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October 4, 2017

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OCT 4 2017
PUBLIC SERVICE
COMMISSION

Talina Mathews, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

Re: Case No. 2017-00287

Dear Ms. Mathews:

Please find enclosed the original and ten (10) copies of the DIRECT TESTIMONY AND EXHIBITS OF LANE KOLLEN on behalf of KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC's for filing in the above-referenced matter. I also enclose a diskette that contains Mr. Kollen's workpapers.

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

Very Truly Yours,

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.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served by electronic mail (when available) and by regular, U.S. mail, unless otherwise noted, this 4th day of October, 2017 to the following:

Michael L. Kurtz, Esq.
Kurt J. Boehm, Esq.
Jody Kyler Cohn, Esq.

Big Rivers Electric Corporation
201 Third Street
P. O. Box 24
Henderson, KY 42420

Honorable James M Miller
Honorable Tyson A Kamuf
Sullivan, Mountjoy, Stainback & Miller, PSC
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PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN EXAMINATION OF THE APPLICATION OF THE FUEL ADJUSTMENT CLAUSE OF BIG RIVERS ELECTRIC CORPORATION FROM NOVEMBER 1, 2016 THROUGH APRIL 30, 2017	)))))	**CASE NO. 2017-00287**

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF

THE KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

OCTOBER 2017

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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IN THE MATTER OF:

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

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

Q. **Please describe your education and professional experience.**

A. I earned a Bachelor of Business Administration ("BBA") degree in accounting and a Master of Business Administration ("MBA") degree from the University of Toledo. I also earned a Master of Arts ("MA") degree in theology from Luther Rice University. I am a Certified Public Accountant ("CPA"), with a practice license, Certified Management Accountant

("CMA"), and Chartered Global Management Accountant ("CGMA"). I am a member of numerous professional organizations.

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, accounting, finance, and tax issues in proceedings before regulatory commissions and courts at the federal and state levels on hundreds of occasions.

I have testified before the Kentucky Public Service Commission ("Commission") on dozens of occasions, including numerous Big Rivers Electric Corporation ("Big Rivers," BREC," or "Company") proceedings.[1]

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC"), a group of large customers taking electric service on the Big Rivers' system through Kenergy Corp. Domtar Paper Co., LLC and Kimberly Clark Corporation are the members of KIUC who participating in KIUC's intervention in this proceeding.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: 1) explain why Big Rivers' allocation of fuel expenses between native load customers and off-system sales was improper and unreasonable during the January 2017 through April 2017 portion of the six-month review period from November 2016 through April 2017, 2) recommend a reasonable allocation methodology for this proceeding and going forward to ensure that native load ratepayers receive the lowest fuel

[1] My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

costs and that off-system sales are allocated the highest (marginal) fuel costs, and 3) quantify the refund due to native load customers for the unreasonable amounts collected through the FAC during the review period.

Q. Please describe the allocation issue and why it is important.

A. The Company incurs fuel expense to meet its native load and to make off-system sales. The fuel expenses incurred to serve native load customers are recovered through the FAC. However, the fuel expenses incurred to make off-system sales are recovered through the terms of bilateral contracts and other sales at market clearing prices. The allocation of fuel expense between native load and off-system sales affects the fuel expense recovered from native load customers through the FAC on the one hand and the Company's margins from off-system sales on the other hand. This issue is particularly important to Big Rivers' native load customers because more than two thirds of the Company's generation does not serve native load customers and is sold off-system.

The fuel expense incurred to serve native load customers and is recovered through the FAC must be proper, fair, just, and reasonable. If the methodology allocates an unreasonably high fuel expense to native load customers, then the Company's FAC rates and recoveries are excessive and the margins from off-system sales are artificially inflated.

Q. Has Big River's method of allocating fuel costs between native load and off-system sales been reviewed by the Commission in prior FAC proceedings?

A. Yes. KIUC disputed the methodology used by the Company to allocate fuel expense between native load customers and off-system sales in two prior FAC cases, Case Nos. 2014-00230 and 2014-00455.[2] During those review periods, Big Rivers allocated its fuel

[2] The Commission consolidated Case Nos. 2014-00230 and 2014-00455.

expense between native load customers and off-system sales using the same system average fuel expense per kWh with only minor reductions in the FAC calculations for specific ratemaking adjustments required by the Commission. In the prior proceedings, KIUC asserted that native load customers should be allocated the system's lowest fuel expense in every hour and that off-system sales should be allocated the highest fuel expense in every hour. In those proceedings, Big Rivers, the Attorney General and KIUC entered into a Stipulation and Recommendation ("Stipulation"), in which Big Rivers agreed to provide a monthly credit of $311,111 through the FAC to all customers (residential, commercial and industrial), or a total of $4.67 million, over 15 months. These 15 payments were credited to customers from October 2015 through December 2016 (expense months).[3] The credit compensated customers for the monthly difference between the two allocation methods and ensured that Big Rivers' native load customers received the benefit of the lowest fuel expense on the system, not the higher average fuel expense. This result was consistent with the allocation methodology used by other Kentucky electric utilities. In addition, Big Rivers agreed to propose a permanent change in its FAC allocation methodology in its next base rate case, which it expected to file in the first quarter of 2016.[4]

Q. Please summarize your conclusions and recommendations.

A. The Company's fuel expense included in the FAC during the January 2017 through April 2017 (expense months) portion of the review period is unjust and unreasonable because it is based on an incorrect allocation methodology. The Company properly credited customers $311,111 monthly during the November 2016 and December 2016 portion of the review period to compensate them for the erroneous allocation method resolved by the Stipulation

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[3] Stipulation and Recommendation at paragraph 1, attached to Order approving Stipulation in Case Nos. 2014-00230 and 2014-00455 (July 27, 2015). I have attached a copy of the Stipulation and Recommendation as my Exhibit___(LK-2).
[4] *Id.*, Paragraph 2.

in the prior proceedings. However, during the January 2017 through April 2017 portion of the review period, Big Rivers continued its practice of allocating system average fuel expense per kWh to native load and off-system sales, but without an offsetting credit in the FAC to mitigate the harm to native load customers from this method.

I recommend that the Commission correct the Big Rivers allocation methodology for the January 2017 through April 2017 portion of the review period and going forward in future FAC filings and proceedings so that the lowest fuel expense is first allocated to native load customers. The Commission should recalculate the fuel expense included in the FAC using a methodology similar to that used by East Kentucky Power Cooperative ("EKPC")/Duke Energy Kentucky ("Duke"). The EKPC/Duke methodology correctly assigns the lowest fuel expense each hour to native load customers and the remaining and higher fuel expense to off-system sales.

I recommend that the Commission disallow $770,174 ($0.00125 per kWh) improperly included in the FAC during the January 2017 through April 2017 portion of the review period and that it direct Big Rivers to refund this amount over a six-month amortization period. I also recommend that the Commission add interest to the refund at the Company's weighted cost of debt. The Commission should include interest to ensure that customers are compensated for the lost carrying charges on the amounts that were improperly collected through the FAC.

II. BIG RIVERS' METHOD OF ALLOCATING SYSTEM AVERAGE FUEL EXPENSE TO NATIVE LOAD AND OFF-SYSTEM SALES IS IMPROPER

Q. Please describe the Big Rivers' methodology used to allocate fuel expense between native load and off-system sales.

A. Big Rivers follows a multi-step process to calculate the allocation to native load customers recovered through the FAC. First, Big Rivers calculates a system average fuel expense per kWh. The system average fuel expense per kWh is the sum of the fuel expense for all units divided by the sum of the generation produced by all units, less line losses. Second, the system average fuel expense per kWh is multiplied times the off-system sales to determine the fuel expense to exclude from the total fuel expense incurred. The residual is the preliminary allocation to native load customers. Third, Big Rivers makes relatively minor adjustments to the preliminary fuel expense allocated to native load customers to reflect adjustments required by the FAC regulation and prior Commission orders.[5]

Q. Is the Company's allocation methodology proper, fair, just and reasonable?

A. No. The Company's allocation methodology fails to allocate the lowest fuel expense to native load or allocate the highest fuel expense to off-system sales. Instead, it allocates all fuel expenses between native load and off-system sales in the same proportion as the mWh sales are allocated to native load and off-system sales. This is improper and unreasonable because the Company is required to first serve native load customers who are entitled to the lowest fuel expense. Off-system sales are supplied only after the native load customers are served and should be served only if the revenues from the sales exceed the incremental cost. Native load customers are entitled to the lowest fuel expense because they paid all allowed non-fuel costs of owning and operating the generating units, except for some environmental

---

[5] Company's response to KIUC 1-1. I have attached a copy of this response as my Exhibit___(LK-3).

costs allocated to off-system sales through the environmental surcharge. These non-fuel costs include non-fuel operation and maintenance expense, depreciation expense, interest expense, and a times interest earned ("TIER") margin in addition to the interest expense.[6]

Q. What is the standard set forth in the FAC Regulation for recovery of fuel and purchase power expenses in the 6-month review proceedings?

A. I have been informed by counsel for KIUC that the relevant Regulation is 807 KAR 5:056 *Fuel Adjustment Clause.* The Regulation requires that rates be "fair, just, and reasonable" and directs the Commission to "review and evaluate past operations of the clause, disallow improper expenses and to the extent appropriate reestablish the fuel clause charge in accordance with subsection (2) of this section." Excerpts from the Regulation are as follows:

> *NECESSITY, FUNCTION, AND CONFORMITY: KRS 278.030(1) provides that all rates received by an electric utility subject to the jurisdiction of the Public Service Commission shall be fair, just and reasonable. This administrative regulation prescribes the requirements with respect to the implementation of automatic fuel adjustment clauses by which electric utilities may immediately recover increases in fuel costs subject to later scrutiny by the Public Service Commission.*
>
> ***
>
> *(11) At six (6) month intervals, the commission will conduct public hearings on a utility's past fuel adjustments. The commission will order a utility to charge off and amortize, by means of a temporary decrease of rates, any adjustments it finds unjustified due to improper calculation or application of the charge or improper fuel procurement practices.*

Q. Is Big Rivers' allocation method consistent with FERC guidance addressing the allocation of fuel expense between native load and off-system sales?

---

[6] The Company presently defers the depreciation expense on the Coleman and Wilson plants.

A. No. Kentucky's FAC regulation, 807 K.A.R. 5:056, is modeled upon the FERC's fuel regulation, 18 C.F.R. §35.14.[7] 807 K.A.R. 5:056(3), provides that fuel costs recovered through the Kentucky fuel adjustment clause include a number of costs "*less...the cost of fossil fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.*" FERC's fuel regulation, 18 C.F.R. §35.14(a)(2), provides that fuel costs recovered through the FERC fuel adjustment clause include a number of costs "*less the cost of fossil and nuclear fuel recovered through all inter-system sales.*" It therefore makes sense to examine how FERC interprets its fuel regulation and use that as guidance in interpreting Kentucky's fuel regulation.

In a 2006 FERC Opinion (Opinion No. 501), the FERC rejected a fuel cost allocation approach that is substantively identical to Big Rivers' allocation methodology. In that case, Southwestern Public Service Company had assigned system average fuel costs to both native load and off-system sales. The FERC concluded that this practice forced native load customers to subsidize off-system sales by paying higher incremental fuel costs associated with those sales.[8] This case is directly on point. According to the FERC, an approach that allocates fuel costs *equally* to native load and off-system sales customers is not proper.

In another case involving Appalachian Power Company ("APCO"), the FERC stated that it "*believe[d] that it is both appropriate, and a common industry practice to assign the highest fuel cost to off-system sales, while lower fuel cost resources are reserved for the benefit of the APCO native load customers who, through their rates, provide for the*

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[7] Order, Case No. 96-524 (February 9, 1999) at 7; Order, Case Nos. 94-461-A (July 15, 1999) at 11 ("*Reviewing the purpose of Order 517 – the Order which established FERC's FAC Regulation and upon which Administrative Regulation 807 KAR 5:056 is modeled.*").

[8] Initial Decision, *Golden Spread Electric Cooperative, Inc. et al v. Southwestern Public Service Company*, 115 FERC ¶63,043 (May 24, 2006) at ¶132 ("Initial Decision"); Opinion No. 501, 123 FERC ¶61,047 (April 21, 2008) at ¶42-47.

construction and operation of the generating facilities."[9] The FERC interpreted its FAC regulation to mean that it would be appropriate if costs from the highest fuel cost units formed the basis for pricing of off-system sales and the lowest cost units were dedicated to native load.[10]

Q. Do any other utilities in the Commonwealth use the Company's methodology to allocate fuel expense between native load customers and off-system sales?

A. No. Big Rivers is the only Kentucky electric utility that relies on system average fuel expense per kWh to allocate fuel expense native load and off-system sales. The other electric utilities regulated by this Commission use some form of an after the fact economic dispatch so that the highest cost resources are allocated to off-system sales customers for this purpose.

For example, under East Kentucky Power Cooperative's ("EKPC") fuel cost allocation approach, *"[f]uel is allocated between native-load sales and off-system sales on a stacked cost basis. EKPC considers each hour of operation, determines if a sale was made from its system during that hour and then allocates the highest cost resource(s) to that sale for FAC purposes."*[11]

As another example, under Duke Energy Kentucky, Inc.'s ("Duke") fuel cost allocation approach, "*After the generating unit is dispatched, the actual energy costs consumed in a generating unit is allocated as either native or non-native based on a stacking process, allocating the lowest cost resources to native load first."*[12]

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[9] Order Accepting Rates for Filing, Granting Intervention and Terminating Docket, Docket No. ER83-63-000 (December 17, 1982) at 2.
[10] Order Accepting Rates for Filing, Granting Intervention and Terminating Docket, Docket No. ER83-63-000 (December 17, 1982) at 5.
[11] EKPC Response to Commission Staff's Information Request Dated 08/13/014, Case No. 2014-00226, Request 29.
[12] Duke Kentucky Response to Staff First Set of Data Requests, Case No. 2014-00229, Staff-DR-01-029.

Similarly, both Kentucky Utilities Company ("KU") and Louisville Gas & Electric Company ("LG&E") *"use the After-the-Fact Billing ('AFB') model to determine the joint dispatch savings between LG&E and KU and to allocate the highest cost energy to off-system sales."*[13]

Q. Does Big Rivers have significant excess generating capacity?

A. Yes. Big Rivers has significantly more generating capacity than it needs to serve its native load customers due to the loss of approximately 850 MW of Smelter loads in 2013 and 2014. The Company shut down all three units at the Coleman plant (421 MW) in May 2014, but continues to operate the Wilson plant. The Big Rivers reserve margin increased to 89% after the loss of the Smelter load and the shutdown of the Coleman plant.

Q. Does the Company sell most of its generation to native load customers?

A. No. The Company sells most of its generation off-system. Since the Company lost the Smelter load, it has become predominantly a merchant generator. The Company sold nearly two thirds of its generation off-system during the six-month review period. To make these off-system sales, the Company operated and dispatched its less efficient and more expensive generating units more frequently, which increased its system average fuel expense per kWh. In turn, this increased the fuel expense allocated to native load customers using the Company's allocation methodology.

Q. What is the relevance of the Company's reserve margin and its status as a merchant generator?

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[13] LG&E Response to Information Request in Appendix of Commission's Order Dated August 13, 2014, Case No. 2014-00228, Question No. 25; KU Response to Information Request in Appendix of Commission's Order Dated August 13, 2014, Case No. 2014-00227, Question No. 25.

