Sales Clause Rider, Environmental Cost Recovery Rider. Net Congestion Rider, Storm damage, vegetation management program, depreciation, off-system sales, maintenance normalization, pension and OPEB.
03/06	PUC Docket 31994	TX	Cities	Texas-New Mexico Power Co.	Stranded cost recovery through competition transition or change.
05/06	31994 Supplemental	TX	Cities	Texas-New Mexico Power Co.	Retrospective ADFIT, prospective ADFIT.
03/06	U-21453, U-20925, U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
03/06	NOPR Reg 104385-OR	IRS	Alliance for Valley Health Care and Houston Council for Health Education	AEP Texas Central Company and CenterPoint Energy Houston Electric	Proposed Regulations affecting flow- through to ratepayers of excess deferred income taxes and investment tax credits on generation plant that is sold or deregulated.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	2002-2004 Audit of Fuel Adjustment Clause Filings. Affiliate transactions.
07/06	R-00061366, Et. al.	PA	Met-Ed Ind. Users Group Pennsylvania Ind. Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of NUG-related stranded costs, government mandated program costs, storm damage costs.
07/06	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
08/06	U-21453, U-20925, U-22092 (Subdocket J)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
11/06	05CVH03-3375 Franklin County Court Affidavit	OH	Various Taxing Authorities (Non-Utility Proceeding)	State of Ohio Department of Revenue	Accounting for nuclear fuel assemblies as manufactured equipment and capitalized plant.
12/06	U-23327 Subdocket A Reply Testimony	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
03/07	PUC Docket 33309	TX	Cities	AEP Texas Central Co.	Revenue requirements, including functionalization of transmission and distribution costs.

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03/07	PUC Docket 33310	TX	Cities	AEP Texas North Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Interim rate increase, RUS loan covenants, credit facility requirements, financial condition.
03/07	U-29157	LA	Louisiana Public Service Commission Staff	Cleco Power, LLC	Permanent (Phase II) storm damage cost recovery.
04/07	U-29764 Supplemental and Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
04/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and state income tax effects on equalization remedy receipts.
04/07	ER07-684-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuel hedging costs and compliance with FERC USOA.
05/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and account 924 effects on MSS-3 equalization remedy payments and receipts.
06/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC, Entergy Gulf States, Inc.	Show cause for violating LPSC Order on fuel hedging costs.
07/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Revenue requirements, post-test year adjustments, TIER, surcharge revenues and costs, financial need.
07/07	ER07-956-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Storm damage costs related to Hurricanes Katrina and Rita and effects of MSS-3 equalization payments and receipts.
10/07	05-UR-103 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	05-UR-103 Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	25060-U Direct	GA	Georgia Public Service Commission Public Interest Adversary Staff	Georgia Power Company	Affiliate costs, incentive compensation, consolidated income taxes, §199 deduction.
11/07	06-0033-E-CN Direct	WV	West Virginia Energy Users Group	Appalachian Power Company	IGCC surcharge during construction period and post-in-service date.

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11/07	ER07-682-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	ER07-682-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	07-551-EL-AIR Direct	OH	Ohio Energy Group, Inc.	Ohio Edison Company, Cleveland Electric Illuminating Company, Toledo Edison Company	Revenue requirements.
02/08	ER07-956-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
03/08	ER07-956-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
04/08	2007-00562, 2007-00563	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas and Electric Co.	Merger surcredit.
04/08	26837 Direct Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Suppl Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
06/08	2008-00115	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Environmental surcharge recoveries, including costs recovered in existing rates, TIER.
07/08	27163 Direct	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Revenue requirements, including projected test year rate base and expenses.
07/08	27163 Taylor, Kollen Panel	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Affiliate transactions and division cost allocations, capital structure, cost of debt.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/08	6680-CE-170 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Nelson Dewey 3 or Colombia 3 fixed financial parameters.
08/08	6680-UR-116 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	CWIP in rate base, labor expenses, pension expense, financing, capital structure, decoupling.
08/08	6680-UR-116 Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Capital structure.
08/08	6690-UR-119 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, incentive compensation, Crane Creek Wind Farm incremental revenue requirement, capital structure.
09/08	6690-UR-119 Surrebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, Section 199 deduction.
09/08	08-935-EL-SSO, 08-918-EL-SSO	OH	Ohio Energy Group, Inc.	First Energy	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	08-917-EL-SSO	OH	Ohio Energy Group, Inc.	AEP	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	2007-00564, 2007-00565, 2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Company	Revenue forecast, affiliate costs, depreciation expenses, federal and state income tax expense, capitalization, cost of debt.
11/08	EL08-51	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities, regulatory asset and bandwidth remedy.
11/08	35717	TX	Cities Served by Oncor Delivery Company	Oncor Delivery Company	Recovery of old meter costs, asset ADFIT, cash working capital, recovery of prior year restructuring costs, levelized recovery of storm damage costs, prospective storm damage accrual, consolidated tax savings adjustment.
12/08	27800	GA	Georgia Public Service Commission	Georgia Power Company	AFUDC versus CWIP in rate base, mirror CWIP, certification cost, use of short term debt and trust preferred financing, CWIP recovery, regulatory incentive.
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
01/09	ER08-1056 Supplemental Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Blytheville leased turbines; accumulated depreciation.
02/09	EL08-51 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities regulatory asset and bandwidth remedy.
02/09	2008-00409 Direct	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Revenue requirements.
03/09	ER08-1056 Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/09 04/09	U-21453, U-20925 U-22092 (Sub J) Direct Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
04/09	2009-00040 Direct-Interim (Oral)	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Emergency interim rate increase; cash requirements.
04/09	PUC Docket 36530	TX	State Office of Administrative Hearings	Oncor Electric Delivery Company, LLC	Rate case expenses.
05/09	ER08-1056 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
06/09	2009-00040 Direct- Permanent	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements, TIER, cash flow.
07/09	080677-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Multiple test years, GBRA rider, forecast assumptions, revenue requirement, O&M expense, depreciation expense, Economic Stimulus Bill, capital structure.
08/09	U-21453, U-20925, U-22092 (Subdocket J) Supplemental Rebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
08/09	8516 and 29950	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Modification of PRP surcharge to include infrastructure costs.
09/09	05-UR-104 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Revenue requirements, incentive compensation, depreciation, deferral mitigation, capital structure, cost of debt.
09/09	09AL-299E	CO	CF&I Steel, Rocky Mountain Steel Mills LP, Climax Molybdenum Company	Public Service Company of Colorado	Forecasted test year, historic test year, proforma adjustments for major plant additions, tax depreciation.
09/09	6680-UR-117 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Power and Light Company	Revenue requirements, CWIP in rate base, deferral mitigation, payroll, capacity shutdowns, regulatory assets, rate of return.
10/09	09A-415E	CO	Cripple Creek & Victor Gold Mining Company, et al.	Black Hills/CO Electric Utility Company	Cost prudence, cost sharing mechanism.
10/09	EL09-50 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
10/09	2009-00329	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Trimble County 2 depreciation rates.
12/09	PUE-2009-00030	VA	Old Dominion Committee for Fair Utility Rates	Appalachian Power Company	Return on equity incentive.
12/09	ER09-1224 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	ER09-1224 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	EL09-50 Rebuttal Supplemental Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
02/10	ER09-1224 Final	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
02/10	30442 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Revenue requirement issues.
02/10	30442 McBride-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Affiliate/division transactions, cost allocation, capital structure.
02/10	2009-00353	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Ratemaking recovery of wind power purchased power agreements.
03/10	2009-00545	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Ratemaking recovery of wind power purchased power agreement.
03/10	E015/GR-09-1151	MN	Large Power Interveners	Minnesota Power	Revenue requirement issues, cost overruns on environmental retrofit project.
03/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation expense and effects on System Agreement tariffs.
04/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Revenue requirement issues.
04/10	2009-00458, 2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	Revenue requirement issues.
08/10	31647	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Revenue requirement and synergy savings issues.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
08/10	31647 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Affiliate transaction and Customer First program issues.
08/10	2010-00204	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	PPL acquisition of E.ON U.S. (LG&E and KU) conditions, acquisition savings, sharing deferral mechanism.
09/10	38339 Direct and Cross-Rebuttal	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Revenue requirement issues, including consolidated tax savings adjustment, incentive compensation FIN 48; AMS surcharge including roll-in to base rates; rate case expenses.
09/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.
09/10	2010-00167	KY	Gallatin Steel	East Kentucky Power Cooperative, Inc.	Revenue requirements.
09/10	U-23327 Subdocket E Direct	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
11/10	U-23327 Rebuttal	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
09/10	U-31351	LA	Louisiana Public Service Commission Staff	SWEPCO and Valley Electric Membership Cooperative	Sale of Valley assets to SWEPCO and dissolution of Valley.
10/10	10-1261-EL-UNC	OH	Ohio OCC, Ohio Manufacturers Association, Ohio Energy Group, Ohio Hospital Association, Appalachian Peace and Justice Network	Columbus Southern Power Company	Significantly excessive earnings test.
10/10	10-0713-E-PC	WV	West Virginia Energy Users Group	Monongahela Power Company, Potomac Edison Power Company	Merger of First Energy and Allegheny Energy.
10/10	U-23327 Subdocket F Direct	LA	Louisiana Public Service Commission Staff	SWEPCO	AFUDC adjustments in Formula Rate Plan.
11/10	EL10-55 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.
12/10	ER10-1350 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
01/11	ER10-1350 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
03/11 04/11	ER10-2001 Direct Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Arkansas, Inc.	EAI depreciation rates.
04/11	U-23327 Subdocket E	LA	Louisiana Public Service Commission Staff	SWEPCO	Settlement, incl resolution of S02 allowance expense, var O&M expense, sharing of OSS margins.
04/11 05/11	38306 Direct Suppl Direct	TX	Cities Served by Texas-New Mexico Power Company	Texas-New Mexico Power Company	AMS deployment plan, AMS Surcharge, rate case expenses.
05/11	11-0274-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company, Wheeling Power Company	Deferral recovery phase-in, construction surcharge.
05/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements.
06/11	29849	GA	Georgia Public Service Commission Staff	Georgia Power Company	Accounting issues related to Vogtle risk-sharing mechanism.
07/11	ER11-2161 Direct and Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
07/11	PUE-2011-00027	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Return on equity performance incentive.
07/11	11-346-EL-SSO 11-348-EL-SSO 11-349-EL-AAM 11-350-EL-AAM	OH	Ohio Energy Group	AEP-OH	Equity Stabilization Incentive Plan; actual earned returns; ADIT offsets in riders.
08/11	U-23327 Subdocket F Rebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Depreciation rates and service lives; AFUDC adjustments.
08/11	05-UR-105	WI	Wisconsin Industrial Energy Group	WE Energies, Inc.	Suspended amortization expenses; revenue requirements.
08/11	ER11-2161 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
09/11	PUC Docket 39504	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Investment tax credit, excess deferred income taxes; normalization.
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility Consumers, Inc.	Louisville Gas & Electric Company, Kentucky Utilities Company	Environmental requirements and financing.
10/11	11-4571-EL-UNC 11-4572-EL-UNC	OH	Ohio Energy Group	Columbus Southern Power Company, Ohio Power Company	Significantly excessive earnings.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/11	4220-UR-117 Direct	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	4220-UR-117 Surrebuttal	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	PUC Docket 39722	TX	Cities Served by AEP Texas Central Company	AEP Texas Central Company	Investment tax credit, excess deferred income taxes; normalization.
02/12	PUC Docket 40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Temporary rates.
03/12	2011-00401	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Big Sandy 2 environmental retrofits and environmental surcharge recovery.
4/12	2011-00036 Direct Rehearing Supplemental Direct Rehearing	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Rate case expenses, depreciation rates and expense.
04/12	10-2929-EL-UNC	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, CRES capacity charges, Equity Stabilization Mechanism
05/12	11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, Equity Stabilization Mechanism, Retail Stability Rider.
05/12	11-4393-EL-RDR	OH	Ohio Energy Group	Duke Energy Ohio, Inc.	Incentives for over-compliance on EE/PDR mandates.
06/12	40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Revenue requirements, including ADIT, bonus depreciation and NOL, working capital, self insurance, depreciation rates, federal income tax expense.
07/12	120015-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Revenue requirements, including vegetation management, nuclear outage expense, cash working capital, CWIP in rate base.
07/12	2012-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental retrofits, including environmental surcharge recovery.
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Company	Section 1603 grants, new solar facility, payroll expenses, cost of debt.
10/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Revenue requirements, including off-system sales, outage maintenance, storm damage, injuries and damages, depreciation rates and expense.
10/12	120015-EI Direct	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.
11/12	120015-EI Rebuttal	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.

**Expert Testimony Appearances
of
Lane Kollen
as of October 2013**

Date	Case	Jurisdict.	Party	Utility	Subject
10/12	40604	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Policy and procedural issues, revenue requirements, including AFUDC, ADIT – bonus depreciation & NOL, incentive compensation, staffing, self-insurance, net salvage, depreciation rates and expense, income tax expense.
11/12	40627 Direct	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
12/12	40443	TX	Cities Served by SWEPCO	Southwestern Electric Power Company	Revenue requirements, including depreciation rates and service lives, O&M expenses, consolidated tax savings, CWIP in rate base, Turk plant costs.
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Termination of purchased power contracts between EGSL and ETI, Spindletop regulatory asset.
01/13	ER12-1384 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Little Gypsy 3 cancellation costs.
02/13	40627 Rebuttal	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
03/13	12-426-EL-SSO	OH	The Ohio Energy Group	The Dayton Power and Light Company	Capacity charges under state compensation mechanism, Service Stability Rider, Switching Tracker.
04/13	12-2400-EL-UNC	OH	The Ohio Energy Group	Duke Energy Ohio, Inc.	Capacity charges under state compensation mechanism, deferrals, rider to recover deferrals.
04/13	2012-00578	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Resource plan, including acquisition of interest in Mitchell plant.
05/13	2012-00535	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.
06/13	12-3254-EL-UNC	OH	The Ohio Energy Group, Inc.	Ohio Power Company	Energy auctions under CBP, including reserve prices.
07/13	2013-00144	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Biomass renewable energy purchase agreement.
07/13	2013-00221	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Hawesville Smelter market access.

EXHIBIT ____ (LK-2)

REDACTED

EXHIBIT ____ (LK-3)

Item 105) *If Big Rivers decides to idle the Wilson plant, which carries the lowest variable costs on Big Rivers' system, describe how this will change MISO's economic dispatch of Big Rivers' generation units.*

a. *Does Big Rivers agree that if Wilson is idled, its sales to MISO will be reduced? If not, why not?*

b. *Provide an analysis of Big Rivers' expected sales to MISO through all of the forecasted test period, both with Wilson being idled, and with Wilson not being idled.*

c. *In the event Big Rivers idles the Wilson plant, please confirm that the plant will remain in the company's rate base and that ratepayers will continue to pay for various costs associated with the plant.*

d. *Please confirm that the budget included in the filing, which forms the basis for Big Rivers' fully forecasted test period assumes Wilson is idled.*

e. *Please provide a summary depicting the expected net total projected savings of shuttering the plant, for as long of a time period as such projections have been made.*

f. *Please provide the specific amount of cost that Big Rivers' ratepayers will bear for keeping the Wilson plant in the company's rate base in the event the plant is idled.*

Response)

a. Agreed.

b. Big Rivers sells all of its generation into and purchases all of its load from MISO. Big Rivers' forecasted generation sold to MISO with Wilson idled during the forecasted test period is [redacted] MWh. Big Rivers' forecasted generation sold to MISO with Wilson operating during forecasted test period is [redacted] MWh.

c. Confirmed.

d. Confirmed.

e. Big Rivers objects to the use of the unduly vague and ambiguous term "shuttering." Big Rivers further states that it does not intend to retire Wilson Station. Notwithstanding these objections, and without waiving them, Big Rivers states that it intends to idle Wilson Station. Big Rivers' analysis estimates that idling the Wilson Station will save its Members a total of approximately $73 Million in fixed costs during the 2014-2016 timeframe.

f. As a result of having Wilson remain in the rate base, Big Rivers' Members will continue to pay the interest, depreciation, insurance, and property taxes on the Wilson Station, as well as the cost of maintaining the unit in an idled state.

Depreciation	20,177,365
Property Tax	1,097,363
Property Insurance	1,252,679
Interest Expense	20,981,499
Fixed Department Expense	[redacted]
Labor/Labor Overhead	1,636,619
Total for FTP	[redacted]

Witness) Robert W. Berry

EXHIBIT ____ (LK-4)

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2013-00199

Response to the Office of the Attorney General's Initial Request for Information dated August 19, 2013

September 3, 2013

Item 106) *If Big Rivers decides to idle the Coleman plant upon completion of the SSR with MISO, describe how this will change MISO's economic dispatch of Big Rivers' generation units.*

a. Does Big Rivers agree that if Coleman is idled, its sales to MISO will be reduced? If not, why not?

b. Provide an analysis of Big Rivers' expected sales to MISO through all of the forecasted test period, both with Coleman being idled, and with Coleman not being idled.

c. In the event Big Rivers idles the Coleman plant, please confirm that the plant will remain in the company's rate base and that ratepayers will continue to pay for various costs associated with the plant.

d. Please confirm that the budget included in the filing, which forms the basis for Big Rivers' fully forecasted test period assumes Coleman is idled.

e. Please provide a summary depicting the expected net total projected savings of shuttering the plant, for as long of a time period as such projections have been made.

f. *Please provide the specific amount of cost that Big Rivers' ratepayers will bear for keeping the Coleman plant in the company's rate base in the event the plant is idled.*

Response)

a. Agreed.

b. Big Rivers sells all of its generation into and purchases all of its load from MISO. Big Rivers' forecasted generation sold to MISO with Coleman idled during the forecasted test period is [redacted] MWh. Big Rivers' forecasted generation sold to MISO with Coleman operating during forecasted test period is [redacted] MWh.

c. Confirmed.

d. Coleman is assumed idled starting on February 1, 2014, with related headcount reductions as of May 1, 2014. Any non-recurring costs for Coleman in the fully forecasted test period (labor and non-labor) are included in a pro forma adjustment to reduce the revenue requirement. Please refer to Exhibit Wolfram-2 from the Direct Testimony of Mr. John Wolfram for all pro forma adjustments.

e. Big Rivers objects to the use of the unduly vague and ambiguous term "shuttering." Big Rivers further states that it does not intend to retire Coleman Station. Notwithstanding these objections, and without waiving them, Big Rivers states that it intends to idle Coleman Station. Big Rivers' analysis estimates that idling the Coleman Station will save its Members a total of approximately $78 Million in fixed costs during the 2014-2016 timeframe.

f. As a result of remaining in the rate base, Big Rivers' Members will continue to pay the interest, depreciation, insurance, and property taxes on the Coleman Station, as well as the cost of maintaining the unit in an idled state..