A. This highlights the importance of the allocation issue. Under the Company's allocation methodology, the greater the off-system sales, the greater the increase in the fuel expense allocated to native load customers through the FAC and the greater the subsidization of the Company's off-system sales margins. Given Big Rivers' high level of off-system sales relative to its native load sales, native load customers are severely disadvantaged by Big Rivers' current fuel cost allocation methodology.

In contrast, the methodology used by EKPC and Duke treats native load customers fairly because the fuel expense allocated to native load customers through the FAC always reflects the lowest cost generation rather than the average cost incurred to serve native load and off-system sales. This is particularly crucial given Big Rivers' high level of off-system sales.

Q. What were the fuel expenses for each of the Company's generating units during the review period?

A. The following table provides the fuel expense for each of the Company's generating units by month and in total for the review period. The least cost units over the review period were Green Unit 1, Green Unit 2, and Wilson, respectively, although their relative cost varied each month. The most expensive units during the review period were Henderson Station Two Unit 1 and Unit 2.[14]

BIG RIVERS GENERATING UNITS
AVERAGE FUEL COST PER NET MWH OF GENERATION (AFTER LOSSES)($/MWH)

	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Total
Station Two - Unit 1	$ 26.797	$ 28.526	$ 28.871	$ 28.407	$ 29.782	$ 26.888	**$ 28.213**
Station Two - Unit 2	$ 28.075	$ 28.623	$ 28.775	$ 32.436	$ 28.272	$ 27.873	**$ 28.564**
Reid CT	N/A	$ 99.488	$ 268.225	$ 91.816	$ 379.038	N/A	**$ 132.928**
Wilson	$ 22.707	$ 23.538	$ 23.546	$ 26.025	$ 24.759	$ 24.907	**$ 24.040**
Green - Unit 1	$ 23.315	$ 24.332	$ 23.895	$ 27.244	$ 23.743	$ 22.606	**$ 23.808**
Green - Unit 2	$ 22.156	$ 24.175	$ 23.952	$ 25.040	$ 24.886	$ 25.043	**$ 23.955**
Average Fuel Cost	**$ 23.574**	**$ 24.824**	**$ 24.499**	**$ 26.635**	**$ 25.457**	**$ 24.672**	**$ 24.764**

[14] Company's response to KIUC 1-11. I have attached a copy of this response as my Exhibit __(LK-4).

Q. Using the preceding table, describe how the Company's allocation methodology improperly increased the fuel expense allocated to native load customers through the FAC during the review period.

A. The Company's allocation method includes the highest cost generation in the system average fuel expense per kWh, which increases the fuel expense allocated to the native load customers. For example, in November 2016, the least cost generation required to meet the native load requirements of 164,361 mWh was Green Unit 2 at $22.16 per mWh (133,834 mWh) and then Wilson at $22.71 per mWh (50,527 mWh). Instead, the Company calculated and used an average of $23.57 per mWh that included the Henderson Station Two Unit 1 at $26.80 per mWh and Unit 2 at $28.08 per mWh.[15]

Q. Why is Big River's fuel cost allocation methodology improper?

A. It is inherently unreasonable and illogical to charge native load customers and off-system sales the same fuel expense per kWh. Big Rivers native load customers are entitled to and should be allocated the lowest fuel costs and off-system sales should be allocated the highest fuel costs. This is true because the Company's native load customers are allocated 100% of the allowed fixed investment and non-fuel operating costs of all the Company's generating units, including the Coleman units that are shut down, except for certain amounts that are allocated to off-system sales in the environmental surcharge. The Company's methodology runs counter to cost causation principles and results in native load customers paying unreasonably high FAC charges in order to enhance the Company's off-system sales margins.

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[15] Company's response to KIUC 1-11. See Exhibit__(LK-4).

Q. Do the inflated margins that Big Rivers is making on off-system sales due to its system average fuel allocation method benefit native load customers?

A. No. If Big Rivers' margins from off-system sales were credited in their entirety to native load customers through the FAC or some other rider, then the allocation of average fuel costs to all sales would have no effect on native load customers. In that scenario, native load customers would pay inflated fuel costs in the FAC, but they would also receive the benefit of the higher off-system sales margins that result from allocating average, rather than incremental, fuel costs to off-system sales. In that manner, customers would be held harmless. However, that scenario does not exist and Big Rivers retains all off-system sales margins in excess of those reflected in its base revenue requirement.

III. THE COMMISSION SHOULD REQUIRE BIG RIVERS TO REFUND EXCESSIVE FUEL EXPENSE PLUS INTEREST

Q. What is your recommendation regarding the allocation of fuel expense?

A. I recommend that the Company's fuel expense be allocated between native load customers and off-system sales using a methodology similar to the EKPC/Duke methodology. Under the EKPC/Duke methodology all generation is economically stacked from the lowest to the highest in each hour. The lowest cost resources, and thus, the lowest fuel expenses first are allocated to native load customers and then the remaining and highest fuel expense then are allocated to off-system sales each hour. This methodology ensures that the highest cost resources and fuel expenses are allocated to off-system sales.

Q. Have you calculated the fuel expense that would have been allocated to native load customers and included in the Company's FAC for the months of January 2017 through April 2017 if the EKPC/Duke methodology had been used?

A. Yes. The fuel expense would have been $14,148,991, or $770,174 less than the fuel expense using the Company's methodology for those four months.[16] The fuel expense would have been $22,758,965, or $1,235,976 less than the fuel expense using the Company's methodology for the entire review period,[17] although this difference was addressed for the first two months of the review period through the monthly $311,111 credits pursuant to the Stipulation in the prior FAC proceedings.

I used the Company's fuel expense per kWh for each generating unit to recalculate the fuel expense allocated to native load customers using the available output from each generating unit starting with the lowest cost generating unit and then following with the next lowest cost generating until all native load requirements were supplied each month.

Q. How does your calculation compare to the Company's calculation provided in response to discovery?[18]

A. The results are significantly different. The Company's calculation increased the fuel expense allocated to native load customers by $299,564 for January 2017 through April 2017, whereas my calculation reduced the fuel expense allocated to native load customers by $770,174 for the four months.

Q. Why is that?

A. In short, Big Rivers apparently developed a new and incorrect allocation method to respond to the discovery request. Despite the specific request to calculate fuel expense for the FAC as "if Big Rivers had assigned its lowest fuel cost generation to native load customers each hour," the Company did not allocate the lowest cost resources to native load customers.

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[16] The calculations are reflected in my Exhibit__(LK-5) and in my electronic workpapers, which have been filed concurrently with my testimony.
[17] *Id.*
[18] Company's response to KIUC 1-11. See Exhibit___(LK-4).

Instead, the Company first allocated the most expensive generation from Station Two Unit 1 and Unit 2 to native load customers and only after all generation available from those two units was allocated to native load did it then allocate generation on an economic or least cost basis to meet the remaining native load requirements.

Q. Is the Company's calculation appropriate?

A. No. It was not responsive to the request and improperly allocated the highest cost generation first to native load customers. It also should be noted that the discovery request in this proceeding was nearly identical to discovery requests in the prior proceedings (Case Nos. 2014-00230 and 2014-00455).[19] In its responses in the prior proceedings, the Company performed an after-the-fact dispatch for each hour during the review period and correctly allocated the least cost generation to native load customers. That calculation formed the quantitative basis for the monthly credits adopted in the Stipulation in the prior proceedings. Despite its correct allocation in response to the same Data Request in the previous proceedings the Company incorrectly allocated the highest cost generation to native load customers in response to KIUC 1-11 in this proceeding.

The calculation that I performed in this proceeding is consistent with the methodology and calculation performed by the Company in the prior proceedings, although I used the monthly fuel expense per kWh for each generating unit instead of the hourly expense per kWh. The results of the monthly calculation in the prior proceedings would not have been materially different than the hourly calculation.

[19] Company's response to KIUC 1-1 in Case No. 2014-00455. I have attached the narrative response and an excerpt of the Excel file that includes a monthly summary for the two-year review period and the first page of the summary and hourly stacking used to calculate the redispatch and allocation of the lowest fuel expense by generating unit to native load customers for October 2014 as my Exhibit___(LK-6). See also Company's Response to Staff 3-1(c) in Case No. 2014-00230.

Q. What is your recommendation regarding a refund?

A. I recommend that the Company refund $770,174 in excessive fuel costs that were improperly allocated and collected through the FAC from January 1, 2017 through April 30, 2017, plus interest through the date the refunds are completed.

Q. Do you have another recommendation?

A. Yes. I recommend that the Commission order Big Rivers to adjust its fuel cost allocation methodology going forward so that the lowest cost resources and the related fuel expense are allocated to native load.

IV. BIG RIVERS HAS ALREADY COMMITTED TO CHANGE ITS FUEL COST ALLOCATION METHODOLOGY TO A LEAST COST HOURLY STACKING METHODOLOGY

Q. Has the Company already committed to changing its fuel cost allocation methodology?

A. Yes. In the Case Nos. 2014-00230 and 2014-00455 Stipulation, Big Rivers agreed to propose a permanent change to its FAC allocation method so that the least cost generation is first allocated to native load customers in its "next base rate case." The Stipulation reflects the Company's expectation that it would file this case in the first quarter of 2016. The Stipulation states:

> *2. In Big Rivers next base rate case, which it expects to file in the first quarter of 2016, Big Rivers shall propose, among other things, to change its FAC calculation methodology to "stack" its generating units for purposes of allocating fuel costs between native load and off-system sales, allocating the highest fuel costs to off-system sales.*[20]

---

[20] Commission's Order approving Stipulation in Case Nos. 2014-00230 and 2014-00455 (July 27, 2015), See attached Stipulation and Recommendation, Paragraph 2.

In its Order approving the Stipulation, the Commission supported Big Rivers' commitment to credit customers with the difference between the two methodologies in the short-term and to change to a "stacking methodology" in its next rate case to be filed in the first quarter of 2016. The Order states:

> *"The Commission appreciates the parties efforts in entering into the Stipulation and supports Big Rivers' commitment to credit customers $4.67 million through the FAC and to change its fuel-cost allocation methodology to a stacking methodology in its next general base rate proceeding."*[21]

Q. Why hasn't the Company yet made this change?

A. The Company has not yet filed a base rate case, some eighteen or more months after the first quarter 2016 date cited in the Stipulation. In the absence of a base rate case, the Company could have and should have made this change so that it was effective during the six-month review period. It could have proposed the change in a FAC proceeding so that it was effective in January 2017 after the expiration of the monthly credits pursuant to the Stipulation. It appears that it did not propose the change in a FAC proceeding because it would have reduced the recovery of fuel expense through the FAC and reduced the retained margins on its off-system sales. Consequently, after the expiration of the $311,111 monthly credit in December 2016, native load customers are once again in the same position that they were in prior to the Settlement Agreement, forcing KIUC to litigate this issue for the second time.

Q. Why shouldn't the Commission wait for Big Rivers' to file a base rate case to change its FAC allocation method?

---

[21] Commission's Order approving Stipulation in Case Nos. 2014-00230 and 2014-00455 (July 27, 2015), p. 5.

A. The Company's allocation method results in excess fuel expense recovery through the FAC. The FAC rates in January 2017 through April 2017 were not fair, just, and reasonable. The FAC rates since then have not been fair, just, and reasonable.

In the Stipulation, KIUC and the AG agreed to allow Big Rivers to wait until its next base rate case to change to a stacking methodology because 1) the Company represented that it expected to file a base rate case in early 2016 and 2) the monthly credit provided compensation for the incorrect methodology on an interim basis until base rates were reset. Now that Big Rivers' has not filed a base rate case and the monthly credits have expired, it is necessary that the Commission take action in this FAC review proceeding in order to avoid harm to Big Rivers' customers.

It is unreasonable for the native load customers of the other Kentucky electric utilities to enjoy the benefit of the lowest cost generation resources through the FAC rates, while Big Rivers' customers are forced to subsidize the fuel expense incurred to make off-system sales. As explained above, this inequity is magnified by the fact that Big Rivers also has by far the highest reserve margin in the Commonwealth and makes more off-system sales relative to native load than any other Kentucky electric utility. To the extent possible, the Commission should require a consistent methodology for the allocation of fuel expense to native load customers among all Kentucky electric utilities.

Q. Can the Commission change Big Rivers' fuel cost allocation methodology outside of a general rate case?

A. Yes. The Commission's FAC Regulation does not require the Commission to wait until there is a base rate case. Excessive fuel expense is subject to refund in the six-month review proceedings. The 807 KAR 5:056 states:

> *This administrative regulation prescribes the requirements with respect to the implementation of automatic fuel adjustment clauses by which electric utilities may immediately recover increases in fuel costs subject to later scrutiny by the Public Service Commission.*
>
> ***
>
> *At six (6) month intervals, the commission will conduct public hearings on a utility's past fuel adjustments. The commission will order a utility to charge off and amortize, by means of a temporary decrease of rates, any adjustments it finds unjustified due to improper calculation or application of the charge or improper fuel procurement practices.*

The Regulation requires the Commission to order refunds in proceedings such as this one if it finds that a utility has improperly calculated or applied its fuel adjustment charge. The better approach going forward is to correct the allocation methodology so that refunds for this purpose are not necessary.

In addition, the Supreme Court of Kentucky has held that rates may be changed outside of a rate case so long as the resulting rates are fair, just, and reasonable, stating:

> *We hold that so long as the rates established by the utility were fair, just and reasonable, the PSC has broad ratemaking power to allow recovery of such costs outside the parameters of a general rate case and even in the absence of a statute specifically authorizing recovery of such costs.*[22]

Q. Has the Commission previously disallowed improperly collected fuel costs outside the context of a general base rate proceeding?

A. Yes. I am aware that the Commission has disallowed improperly collected fuel expenses outside of a base rate case on at least three occasions: with respect to Big Rivers in the mid

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[22] *Kentucky Pub. Service Com'n v. Com. ex. rel. Conway*, 324 S.W. 3d 373, 374 (Ky. 2010).

1990s,[23] with respect to KU/LG&E in the late-1990s, [24] and most recently with respect to Kentucky Power's "no-load" fuel expenses in 2015.[25]

Q. Does this conclude your testimony?

A. Yes.

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[23] *An Examination by the Public Service Commission of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from November 1, 1991 to April 30, 1992*, Order (July 21, 1994).

[24] *An Examination by the Public Service Commission of the Application of the Fuel Adjustment Clause of Louisville Gas & Electric Company From November 1, 1998 to October 31, 1996*, Case No. 96-524, Order (February 9, 1999); *An Examination by the Public Service Commission of the Application of the Fuel Adjustment Clause of Kentucky Utilities Company From November 1, 1997 to April 30, 1998,* Case No. 96-523-C; Order (July 21, 1999);

[25] *The Application Of The Fuel Adjustment Clause Of Kentucky Power Company From November 1, 2013 Through April 30, 2014*, Case No. 2014-00225, Order (January 22, 2015)

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
4th day of October 2017.

Jessica K. I

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY PUBLIC
JULY 31, 2019
CHEROKEE COUNTY, GEORGIA

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN EXAMINATION OF THE APPLICATION OF THE FUEL ADJUSTMENT CLAUSE OF BIG RIVERS ELECTRIC CORPORATION FROM NOVEMBER 1, 2016 THROUGH APRIL 30, 2017	)	CASE NO. 2017-00287

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF

THE KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

OCTOBER 2017

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.

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
CF&I Steel, L.P.
Climax Molybdenum Company
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 September 2017

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.

Expert Testimony Appearances
of
Lane Kollen
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.
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.