Depreciation	$	6,466,191
Property Tax		476,341
Property Insurance		732,474
Interest Expense		6,786,057
**Fixed Department Expense		[redacted]
** Labor/Labor Overhead		1,500,832
Total for FTP	**$**	[redacted]

**Pro Forma adjustments have been applied.

Witness) Robert W. Berry

EXHIBIT ____ (LK-5)

Item 15) *Refer to page 11 of the Berry Testimony. Lines 14-17 indicate that Big Rivers has offered to sell the Wilson and Coleman stations to multiple parties but that its efforts have not produced results.*

a. Provide details on the status of negotiations to sell any Big Rivers generating stations.

b. Provide:

1) the prices at which Big Rivers has offered to sell the Wilson and Coleman stations;

2) the net book value of each station; and

3) the long-term debt associated with each station.

Response)

a. Big Rivers has offered both the Wilson and Coleman Stations for sale to a number of counterparties. Big Rivers' offer prices for the sale of both Coleman and Wilson have been consistent among counterparties. Big Rivers has also offered the option of joint-ownership to a number of counterparties. Please see Big Rivers' response to PSC 2-16 for details of Big Rivers' discussions with counterparties regarding all mitigation efforts, including the sale of assets. [redacted]

b.

1) Big Rivers has offered Wilson Station for sale at a price of [redacted] or roughly [redacted]. Big Rivers has offered Coleman Station for sale at a price of [redacted] or roughly [redacted].

2) The net book value (excluding construction work in progress), as of 7/31/2013, for the Wilson Station was $448,305,346. The net book value (excluding construction work in progress), as of 7/31/2013, for the Coleman Station was $180,092,893.

3) As of July 31, 2013, Big Rivers' total outstanding long-term debt was $858,905,176.41. Big Rivers does not allocate long-term debt balances to individual stations. As a result, long-term debt balances associated with each station are not available.

Witness) Robert W. Berry

EXHIBIT ____ (LK-6)

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2013-00199

Response to the Commission Staff's Second Request for Information dated August 19, 2013

September 3, 2013

Item 16) *Refer to page 12, lines 8-14, of the Berry Testimony, which indicates that Requests for Proposals have been issued in Kentucky for long-term power contracts. Describe Big Rivers' response to these opportunities for the potential sale of capacity that is no longer needed to serve the smelter load.*

Response) Big Rivers continues to evaluate options to enter into short or long term power contracts with counterparties, sell or lease generating assets, enter into tolling agreements with another entity, or serving a new or existing load in one of our Members' territories. Big Rivers continues to follow a multi-pronged approach, with Big Rivers' members focusing on economic development opportunities and Big Rivers' Energy Services Department working to find wholesale marketing opportunities for the power.

Big Rivers' members (Kenergy Corp., Jackson Purchase Energy Corporation, and Meade County Rural Electric Cooperative Corporation (collectively, the "Members")) continue to aggressively seek new commercial and industrial loads within their territory. Each Member has resources dedicated to this task. The Members' staffs actively work with local, regional and state economic development officials to identify and provide technical planning support and electricity pricing quotes to interested economic development prospects. Big Rivers' staff supports the Members' economic development efforts by attending economic development meetings at the request of its Members while providing timely transmission infrastructure cost projections and energy rate pricing estimates given the specific load parameters of the prospect. Big Rivers and the Members have recently joined Kentucky United, which is a collaborative partnership to market and promote economic development within Kentucky. Kentucky United works alongside the Kentucky Cabinet for Economic Development and other economic development professionals from across the state to proactively attract and recruit new industry to the Commonwealth.

Through their participation in Kentucky United, Big Rivers and its Members attend a variety of marketing mission trips that include meeting with out-of-state economic development consultants and potential projects through marketing recruiting trips that could help its system secure new load growth through the attraction of new industry. Our economic development team has already scheduled the following trips through the Kentucky United program: Dallas, Texas Consultant Trip; Atlanta, Georgia Consultant Trip; Phoenix, Arizona Consultant Trip; Philadelphia, Pennsylvania Marketing Trip; and Washington, D.C. Marketing Trip.[1]

Additionally, Big Rivers provides its three distribution Members with financial support to promote economic development initiatives within their cooperative communities.

[1] The cost for these trips is not included in the revenue requirement.

In 2012, Big Rivers supported its distribution Members with more than $100,000 in funding to encourage economic development efforts in Western Kentucky.[2] Big Rivers believes these efforts can have a positive impact on influencing industrial and commercial load growth within our distribution Members' service territories.

As part of Big Rivers' efforts to market the capacity that is no longer needed to serve smelter load, Big Rivers has responded to a number of Requests for Proposals ("RFPs"). The details of each RFP response are outlined below and the RFPs are provided electronically with these responses.

Kentucky-Based RFPs

Louisville Gas and Electric Company/Kentucky Utilities Company ("LGE/KU"): Big Rivers submitted a confidential proposal in response to a RFP from LGE/KU for up to 700MW of firm capacity and energy. [redacted]

[2] These costs are removed from the revenue requirement for ratemaking purposes.

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
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Response to the Commission Staff's
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[redacted]

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

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[redacted]

BIG RIVERS ELECTRIC CORPORATION

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[redacted]

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
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[redacted]

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[redacted]

[redacted]

[redacted]

[redacted]

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
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[redacted]

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2013-00199

Response to the Commission Staff's Second Request for Information dated August 19, 2013

September 3, 2013

[redacted]

Witness) Robert W. Berry

EXHIBIT ____ (LK-7)

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 32) *Refer to the Company's response to KIUC 1-48 in which it provides the assumptions used for "replacement load" starting in 2016 at 100 mW, additional annual increments of 100 mW from 2017 through 2019 and then additional annual increments of 200 mW from 2020 through 2021. Please provide all support for these load growth assumptions, including all underlying assumptions, such as the composition and sources of the additional load, the pricing discounts necessary to entice and obtain each of these loads, if any, and whether each of these loads is new load due to a new facility or load transferred from and presently served by another utility or supplier.*

Response) Big Rivers objects to this request on the grounds that it is overly broad and unduly burdensome. Notwithstanding these objections, but without waiving them, Big Rivers states that the replacement load forecasted in Big Rivers' long-term load forecast was determined based on informed judgment. Big Rivers forecasted replacement load assuming the replacement load could take many forms. Please see Big Rivers' response to PSC 2-16 for a detailed discussion of the various replacement load efforts undertaken by Big Rivers in determining Big Rivers' replacement load forecast. The replacement load was not meant to be specific, but rather represented what Big Rivers' management believed was a reasonable expectation for load replacement given all of the information available to it at the time. The replacement load was assumed to have a 75% load factor because Big Rivers believed it was likely to be composed of a combination of rural, large industrial, and market transactions.

Witness) Lindsay N. Barron

EXHIBIT ____ (LK-8)

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 35) *Refer to the file Demand Energy Budget 2013-2017.xlsx.*

a. *Please indicate if the Company's BOD approved this Demand Energy Budget 2013-2017, and if so, for what purpose(s) it was approved. If so, then please provide all documents that were provided to the BOD prior to its approval, including all support for the projected new load and related assumptions, and a copy of all documentation of the BOD's approval of this Demand Energy Budget.*

b. *Please identify each of the projected new loads that will commence taking service on January 1, 2016. Describe the status of each such new load and the terms used to attract the new load, e.g., discounted tariff rates, fixed price contracts, etc.*

c. *Please identify each of the projected new loads that will commence taking service on January 1, 2017. Describe the status of each such new load and the terms used to attract the new load, e.g., discounted tariff rates, fixed price contracts, etc.*

d. *Please provide a copy of all analyses prepared by, available to Big Rivers through its various economic development affiliations/memberships, and/or otherwise relied on by Big Rivers to assess the lead time necessary for a new*

Large Industrial load to locate and develop a new site and production facility.

e. *Please provide the source of the "Projected New Load MW" line item (line 38). Provide all analyses in support of and underlying this projection.*

f. *Please provide the source of the load factor that was used to derive the "Projected New Load MWh" line item (line 74). Provide all analyses in support of and underlying this assumption.*

g. *Please separate the new load into Rural Residential, Rural Commercial, and Large Industrial for each month 2016-2017.*

h. *Please identify, describe, and provide a copy of all programs adopted or that the Company plans to adopt to increase its Rural Residential load by 2016 for purposes of the "Projected New Load."*

i. *Please identify, describe, and provide a copy of all programs adopted or that the Company plans to adopt to increase its Rural Commercial load by 2016 for purposes of the "Projected New Load."*

j. *Please identify, describe, and provide a copy of all programs adopted or that the Company plans to adopt to increase its Large Industrial load by 2016 for purposes of the "Projected New Load."*

Response)

a. The referenced Demand and Energy file is an input to the overall Big Rivers corporate budget that is approved by the Board of Directors. Please see the attachment to Big Rivers' response to PSC 2-19 for the presentation given to the Board related to the budget. Please also see page 864 of the CONFIDENTIAL attachment to Big Rivers' response to AG 1-38 in Case No. 2012-00535 for documentation of the Board's approval of the budget.

b. Please see Big Rivers' response to KIUC 2-32.

c. Please see Big Rivers' response to KIUC 2-32.

d. There are no such analyses; however, based on past experience, Big Rivers is aware that there is a significant lead time for new large industrial load site development.

e. Please see Big Rivers' response to KIUC 2-32.

f. Please see Big Rivers' response to KIUC 2-32.

g. Please see Big Rivers' response to KIUC 2-32.

h. No specific programs have been adopted by the company for these purposes.