**Expert Testimony Appearances
of
Lane Kollen
As of September 2017**

Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

Expert Testimony Appearances
of
Lane Kollen
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

**Expert Testimony Appearances
of
Lane Kollen
As of September 2017**

Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.
4/94	U-20647 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.

**Expert Testimony Appearances
of
Lane Kollen
As of September 2017**

Date	Case	Jurisdict.	Party	Utility	Subject
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 (Surrebuttal)	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.
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.

**Expert Testimony Appearances
of
Lane Kollen
As of September 2017**

Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

Expert Testimony Appearances
of
Lane Kollen
As of September 2017

Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.
3/98	U-22491 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.

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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.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.

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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.

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12/00	U-21453, U-20925, U-22092 (Subdocket C) Surrebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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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.
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.

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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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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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.
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.

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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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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, ELG v ASL depreciation procedures, 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.
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.

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Date	Case	Jurisdict.	Party	Utility	Subject
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 Answer	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.
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.

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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., Attorney General	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	2009-00548, 2009-00549	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.
08/10	31647 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Affiliate transaction and Customer First program issues.

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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.

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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	11AL-947E Answer	CO	Climax Molybdenum Company and CF&I Steel, L.P. d/b/a Evraz Rocky Mountain Steel	Public Service Company of Colorado	Revenue requirements, including historic test year, future test year, CACJA CWIP, contra-AFUDC.
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.

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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.
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., Office of the Ohio Consumers' Counsel	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.

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Date	Case	Jurisdict.	Party	Utility	Subject
07/13	2013-00221	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Hawesville Smelter market access.
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.
12/13	2013-00413	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Sebree Smelter market access.
01/14	ER10-1350	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 lease accounting and treatment in annual bandwidth filings.
02/14	U-32981	LA	Louisiana Public Service Commission	Entergy Louisiana, LLC	Montauk renewable energy PPA.
04/14	ER13-432 Direct	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	UP Settlement benefits and damages.
05/14	PUE-2013-00132	VA	HP Hood LLC	Shenandoah Valley Electric Cooperative	Market based rate; load control tariffs.
07/14	PUE-2014-00033	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting, change in FAC Definitional Framework.
08/14	ER13-432 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	UP Settlement benefits and damages.
08/14	2014-00134	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Requirements power sales agreements with Nebraska entities.
09/14	E-015/CN-12-1163 Direct	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class cost allocation.
10/14	2014-00225	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Allocation of fuel costs to off-system sales.
10/14	ER13-1508	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy service agreements and tariffs for affiliate power purchases and sales; return on equity.
10/14	14-0702-E-42T 14-0701-E-D	WV	West Virginia Energy Users Group	First Energy-Monongahela Power, Potomac Edison	Consolidated tax savings; payroll; pension, OPEB, amortization; depreciation; environmental surcharge.
11/14	E-015/CN-12-1163 Surrebuttal	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class allocation.
11/14	05-376-EL-UNC	OH	Ohio Energy Group	Ohio Power Company	Refund of IGCC CWIP financing cost recoveries.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/14	14AL-0660E	CO	Climax, CF&I Steel	Public Service Company of Colorado	Historic test year v. future test year; AFUDC v. current return; CACJA rider, transmission rider; equivalent availability rider; ADIT; depreciation; royalty income; amortization.
12/14	EL14-026	SD	Black Hills Industrial Intervenors	Black Hills Power Company	Revenue requirement issues, including depreciation expense and affiliate charges.
12/14	14-1152-E-42T	WV	West Virginia Energy Users Group	AEP-Appalachian Power Company	Income taxes, payroll, pension, OPEB, deferred costs and write offs, depreciation rates, environmental projects surcharge.
01/15	9400-YO-100 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Energy Corporation	WEC acquisition of Integrys Energy Group, Inc.
01/15	14F-0336EG 14F-0404EG	CO	Development Recovery Company LLC	Public Service Company of Colorado	Line extension policies and refunds.
02/15	9400-YO-100 Rebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Energy Corporation	WEC acquisition of Integrys Energy Group, Inc.
03/15	2014-00396	KY	Kentucky Industrial Utility Customers, Inc.	AEP-Kentucky Power Company	Base, Big Sandy 2 retirement rider, environmental surcharge, and Big Sandy 1 operation rider revenue requirements, depreciation rates, financing, deferrals.
03/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company and Louisville Gas and Electric Company	Revenue requirements, staffing and payroll, depreciation rates.
04/15	2014-00450	KY	Kentucky Industrial Utility Customers, Inc. and the Attorney General of the Commonwealth of Kentucky	AEP-Kentucky Power Company	Allocation of fuel costs between native load and off-system sales.
04/15	2014-00455	KY	Kentucky Industrial Utility Customers, Inc. and the Attorney General of the Commonwealth of Kentucky	Big Rivers Electric Corporation	Allocation of fuel costs between native load and off-system sales.
04/15	ER2014-0370	MO	Midwest Energy Consumers' Group	Kansas City Power & Light Company	Affiliate transactions, operation and maintenance expense, management audit.
05/15	PUE-2015-00022	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting; change in FAC Definitional Framework.
05/15 09/15	EL10-65 Direct, Rebuttal Complaint	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Accounting for AFUDC Debt, related ADIT.

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Date	Case	Jurisdict.	Party	Utility	Subject
07/15	EL10-65 Direct and Answering Consolidated Bandwidth Dockets	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback ADIT, Bandwidth Formula.
09/15	14-1693-EL-RDR	OH	Public Utilities Commission of Ohio	Ohio Energy Group	PPA rider for charges or credits for physical hedges against market.
12/15	45188	TX	Cities Served by Oncor Electric Delivery Company	Oncor Electric Delivery Company	Hunt family acquisition of Oncor; transaction structure; income tax savings from real estate investment trust (REIT) structure; conditions.
12/15 01/16	6680-CE-176 Direct, Surrebuttal, Supplemental Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Need for capacity and economics of proposed Riverside Energy Center Expansion project; ratemaking conditions.
03/16 0/16 04/16 05/16 06/16	EL01-88 Remand Direct Answering Cross-Answering Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Bandwidth Formula: Capital structure, fuel inventory, Waterford 3 sale/leaseback, Vidalia purchased power, ADIT, Blythesville, Spindletop, River Bend AFUDC, property insurance reserve, nuclear depreciation expense.
03/16	15-1673-E-T	WV	West Virginia Energy Users Group	Appalachian Power Company	Terms and conditions of utility service for commercial and industrial customers, including security deposits.
04/16	39971 Panel Direct	GA	Georgia Public Service Commission Staff	Southern Company, AGL Resources, Georgia Power Company, Atlanta Gas Light Company	Southern Company acquisition of AGL Resources, risks, opportunities, quantification of savings, ratemaking implications, conditions, settlement.
04/16	2015-00343	KY	Office of the Attorney General	Atmos Energy Corporation	Revenue requirements, including NOL ADIT, affiliate transactions.
04/16	2016-00070	KY	Office of the Attorney General	Atmos Energy Corporation	R & D Rider.
05/16	2016-00026 2016-00027	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Need for environmental projects, calculation of environmental surcharge rider.
05/16	16-G-0058 16-G-0059	NY	New York City	Keyspan Gas East Corp., Brooklyn Union Gas Company	Depreciation, including excess reserves, leak prone pipe.
06/16	160088-EI	FL	South Florida Hospital and Healthcare Association	Florida Power and Light Company	Fuel Adjustment Clause Incentive Mechanism re: economy sales and purchases, asset optimization.

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Date	Case	Jurisdict.	Party	Utility	Subject
07/16	160021-EI	FL	South Florida Hospital and Healthcare Association	Florida Power and Light Company	Revenue requirements, including capital recovery, depreciation, ADIT.
08/16	15-1022-EL-UNC 16-1105-EL-UNC	OH	Ohio Energy Group	AEP Ohio Power Company	SEET earnings, effects of other pending proceedings.
9/16	2016-00162	KY	Office of the Attorney General	Columbia Gas Kentucky	Revenue requirements, O&M expense, depreciation, affiliate transactions.
09/16	E-22 Sub 519, 532, 533	NC	Nucor Steel	Dominion North Carolina Power Company	Revenue requirements, deferrals and amortizations.
09/16	15-1256-G-390P (Reopened) 16-0922-G-390P	WV	West Virginia Energy Users Group	Mountaineer Gas Company	Infrastructure rider, including NOL ADIT and other income tax normalization and calculation issues.
10/16	10-2929-EL-UNC 11-346-EL-SSO 11-348-EL-SSO 11-349-EL-SSO 11-350-EL-SSO 14-1186-EL-RDR	OH	Ohio Energy Group	AEP Ohio Power Company	State compensation mechanism, capacity cost, Retail Stability Rider deferrals, refunds, SEET.
11/16	16-0395-EL-SSO Direct	OH	Ohio Energy Group	Dayton Power & Light Company	Credit support and other riders; financial stability of Utility, holding company.
12/16	Formal Case 1139	DC	Healthcare Council of the National Capital Area	Potomac Electric Power Company	Post test year adjust, merger costs, NOL ADIT, incentive compensation, rent.
01/17	46238	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Company	Acquisition of Oncor by Next Era Energy; goodwill, transaction costs, transition costs, cost deferrals, ratemaking issues.
02/17	16-0395-EL-SSO Direct (Stipulation)	OH	Ohio Energy Group	Dayton Power & Light Company	Non-unanimous stipulation re: credit support and other riders; financial stability of utility, holding company.
02/17	45414	TX	Cities of Midland, McAllen, and Colorado City	Sharyland Utilities, LP, Sharyland Distribution & Transmission Services, LLC	Income taxes, depreciation, deferred costs, affiliate expenses.
03/17	2016-00370 2016-00371	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	AMS, capital expenditures, maintenance expense, amortization expense, depreciation rates and expense.
06/17	29849 (Panel with Philip Hayet)	GA	Georgia Public Service Commission Staff	Georgia Power Company	Vogtle 3 and 4 economics.

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08/17	17-0296-E-PC	WV	Public Service Commission of West Virginia Charleston	Monongahela Power Company, The Potomac Edison Power Company	ADIT, OPEB.

EXHIBIT ____ (LK-2)

STIPULATION AND RECOMMENDATION

This Stipulation and Recommendation ("*Stipulation*") is entered into this 26th day of May, 2015, by and between Big Rivers Electric Corporation ("*Big Rivers*"), the Office of the Attorney General ("*AG*"), and Kentucky Industrial Utility Customers, Inc. ("*KIUC*")(collectively, the "*Signatory Parties*") in the proceedings involving Big Rivers that are the subject of this Stipulation, as set forth below:

WITNESSETH:

WHEREAS, pursuant to 807 KAR 5:056, the Kentucky Public Service Commission ("*Commission*") established Case No. 2014-00230 to review and evaluate the reasonableness of the application of Big Rivers' fuel adjustment clause ("*FAC*") for the six-month period that ended on April 30, 2014, and the Commission established Case No. 2014-00455 to review and evaluate the reasonableness of the application of Big Rivers' FAC for the two-year period that ended on October 31, 2014, and consolidated it with Case No. 2014-00230;

WHEREAS, the Commission has granted the AG and KIUC full intervention in these proceedings;

WHEREAS, the AG and KIUC have raised issues relating to Big Rivers' FAC practices during the periods under review;

WHEREAS, the Signatory Parties have reviewed the issues raised in Case Nos. 2014-00230 and 2014-00455, and the Signatory Parties have reached a settlement of the case, including the issues raised therein, as embodied in this Stipulation;

WHEREAS, Big Rivers believes its current FAC methodology and practices are reasonable, but desires to allocate certain margins to its three distribution cooperative members (the "*Members*");

WHEREAS, Big Rivers expects to file an application for a general adjustment in rates during the first quarter of 2016 (the "*2016 Rate Case*"), in which Big Rivers will propose, among other things, to change its FAC calculation methodology to "stack" its generating units for purposes of allocating fuel costs between native load and off-system sales, allocating the highest fuel costs to off-system sales, with the rates proposed in that proceeding to become effective on or about November 1, 2016;

WHEREAS, the Signatory Parties desire to settle issues pending before the Commission in the above-referenced proceedings;

WHEREAS, the adoption of this Stipulation will reduce the resources required of the Commission to finalize these proceedings and eliminate the need for the Signatory Parties potentially to expend significant resources litigating these proceedings;

WHEREAS, the Signatory Parties agree that this Stipulation, viewed in its entirety, is a fair, just, and reasonable resolution of all of the issues in the above-referenced proceedings; and

WHEREAS, it is the position of the Signatory Parties that this Stipulation is supported by sufficient and adequate data and information and should be approved by the Commission.

WHEREAS, this Stipulation shall not be deemed to constitute an admission by any Signatory Party to this Stipulation that any computation, formula, allegation, assertion or contention made by any other Signatory Party in these proceedings is true or valid. Nothing in this Stipulation shall be used or construed for any purpose to imply, suggest, or otherwise indicate that the results produced through the compromise reflected herein represent fully the objectives of the Stipulation.

NOW, THEREFORE, for and in consideration of the premises and terms and conditions set forth herein, the Signatory Parties stipulate and recommend as follows:

1. Big Rivers will credit $311,111.11 (the "FAC Credit") each month through its FAC to its Members beginning on the wholesale invoices issued for August 2015 consumption. The FAC Credits shall cease upon the first to occur of the following:

    (a) The date of the fifteenth FAC Credit;

    (b) The effective date of new rates to be set in Big Rivers' next base rate case;

    (c) The date the methodology Big Rivers uses to allocate fuel costs to off-system sales for purposes of calculating FAC charges is changed from a system average cost methodology to a stacked-cost methodology; and

    (d) The date, if any, the Commission orders a refund of amounts collected through Big Rivers' FAC on the basis of the methodology Big Rivers uses to allocate fuel costs to off-system sales.

Any cessation of FAC Credits under (b), (c), and (d) shall take effect beginning with the month in which that change is effective.

2. In Big Rivers next base rate case, which it expects to file in the first quarter of 2016, Big Rivers shall propose, among other things, to change its FAC

calculation methodology to "stack" its generating units for purposes of allocating fuel costs between native load and off-system sales, allocating the highest fuel costs to off-system sales.

3. The AG and KIUC each agree not to contest, seek a change in, or oppose the manner in which Big Rivers allocates FAC costs between native load and off-system sales in any Commission proceeding initiated prior to November 1, 2016, or for any FAC review period prior to November 1, 2016, but shall not be prohibited in any respect from: (a) raising issues related to the manner in which Big Rivers allocates FAC costs between native load and off-system sales in FAC proceedings initiated by Commission order after November 1, 2016, for review periods after November 1, 2016, if Big Rivers has not changed its FAC calculation methodology to an hourly stacked-cost methodology; or (b) contesting the appropriateness of the changes proposed by Big Rivers to its FAC calculation methodology in the 2016 Rate Case or in any other proceeding initiated after November 1, 2016.

4. The Signatory Parties agree that the foregoing stipulations and agreements represent a fair, just, and reasonable resolution of the issues addressed herein, and request that the Commission approve the Stipulation.

5. The Signatory Parties agree that, following the execution of this Stipulation, they will cause the Stipulation to be filed with the Commission together with a request that the Commission consider and approve the Stipulation. The Signatory Parties agree that this Stipulation is subject to the acceptance of and approval by the Commission and the Rural Utilities Service ("*RUS*"), and they agree to act in good faith and to use their best efforts to seek the Commission's acceptance and approval of this

Stipulation. If the Commission approves this Stipulation without modification, the Signatory Parties each waive any right to appeal or to file an action seeking review of or to seek reconsideration of any order of the Commission issued in accordance with this Stipulation.