i. Big Rivers' members (Kenergy Corp., Jackson Purchase Energy Corporation, and Meade County Rural Electric Cooperative Corporation (collectively, the "Members")) continue to aggressively seek new commercial and industrial loads within their territory. Each Member has resources dedicated to this task. The Members' staffs actively work with local, regional and state economic development officials to identify and provide technical planning support and electricity pricing quotes to interested economic development prospects. Big Rivers' staff supports the Members' economic development efforts by attending economic development visits at the request of its Members while providing timely transmission infrastructure cost projections and energy rate pricing estimates given the specific load parameters of the prospect. Big Rivers and the Members have recently joined Kentucky United, which is a collaborative partnership to market and promote economic development within Kentucky. Kentucky United works alongside the Kentucky Cabinet for Economic Development and other economic development professionals from across the state to proactively attract and recruit new industry to the Commonwealth.

j. See Big Rivers' response to subpart (i) above.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information
dated September 16, 2013

September 30, 2013

Witness) Lindsay N. Barron

EXHIBIT ____ (LK-9)

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s Second Request for Information dated September 16, 2013

September 30, 2013

Item 36) *Refer to the Company's response to PSC 2-16.*

a. *Has the Company offered discounts off the tariffed rates that it proposes in this proceeding to attract any of the potential customer loads? If so, please provide this additional detail for each such transaction identified in response to PSC 2-16.*

b. *If the Company has offered discounts off the tariffed rates that it proposes in this proceeding, then please provide all principles relied on for this purpose and the quantitative basis for each such discount. Also provide all documentation of these principles and their application to the specific transactions set forth in the response to PSC 2-16.*

c. *Does the Company plan to offer discounts off the tariffed rates that it proposes in this proceeding to attract any of the potential customer loads?*

d. *Is the Company agreeable in principle to discounting the tariffed rates that it proposes in this proceeding to attract potential customer loads? If so, then provide all principles the Company will apply for such discounts and describe how it plans to determine and quantify the discount for a potential customer load.*

e. *If the Company has offered or is willing to offer discounts off the tariffed rates that it proposes in this proceeding, identify the officers who approved these discounts and indicate if the Company's BOD approved these discounts. Provide all documentation.*

f. *Is it the Company's position that it can discount tariffed rates without approval by the Commission? If the Company's position is that it must obtain the Commission's approval to discount tariffed rates, does the Company plan to do so, and if so, when does it plan to do so?*

g. *Is the Company aware of any other cooperative or other supplier that has successfully acquired customer loads that previously were supplied by TVA?*

Response)

a. Big Rivers has made a number of proposals to counterparties, some of which were market-based products and others of which were tariff-based products. Many of the proposals combined fixed demand charges with tariff-based energy charges. Big Rivers has proposed an economic development incentive rate in a number of its proposals. The economic development incentive rate contemplated by Big Rivers includes a fixed demand component of $[redacted] with energy charges and riders charged at [redacted].

b. Big Rivers relied on the principles outlined in an order by the Kentucky Public Service Commission in Administrative Case No. 327 (September 24, 1990), which is attached hereto for reference.

c. Yes.

d. Yes, please see Big Rivers' response to subpart (b) above.

e. Big Rivers' CEO and COO have authorized the proposal of economic development rates to potential counterparties; however, any retail agreements that deviate from tariffed rates will require approval by Big Rivers' board of directors, RUS, and the PSC prior to execution.

f. Big Rivers' position is that economic development rates offered to encourage new or expanded large industrial load should be implemented by special contract between and among Big Rivers, its respective distribution cooperative, and the large industrial customer. Any such contract would be submitted to the Commission for review in accordance with the principles established by the Commission in Administrative Case No. 327.

g. Big Rivers is not currently aware of loads that were previously supplied by TVA that have been successfully acquired by others; however, Big Rivers has not historically monitored TVA customer base changes.

Witness) Robert W. Berry

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN INVESTIGATION INTO THE IMPLEMENTATION OF ECONOMIC DEVELOPMENT RATES BY ELECTRIC AND GAS UTILITIES	)))	ADMINISTRATIVE CASE NO. 327

O R D E R

On February 10, 1989, the Commission initiated this proceeding to examine its guidelines regarding economic development rates and to seek comments and recommendations from the major gas and electric utilities in the state on the use of these special rates. For the purposes of this investigation, an economic development rate ("EDR") is considered to be a gas or electric rate discount, offered to large commercial and industrial customers, which is intended to stimulate the creation of new jobs and capital investment both by encouraging existing customers to expand their operations and by improving the likelihood that new large commercial and industrial customers will locate in Kentucky.

The Commission's EDR guidelines were outlined in its July 1, 1988 Order in Case No. 10064[1]. As stated in that Order, any utility wishing to offer economic development rates to specific customers should satisfy the following six guidelines:[2]

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1 Case No. 10064, Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company.

2 Case No. 10064, Order dated July 1, 1988, pages 93-94.

1. 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.

2. 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.

3. Each utility that offers an economic development rate should be required to document and report any increase in employment and capital investment resulting from the tariff and contract. These reports should be filed on an annual basis with the Commission.

4. Each utility that intends to offer economic incentive rates should be required to file a tariff stating the terms and conditions of its offering. Furthermore, each utility should be required to enter into a contract with each customer which specifies the minimum bill, estimated annual load, and length of contracting period. No contract should exceed 5 years. All contracts shall be subject to the review and approval of the Commission.

5. Each utility should be required to include a clause in its contract that states that the tariff will be withdrawn when the utility no longer has adequate reserve to meet anticipated load growth.

6. Each utility should be required to demonstrate that rate classes that are not party to the transaction should be no worse off than if the transaction had not occurred. Under special circumstances, the Commission will consider utility proposals for contracts that share risk between utility shareholders and other ratepayers. However, if a utility proposes to charge the general body of ratepayers for the revenue deficiency resulting from the EDR through a risk-sharing mechanism then the utility will be required to demonstrate that these ratepayers should benefit in both the short- and long-run. In addition, at least one-half of the deficiency will be absorbed by the stockholders of the utility and will not be passed on to the

> general body of ratepayers. The amount of the deficiency will be determined in future rate cases by multiplying at least one-half of the billing units of the EDR contract(s) by the tariffed rate that would have been applied to customer(s) if the EDR contract(s) had not been in effect.

The following gas and electric utilities were made parties to this proceeding: Louisville Gas and Electric Company ("LG&E"); Kentucky Power Company ("KPC"); Kentucky Utilities Company ("KU"); The Union Light, Heat and Power Company ("ULH&P"); Big Rivers Electric Corporation ("Big Rivers"); East Kentucky Power Cooperative, Inc. ("EKPC"); Columbia Gas of Kentucky, Inc. ("Columbia"); Delta Natural Gas Company, Inc. ("Delta"); and Western Kentucky Gas Company ("Western"); collectively ("participating utilities"). In addition, the following parties sought and were granted intervention status: the Office of the Attorney General ("AG"); Green River Electric Corporation ("Green River"); Henderson-Union Rural Electric Cooperative Corporation ("Henderson-Union"); and the Kentucky Cabinet for Economic Development ("Cabinet").

In its February 10, 1989 Order in this case, the Commission posed several questions pertaining to the feasibility, design and implementation of EDRs. The responses filed by the participating utilities and testimony filed by the Cabinet greatly assisted the Commission in its consideration of effective EDR guidelines. In addition, testimony provided at a hearing conducted on June 22, 1989, and post-hearing briefs filed by several parties further elucidated some of the important issues related to EDRs. The primary issues to be addressed by the Commission in this Order are adequate capacity requirements, variable cost recovery, customer-specific fixed cost recovery, job creation and capital investment criteria, implementation of EDRs, risk allocation, load eligibility, retention rates, waivers of gas main extension costs, and the appropriate term of EDR contracts. Finally, the Commission will address a Cabinet proposal that it be allowed to file comments pertaining to utilities' EDR contracts.

ADEQUATE CAPACITY REQUIREMENT

The capacity requirements contained in Guidelines 1 and 5 are based on two premises. First, additional load resulting from discounted rates should not create a need for new plant capacity. Second, during periods of excess capacity, the load resulting from EDRs increases a utility's operating efficiency and allows sales of capacity that may not have occurred without the EDRs. Any capacity in excess of a reserve margin normally considered adequate to ensure system reliability could be used to provide service under EDRs without unduly hastening the need for new capacity.

Several participating utilities contend that specific capacity requirements should not be imposed on utilities offering EDRs. Columbia and Delta assert that adequate capacity availability is a responsibility of the utility and should not be a specific requirement of an EDR.[3] EKPC contends that, as long as EDRs exceed marginal costs, EDRs should be offered, even if a

3 Columbia's Response to the Commission's Order dated February 10, 1989, Item 11; Delta's Response to the Commission's Order dated February 10, 1989, Item 11.

utility must add capacity to serve the load.[4] Similarly, KPC states that economic growth should not be capped by a desire to avoid electric capacity additions.[5]

LG&E, on the other hand, contends that without an adequate capacity requirement, new capacity additions could be required to serve a load that is not sharing fully in the fixed cost associated with the capacity addition.[6] Big Rivers states that a utility should demonstrate that adequate capacity is available to serve EDR customers unless the utility can show that any additional capacity needed to serve the new load would not increase its cost of service.[7] Western states that the availability of EDRs should be contingent on a demonstration of adequate capacity.[8]

The Commission finds that EDRs should only be offered during periods of excess capacity and that each utility should demonstrate, upon submission of each EDR contract, that the load expected to be served during each year of the contract period will not cause the utility to fall below a reserve margin that is considered essential for system reliability. Such a reserve

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4 EKPC's Response to the Commission's Order dated February 10, 1989, Item 11.

5 KPC's Response to the Commission's Order dated February 10, 1989, Item 11.

6 LG&E's Response to the Commission's Order dated February 10, 1989, Item 11.

7 Big Rivers' Response to the Commission's Order dated February 10, 1989, Item 11.

8 Western's Response to the Commission's Order dated February 10, 1989, Item 11.

margin should be identified and justified with each EDR contract filing.