6. Upon execution of this Stipulation, Big Rivers will promptly seek all required RUS review and approvals.

7. The Signatory Parties agree that if the Commission or RUS does not accept and approve this Stipulation in its entirety and unchanged, or if the Commission or RUS imposes conditions on its acceptance and approval that are unacceptable to Big Rivers, then:

(a) This Stipulation shall be void and withdrawn by the Signatory Parties hereto from any further consideration by the Commission, and none of the Signatory Parties shall be bound by any of the provisions herein, provided that none of the Signatory Parties is precluded from advocating any position contained in this Stipulation; and

(b) Neither the terms of the Stipulation nor any matters raised during the negotiations of this Stipulation shall be binding on any of the Signatory Parties or be construed against any of the Signatory Parties.

8. Subsequent to obtaining all required Commission and RUS review and approvals, Big Rivers shall cause the tariff amendments attached hereto as Exhibit A to be filed with the Commission. The Signatory Parties recommend that the Commission allow the tariff amendments to become effective without suspension or change.

9. The Signatory Parties hereto agree that this Stipulation shall inure to the benefit of and be binding upon the Signatory Parties hereto, their successors, and assigns.

10. The Signatory Parties hereto agree that this Stipulation constitutes the complete agreement and understanding among the Signatory Parties hereto, and any and all oral statements, representations or agreements made prior hereto or contemporaneously herewith shall be null and void and shall be deemed to have been merged into this Stipulation.

11. The Signatory Parties hereto agree that, for purposes of this Stipulation only, the terms of this Stipulation are based upon the independent analyses of the Signatory Parties, reflect a fair, just, and reasonable resolution of the issues herein, and are the product of compromise and negotiation.

12. The Stipulation shall not have any precedential value in this or any other jurisdiction.

13. Counsel for KIUC hereto warrants that he or she has informed, advised, and consulted with the KIUC members participating in these proceedings in regard to the contents and the significance of this Stipulation, and based upon the foregoing, is authorized to execute this Stipulation on behalf of those clients. The other Signatory Parties hereto warrant that they have informed, advised, and consulted with their respective clients in regard to the contents and the significance of this Stipulation, and based upon the foregoing, are authorized to execute this Stipulation on behalf of those clients.

14. The Signatory Parties agree that this Stipulation being a product of negotiation among all Signatory Parties, no provision of this Stipulation shall be strictly construed in favor of or against any party.

15. The Signatory Parties hereto agree that this Stipulation may be executed in multiple counterparts.

The Attorney General of Kentucky, by and through
his Office of the Rate Intervention Division

By: Jennifer Black Hans

Kentucky Industrial Utility Customers, Inc.

By:______________________________

Big Rivers Electric Corporation

By:______________________________

14. The Signatory Parties agree that this Stipulation being a product of negotiation among all Signatory Parties, no provision of this Stipulation shall be strictly construed in favor of or against any party.

15. The Signatory Parties hereto agree that this Stipulation may be executed in multiple counterparts.

The Attorney General of Kentucky, by and through
his Office of the Rate Intervention Division

By: Mich C. Kurtz

Kentucky Industrial Utility Customers, Inc.

By:____________________________

Big Rivers Electric Corporation

By:____________________________

14. The Signatory Parties agree that this Stipulation being a product of negotiation among all Signatory Parties, no provision of this Stipulation shall be strictly construed in favor of or against any party.

15. The Signatory Parties hereto agree that this Stipulation may be executed in multiple counterparts.

The Attorney General of Kentucky, by and through
his Office of the Rate Intervention Division

By:________________________________

Kentucky Industrial Utility Customers, Inc.

By:________________________________

Big Rivers Electric Corporation

By: Robert W Berry

FAC - Fuel Adjustment Clause

Applicability:

To all Big Rivers' Members.

Availability:

The Fuel Adjustment Clause ("FAC") is a mandatory rider to all wholesale sales by Big Rivers to its Members, including Base Energy sales to the Smelters under the Smelter Agreements but excluding Supplemental and Back-Up Energy sales to the Smelters under those two Agreements.

Rate:

The FAC shall provide for periodic adjustment per kWh of sales when the unit cost of fuel [F(m)/S(m)] is above or below the base unit cost of $0.020932 per kWh [F(b)/S(b)]. The current monthly charges shall be increased or decreased by the product of the kWh furnished during the current month and the FAC factor for the preceding month where the FAC factor is defined below:

$$\text{FAC Factor} = \frac{F(m)}{S(m)} - \frac{F(b)}{S(b)}$$

Where "F" is the expense of fossil fuel in the base (b) and current (m) periods; and S is sales in the base (b) and current (m) periods as defined in 807 KAR 5:056, all defined below:

Definitions:

Please see Section 4 for definitions common to all tariffs.

(1) Fuel cost (F) shall be the most recent actual monthly cost of:

(a) Fossil fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants, plus the cost of fuel which would have been used in plants suffering forced generation or transmission outages, but less the cost of fuel related to substitute generation, *plus*

(b) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (c) below, but excluding the cost of fuel related to purchases to substitute the forced outages, *plus*

(c) The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis and exclusive of energy purchases directly related to Supplemental and Back-Up Energy sales to the Smelters. Included therein may be such costs as the charges for economy energy purchased and the charges as a result of scheduled outages, also such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; ~~and~~ *less*

(d) The cost of fossil fuel, as denoted in (1)(a) above, recovered through inter-system sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis~~.~~; and *less*

(e) A monthly credit of $311,111.11 for each month from the August 2015 service month, through the October 2016 service month, except that if Big Rivers' FAC methodology is changed to a stacking methodology prior to November 1, 2016, or if Big Rivers is ordered to refund amounts collected through its FAC based on its allocation methodology prior to November 1, 2016, the monthly credit shall be zero. In all other months, the monthly credit shall be zero.

All fuel costs shall be based on weighted average inventory costing.

(2) Forced outages are all non-scheduled losses of generation or transmission which require substitute power for a continuous period in excess of six (6) hours. Where forced outages are not a result of faulty equipment, faulty manufacture, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection or acts of public enemy, the utility may, upon proper showing, with the approval of the Commission, include the fuel cost of substitute energy in the adjustment.

(3) Sales (S) shall be kWh sold, excluding inter-system sales and Supplemental and Back-Up Energy sales to the Smelters. Where for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of:

(i) generation, *plus*
(ii) purchases, *plus*
(iii) interchange in, *less*
(iv) energy associated with pumped storage operations, *less*
(v) inter-system sales referred to in subsection (1)(d) above, *less*
(vi) total system losses.

Utility-used energy shall not be excluded in the determination of sales (S).

(4) The cost of fossil fuel shall include no items other than the invoice price of fuel less any cash or other discounts. The invoice price of fuel includes the cost of the fuel itself and necessary charges for transportation of the fuel from the point of acquisition to the unloading point, as listed in Account 151 of the FERC Uniform System of Accounts for Public Utilities and Licenses.

(5) Current (m) period shall be the second month preceding the month in which the FAC factor is billed.

EXHIBIT ____ (LK-3)

BIG RIVERS ELECTRIC CORPORATION

AN EXAMINATION OF THE APPLICATION OF THE FUEL ADJUSTMENT CLAUSE OF BIG RIVERS ELECTRIC CORPORATION FROM NOVEMBER 1, 2016 THROUGH APRIL 30, 2017
CASE NO. 2017-00287

Responses to the Kentucky Industrial Utility Customers, Inc.'s Request for Information Dated September 18, 2017

September 29, 2017

Item 1) ***Please generally describe the process by which Big Rivers allocates fuel costs between native load and off-system sales for Fuel Adjustment Charge (FAC) purposes.***

Response) Big Rivers accounts for its fuel inventory using weighted average inventory costing. The total cost of coal, pet coke, oil, gas, and propane burned for generation by each of Big Rivers' units during the month is calculated by multiplying the volumes (*i.e.*, tons, gallons, or MCF) used for generation by the weighted average cost per unit for the respective fuel.

The total costs of coal, pet coke, oil, gas, and propane burned for generation by all of Big Rivers' units during the expense month are included in the Fuel Cost Schedule (Page 2 of Big Rivers' monthly Form A filing), under Company Generation, for purposes of calculating the total fuel cost to be recovered from Big Rivers' Members through the Fuel Adjustment Clause (FAC).

An overall system weighted average generation fuel cost per net MWh is calculated each month by dividing the total cost of fuel used for generation by the net MWh generated (after accounting for line losses). Fuel costs are then allocated to off-system sales by multiplying the system weighted average system generation fuel cost per net MWh (after accounting for line losses) by the total off-system sales volume (MWh) during the month.

The total fuel cost allocated to off-system sales each month is included in the Inter-System Sales Including Interchange-Out line on Big Rivers'

Fuel Cost Schedule, and subtracted from the total fuel expense to be recovered from Big Rivers' Members for purposes of calculating the monthly FAC factor.

Witness) Nicholas R. Castlen

EXHIBIT ____ (LK-4)

BIG RIVERS ELECTRIC CORPORATION

AN EXAMINATION OF THE APPLICATION OF THE FUEL ADJUSTMENT CLAUSE OF BIG RIVERS ELECTRIC CORPORATION FROM NOVEMBER 1, 2016 THROUGH APRIL 30, 2017
CASE NO. 2017-00287

Responses to the Kentucky Industrial Utility Customers, Inc.'s Request for Information Dated September 18, 2017

September 29, 2017

Item 11) ***For each month during the period under review in this proceeding, please provide the dollar amount of fuel costs that would have been included in the calculation of the fuel adjustment clause if Big Rivers had assigned its lowest fuel cost generation to native load customers each hour and compare that amount to the dollar amount that was included in the calculation. Please provide the information in the same format as the Attachment to Big Rivers' Response to Commission Staff's Third Request for Information, Item No. 1.c. in Case No. 2014-00230. Please provide all workpapers electronically in spreadsheet format, with all formulas intact. In responding to this Request please ignore any dollar impacts associated with the $311,111.11 monthly "FAC Credit" paid by Big Rivers pursuant to the Stipulation and Recommendation in Case No. 2014-00455.***

Response) Big Rivers objects to this request on the grounds that it is overly broad and unduly burdensome. Big Rivers further objects to this request on the grounds that it is irrelevant and unreasonable because Big Rivers' current methodology is reasonable and consistent with Commission precedent. Big Rivers' current fuel cost allocation is built into the determination of its base rates. Big Rivers' fuel cost allocation methodology was used in the test periods filed in Big Rivers' last three rate cases and to establish Big Rivers' current rates, which were approved by the Commission as fair, just, and reasonable. It would be unreasonable and a violation of the matching principle to change how Big Rivers allocates fuel costs between native load and off-system sales for purposes of calculating FAC charges outside of a general rate case where the reasonableness of alternate allocations can be considered in the context of Big Rivers' overall financial circumstances, including whether Big Rivers' rates are still fair, just and reasonable with such a change.

Notwithstanding that objection, Big Rivers has calculated an estimated impact of "stacking" Big Rivers' units in a method it believes to be similar to that requested by KIUC. Given the time and inherent complexity required to perform an hourly stacking calculation, Big Rivers has approximated the impact by "stacking" on a monthly basis. Please see the attachment to this response. An Excel file containing this attachment, including all workpapers in spreadsheet format with formulas intact, is provided on the CD accompanying these responses.

Witness) Lindsay N. Durbin

Big Rivers Electric Corporation
Case No. 2017-00287

	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Total
As Filed:							
Total Generation Fuel Cost	$ 12,194,218	$ 16,419,188	$ 14,677,605	$ 7,111,193	$ 10,042,142	$ 10,253,333	$ 70,697,679
Less: MISO Make Whole Payments	(2,110)	(15,222)	(6,508)	(582)	(7,468)	-	(31,890)
Less: Net Forced Outage Fuel Cost Adjustment[1]	(76,576)	(60,896)	(179,523)	(67,362)	(126,735)	(203,746)	(714,838)
Less: Fuel Cost Assigned to Off-System Sales from Generation	(8,319,336)	(11,063,491)	(9,846,618)	(3,756,644)	(5,769,064)	(7,200,859)	(45,956,011)
Total Generation Fuel Cost Assigned to Native Load	**$ 3,796,196**	**$ 5,279,579**	**$ 4,644,956**	**$ 3,286,605**	**$ 4,138,875**	**$ 2,848,728**	**$ 23,994,940**
Native Load Sales Volumes from Generation (MWh)	164,361.130	215,737.089	197,189.810	125,947.203	167,855.330	123,717.554	994,808.116
Average Generation Fuel Cost Assigned to Native Load ($/MWh)	**$ 23.10**	**$ 24.47**	**$ 23.56**	**$ 26.10**	**$ 24.66**	**$ 23.03**	**$ 24.12**
Proforma - Using Stacking Method							
Generation Fuel Cost Assigned to Native Load	$ 4,098,329	$ 5,617,823	$ 5,048,584	$ 3,343,598	$ 4,360,634	$ 3,043,279	$ 25,512,247
Less: MISO Make Whole Payments[2]	-	-	-	-	-	-	-
Less: Net Forced Outage Fuel Cost Adjustment	(76,576)	(60,896)	(179,523)	(67,362)	(126,735)	(203,746)	(714,838)
Total Generation Fuel Cost Assigned to Native Load	**$ 4,021,753**	**$ 5,556,927**	**$ 4,869,061**	**$ 3,276,236**	**$ 4,233,899**	**$ 2,839,533**	**$ 24,797,409**
Native Load Sales Volumes from Generation (MWh)	164,361.130	215,737.089	197,189.810	125,947.203	167,855.330	123,717.554	994,808.116
Average Generation Fuel Cost Assigned to Native Load ($/MWh)	**$ 24.47**	**$ 25.76**	**$ 24.69**	**$ 26.01**	**$ 25.22**	**$ 22.95**	**$ 24.93**
Difference:							
Difference in Total Fuel Cost Allocated to Native Load	**$ (225,557)**	**$ (277,348)**	**$ (224,105)**	**$ 10,370**	**$ (95,024)**	**$ 9,195**	**$ (802,469)**
Difference in Average Fuel Cost Allocated to Native Load ($/MWh)	**$ (1.37)**	**$ (1.29)**	**$ (1.13)**	**$ 0.09**	**$ (0.56)**	**$ 0.08**	**$ (0.81)**

(1) Net Forced Outage Fuel Cost Adjustment = Fuel (assigned cost during Forced Outage) - Fuel (substitute cost for Forced Outage) - Identifiable fuel cost (substitute for Forced Outage)

(2) During the review period, MISO Make Whole Payments received for start-up fuel costs related to the Reid CT (for Nov. 2016 through Apr. 2017) and Green Unit 2 (for Mar. 2017 only). Because none of the generation from these units were assigned to native load during those months under the stacking method, none of the corresponding MISO Make Whole Payments received were assigned to native load under the stacking method.

Big Rivers Electric Corporation
Case No. 2017-00287

	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Total
As Filed:							
Total Generation Fuel Cost	$ 12,194,218	$ 16,419,188	$ 14,677,605	$ 7,111,193	$ 10,042,142	$ 10,253,333	$ 70,697,679
Less: MISO Make Whole Payments	(2,110)	(15,222)	(6,508)	(582)	(7,468)	-	(31,890)
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Less: MISO Make Whole Payments[2]	-	-	-	-	-	-	-
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Difference in Average Fuel Cost Allocated to Native Load ($/MWh)	**$ (1.37)**	**$ (1.29)**	**$ (1.13)**	**$ 0.09**	**$ (0.56)**	**$ 0.08**	**$ (0.81)**

(1) Net Forced Outage Fuel Cost Adjustment = Fuel (assigned cost during Forced Outage) - Fuel (substitute cost for Forced Outage) - Identifiable fuel cost (substitute for Forced Outage)

(2) During the review period, MISO Make Whole Payments received for start-up fuel costs related to the Reid CT (for Nov. 2016 through Apr. 2017) and Green Unit 2 (for Mar. 2017 only). Because none of the generation from these units were assigned to native load during those months under the stacking method, none of the corresponding MISO Make Whole Payments received were assigned to native load under the stacking method.