Guideline 5 currently requires utilities to withdraw the EDR if adequate reserves are not available to meet anticipated load growth. There is a general feeling among the participating utilities that once the Commission approves an EDR contract for a customer it should not be withdrawn. Columbia maintains that the use of EDRs should be discontinued if adequate capacity is not available to serve new EDR load, however EDRs should not be withdrawn from customers to whom commitments have already been made.[9] Big Rivers states that, at the time an EDR contract is being considered, if the added load cannot be served without increasing system costs, a contractual commitment should not be made.[10] The Commission concludes that, while the load of EDR customers should not create a need for additional capacity, an EDR should not be withdrawn from a customer already under contract.

VARIABLE COST RECOVERY

Guideline 2 currently requires all EDRs to recover variable costs and make some contribution to system fixed costs. The requirement that EDRs exceed variable costs is essential to an effective EDR policy. Revenues received from EDRs that exceed variable costs contribute to a portion of the utility's fixed costs that otherwise would have been paid by nonparticipating

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9 Columbia's Response to the Commission's Order dated February 10, 1989, Item 11(b).

10 Big Rivers' Response to the Commission's Order dated February 10, 1989, Item 11(b).

ratepayers. This contribution results in lower costs for all ratepayers as utility fixed costs are spread over a larger total load.

The participating utilities agree that discounted rates should, in all instances, cover the variable costs associated with serving EDR customers. In addition, EKPC maintains that short-run marginal (variable) costs should include the marginal cost of capacity as well as the marginal cost of energy.[11] LG&E contends that EDRs should not only recover all customer and variable costs, but should also make a contribution to system fixed costs.[12] Western, Big Rivers, KPC and ULH&P assert that utilities should be required to demonstrate that the discounted rate recovers variable cost each time an EDR contract is submitted to the Commission for approval.[13] ULH&P also suggests that a follow-up analysis be performed after the EDR has been in place for at least one year. This analysis should use cost-of-service principles to compare scenarios with and without the EDR customer. Similarly, EKPC states that utilities should submit an annual report to the Commission showing revenues collected from each EDR customer as

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11 EKPC's Response to the Commission's Order dated February 10, 1989, Item 12, page 1 of 3.

12 LG&E's Response to the Commission's Order dated February 10, 1989, Item 12.

13 Western's Response to the Commission's Order dated February 10, 1989, Item 12(a); Big Rivers' Response to the Commission's Order dated February 10, 1989, Item 12(a); KPC's Response to the Commission's Order dated February 10, 1989, Item 12(a); ULH&P's Response to the Commission's Order dated February 10, 1989, Item 12(a).

well as the variable and customer-specific costs associated with serving each customer.[14]

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 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. Demonstration of marginal cost recovery should be accomplished through the use of a current marginal cost-of-service study. A current study is one conducted no more that one year prior to the date of the contract. Furthermore, utilities should submit an annual report to the Commission showing revenues received from each EDR customer and the marginal costs associated with serving each EDR customer. Finally, during rate proceedings, utilities with EDR customers should demonstrate through detailed cost-of-service analysis that nonparticipating ratepayers are not adversely affected by these EDR customers.

CUSTOMER-SPECIFIC FIXED COST RECOVERY

Guideline 2 requires that customer-specific fixed costs associated with serving an EDR customer be recovered either as an up-front payment or as part of a minimum bill over the life of the contract. The participating utilities were fairly evenly divided

14 EKPC's Response to the Commission's Order dated February 10, 1989, Item 12(a).

on this issue. Columbia, Western, and ULH&P contend that, although customer-specific fixed costs should, in most instances, be recovered from the EDR customer, the recovery mechanism should be developed on a case-by-case basis.[15] EKPC suggests that customer-specific fixed costs be recovered either by a lump-sum payment by the EDR customers or through annual or monthly payments amortized over the EDR period.[16] Big Rivers recommends recovery through a contribution in aid of construction, monthly facilities charge, termination charge, minimum billing demand, or a combination of these methods.[17]

Delta, KU, and LG&E, on the other hand, contend, for various reasons, that customer-specific fixed costs should not be recovered from EDR customers.[18] KU asserts that EDR-specific fixed costs should be assigned to the EDR class as a whole, not to individual customers within the class. LG&E proposes to handle the customer-specific fixed costs associated with EDR customers in a manner similar to its present handling of other customer-specific capital expenditures. LG&E currently provides

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15 Columbia's Response to the Commission's Order dated February 10, 1989, Item 13; Western's Response to the Commission's Order dated February 10, 1989, Item 13; ULH&P's Response to the Commission's Order dated February 10, 1989, Item 13.

16 EKPC's Response to the Commission's Order dated February 10, 1989, Item 13.

17 Big Rivers' Response to the Commission's Order dated February 10, 1989, Item 13.

18 Delta's Response to the Commission's Order dated February 10, 1989, Item 13; KU's Response to the Commission's Order dated February 10, 1989, Item 13; LG&E's Response to the Commission's Order dated February 10, 1989, Item 13.

capital expenditures in an amount up to three times the expected annual net revenues of a customer. The customer must then provide the balance.

The Commission finds that nonparticipating ratepayers should be protected from contributing to the customer-specific fixed costs associated with serving customers who will be receiving a rate discount. It is not unreasonable to require these customers to reimburse the utility for these capital expenditures over the term of an EDR contract. However, the Commission finds that utilities should have the flexibility to design particular mechanisms by which these customer-specific fixed costs are to be recovered. Therefore, all EDR contracts should include a provision allowing for the recovery of customer-specific fixed costs over the term of the contract.

JOB CREATION AND CAPITAL INVESTMENT CRITERIA

Increased economic activity is the major objective of EDRs. Two key indicators of economic activity are job creation and capital investment. EDRs are expected to promote growth in both of these areas. The issue to be addressed here is whether specific job creation and capital investment levels necessary to qualify for EDRs should be established by the Commission, or whether these levels should merely be monitored by the Commission in order to assess the impact of EDRs on economic activity in the state.

The Commission finds that, while job creation and increases in capital investment are the desired outcome of EDRs, requiring specific levels of job creation and capital investment for EDR eligibility might, in some instances, impede rather than promote economic activity. For instance, such a requirement might prevent a customer from participating in an EDR program even if tangible economic benefits unrelated to job creation or capital investment would have been realized. Furthermore, specific job creation and capital investment levels would be arbitrary and would not recognize the needs and characteristics of individual service areas and of new and expanding customers.

Several participating utilities express similar concerns. EKPC states that while job creation and increased capital investment are expected results of an EDR, an explicit requirement for increases in these areas would not necessarily help an existing customer whose current investment in facilities and employees is underutilized.[19] KPC asserts that, if the Commission establishes a threshold level of jobs or capital investment necessary to qualify for an EDR, some desired new industry might be lost.[20] Columbia and Western both maintain that job creation and capital investment potential are secondary to the load characteristics of the potential EDR customer.[21]

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19 EKPC's Response to the Commission's Order dated February 10, 1989, Item 5.

20 KPC's Response to the Commission's Order dated February 10, 1989, Item 5.

21 Columbia's Response to the Commission's Order dated February 10, 1989, Item 5; Western's Response to the Commission's Order dated February 10, 1989, Item 5.

The Commission finds that a uniform job creation and capital investment requirement for each EDR contract is inappropriate. However, the Commission has determined that monitoring the job creation and capital investment performance of EDRs would provide it with important information with which to measure the effectiveness of its EDR program. Therefore, all utilities with active EDR contracts should file annual reports to the Commission providing information as shown in Appendix A, which is attached hereto and incorporated herein.

IMPLEMENTATION OF EDRs

An EDR can be implemented by either of two methods. First, a standard EDR tariff or rider, explicitly stating all rates, terms and conditions, is filed by a utility and made available to a general classification of customers. Second, a utility files a special contract with an individual customer, which states rates, terms and conditions applicable to that specific customer. Guideline 4 currently requires a utility to submit a general EDR tariff, as well as individual contracts with each EDR customer. This procedure was intended to ensure the uniformity of EDRs while identifying the unique usage characteristics of the EDR customers.

The participating utilities have expressed varying opinions regarding the methods by which EDRs should be implemented. Columbia and Western contend that utilities should have the flexibility to design EDRs to match their individual situations.[22]

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[22] Columbia's Response to the Commission's Order dated February 10, 1989, Item 8; Western's Response to the Commission's Order dated February 10, 1989, Item 8.

Big Rivers, KPC, and ULH&P assert that EDRs should be negotiated and offered through special contracts.[23] KPC further states that special contracts would allow the greatest amount of freedom in identifying a customer's needs, while at the same time minimizing the needless revenue reduction that occurs when all new industrial load is granted an EDR concession. Similarly, ULH&P contends that circumstances to be encountered in implementing an EDR are too diverse in nature to be covered by a general tariff. The utility needs to be flexible in negotiating EDRs.

Conversely, EKPC feels that a general tariff would allow better coordination of the review process by the Commission.[24] LG&E contends that a general tariff would avoid a proliferation of individual contracts that could hamper consistent planning.[25] However, LG&E further states that special contracts may be warranted in cases involving extenuating circumstances (i.e. those instances when application of a tariff would be inequitable to the customer class or to the customer).

Initially, the Commission was concerned that implementing EDRs through special contracts would increase the likelihood of the discriminatory use of EDRs by utilities. Even if price discrimination is unintended, EDR contracts would give utilities

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23 Big River's Response to the Commission's Order dated February 10, 1989, Item 8; KPC's Response to the Commission's Order dated February 10, 1989, Item 8; ULH&P's Response to the Commission's Order dated February 10, 1989, Item 8.