KIUC 1-11 (Case No. 2017-00287)
Stacking Calculations for Assigning Fuel Cost to Native Load

	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Total
Total Generation Fuel Cost by Unit ($):							
Reid - Unit 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Coleman - Unit 1	-	-	-	-	-	-	-
Coleman - Unit 2	-	-	-	-	-	-	-
Coleman - Unit 3	-	-	-	-	-	-	-
Station Two - Unit 1	1,180,544.15	1,502,200.65	1,115,797.24	729,308.46	797,341.52	535,847.49	**5,861,039.51**
Station Two - Unit 2	1,196,643.71	1,559,949.69	1,099,210.03	362,312.96	1,210,518.29	852,968.52	**6,281,603.20**
Reid CT	3,080.00	55,407.86	12,670.40	7,673.80	6,159.37	-	**84,991.43**
Wilson	5,290,307.85	6,196,251.77	6,307,935.18	3,461,567.31	4,609,216.05	5,097,845.34	**30,963,123.50**
Green - Unit 1	2,001,571.19	3,618,682.28	3,100,054.00	848,535.60	1,874,060.39	2,801,446.25	**14,244,349.71**
Green - Unit 2	2,522,070.61	3,486,695.49	3,041,938.59	1,701,794.69	1,544,846.07	965,225.47	**13,262,570.92**
Total Generation Fuel Cost ($)	**$ 12,194,217.51**	**$ 16,419,187.74**	**$ 14,677,605.44**	**$ 7,111,192.82**	**$ 10,042,141.69**	**$ 10,253,333.07**	**$ 70,697,678.27**
Net Generation by Unit (Before Losses) (MWh):							
Reid - Unit 1	(1,394.000)	(1,589.000)	(1,625.000)	(1,488.000)	(1,548.000)	(1,431.000)	**(9,075.000)**
Coleman - Unit 1	(242.000)	(334.000)	(298.000)	(243.000)	(288.000)	(232.000)	**(1,637.000)**
Coleman - Unit 2	(242.000)	(334.000)	(297.000)	(244.000)	(288.000)	(232.000)	**(1,637.000)**
Coleman - Unit 3	(242.000)	(333.000)	(297.000)	(244.000)	(288.000)	(232.000)	**(1,636.000)**
Station Two - Unit 1	45,431.348	54,653.233	40,089.448	27,646.583	28,008.194	20,703.137	**216,531.943**
Station Two - Unit 2	43,955.652	56,561.767	39,625.552	12,028.417	44,792.806	31,790.863	**228,755.057**
Reid CT	(17.000)	578.000	49.000	90.000	17.000	(50.000)	**667.000**
Wilson	240,258.820	273,206.790	277,894.950	143,232.610	194,753.880	212,626.630	**1,341,973.680**
Green - Unit 1	88,531.425	154,347.274	134,573.239	33,539.595	82,573.028	128,736.934	**622,301.495**
Green - Unit 2	117,391.977	149,681.853	131,738.073	73,186.634	64,941.261	40,038.907	**576,978.705**
Total Net Generation (Before Losses) (MWh)	**533,432.222**	**686,438.917**	**621,453.262**	**287,504.839**	**412,674.169**	**431,719.471**	**2,973,222.880**
Total System Losses:	16,168.064	25,024.610	22,344.292	20,516.008	18,198.904	16,138.326	**118,390.204**
Allocation of System Losses to Generation Units							
Reid - Unit 1	(42.251)	(57.928)	(58.427)	(106.182)	(68.267)	(53.493)	**(386.548)**
Coleman - Unit 1	(7.335)	(12.176)	(10.715)	(17.340)	(12.701)	(8.673)	**(68.939)**
Coleman - Unit 2	(7.335)	(12.176)	(10.679)	(17.412)	(12.701)	(8.673)	**(68.975)**
Coleman - Unit 3	(7.335)	(12.140)	(10.679)	(17.412)	(12.701)	(8.673)	**(68.938)**
Station Two - Unit 1	1,377.001	1,992.422	1,441.412	1,972.828	1,235.160	773.915	**8,792.737**
Station Two - Unit 2	1,332.274	2,061.999	1,424.733	858.334	1,975.360	1,188.390	**8,841.089**
Reid CT	(0.515)	21.071	1.762	6.422	0.750	(1.869)	**27.621**
Wilson	7,282.125	9,959.944	9,991.686	10,220.911	8,588.633	7,948.305	**53,991.604**
Green - Unit 1	2,683.343	5,626.838	4,838.568	2,393.346	3,641.465	4,812.381	**23,995.941**
Green - Unit 2	3,558.092	5,456.756	4,736.630	5,222.512	2,863.905	1,496.715	**23,334.611**
Total System Losses (MWh)	**16,168.064**	**25,024.610**	**22,344.292**	**20,516.008**	**18,198.904**	**16,138.326**	**118,390.204**
	-	-	-	-	-	-	
Net Generation by Unit (After Allocated Losses):							
Reid - Unit 1	(1,351.749)	(1,531.072)	(1,566.573)	(1,381.818)	(1,479.733)	(1,377.507)	**(8,688.452)**
Coleman - Unit 1	(234.665)	(321.824)	(287.285)	(225.660)	(275.299)	(223.327)	**(1,568.060)**
Coleman - Unit 2	(234.665)	(321.824)	(286.321)	(226.588)	(275.299)	(223.327)	**(1,568.024)**
Coleman - Unit 3	(234.665)	(320.860)	(286.321)	(226.588)	(275.299)	(223.327)	**(1,567.060)**
Station Two - Unit 1	44,054.347	52,660.811	38,648.036	25,673.755	26,773.034	19,929.222	**207,739.205**
Station Two - Unit 2	42,623.378	54,499.768	38,200.819	11,170.083	42,817.446	30,602.473	**219,913.967**
Reid CT	(16.485)	556.929	47.238	83.578	16.250	(48.131)	**639.379**
Wilson	232,976.695	263,246.846	267,903.264	133,011.699	186,165.247	204,678.325	**1,287,982.076**
Green - Unit 1	85,848.082	148,720.436	129,734.671	31,146.249	78,931.563	123,924.553	**598,305.554**
Green - Unit 2	113,833.885	144,225.097	127,001.443	67,964.122	62,077.356	38,542.192	**553,644.095**
Total Net Generation (After Lossess) (MWh)	**517,264.158**	**661,414.307**	**599,108.971**	**266,988.832**	**394,475.266**	**415,581.146**	**2,854,832.680**

KIUC 1-11 (Case No. 2017-00287)
Stacking Calculations for Assigning Fuel Cost to Native Load

Average Fuel Cost per Net MWh of Generation (After Losses) ($/MWh):	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Total
Reid - Unit 1	N/A	N/A	N/A	N/A	N/A	N/A	$ -
Coleman - Unit 1	N/A	N/A	N/A	N/A	N/A	N/A	$ -
Coleman - Unit 2	N/A	N/A	N/A	N/A	N/A	N/A	$ -
Coleman - Unit 3	N/A	N/A	N/A	N/A	N/A	N/A	$ -
Station Two - Unit 1	$ 26.797	$ 28.526	$ 28.871	$ 28.407	$ 29.782	$ 26.888	**$ 28.213**
Station Two - Unit 2	$ 28.075	$ 28.623	$ 28.775	$ 32.436	$ 28.272	$ 27.873	**$ 28.564**
Reid CT	N/A	$ 99.488	$ 268.225	$ 91.816	$ 379.038	N/A	**$ 132.928**
Wilson	$ 22.707	$ 23.538	$ 23.546	$ 26.025	$ 24.759	$ 24.907	**$ 24.040**
Green - Unit 1	$ 23.315	$ 24.332	$ 23.895	$ 27.244	$ 23.743	$ 22.606	**$ 23.808**
Green - Unit 2	$ 22.156	$ 24.175	$ 23.952	$ 25.040	$ 24.886	$ 25.043	**$ 23.955**
Average Fuel Cost per Net MWh of Gen (After Losses) ($/MWh)	**$ 23.574**	**$ 24.824**	**$ 24.499**	**$ 26.635**	**$ 25.457**	**$ 24.672**	**$ 24.764**

Average Fuel Cost for Stacked Units:

	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17
1st	$ 26.797	$ 28.526	$ 28.775	$ 28.407	$ 28.272	$ 26.888
2nd	$ 28.075	$ 28.623	$ 28.871	$ 32.436	$ 29.782	$ 27.873
3rd	$ 22.156	$ 23.538	$ 23.546	$ 25.040	$ 23.743	$ 22.606
4th	$ 22.707	$ 24.175	$ 23.895	$ 26.025	$ 24.759	$ 24.907
5th	$ 23.315	$ 24.332	$ 23.952	$ 27.244	$ 24.886	$ 25.043

Unit Rank in Stack

	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17
1st	Station Two - Unit 1	Station Two - Unit 1	Station Two - Unit 2	Station Two - Unit 1	Station Two - Unit 2	Station Two - Unit 1
2nd	Station Two - Unit 2	Station Two - Unit 2	Station Two - Unit 1	Station Two - Unit 2	Station Two - Unit 1	Station Two - Unit 2
3rd	Green - Unit 2	Wilson	Wilson	Green - Unit 2	Green - Unit 1	Green - Unit 1
4th	Wilson	Green - Unit 2	Green - Unit 1	Wilson	Wilson	Wilson
5th	Green - Unit 1	Green - Unit 1	Green - Unit 2	Green - Unit 1	Green - Unit 2	Green - Unit 2

	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Total
Native Load Sales from Generation (MWh)	**164,361.130**	**215,737.089**	**197,189.810**	**125,947.203**	**167,855.330**	**123,717.554**	**994,808.116**

Volumes (MWh) Units by Stacking Position:

	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17
1st	44,054.347	52,660.811	38,200.819	25,673.755	42,817.446	19,929.222
2nd	42,623.378	54,499.768	38,648.036	11,170.083	26,773.034	30,602.473
3rd	77,683.405	108,576.510	120,340.955	67,964.122	78,931.563	73,185.859
4th				21,139.243	19,333.287	
5th						
Total	**164,361.130**	**215,737.089**	**197,189.810**	**125,947.203**	**167,855.330**	**123,717.554**
	-	-	-	-	-	-

Fuel Costs Allocated to Native Load by Unit:

	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Total
1st	$ 1,180,524.34	$ 1,502,202.29	$ 1,099,228.57	$ 729,314.36	$ 1,210,534.83	$ 535,856.92	$ 6,257,661.31
2nd	$ 1,196,651.34	$ 1,559,946.86	$ 1,115,807.45	$ 362,312.81	$ 797,354.50	$ 852,982.73	$ 5,885,055.68
3rd	$ 1,721,153.52	$ 2,555,673.89	$ 2,833,548.13	$ 1,701,821.61	$ 1,874,072.10	$ 1,654,439.53	$ 12,340,708.78
4th	$ -	$ -	$ -	$ 550,148.80	$ 478,672.85	$ -	$ 1,028,821.65
5th	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 4,098,329.20**	**$ 5,617,823.05**	**$ 5,048,584.14**	**$ 3,343,597.58**	**$ 4,360,634.29**	**$ 3,043,279.18**	**$ 25,512,247.43**

KIUC 1-6 and 1-7
DETAIL SUPPORT

FAC Review Case No. 2017-00287 (Detail Calcs for KIUC 1-6 & KIUC 1-7)

Fuel Cost ($/MWh) Assigned to NL & OSS and Purchased Power Cost Assigned to NL & OSS in FAC