24 EKPC's Response to the Commission's Order dated February 10, 1989, Item 8.

25 LG&E's Response to the Commission's Order dated February 10, 1989, Item 8.

the right to selectively choose the customers to whom discounted rates would be offered. This would be unfair to customers whose usage characteristics were similar to customers receiving EDRs through special contracts but for some reason were not offered an EDR by the utility.

On the other hand, however, the Commission realizes that customers do not require identical incentives in order to locate a new facility in a particular area or to expand existing operations. In fact, for some customers, utility rate incentives may not even be a factor in their locational or expansionary decision-making process. Customers who would have decided to locate in Kentucky or expand existing operations even in the absence of rate discounts, but who would take advantage of EDRs that are offered to all new or expanding customers, in effect, become "free riders" on the utility system at the expense of all other ratepayers.

Current Commission EDR guidelines require utilities to file a general EDR rate schedule. This requirement, in effect, fixes the rate discount that is offered to all EDR customers regardless of their individual needs or usage characteristics. This precludes utilities from determining the minimum discount necessary to provide an incentive to new and existing customers and to identify potential free riders who do not require a discounted rate.

The Commission concludes that the revenue loss resulting from free riders taking advantage of rate discounts offered through general EDR tariffs is detrimental to the utility and all nonparticipating ratepayers. The Commission seeks to minimize the number of free riders taking advantage of discounted utility rates in Kentucky. Therefore, the Commission finds that utilities should have the ability to negotiate discounted rates with individual customers through the use of special contracts. This flexibility should enable the utilities to limit the number of EDRs they offer, thereby reducing the amount of foregone revenues resulting from discounted rates. Consequently, full contributions to system fixed costs would be made by some industrial customers that, under general EDR tariff provisions, would have automatically received rate discounts.

The Commission has previously approved EDR tariffs for Delta[26], Big Rivers[27], Green River[28], and Henderson-Union.[29] These utilities are hereby advised that the Commission will no longer require the implementation of EDRs through general tariffs. EDRs should now be implemented solely through special contracts negotiated with individual large commercial and industrial customers. The Commission finds that Delta, Big Rivers, Green River, and Henderson-Union should continue to honor all existing

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26 Delta's Economic Development Rate was initially approved in 1986. An extension of the tariff was subsequently approved on November 1, 1988.

27 Case No. 10424, The Notice of Big Rivers Electric Corporation of a Proposed Contract with Henderson-Union RECC to Implement an Industrial Incentive Rate.

28 Case No. 89-215, Green River Electric Corporation's Establishment of an Economic Development Rate.

29 Case No. 10422, The Notice of Henderson-Union RECC of a Proposed Contract with Valley Grain Products, Inc., to Implement an Industrial Incentive Plan.

contracts executed pursuant to an approved EDR tariff, but no new contracts related to an EDR tariff should be executed. Furthermore, each of these utilities should modify the availability clause of its EDR tariff to prohibit new customers after the date of this Order.

RISK ALLOCATION

Guideline 6 was developed to allocate fairly between utility shareholders and ratepayers the risk of revenue deficiencies created by discounted rates. A revenue deficiency is the difference between revenue which would have been received in the absence of an EDR (standard rates) and revenue actually received (discounted rates). The Commission sought to ensure that nonparticipating ratepayers were not negatively impacted by discounted rates. To accomplish this, the Commission ordered that utilities allocate at least one-half of all revenue deficiencies to their shareholders. This would likely have been achieved in a rate case by imputing to a utility's test-year revenue an amount equal to one-half of any revenue deficiency.

The participating utilities argue that if a discounted rate covers the marginal cost associated with serving an EDR customer and makes a contribution to system fixed costs, any difference between the regular tariff and the EDR should not be considered a deficiency and recovery of such revenues should not be imputed to the utility in rate proceedings. KPC states that all ratepayers will benefit from the economic improvements stimulated in part by

EDRs.[30] EKPC contends that EDR customers will not be receiving a subsidy from other ratepayers when their rate is equal to or greater than marginal cost.[31]

The Commission concludes that EDRs which are designed to recover all marginal costs and make a contribution to a utility's system fixed costs will benefit all nonparticipating ratepayers. Furthermore, the ratepayers of Kentucky are likely to enjoy additional benefits as a result of increased economic activity in the state. For these reasons, the Commission finds that a specific risk sharing mechanism designed to allocate revenue deficiencies to utility ratepayers and shareholders would be inappropriate and unnecessary. However, the Commission will continue to require all utilities with EDR contracts to demonstrate during rate proceedings that nonparticipating ratepayers are not adversely affected by EDR customers.

LOAD ELIGIBILITY

An important element in the development of an EDR program is the determination of which type load will be eligible for a rate discount. For new large commercial and industrial customers, an EDR is usually applied to all load in excess of a predetermined minimum usage level. For example, if required minimum usage levels are 1,000 KW per month for new electric customers and

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30 KPC's Response to the Commission's Order dated February 10, 1989, Item 12(c).

31 EKPC's Response to the Commission's Order dated February 10, 1989, Item 12(c).

100,000 Mcf per year for new gas customers, a new large commercial or industrial customer that initially contracts for more than 1,000 KW or 100,000 Mcf would qualify for an EDR on all KW or Mcf in excess of those minimum usage levels. For existing large commercial and industrial customers, new load in excess of a specific incremental usage level above a normalized base level may qualify for an EDR. For example, if required incremental usage levels are 1,000 KW per month for existing electric customers and 100,000 Mcf per year for existing gas customers, an existing customer that increases its load by more than 1,000 KW or 100,000 Mcf above its normalized base load would qualify for an EDR on all load in excess of the required incremental usage levels. EDRs applied to either of these type customers serve as an incentive for customers to locate or expand facilities and create new jobs.

The participating utilities agree that EDRs should apply both to the incremental load of existing customers and the load of new customers which exceed certain threshold amounts. All agree that an existing customer should be required to satisfy a minimum level of incremental load above a normalized base load and that new customers should be required to satisfy a minimum usage level before qualifying for EDRs. Most of the participating electric utilities state that a minimum incremental usage level of 1,000 KW above a normalized base load should be required for existing customers and a threshold usage level of 1,000 KW should be required of new customers. EKPC, however, suggests that lower levels be established. EKPC contends that by allowing loads in excess of a minimum incremental usage level of 100 KW to qualify for an EDR, the opportunities for participation by smaller businesses increase significantly.[32] EKPC maintains that lower incremental usage levels would create an incentive for smaller industries in eastern Kentucky to expand, thereby providing more employment opportunities.

Columbia suggests that the threshold for an EDR offering to an existing gas customer be 100,000 Mcf per year of sustained new gas consumption of a high load factor.[33] The other participating gas utilities did not recommend a specific threshold amount.

The Commission concurs that the job creation potential of EDRs might be enhanced by setting required minimum usage levels as low as possible. Providing an opportunity for smaller commercial and industrial customers to qualify for EDRs would likely result in an increase in new jobs in Kentucky. In addition, free riders will be limited since minimum incremental usage requirements would be retained, although at lower levels.

The Commission will not attempt to determine specific minimum incremental usage levels required for existing customers or the base usage levels required for new customers. Rather, the Commission finds that utilities should have the flexibility to determine the usage levels that will best serve to promote economic development in their service areas. However, at the time

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32 EKPC's Response to the Commission's Order dated February 10, 1989, Item 3(b).

33 Columbia's Response to the Commission's Order dated February 10, 1989, Item 3(b).

an EDR contract is filed, the Commission will expect the utility to identify and justify the minimum incremental usage level and the normalized base load required for an existing customer or the minimum usage level required for a new customer, whichever is applicable. In its review of EDR contracts, the Commission will not only consider the customer's load which is eligible for an EDR, but also the number of new jobs, amount of new capital investment, and the general economic benefits associated with the new or expanding load.

RETENTION RATES

Several participating utilities maintain that EDRs should also be used for the retention of existing load. ULH&P contends that the economic benefits derived from a new customer are the same as those derived from the retention of an existing customer.[34] Big Rivers suggests that EDRs could work for the retention of customers.[35] EKPC expresses its support of the concept of retention rates and states that retaining existing customers is an essential economic development goal.[36]

The Commission finds that EDRs used for the purpose of retaining existing load should be strictly limited and closely monitored. Any utility that files such an EDR contract will also be expected to file a sworn affidavit of the customer stating

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34 Transcript of Evidence ("T.E."), page 133.

35 Id., page 97.

36 EKPC's Response to the Commission's Order dated February 10, 1989, Item 5.

that, in the absence of a discounted rate, business operations will cease or be severely restricted. The utility must also demonstrate the financial hardship experienced by the existing customer seeking discounted rates in order to maintain its load on the utility's system.

WAIVERS OF GAS MAIN EXTENSION COSTS

Western proposes that gas utilities be allowed to offer discounts or waivers of the costs of gas main extensions as an alternative to rate discounts.[37] Similarly, the Cabinet stresses the importance of gas utilities being allowed to assist industrial customers with gas main extensions.[38]

The Commission believes that inherent differences which exist between the services provided by gas and electric utilities might necessitate certain differences in the style and format of incentives offered to new and existing customers. Discounts or waivers of gas main extension costs could encourage new large commercial or industrial customers to locate in Kentucky. The Commission, therefore, finds that gas utilities proposing to offer a discount or waiver of gas main extension costs should provide a detailed cost-benefit analysis which compares, among other things, the total costs incurred by the utility by offering such a discount or waiver to the expected revenue stream from the new or expanding customer and the number of new jobs and the amount of

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37 Western's Response to the Commission's Order dated February 10, 1989, page 2.

38 T.E., page 17.

new capital investment to be created. Furthermore, the Commission finds that EDR contracts that include a discount or waiver of gas main extension costs should also include a provision which requires the customer to remain on gas service for a specified term. Gas utilities proposing to offer a discount or waiver of gas main extension costs should provide justification for the required contract term.

TERM OF EDR CONTRACTS

Some of the participating utilities have indicated that the term of an EDR contract should extend for a period of time following the end of the discount period. Service during the final years of the contract would be provided at the rates contained in the standard tariffs. This ensures that each EDR customer will contribute fully to system fixed costs during a portion of their special contract. KU contends that an EDR customer should agree to be served on a standard rate for a period of time commensurate with the discount period.[39] Big Rivers states that a total ten-year contract period should be allowed so that the utility will receive five years of standard rate revenues following a five-year discount period.[40] Finally, EKPC asserts that it would be appropriate to require a customer to sign a

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39 KU's Response to the Commission's Order dated February 10, 1989, Item 10.

40 Big Rivers' Response to the Commission's Order dated February 10, 1989, Item 10.

contract which extends for some period of time beyond the expiration of the discount period.[41]

The Commission concurs with these participating utilities and finds that an EDR contract should extend for a period twice the length of the discount period. Furthermore, the discount period should not extend beyond five years. During the second half of an EDR contract, the rates charged to the customer should be identical to those contained in a standard rate schedule that is applicable to the customer's rate class and usage characteristics.

CABINET'S PROPOSAL TO COMMENT ON EDR CONTRACTS

The Cabinet has suggested that it be afforded the opportunity to assist the Commission in its review of EDR contracts by providing comments on each filed EDR contract and the individual merits of the potential EDR customers.[42] The Cabinet asserts that some potential customers, especially those in declining industries, might not deserve an EDR.[43]

The Cabinet currently works closely with utilities in their efforts to locate industries in the state through the activities of an economic development task force known as the Kentucky Industrial Team ("Team").[44] In addition to locating industries in Kentucky, the Team, which is comprised of utility representatives,

41 T.E., page 89.

42 Cabinet Testimony filed on May 31, 1980, page 5 and T.E., pages 21-22.

43 T.E., page 22.

44 Id., page 23.

Cabinet officials and local economic developers, helps prepare communities for industry.

The Commission acknowledges that Cabinet officials are experienced in dealing with economic development issues as they pertain to Kentucky communities. Furthermore, through its work with the Team, the Cabinet is likely involved in the development of economic development proposals and negotiations, possibly including EDRs, with new and existing large commercial and industrial customers. The Commission believes that comments submitted by the Cabinet pertaining to EDR contracts filed by utilities may be helpful and pertinent.

As stated in 807 KAR 5:011 Section 13, the Commission's regulations applicable to tariffs containing rates, rules and regulations, and general agreements, also apply to the rates and schedules set out in special contracts. Accordingly, the Commission has 30 days following the filing of a special contract during which it can accept, reject, or suspend the contract. Hence, in order to be sufficiently reviewed and considered by the Commission, any written comments prepared by the Cabinet or other interested parties pertaining to an EDR contract filed by a utility must be received by the Commission no more than 20 days after the filing of an EDR contract.

SUMMARY

The Commission, having considered the evidence of record and being otherwise sufficiently advised, finds that:

1. EDRs will provide important incentives to new large commercial and industrial customers to locate facilities in Kentucky and to existing large commercial and industrial customers to expand their operations, thereby bringing much needed jobs and capital investment into Kentucky.

2. Utilities should have the flexibility to design EDRs according to the needs of their customers and service areas and to offer EDRs to those new and existing customers who require such an incentive to locate new facilities in the state and to expand existing ones.

3. EDRs should be implemented by special contracts negotiated between the utilities and their large commercial and industrial customers.

4. An EDR contract should specify all terms and conditions of service including, but not limited to, the applicable rate discount and other discount provisions, the number of jobs and capital investment to be created as a result of the EDR, customer-specific fixed costs associated with serving the customer, minimum bill, estimated load, estimated load factor, and length of contract.

5. EDRs should only be offered during periods of excess capacity. Utilities should demonstrate, upon submission of each EDR contract, that the load expected to be served during each year of the contract period will not cause them to fall below a reserve margin that is considered essential for system reliability. Such a reserve margin should be identified and justified with each EDR contract filing.

6. Upon submission of each EDR contract, a utility should demonstrate that the discounted rate exceeds the marginal cost associated with serving the customer. Marginal cost includes both the marginal cost of capacity as well as the marginal cost of energy. In order to demonstrate marginal cost recovery, a utility should submit, with each EDR contract, a current marginal cost-of-service study. A current study is one conducted no more than one year prior to the date of the contract.

7. Utilities with active EDRs should file an annual report with the Commission detailing revenues received from individual EDR customers and the marginal costs associated with serving those individual customers.

8. During rate proceedings, utilities with active EDR contracts should demonstrate through detailed cost-of-service analysis that nonparticipating ratepayers are not adversely affected by these EDR customers.

9. All EDR contracts should include a provision providing for the recovery of EDR customer-specific fixed costs over the life of the contract.

10. The major objectives of EDRs are job creation and capital investment. However, specific job creation and capital investment requirements should not be imposed on EDR customers.

11. All utilities with active EDR contracts should file an annual report to the Commission providing the information as shown in Appendix A, which is attached hereto and incorporated herein.

12. For new industrial customers, an EDR should apply only to load which exceeds a minimum base level. For existing

industrial customers, an EDR shall apply only to new load which exceeds an incremental usage level above a normalized base load. At the time an EDR contract is filed, a utility should identify and justify the minimum incremental usage level and normalized base load required for an existing customer or the minimum usage level required for a new customer.

13. EDR contracts designed to retain the load of existing customers should be accompanied by an affidavit of the customer stating that, without the rate discount, operations will cease or be severely restricted. In addition, the utility must demonstrate the financial hardship experienced by the customer.

14. The term of an EDR contract should be for a period twice the length of the discount period, with the discount period not exceeding five years. During the second half of an EDR contract, the rates charged to the customer should be identical to those contained in a standard rate schedule that is applicable to the customer's rate class and usage characteristics.

15. Gas utilities proposing to offer a discount or waiver of gas main extension costs should provide a detailed cost-benefit analysis which compares, among other things, the expected revenue stream from the new or expanding customer and the number of new jobs and the amount of new capital investment to be created to the total costs incurred by the utility by offering such a discount or waiver.

16. EDR contracts that include a discount or waiver of gas main extension costs should include a provision which requires the customer to remain on gas service for a specified term. Gas

utilities proposing to offer a discount or waiver of gas main extension costs should provide justification for the required contract term.

17. Comments submitted by the Cabinet or other interested parties pertaining to EDR contracts should be filed with the Commission no more than 20 days following the filing of an EDR contract by a utility.

18. Delta, Big Rivers, Green River, and Henderson-Union should continue to honor all existing contracts executed pursuant to an approved EDR tariff, but no new contracts related to an EDR tariff should be executed. Each of these utilities should modify the availability clause of its EDR tariff to prohibit new customers after the date of this Order.

IT IS THEREFORE ORDERED that:

1. When filing EDR contracts, all jurisdictional gas and electric utilities shall comply with Findings 3-17 as if the same were individually so ordered.

2. Delta, Big Rivers, Green River, and Henderson-Union shall continue to honor all existing contracts executed pursuant to an approved EDR tariff, but no new contracts related to an EDR tariff shall be executed. Within 20 days of the date of this Order, each of these utilities shall file new economic development tariffs in which the availability clause has been modified to prohibit new customers after the date of this Order.

Done at Frankfort, Kentucky, this 24th day of September, 1990.

PUBLIC SERVICE COMMISSION

Chairman

Vice Chairman

Commissioner

ATTEST:

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN ADMINISTRATIVE CASE NO. 327 DATED 9/24/90

ECONOMIC DEVELOPMENT RATE CONTRACT REPORT

UTILITY: ______________________ YEAR: __________

	Current Reporting Period	Cumulative
1) Number of EDR Contracts -		
Total:	______	______
Existing Customers:	______	______
New Customers:	______	______
2) Number of Jobs Created -		
Total:	______	______
Existing Customers:	______	______
New Customers:	______	______
3) Amount of Capital Investment -		
Total:	______	______
Existing Customers:	______	______
New Customers:	______	______

4) Consumption -

	Current Reporting Period	Cumulative
(A) DEMAND:		
Total:	______ KW | MCF	______ KW | MCF
Existing Customers:	______ KW | MCF	______ KW | MCF
New Customers:	______ KW | MCF	______ KW | MCF
(B) ENERGY/CONSUMPTION:		
Total:	______ KWH | MCF	______ KWH | MCF
Existing Customers:	______ KWH | MCF	______ KWH | MCF
New Customers:	______ KWH | MCF	______ KWH | MCF

EXHIBIT ____ (LK-10)

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 39) *Please provide a schedule of the Company's temporary investments at month end by type of investment from January 2013 through December 2013 based on the Company's budget for 2013 and for January 2014 through December 2017 based on the corporate financial model forecast for those years consistent with the Company's rate filing proceeding. Also provide the interest income for each month.*

Response) Please see the attachment to this response for Big Rivers' temporary investments at month end by type of investment from January 2013 through December 2013 based on Big Rivers' budget for 2013. Please refer to the attachment to Big Rivers' response to PSC 2-19, page 11 of 23, for the interest income by month for January 2013 through December 2013 based on Big Rivers' budget for 2013.