Nov-16 through Apr-17

	SOURCE	pense Month:	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Six-Month Total
Inputs:									
+ Coal Burned	*Form A, p.2*		$ 10,545,722	$ 14,601,582	$ 12,602,110	$ 6,215,542	$ 8,453,818	$ 9,185,498	**$ 61,604,272**
+ Pet Coke Burned	*Form A, p.2*		$ 1,407,158	$ 1,460,090	$ 1,924,610	$ 674,208	$ 1,339,461	$ 810,929	**$ 7,616,456**
+ Oil Burned	*Form A, p.2*		$ 238,258	$ 302,108	$ 138,215	$ 213,769	$ 242,704	$ 256,906	**$ 1,391,960**
+ Gas Burned	*Form A, p.2*		$ 3,080	$ 55,408	$ 12,670	$ 7,674	$ 6,159	$ -	**$ 84,991**
+ Propane Burned	*Form A, p.2*		$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
- MISO Make Whole Payments (for start up costs)	*Form A, p.2*		$ 2,110	$ 15,222	$ 6,508	$ 582	$ 7,468	$ -	**$ 31,890**
+ Fuel (Assigned Cost During F.O.)	*Form A, p.2*		$ 347,768	$ 699,996	$ 696,328	$ 2,434,554	$ 338,644	$ 937,028	**$ 5,454,318**
- Fuel (Substitute Cost for FO)	*Form A, p.2*		$ 143,017	$ 323,077	$ 258,269	$ 1,586,220	$ 91,777	$ 200,388	**$ 2,602,748**
- Fuel (Supp. & Back-Up Energy to Smelters)	*Form A, p.2*		$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
- Fuel (Domtar Back-Up/ Imbalance Generation)	*Form A, p.2*		$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Sub-Total			**$ 12,396,859**	**$ 16,780,885**	**$ 15,109,156**	**$ 7,958,945**	**$ 10,281,541**	**$ 10,989,973**	$ 73,517,359
+ Net Energy Cost - Economy Purchases	*Form A, p.2*		$ 709,815	$ 1,076,649	$ 1,145,646	$ 819,446	$ 538,450	$ 509,007	**$ 4,799,013**
+ Identifiable Fuel Cost - Other Purchases	*Form A, p.2*		$ 4,613,123	$ 4,821,106	$ 9,383,094	$ 9,357,862	$ 3,297,704	$ 1,213,869	**$ 32,686,758**
+ Identifiable fuel cost - Forced Outage purchases	*Form A, p.2*		$ 281,327	$ 437,815	$ 617,582	$ 915,696	$ 373,602	$ 940,386	**$ 3,566,408**
- Identifiable fuel cost (substitute for Forced Outage)	*Form A, p.2*		$ 281,327	$ 437,815	$ 617,582	$ 915,696	$ 373,602	$ 940,386	**$ 3,566,408**
- Less Purchases for Supp. & Back-Up energy to Smelters	*Form A, p.2*		$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
- Less Purchases for Domtar back up	*Form A, p.2*		$ 115,628	$ 290,598	$ 161,505	$ 151,128	$ 134,181	$ 88,250	**$ 941,290**
- Less Purchases Above Highest Cost Units	*Form A, p.2*		$ 69,329	$ 81	$ -	$ 517	$ -	$ 6,291	**$ 76,218**
Sub-Total			**$ 5,137,981**	**$ 5,607,076**	**$ 10,367,235**	**$ 10,025,663**	**$ 3,701,973**	**$ 1,628,335**	**$ 36,468,263**
Total Energy Cost of Purchased Power	*"Form A Support & Calcs-YYYY.MM.xlsx", tab "PowerTransactionSummary"*		$ 6,511,037	$ 8,168,698	$ 13,657,476	$ 11,031,963	$ 4,910,299	$ 3,982,737	**$ 48,272,209**
Purchases for Off-System Sales (Total Energy $)	*"Form A Support & Calcs-YYYY.MM.xlsx", tab "PowerTransactionSummary"*		$ 5,093,514	$ 6,361,026	$ 11,629,883	$ 8,893,647	$ 3,459,402	$ 2,088,038	**$ 37,525,510**
Purchases for Off-System Sales (kWh)	*"Form A Support & Calcs-YYYY.MM.xlsx", tab "PowerTransactionSummary"*		177,600,000	182,400,000	371,800,000	336,200,000	108,373,300	31,151,240	**1,207,524,540**
Off-system Sales of Generation (Fuel $)	*"Form A Support & Calcs-YYYY.MM.xlsx", tab "PowerTransactionSummary"*		$ 8,319,336	$ 11,063,491	$ 9,846,618	$ 3,756,644	$ 5,769,064	$ 7,200,859	**$ 45,956,011**
Off-system Sales of Generation (kWh)	*"Form A Support & Calcs-YYYY.MM.xlsx", tab "PowerTransactionSummary"*		352,903,028	445,677,218	401,919,160	141,041,628	226,619,935	291,863,591	**1,860,024,560**
Net Generation (before losses) (kWh)	*Form A, p.3*		533,432,222	686,438,917	621,453,262	287,504,839	412,674,169	431,719,471	**2,973,222,880**
Back-Up & Supp. Sales to Smelters (from Gen) (kWh)	*"Form A Support & Calcs-YYYY.MM.xlsx", tab "SmelterFuelCost"*		-	-	-	-	-	-	-
Domtar Back-Up Power Sales (from Gen) (kWh)	*"Form A Support & Calcs-YYYY.MM.xlsx", tab "DomtarFuelCost"*		-	-	-	-	-	-	-
Total Purchased Power (kWh)	*"Form A Support & Calcs-YYYY.MM.xlsx", tab "PowerTransactionSummary"*		242,687,803	255,720,206	452,080,250	434,880,950	176,835,562	115,709,741	**1,677,914,512**
Net Interchange In/(Out) (kWh)	*Form A Filing (Inputs)*		11,809,724	22,872,000	20,980,000	17,448,023	16,660,000	13,265,584	**103,035,331**
Total Purchased Power Including Net Interchange (kWh)			254,497,527	278,592,206	473,060,250	452,328,973	193,495,562	128,975,325	**1,780,949,843**
Total Purchased Power assigned to Native Load (kWh)	*"Form A Support & Calcs-YYYY.MM.xlsx", tab "PowerTransactionSummary"*		60,428,723	65,151,232	74,813,015	92,732,776	64,227,323	81,335,450	**438,688,519**
Net Interchange In/(Out) (kWh)	*Form A Filing (Inputs)*		11,809,724	22,872,000	20,980,000	17,448,023	16,660,000	13,265,584	**103,035,331**
Total Purchased Power & Net Interchange Assigned to NL			**72,238,447**	**88,023,232**	**95,793,015**	**110,180,799**	**80,887,323**	**94,601,034**	**541,723,850**
System Losses (kWh)	*Form A, p.3*		16,168,064	25,024,610	22,344,292	20,516,008	18,198,904	16,138,326	**118,390,204**
Total Native Load (Member) Sales (kWh)	*Form A, p.3*		236,599,577	303,760,321	292,982,825	236,128,002	248,742,653	218,318,588	**1,536,531,966**

KIUC 1-6 and 1-7
DETAIL SUPPORT

FAC Review Case No. 2017-00287 (Detail Calcs for KIUC 1-6 & KIUC 1-7)

Fuel Cost ($/MWh) Assigned to NL & OSS and Purchased Power Cost Assigned to NL & OSS in FAC

Nov-16 through Apr-17

	SOURCE	:pense Month:	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Six-Month Total
KIUC 1-6 Calculations:									
Fuel for Generation - Native Load									
Coal Burned			$ 10,545,722	$ 14,601,582	$ 12,602,110	$ 6,215,542	$ 8,453,818	$ 9,185,498	$ 61,604,272
Pet Coke Burned			$ 1,407,158	$ 1,460,090	$ 1,924,610	$ 674,208	$ 1,339,461	$ 810,929	$ 7,616,456
Oil Burned			$ 238,258	$ 302,108	$ 138,215	$ 213,769	$ 242,704	$ 256,906	
Gas Burned			$ 3,080	$ 55,408	$ 12,670	$ 7,674	$ 6,159	$ -	$ 84,991
Propane Burned			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Less: MISO Make Whole Payments			$ 2,110	$ 15,222	$ 6,508	$ 582	$ 7,468	$ -	$ 31,890
Plus: Fuel (Assigned Cost During F.O.)			$ 347,768	$ 699,996	$ 696,328	$ 2,434,554	$ 338,644	$ 937,028	$ 5,454,318
Less: Fuel (Substitute Cost for F.O.)			$ 143,017	$ 323,077	$ 258,269	$ 1,586,220	$ 91,777	$ 200,388	$ 2,602,748
Less: Identifiable Fuel Cost (Substitute for F.O.)			$ 281,327	$ 437,815	$ 617,582	$ 915,696	$ 373,602	$ 940,386	$ 3,566,408
Less: Fuel (Supp. and Back-Up Energy to Smelters)			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Less: Domtar Back-Up/ Imbalance Generation			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Less: Fuel Cost of Generation for OSS			$ 8,319,336	$ 11,063,491	$ 9,846,618	$ 3,756,644	$ 5,769,064	$ 7,200,859	$ 45,956,011
Total Cost of Fuel for Generation Allocated to Native Load			$ 3,796,196	$ 5,279,579	$ 4,644,956	$ 3,286,605	$ 4,138,875	$ 2,848,728	$ 23,994,940
Native Load Sales Volumes from Generation (kWh)			164,361,130	215,737,089	197,189,810	125,947,203	167,855,330	123,717,554	994,808,116
Generation Fuel Cost for Native Load ($/MWH)			$ 23.10	$ 24.47	$ 23.56	$ 26.10	$ 24.66	$ 23.03	$ 24.12
Fuel for Generation - OSS									
Fuel Cost of Generation for OSS			$ 8,319,336	$ 11,063,491	$ 9,846,618	$ 3,756,644	$ 5,769,064	$ 7,200,859	$ 45,956,011
OSS Volumes from Generation			352,903,028	445,677,218	401,919,160	141,041,628	226,619,935	291,863,591	1,860,024,560
Generation Fuel Cost for OSS ($/MWH)			$ 23.57	$ 24.82	$ 24.50	$ 26.64	$ 25.46	$ 24.67	$ 24.71
KIUC 1-7 Calculations:									
Purchased Power - Native Load									
Total Energy Cost of Purchased Power			$ 6,511,037	$ 8,168,698	$ 13,667,476	$ 11,031,963	$ 4,910,299	$ 3,982,737	$ 48,272,209
Less: Total Energy Cost of Purchased Power for OSS			$ 5,093,514	$ 6,361,026	$ 11,629,883	$ 8,893,647	$ 3,459,402	$ 2,088,038	$ 37,525,510
Less: Purchases for Supp. & Back-Up Energy to Smelters			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Less: Purchases for Domtar Back-Up Power			$ 115,628	$ 290,598	$ 161,505	$ 151,128	$ 134,181	$ 88,250	$ 941,290
Less: Purchases Above Highest Cost Units			$ 69,329	$ 81	$ -	$ 517	$ -	$ 6,291	$ 76,218
Energy Cost of Purchased Power for Native Load Recovered through FAC			$ 1,232,566	$ 1,516,993	$ 1,876,088	$ 1,986,671	$ 1,316,716	$ 1,800,157	$ 9,729,191
Native Load Volumes from Purchased Power (kWh)			72,238,447	88,023,232	95,793,015	110,180,799	80,887,323	94,501,034	541,723,850
Total Energy Cost of Purchased Power for Native Load ($/MWH)			$ 17.06	$ 17.23	$ 19.58	$ 18.03	$ 16.28	$ 19.03	$ 17.96
Purchased Power - OSS									
Total Energy Cost of Purchased Power for OSS[1]			$ 5,093,514	$ 6,361,026	$ 11,629,883	$ 8,893,647	$ 3,459,402	$ 2,088,038	$ 37,525,510
OSS Volumes from Purchased Power			177,600,000	182,400,000	371,800,000	336,200,000	108,373,300	31,151,240	1,207,524,540
Total Energy Cost of Purchased Power for OSS ($/MWH)			$ 28.68	$ 34.87	$ 31.28	$ 26.45	$ 31.92	$ 67.03	$ 31.08
OSS - Total $/MWH in FAC			$ 25.28	$ 27.74	$ 27.76	$ 26.51	$ 27.55	$ 28.76	$ 27.21
NATIVE LOAD - Total $/MWH in FAC			$ 21.25	$ 22.37	$ 22.26	$ 22.33	$ 21.93	$ 21.29	$ 21.95
Difference (OSS vs. NL $/MWH)			$ 4.03	$ 5.37	$ 5.50	$ 4.17	$ 5.62	$ 7.46	$ 5.27
Reconciliation to Form A Filings:									
Total Member Fuel & Purchased Power Recoverable from Above:			$ 5,028,762	$ 6,796,572	$ 6,521,045	$ 5,273,276	$ 5,455,591	$ 4,648,886	$ 33,724,131
Less: Over/(Under) Recovery	*Form A Filing, p. 2, Over/(Under)*		$ 10,630	$ (69,713)	$ (6,984)	$ (76,697)	$ 21,760	$ (27,777)	$ (148,781)
Less: FAC Credits	*Form A Filing, p. 2, FAC Credits*		$ 311,111	$ 311,111	$ -	$ -	$ -	$ -	$ 622,222
Recalculated Total Fuel Recovery from Detail Above			$ 4,707,021	$ 6,555,174	$ 6,528,029	$ 5,349,973	$ 5,433,831	$ 4,676,663	$ 33,250,690
Form A Filing - Total Fuel Recovery	*Form A Filing, p. 1, Fuel "Fm"*		$ 4,707,021	$ 6,555,174	$ 6,528,029	$ 5,349,974	$ 5,433,831	$ 4,676,663	$ 33,250,692
Difference			$ (0)	$ (0)	$ (0)	$ (0)	$ 0	$ (0)	$ (2)
Total Member Sales (Used in NL Fuel & Purchased $/MWh Calcs Above)			236,599,577	303,760,321	292,982,825	236,128,002	248,742,653	218,318,588	1,536,531,966
Total Member Sales per Form A Filing	*Form A Filing, p. 1, Sales "Sm"*		236,599,577	303,760,321	292,982,825	236,128,002	248,742,653	218,318,588	1,536,531,966
Difference			-	-	-	-	-	-	-

Native Load Sales Volumes by Source
(MWh)

		Nov-16 (MWh)	Dec-16 (MWh)	Jan-17 (MWh)	Feb-17 (MWh)	Mar-17 (MWh)	Apr-17 (MWh)	6-Mo. Total (Nov-16 to Apr-17)
Native Load Sales From Generation:								
Net Generation (before losses)		533,432.222	686,438.917	621,453.262	287,504.839	412,674.169	431,719.471	2,973,222.880
Less: Back-Up & Supp. Sales to Smelters (from Gen)		-	-	-	-	-	-	-
Less: Domtar Back-Up Power Sales (from Gen)		-	-	-	-	-	-	-
Less: Inter-system Sales of Generation		(352,903.028)	(445,677.218)	(401,919.160)	(141,041.628)	(226,619.935)	(291,863.591)	(1,860,024.560)
Less: System Losses		(16,168.064)	(25,024.610)	(22,344.292)	(20,516.008)	(18,198.904)	(16,138.326)	(118,390.204)
NL Sales Volumes from Generation	**(A)**	**164,361.130**	**215,737.089**	**197,189.810**	**125,947.203**	**167,855.330**	**123,717.554**	**994,808.116**
Native Load Sales From Purchased Power & Net Interchange:								
Native Load Sales Volumes from Purchased Power (Excl. Net Interchange)	**(B)**	60,428.723	65,151.232	74,813.015	92,732.776	64,227.323	81,335.450	438,688.519
Native Load Sales Volumes from Net Interchange	**(C)**	11,809.724	22,872.000	20,980.000	17,448.023	16,660.000	13,265.584	103,035.331
NL Sales Volumes from Purch. Power (Incl. Net Interchange)	**(D) = [(B) + (C)]**	**72,238.447**	**88,023.232**	**95,793.015**	**110,180.799**	**80,887.323**	**94,601.034**	**541,723.850**
Total Native Load Sales Volumes	**(E) = [(A) + (D)]**	**236,599.577**	**303,760.321**	**292,982.825**	**236,128.002**	**248,742.653**	**218,318.588**	**1,536,531.966**
Total Native Load Sales Volume per FAC Filings		**236,599.577**	**303,760.321**	**292,982.825**	**236,128.002**	**248,742.653**	**218,318.588**	**1,536,531.966**

EXHIBIT ____ (LK-5)

Big Rivers Electric Corporation
Case No. 2017-00287

	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Total	Jan-Apr 2017 Total
As Filed:								
Total Generation Fuel Cost	$ 12,194,218	$ 16,419,188	$ 14,677,605	$ 7,111,193	$ 10,042,142	$ 10,253,333	$ 70,697,679	
Less: MISO Make Whole Payments	(2,110)	(15,222)	(6,508)	(582)	(7,468)	-	(31,890)	
Less: Net Forced Outage Fuel Cost Adjustment[1]	(76,576)	(60,896)	(179,523)	(67,362)	(126,735)	(203,746)	(714,838)	
Less: Fuel Cost Assigned to Off-System Sales from Generation	(8,319,336)	(11,063,491)	(9,846,618)	(3,756,644)	(5,769,064)	(7,200,859)	(45,956,011)	
Total Generation Fuel Cost Assigned to Native Load	**$ 3,796,196**	**$ 5,279,579**	**$ 4,644,956**	**$ 3,286,605**	**$ 4,138,875**	**$ 2,848,728**	**$ 23,994,940**	**$ 14,919,166**
Native Load Sales Volumes from Generation (MWh)	164,361.130	215,737.089	197,189.810	125,947.203	167,855.330	123,717.554	994,808.116	614,709.897
Average Generation Fuel Cost Assigned to Native Load ($/MWh)	**$ 23.10**	**$ 24.47**	**$ 23.56**	**$ 26.10**	**$ 24.66**	**$ 23.03**	**$ 24.12**	**$ 24.27**
Proforma - Using Stacking Method								
Generation Fuel Cost Assigned to Native Load	$ 3,669,426	$ 5,078,020	$ 4,643,031	$ 3,210,831	$ 4,075,736	$ 2,796,759	$ 23,473,803	
Less: MISO Make Whole Payments[2]	-	-	-	-	-	-	-	
Less: Net Forced Outage Fuel Cost Adjustment	(76,576)	(60,896)	(179,523)	(67,362)	(126,735)	(203,746)	(714,838)	
Total Generation Fuel Cost Assigned to Native Load	**$ 3,592,850**	**$ 5,017,124**	**$ 4,463,508**	**$ 3,143,469**	**$ 3,949,001**	**$ 2,593,013**	**$ 22,758,965**	**$ 14,148,991**
Native Load Sales Volumes from Generation (MWh)	164,361.130	215,737.089	197,189.810	125,947.203	167,855.330	123,717.554	994,808.116	614,709.897
Average Generation Fuel Cost Assigned to Native Load ($/MWh)	**$ 21.86**	**$ 23.26**	**$ 22.64**	**$ 24.96**	**$ 23.53**	**$ 20.96**	**$ 22.88**	**$ 23.02**
Difference:								
Difference in Total Fuel Cost Allocated to Native Load	**$ 203,346**	**$ 262,455**	**$ 181,448**	**$ 143,136**	**$ 189,875**	**$ 255,715**	**$ 1,235,976**	**$ 770,174**
Difference in Average Fuel Cost Allocated to Native Load ($/MWh)	**$ 1.24**	**$ 1.21**	**$ 0.92**	**$ 1.14**	**$ 1.13**	**$ 2.07**	**$ 1.24**	**$ 1.25**

[1] Net Forced Outage Fuel Cost Adjustment = Fuel (assigned cost during Forced Outage) - Fuel (substitute cost for Forced Outage) - Identifiable fuel cost (substitute for Forced Outage)

[2] During the review period, MISO Make Whole Payments received for start-up fuel costs related to the Reid CT (for Nov. 2016 through Apr. 2017) and Green Unit 2 (for Mar. 2017 only). Because none of the generation from these units were assigned to native load during those months under the stacking method, none of the corresponding MISO Make Whole Payments received were assigned to native load under the stacking method.