Please refer to Big Rivers' "Financial Forecast (2014-2027) 5-16-2013" attached to Big Rivers' response to PSC 1-57, tab "Stmts RUS", rows 150 and 120, for Big Rivers' temporary investments at month end and interest income each month, respectively, for January 2014 through December 2017 based on the corporate financial model forecast for those years consistent with Big Rivers' rate filing proceeding.

Witness) Billie J. Richert

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to KIUC 2-39
Temporary Investment Account Balances by Month (2013 Budget)

Fidelity Prime Money Market Portfolio *(Whole $)*		2013 Budgeted Amounts
January 31, 2013	$	107,678,230.68
February 28, 2013	$	110,082,574.25
March 31, 2013	$	114,271,290.76
April 30, 2013	$	113,780,230.67
May 31, 2013	$	102,031,718.33
June 30, 2013	$	101,933,779.94
July 31, 2013	$	100,198,356.27
August 31, 2013	$	94,012,694.20
September 30, 2013	$	114,205,354.92
October 31, 2013	$	105,976,444.82
November 30, 2013	$	95,159,390.56
December 31, 2013	$	82,843,418.27

EXHIBIT ____ (LK-11)

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to Ben Taylor and Sierra Club's
Initial Request for Information
dated August 19, 2013

September 3, 2013

Item 12) *Refer to page 17 of the Direct Testimony of Robert Berry.*

a. *Please confirm that the contracts among Big Rivers, Kenergy, and Century that were approved by the Commission in Case No. 2013-00221 have been executed.*

b. *Has MISO determined at what Base Load Century may operate without Coleman Station being required to run for reliability purposes?*

   i. *If yes, please describe MISO's determination and produce any documents reflecting that determination.*

   ii. *If no, please explain why MISO has not yet provided a determination and when Big Rivers expects such a determination to be made.*

c. *Regarding the exclusion of transmission revenues from Century in the forecast test year: Under the approved agreements between Century, BREC, and Kenergy, if Century continues to operate at the same load as in recent years, while buying all of its power from outside the BREC system, what level of recurring annual transmission revenues would BREC receive from Century or its suppliers?*

d. How much transmission revenue will BREC receive if Century operates at the baseload level determined by MISO that would allow Coleman to be idled?

Response)

a-b. Please see Big Rivers' response to PSC 2-17(b) in this instant filing.

c. Utilizing rates published by MISO effective July 1, 2013 for Schedule 9 of \$15,586.7989/MW-yr and Century monthly peak loads of 482 MW, Big Rivers would expect to receive about \$7,512,837/yr in transmission revenues.

d. Utilizing the same rates and Century monthly peak loads equal to the base load level determined by MISO of 338 MW, Big Rivers would expect to receive about \$5,268,338/yr in transmission revenues.

Witness) Robert W. Berry

EXHIBIT ____ (LK-12)

Item 42) *Refer to the Company's response to KIUC 1-42(a);*

a. Please describe the capital expenditures shown for the Wilson plant in 2014. Are these related solely to the layup in the same manner that the capital expenditures for the Coleman plant are related solely to the layup?

b. Please indicate if any of the capital expenditures shown for HAP/MATS in 2014 are for the Wilson or Coleman plants. If so, then provide the amounts for each plant in 2014 and explain why these capital expenditures will not be delayed until a later date commensurate with a return to service of the plants.

Response)

a. Please see Exhibit Berry-2 in the Direct Testimony of Robert W. Berry for a description of the capital expenditures shown for the Wilson plant in 2014. The capital expenditures shown for the Wilson plant in Exhibit Berry-2 are not solely related to the layup. The current Wilson Station 2013-2016 capital plan was developed in 2012 when there was still much uncertainty surrounding the timing of the unit lay-up and its return to service. The 2014-2017 Wilson Station capital plan that will be presented to the Big Rivers

Board for approval in November 2013 will include only layup related expenditures for Wilson in 2014, and will not include any capital dollars for Wilson in 2015 or 2016.

b. There is $[redacted] for Wilson MATS and $[redacted] for Coleman MATS included in this number (before capitalized interest). These figures were included in the original 2013 capital expenditure budget, which is the basis for Big Rivers' response to KIUC 1-42(a). As a result of termination of the smelter contracts by Century and Rio Tinto, and the subsequent uncertainty over future operation of these plants, Big Rivers' management agrees that the MATS capital expenditures for Wilson and Coleman should be delayed until a later date that supports the return to service of these plants.

Witness) Robert W. Berry

EXHIBIT ____ (LK-13)

REDACTED

EXHIBIT ____ (LK-14)

BIG RIVERS ELECTRIC CORPORATION

**APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199**

**Response to the Kentucky Industrial Utility Customers, Inc.'s
Initial Request for Information
dated August 19, 2013**

September 3, 2013

Item 57) *With regard to the $2.27 million in ACES fees,*

a. *Please provide the workpapers, models, documentation electronically with all formulas attached that derived this value. Also, provide this information yearly for the longest period for which this data is available.*

b. *Please explain how these fees would vary depending on whether Coleman or Wilson operate or are idled, or whether the Century or Alcan smelters are part of Big Rivers' load or not.*

Response)

a. Please see Big Rivers' response to AG 1-126.

b. Big Rivers' fees will not change with the idling of either Wilson or Coleman. ACES fees are calculated on a two year lag, thus Big Rivers' 2013 fees were calculated based on Big Rivers' 2011 sales. Big Rivers' 2014 fees will be calculated based on Big Rivers' 2012 sales. Although ACES will not reduce Big Rivers' fees as a result of the smelter departures, Big Rivers will require Century to pay its pro-rata share of the ACES fee in 2014 as a result of the executed Century contract, which will result in a savings to Big Rivers' Members, estimated to be roughly 34.5% of the total fee.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

Response to the Kentucky Industrial Utility Customers, Inc.'s
Initial Request for Information
dated August 19, 2013

September 3, 2013

1 Witness) Robert W. Berry

EXHIBIT ____ (LK-15)

BIG RIVERS ELECTRIC CORPORATION

**APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199**

**Response to the Commission Staff's
Third Request for Information
dated September 16, 2013**

September 30, 2013

Item 10) *Refer to the response to Item 57 of the first information request of KIUC and page 1 of Exhibit Wolfram-2 to the Wolfram Testimony. Given that Century will be required to pay roughly 34.5 percent of the ACES fees of $2.27 million in 2014, explain why an adjustment to decrease Big Rivers' test-year expenses by approximately $783,150 was not included in the exhibit.*

Response) At the time Exhibit Wolfram-2 was prepared, the agreement with Century Kentucky for the Hawesville smelter had not yet been finalized, filed, approved or closed, so any requirement for Century Kentucky to compensate Big Rivers for a portion of the ACES fees was not known and thus could not be included in the exhibit.

Big Rivers acknowledges that Century Kentucky will reimburse Big Rivers for a portion of the ACES fees, pursuant to Exhibit A of the Direct Agreement approved by the Commission in Case No. 2013-00221. Thus, Big Rivers' proposed revenue requirement should be reduced by $783,724, which is Century's 34.5 percent share of the ACES fees in the test period.

Please note that Century Kentucky may be required to reimburse Big Rivers for other cost items included in the test period revenue requirement in this case. However, it is not certain at this time whether such reimbursements will take place. Furthermore, if reimbursement does occur, both the timing and the amounts of any payments are unknown. For these reasons, Big Rivers is not proposing any adjustments to the test period revenue requirement in this case for such items.

One example is the costs related to the SSR (including reimbursements for property tax and insurance, inventory carrying costs, and a portion of certain Big Rivers' labor costs). Big Rivers has provided an SSR Agreement to MISO (which includes a proposed description of SSR unit going-forward compensation and a proposed SSR budget). MISO has not yet approved it. If MISO approves the proposed SSR Agreement, or if MISO modifies the SSR Agreement, MISO must then make a filing at FERC seeking FERC approval of the same. It is Big Rivers' understanding that the SSR Agreement may be contested at MISO and/or at FERC by Century Kentucky, but this is not yet known. The extent to which FERC and MISO will agree with Big Rivers that the items such as property tax, property insurance, etc. are SSR costs is unknown at this time.

Another example includes the costs for Ancillary Services. Big Rivers submitted a filing at FERC regarding Ancillary Service Schedule 2 (Reactive Supply and Voltage Control Service) under the MISO tariff, but this has not yet been approved. See *Proposed Revenue Requirement of Big Rivers Electric Corporation for reactive supply service under*

Midcontinent Independent System Operator, Inc. Tariff Schedule 2, FERC Docket No. EL13-85-000.[1]

The aforementioned items relate to the provision of service to Century Kentucky's Hawesville smelter. Big Rivers expects that similar agreements will be reached (subject to Commission approval) at some point in the coming months among Big Rivers, Kenergy Corp., and Century Kentucky for the provision of service to the Sebree smelter, but at present this too is uncertain.

Big Rivers will provide information on these items and any other similar items when such information becomes known. Big Rivers will provide this information in the form of on-going updates to the response to PSC 4-3 in Case No. 2012-00535, in the quarterly reports that are required pursuant to Ordering Paragraph No. 5 in the Commission's Order dated August 14, 2013 in Case No. 2013-00221, and/or in updates to items in the record in this case as appropriate.

Witnesses) Robert W. Berry, John Wolfram

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[1] As a non-jurisdictional utility, Big Rivers submitted its proposed Reactive Power Revenue Requirements in accordance with the FERC's directives in its orders accepting Schedule 2 of the MISO Tariff. The FERC has clarified that a non-public utility, such as Big Rivers, is not required to file a rate schedule in order to be compensated for providing reactive power.