KIUC 1-11 (Case No. 2017-00287)
Stacking Calculations for Assigning Fuel Cost to Native Load

	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Total
Total Generation Fuel Cost by Unit ($):							
Reid - Unit 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Coleman - Unit 1	-	-	-	-	-	-	-
Coleman - Unit 2	-	-	-	-	-	-	-
Coleman - Unit 3	-	-	-	-	-	-	-
Station Two - Unit 1	1,180,544.15	1,502,200.65	1,115,797.24	729,308.46	797,341.52	535,847.49	5,861,039.51
Station Two - Unit 2	1,196,643.71	1,559,949.69	1,099,210.03	362,312.96	1,210,518.29	852,968.52	6,281,603.20
Reid CT	3,080.00	55,407.86	12,670.40	7,673.80	6,159.37	-	84,991.43
Wilson	5,290,307.85	6,196,251.77	6,307,935.18	3,461,567.31	4,609,216.05	5,097,845.34	30,963,123.50
Green - Unit 1	2,001,571.19	3,618,682.28	3,100,054.00	848,535.60	1,874,060.39	2,801,446.25	14,244,349.71
Green - Unit 2	2,522,070.61	3,486,695.49	3,041,938.59	1,701,794.69	1,544,846.07	965,225.47	13,262,570.92
Total Generation Fuel Cost ($)	$ 12,194,217.51	$ 16,419,187.74	$ 14,677,605.44	$ 7,111,192.82	$ 10,042,141.69	$ 10,253,333.07	$ 70,697,678.27

	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Total
Net Generation by Unit (Before Losses) (MWh):							
Reid - Unit 1	(1,394.000)	(1,589.000)	(1,625.000)	(1,488.000)	(1,548.000)	(1,431.000)	(9,075.000)
Coleman - Unit 1	(242.000)	(334.000)	(298.000)	(243.000)	(288.000)	(232.000)	(1,637.000)
Coleman - Unit 2	(242.000)	(334.000)	(297.000)	(244.000)	(288.000)	(232.000)	(1,637.000)
Coleman - Unit 3	(242.000)	(333.000)	(297.000)	(244.000)	(288.000)	(232.000)	(1,636.000)
Station Two - Unit 1	45,431.348	54,653.233	40,089.448	27,646.583	28,008.194	20,703.137	216,531.943
Station Two - Unit 2	43,955.652	56,561.767	39,625.552	12,028.417	44,792.806	31,790.863	228,755.057
Reid CT	(17.000)	578.000	49.000	90.000	17.000	(50.000)	667.000
Wilson	240,258.820	273,206.790	277,894.950	143,232.610	194,753.880	212,626.630	1,341,973.680
Green - Unit 1	88,531.425	154,347.274	134,573.239	33,539.595	82,573.028	128,736.934	622,301.495
Green - Unit 2	117,391.977	149,681.853	131,738.073	73,186.634	64,941.261	40,038.907	576,978.705
Total Net Generation (Before Losses) (MWh)	533,432.222	686,438.917	621,453.262	287,504.839	412,674.169	431,719.471	2,973,222.880

	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Total
Total System Losses:	16,168.064	25,024.610	22,344.292	20,516.008	18,198.904	16,138.326	118,390.204
Allocation of System Losses to Generation Units							
Reid - Unit 1	(42.251)	(57.928)	(58.427)	(106.182)	(68.267)	(53.493)	(386.548)
Coleman - Unit 1	(7.335)	(12.176)	(10.715)	(17.340)	(12.701)	(8.673)	(68.939)
Coleman - Unit 2	(7.335)	(12.176)	(10.679)	(17.412)	(12.701)	(8.673)	(68.975)
Coleman - Unit 3	(7.335)	(12.140)	(10.679)	(17.412)	(12.701)	(8.673)	(68.938)
Station Two - Unit 1	1,377.001	1,992.422	1,441.412	1,972.828	1,235.160	773.915	8,792.737
Station Two - Unit 2	1,332.274	2,061.999	1,424.733	858.334	1,975.360	1,188.390	8,841.089
Reid CT	(0.515)	21.071	1.762	6.422	0.750	(1.869)	27.621
Wilson	7,282.125	9,959.944	9,991.686	10,220.911	8,588.633	7,948.305	53,991.604
Green - Unit 1	2,683.343	5,626.838	4,838.568	2,393.346	3,641.465	4,812.381	23,995.941
Green - Unit 2	3,558.092	5,456.756	4,736.630	5,222.512	2,863.905	1,496.715	23,334.611
Total System Losses (MWh)	16,168.064	25,024.610	22,344.292	20,516.008	18,198.904	16,138.326	118,390.204
	-	-	-	-	-	-	

	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Total
Net Generation by Unit (After Allocated Losses):							
Reid - Unit 1	(1,351.749)	(1,531.072)	(1,566.573)	(1,381.818)	(1,479.733)	(1,377.507)	(8,688.452)
Coleman - Unit 1	(234.665)	(321.824)	(287.285)	(225.660)	(275.299)	(223.327)	(1,568.060)
Coleman - Unit 2	(234.665)	(321.824)	(286.321)	(226.588)	(275.299)	(223.327)	(1,568.024)
Coleman - Unit 3	(234.665)	(320.860)	(286.321)	(226.588)	(275.299)	(223.327)	(1,567.060)
Station Two - Unit 1	44,054.347	52,660.811	38,648.036	25,673.755	26,773.034	19,929.222	207,739.205
Station Two - Unit 2	42,623.378	54,499.768	38,200.819	11,170.083	42,817.446	30,602.473	219,913.967
Reid CT	(16.485)	556.929	47.238	83.578	16.250	(48.131)	639.379
Wilson	232,976.695	263,246.846	267,903.264	133,011.699	186,165.247	204,678.325	1,287,982.076
Green - Unit 1	85,848.082	148,720.436	129,734.671	31,146.249	78,931.563	123,924.553	598,305.554
Green - Unit 2	113,833.885	144,225.097	127,001.443	67,964.122	62,077.356	38,542.192	553,644.095
Total Net Generation (After Lossess) (MWh)	517,264.158	661,414.307	599,108.971	266,988.832	394,475.266	415,581.146	2,854,832.680

KIUC 1-11 (Case No. 2017-00287)
Stacking Calculations for Assigning Fuel Cost to Native Load

Average Fuel Cost per Net MWh of Generation (After Losses) ($/MWh):	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Total
Reid - Unit 1	N/A	N/A	N/A	N/A	N/A	N/A	$ -
Coleman - Unit 1	N/A	N/A	N/A	N/A	N/A	N/A	$ -
Coleman - Unit 2	N/A	N/A	N/A	N/A	N/A	N/A	$ -
Coleman - Unit 3	N/A	N/A	N/A	N/A	N/A	N/A	$ -
Station Two - Unit 1	$ 26.797	$ 28.526	$ 28.871	$ 28.407	$ 29.782	$ 26.888	$ 28.213
Station Two - Unit 2	$ 28.075	$ 28.623	$ 28.775	$ 32.436	$ 28.272	$ 27.873	$ 28.564
Reid CT	N/A	$ 99.488	$ 268.225	$ 91.816	$ 379.038	N/A	$ 132.928
Wilson	$ 22.707	$ 23.538	$ 23.546	$ 26.025	$ 24.759	$ 24.907	$ 24.040
Green - Unit 1	$ 23.315	$ 24.332	$ 23.895	$ 27.244	$ 23.743	$ 22.606	$ 23.808
Green - Unit 2	$ 22.156	$ 24.175	$ 23.952	$ 25.040	$ 24.886	$ 25.043	$ 23.955
Average Fuel Cost per Net MWh of Gen (After Losses) ($/MWh)	**$ 23.574**	**$ 24.824**	**$ 24.499**	**$ 26.635**	**$ 25.457**	**$ 24.672**	**$ 24.764**

Average Fuel Cost for Stacked Units:	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17
1st	$ 22.156	$ 23.538	$ 23.546	$ 25.040	$ 23.743	$ 22.606
2nd	$ 22.707	$ 24.175	$ 23.895	$ 26.025	$ 24.759	$ 24.907
3rd	$ 23.315	$ 24.332	$ 23.952	$ 27.244	$ 24.886	$ 25.043
4th	$ 26.797	$ 28.526	$ 28.775	$ 28.407	$ 28.272	$ 26.888
5th	$ 28.075	$ 28.623	$ 28.871	$ 32.436	$ 29.782	$ 27.873

Unit Rank in Stack	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17
1st	Green - Unit 2	Wilson	Wilson	Green - Unit 2	Green - Unit 1	Green - Unit 1
2nd	Wilson	Green - Unit 2	Green - Unit 1	Wilson	Wilson	Wilson
3rd	Green - Unit 1	Green - Unit 1	Green - Unit 2	Green - Unit 1	Green - Unit 2	Green - Unit 2
4th	Station Two - Unit 1	Station Two - Unit 1	Station Two - Unit 2	Station Two - Unit 1	Station Two - Unit 2	Station Two - Unit 1
5th	Station Two - Unit 2	Station Two - Unit 2	Station Two - Unit 1	Station Two - Unit 2	Station Two - Unit 1	Station Two - Unit 2

	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Total
Native Load Sales from Generation (MWh)	**164,361.130**	**215,737.089**	**197,189.810**	**125,947.203**	**167,855.330**	**123,717.554**	**994,808.116**

Volumes (MWh) Units by Stacking Position:	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17
1st	113,833.885	215,737.089	197,189.810	67,964.122	78,931.563	123,717.554
2nd	50,527.245			57,983.081	88,923.767	
3rd						
4th						
5th						
Total	**164,361.130**	**215,737.089**	**197,189.810**	**125,947.203**	**167,855.330**	**123,717.554**
	-	-	-	-	-	-

Fuel Costs Allocated to Native Load by Unit:	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Total
1st	$ 2,522,103.56	$ 5,078,019.60	$ 4,643,031.27	$ 1,701,821.61	$ 1,874,072.10	$ 2,796,759.03	$ 18,615,807.16
2nd	$ 1,147,322.15	$ -	$ -	$ 1,509,009.68	$ 2,201,663.55	$ -	$ 4,857,995.38
3rd	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4th	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5th	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 3,669,425.71**	**$ 5,078,019.60**	**$ 4,643,031.27**	**$ 3,210,831.30**	**$ 4,075,735.65**	**$ 2,796,759.03**	**$ 23,473,802.55**

KIUC 1-6 and 1-7
DETAIL SUPPORT

FAC Review Case No. 2017-00287 (Detail Calcs for KIUC 1-6 & KIUC 1-7)

Fuel Cost ($/MWh) Assigned to NL & OSS and Purchased Power Cost Assigned to NL & OSS in FAC

Nov-16 through Apr-17

	SOURCE	pense Month:	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Six-Month Total
Inputs:									
+ Coal Burned	*Form A, p.2*		$ 10,545,722	$ 14,601,582	$ 12,602,110	$ 6,215,542	$ 8,453,818	$ 9,185,498	**$ 61,604,272**
+ Pet Coke Burned	*Form A, p.2*		$ 1,407,158	$ 1,460,090	$ 1,924,610	$ 674,208	$ 1,339,461	$ 810,929	**$ 7,616,456**
+ Oil Burned	*Form A, p.2*		$ 238,258	$ 302,108	$ 138,215	$ 213,769	$ 242,704	$ 256,906	**$ 1,391,960**
+ Gas Burned	*Form A, p.2*		$ 3,080	$ 55,408	$ 12,670	$ 7,674	$ 6,159	$ -	**$ 84,991**
+ Propane Burned	*Form A, p.2*		$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
- MISO Make Whole Payments (for start up costs)	*Form A, p.2*		$ 2,110	$ 15,222	$ 6,508	$ 582	$ 7,468	$ -	**$ 31,890**
+ Fuel (Assigned Cost During F.O.)	*Form A, p.2*		$ 347,768	$ 699,996	$ 696,328	$ 2,434,554	$ 338,644	$ 937,026	**$ 5,454,318**
- Fuel (Substitute Cost for FO)	*Form A, p.2*		$ 143,017	$ 323,077	$ 258,269	$ 1,586,220	$ 91,777	$ 200,388	**$ 2,602,748**
- Fuel (Supp. & Back-Up Energy to Smelters)	*Form A, p.2*		$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
- Fuel (Domtar Back-Up/ Imbalance Generation)	*Form A, p.2*		$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Sub-Total			**$ 12,396,859**	**$ 16,780,885**	**$ 15,109,156**	**$ 7,958,945**	**$ 10,281,541**	**$ 10,989,973**	**$ 73,517,359**
+ Net Energy Cost - Economy Purchases	*Form A, p.2*		$ 709,815	$ 1,076,649	$ 1,145,646	$ 819,446	$ 538,450	$ 509,007	**$ 4,799,013**
+ Identifiable Fuel Cost - Other Purchases	*Form A, p.2*		$ 4,613,123	$ 4,821,106	$ 9,383,094	$ 9,357,862	$ 3,297,704	$ 1,213,869	**$ 32,686,758**
+ Identifiable fuel cost - Forced Outage purchases	*Form A, p.2*		$ 281,327	$ 437,815	$ 617,582	$ 915,696	$ 373,602	$ 940,386	**$ 3,566,408**
- Identifiable fuel cost (substitute for Forced Outage)	*Form A, p.2*		$ 281,327	$ 437,815	$ 617,582	$ 915,696	$ 373,602	$ 940,386	**$ 3,566,408**
- Less Purchases for Supp. & Back-Up energy to Smelters	*Form A, p.2*		$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
- Less Purchases for Domtar back up	*Form A, p.2*		$ 115,628	$ 290,598	$ 161,505	$ 151,128	$ 134,181	$ 88,250	**$ 941,290**
- Less Purchases Above Highest Cost Units	*Form A, p.2*		$ 69,329	$ 81	$ -	$ 517	$ -	$ 6,291	**$ 76,218**
Sub-Total			**$ 5,137,981**	**$ 5,607,076**	**$ 10,367,235**	**$ 10,025,663**	**$ 3,701,973**	**$ 1,628,335**	**$ 36,468,263**
Total Energy Cost of Purchased Power	*Form A Support & Calcs-YYYY.MM.xlsx , tab "PowerTransactionSummary"*		$ 6,511,037	$ 8,168,698	$ 13,657,476	$ 11,031,963	$ 4,910,299	$ 3,982,737	**$ 48,272,209**
Purchases for Off-System Sales (Total Energy $)	*Form A Support & Calcs-YYYY.MM.xlsx , tab "PowerTransactionSummary"*		$ 5,093,514	$ 6,361,026	$ 11,629,883	$ 8,893,647	$ 3,459,402	$ 2,088,038	**$ 37,525,510**
Purchases for Off-System Sales (kWh)	*Form A Support & Calcs-YYYY.MM.xlsx , tab "PowerTransactionSummary"*		177,600,000	182,400,000	371,800,000	336,200,000	108,373,300	31,151,240	**1,207,524,540**
Off-system Sales of Generation (Fuel $)	*Form A Support & Calcs-YYYY.MM.xlsx , tab "PowerTransactionSummary"*		$ 8,319,336	$ 11,063,491	$ 9,846,618	$ 3,756,644	$ 5,769,064	$ 7,200,859	**$ 45,956,011**
Off-system Sales of Generation (kWh)	*Form A Support & Calcs-YYYY.MM.xlsx , tab "PowerTransactionSummary"*		352,903,028	445,677,218	401,919,160	141,041,628	226,619,935	291,863,591	**1,860,024,560**
Net Generation (before losses) (kWh)	*Form A, p.3*		533,432,222	686,438,917	621,453,262	287,504,839	412,674,169	431,719,471	**2,973,222,880**
Back-Up & Supp. Sales to Smelters (from Gen) (kWh)	*Form A Support & Calcs-YYYY.MM.xlsx , tab "SmelterFuelCost"*		-	-	-	-	-	-	**-**
Domtar Back-Up Power Sales (from Gen) (kWh)	*Form A Support & Calcs-YYYY.MM.xlsx , tab "DomtarFuelCost"*		-	-	-	-	-	-	**-**
Total Purchased Power (kWh)	*Form A Support & Calcs-YYYY.MM.xlsx , tab "PowerTransactionSummary"*		242,687,803	255,720,206	452,080,250	434,880,950	176,835,562	115,709,741	**1,677,914,512**
Net Interchange In/(Out) (kWh)	*Form A Filing (Inputs)*		11,809,724	22,872,000	20,980,000	17,448,023	16,660,000	13,265,584	**103,035,331**
Total Purchased Power Including Net Interchange (kWh)			254,497,527	278,592,206	473,060,250	452,328,973	193,495,562	128,975,325	**1,780,949,843**
Total Purchased Power assigned to Native Load (kWh)	*Form A Support & Calcs-YYYY.MM.xlsx , tab "PowerTransactionSummary"*		60,428,723	65,151,232	74,813,015	92,732,776	64,227,323	81,335,450	**438,688,519**
Net Interchange In/(Out) (kWh)	*Form A Filing (Inputs)*		11,809,724	22,872,000	20,980,000	17,448,023	16,660,000	13,265,584	**103,035,331**
Total Purchased Power & Net Interchange Assigned to NL			**72,238,447**	**88,023,232**	**95,793,015**	**110,180,799**	**80,887,323**	**94,601,034**	**541,723,850**
System Losses (kWh)	*Form A, p.3*		16,168,064	25,024,610	22,344,292	20,516,008	18,198,904	16,138,326	**118,390,204**
Total Native Load (Member) Sales (kWh)	*Form A, p.3*		236,599,577	303,760,321	292,982,825	236,128,002	248,742,653	218,318,588	**1,536,531,966**

KIUC 1-6 and 1-7
DETAIL SUPPORT

FAC Review Case No. 2017-00287 (Detail Calcs for KIUC 1-6 & KIUC 1-7)

Fuel Cost ($/MWh) Assigned to NL & OSS and Purchased Power Cost Assigned to NL & OSS in FAC

Nov-16 through Apr-17

KIUC 1-6 Calculations:

	SOURCE	:pense Month:	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Six-Month Total
Fuel for Generation - Native Load									
Coal Burned			$ 10,545,722	$ 14,601,582	$ 12,602,110	$ 6,215,542	$ 8,453,818	$ 9,185,498	$ 61,604,272
Pet Coke Burned			$ 1,407,158	$ 1,460,090	$ 1,924,610	$ 674,208	$ 1,339,461	$ 810,929	$ 7,616,456
Oil Burned			$ 238,258	$ 302,108	$ 138,215	$ 213,769	$ 242,704	$ 256,906	
Gas Burned			$ 3,080	$ 55,408	$ 12,670	$ 7,674	$ 6,159	$ -	$ 84,991
Propane Burned			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Less: MISO Make Whole Payments			$ 2,110	$ 15,222	$ 6,508	$ 582	$ 7,468	$ -	$ 31,890
Plus: Fuel (Assigned Cost During F.O.)			$ 347,768	$ 699,996	$ 696,328	$ 2,434,554	$ 338,644	$ 937,028	$ 5,454,318
Less: Fuel (Substitute Cost for F.O.)			$ 143,017	$ 323,077	$ 258,269	$ 1,586,220	$ 91,777	$ 200,388	$ 2,602,748
Less: Identifiable Fuel Cost (Substitute for F.O.)			$ 281,327	$ 437,815	$ 617,582	$ 915,696	$ 373,602	$ 940,386	$ 3,566,408
Less: Fuel (Supp. and Back-Up Energy to Smelters)			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Less: Domtar Back-Up/ Imbalance Generation			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Less: Fuel Cost of Generation for OSS			$ 8,319,336	$ 11,063,491	$ 9,846,618	$ 3,756,644	$ 5,769,064	$ 7,200,859	$ 45,956,011
Total Cost of Fuel for Generation Allocated to Native Load			$ 3,796,196	$ 5,279,579	$ 4,644,956	$ 3,286,605	$ 4,138,875	$ 2,848,728	$ 23,994,940
Native Load Sales Volumes from Generation (kWh)			164,361,130	215,737,089	197,189,810	125,947,203	167,855,330	123,717,554	994,808,116
Generation Fuel Cost for Native Load ($/MWH)			**$ 23.10**	**$ 24.47**	**$ 23.56**	**$ 26.10**	**$ 24.66**	**$ 23.03**	**$ 24.12**
Fuel for Generation - OSS									
Fuel Cost of Generation for OSS			$ 8,319,336	$ 11,063,491	$ 9,846,618	$ 3,756,644	$ 5,769,064	$ 7,200,859	$ 45,956,011
OSS Volumes from Generation			352,903,028	445,677,218	401,919,160	141,041,628	226,619,935	291,863,591	1,860,024,560
Generation Fuel Cost for OSS ($/MWH)			**$ 23.57**	**$ 24.82**	**$ 24.50**	**$ 26.64**	**$ 25.46**	**$ 24.67**	**$ 24.71**

KIUC 1-7 Calculations:

			Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Six-Month Total
Purchased Power - Native Load									
Total Energy Cost of Purchased Power			$ 6,511,037	$ 8,168,698	$ 13,667,476	$ 11,031,963	$ 4,910,299	$ 3,982,737	$ 48,272,209
Less: Total Energy Cost of Purchased Power for OSS			$ 5,093,514	$ 6,361,026	$ 11,629,883	$ 8,893,647	$ 3,459,402	$ 2,088,038	$ 37,525,510
Less: Purchases for Supp. & Back-Up Energy to Smelters			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Less: Purchases for Domtar Back-Up Power			$ 115,628	$ 290,598	$ 161,505	$ 151,128	$ 134,181	$ 88,250	$ 941,290
Less: Purchases Above Highest Cost Units			$ 69,329	$ 81	$ -	$ 517	$ -	$ 6,291	$ 76,218
Energy Cost of Purchased Power for Native Load Recovered through FAC			$ 1,232,566	$ 1,516,993	$ 1,876,088	$ 1,986,671	$ 1,316,716	$ 1,800,157	$ 9,729,191
Native Load Volumes from Purchased Power (kWh)			72,238,447	88,023,232	95,793,015	110,180,799	80,887,323	94,601,034	541,723,850
Total Energy Cost of Purchased Power for Native Load ($/MWH)			**$ 17.06**	**$ 17.23**	**$ 19.58**	**$ 18.03**	**$ 16.28**	**$ 19.03**	**$ 17.96**
Purchased Power - OSS									
Total Energy Cost of Purchased Power for OSS[1]			$ 5,093,514	$ 6,361,026	$ 11,629,883	$ 8,893,647	$ 3,459,402	$ 2,088,038	$ 37,525,510
OSS Volumes from Purchased Power			177,600,000	182,400,000	371,800,000	336,200,000	108,373,300	31,151,240	1,207,524,540
Total Energy Cost of Purchased Power for OSS ($/MWH)			**$ 28.68**	**$ 34.87**	**$ 31.28**	**$ 26.45**	**$ 31.92**	**$ 67.03**	**$ 31.08**
OSS - Total $/MWH in FAC			**$ 25.28**	**$ 27.74**	**$ 27.76**	**$ 26.51**	**$ 27.55**	**$ 28.76**	**$ 27.21**
NATIVE LOAD - Total $/MWH in FAC			**$ 21.25**	**$ 22.37**	**$ 22.26**	**$ 22.33**	**$ 21.93**	**$ 21.29**	**$ 21.95**
Difference (OSS vs. NL $/MWH)			***$ 4.03***	***$ 5.37***	***$ 5.50***	***$ 4.17***	***$ 5.62***	***$ 7.46***	***$ 5.27***

Reconciliation to Form A Filings:

			Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	Six-Month Total
Total Member Fuel & Purchased Power Recoverable from Above:			$ 5,028,762	$ 6,796,572	$ 6,521,045	$ 5,273,276	$ 5,455,591	$ 4,648,886	$ 33,724,131
Less: Over/(Under) Recovery	*Form A Filing, p. 2, Over/(Under)*		$ 10,630	$ (69,713)	$ (6,984)	$ (76,697)	$ 21,760	$ (27,777)	$ (148,781)
Less: FAC Credits	*Form A Filing, p. 2, FAC Credits*		$ 311,111	$ 311,111	$ -	$ -	$ -	$ -	$ 622,222
Recalculated Total Fuel Recovery from Detail Above			$ 4,707,021	$ 6,555,174	$ 6,528,029	$ 5,349,973	$ 5,433,831	$ 4,676,663	$ 33,250,690
Form A Filing - Total Fuel Recovery	*Form A Filing, p. 1, Fuel "Fm"*		$ 4,707,021	$ 6,555,174	$ 6,528,029	$ 5,349,974	$ 5,433,831	$ 4,676,663	$ 33,250,692
Difference			*$ (0)*	*$ (0)*	*$ (0)*	*$ (0)*	*$ 0*	*$ (0)*	*$ (2)*
Total Member Sales (Used in NL Fuel & Purchased	$/MWh Calcs Above)		236,599,577	303,760,321	292,982,825	236,128,002	248,742,653	218,318,588	1,536,531,966
Total Member Sales per Form A Filing	*Form A Filing, p. 1, Sales "Sm"*		236,599,577	303,760,321	292,982,825	236,128,002	248,742,653	218,318,588	1,536,531,966
Difference			-	-	-	-	-	-	-

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Native Load Sales Volumes by Source
(MWh)

		Nov-16 (MWh)	Dec-16 (MWh)	Jan-17 (MWh)	Feb-17 (MWh)	Mar-17 (MWh)	Apr-17 (MWh)	6-Mo. Total (Nov-16 to Apr-17)
Native Load Sales From Generation:								
Net Generation (before losses)		533,432.222	686,438.917	621,453.262	287,504.839	412,674.169	431,719.471	2,973,222.880
Less: Back-Up & Supp. Sales to Smelters (from Gen)		-	-	-	-	-	-	-
Less: Domtar Back-Up Power Sales (from Gen)		-	-	-	-	-	-	-
Less: Inter-system Sales of Generation		(352,903.028)	(445,677.218)	(401,919.160)	(141,041.628)	(226,619.935)	(291,863.591)	(1,860,024.560)
Less: System Losses		(16,168.064)	(25,024.610)	(22,344.292)	(20,516.008)	(18,198.904)	(16,138.326)	(118,390.204)
NL Sales Volumes from Generation	(A)	**164,361.130**	**215,737.089**	**197,189.810**	**125,947.203**	**167,855.330**	**123,717.554**	**994,808.116**
Native Load Sales From Purchased Power & Net Interchange:								
Native Load Sales Volumes from Purchased Power (Excl. Net Interchange)	**(B)**	60,428.723	65,151.232	74,813.015	92,732.776	64,227.323	81,335.450	438,688.519
Native Load Sales Volumes from Net Interchange	**(C)**	11,809.724	22,872.000	20,980.000	17,448.023	16,660.000	13,265.584	103,035.331
NL Sales Volumes from Purch. Power (Incl. Net Interchange)	**(D) = [(B) + (C)]**	**72,238.447**	**88,023.232**	**95,793.015**	**110,180.799**	**80,887.323**	**94,601.034**	**541,723.850**
Total Native Load Sales Volumes	**(E) = [(A) + (D)]**	**236,599.577**	**303,760.321**	**292,982.825**	**236,128.002**	**248,742.653**	**218,318.588**	**1,536,531.966**
Total Native Load Sales Volume per FAC Filings		**236,599.577**	**303,760.321**	**292,982.825**	**236,128.002**	**248,742.653**	**218,318.588**	**1,536,531.966**

EXHIBIT ____ (LK-6)

BIG RIVERS ELECTRIC CORPORATION

AN EXAMINATION OF THE APPLICATION OF THE FUEL ADJUSTMENT CLAUSE OF BIG RIVERS ELECTRIC CORPORATION FROM NOVEMBER 1, 2013 THROUGH APRIL 30, 2014 CASE NO. 2014-00230

AN EXAMINATION OF THE APPLICATION OF THE FUEL ADJUSTMENT CLAUSE OF BIG RIVERS ELECTRIC CORPORATION FROM NOVEMBER 1, 2012 THROUGH OCTOBER 31, 2014 CASE NO. 2014-00455

Response to Item 1 of the Kentucky Industrial Utility Customers, Inc.'s Request for Information dated March 6, 2015

April 14, 2015

Item 1) *For each month during the period under review in this proceeding, please provide the dollar amount of fuel costs that would have been included in the calculation of the fuel adjustment clause if Big Rivers had assigned its lowest fuel cost generation to native load customers each hour and compare that amount to the dollar amount that was included in the calculation. Please provide the information in the same format as the Attachment to Big Rivers' Response to Commission Staff's Third Request for Information, Item No. 1 in Case No. 2014-00230. Please provide all workpapers electronically in spreadsheet format, with all formulas intact.*

Response) As Big Rivers explained in its response to Item 1 of the Public Service Commission Staff's Third Request for Information in Case No. 2014-00230 ("PSC 3-1"), Big Rivers does not have the process in place to allocate fuel costs between off-system sales and native load on an hourly stacked cost basis. Big Rivers has begun work to develop a process for such an allocation methodology, but development of the process will require a significant amount of time, research and effort. However, Big Rivers has calculated an estimate of the potential impact of switching to an hourly stacked cost approach by allocating its least expensive units based on monthly average costs for each specific unit to native load on an hourly basis and applying the cost differential per MWh to FAC generation volumes used to serve native load, which is the same methodology Big Rivers employed in responding to PSC 3-1. This monthly cost approach is different than the stacked cost methodology Big Rivers plans to implement as part of its next rate case, it is different than the incremental cost approach proposed by KIUC, and it is different than the allocation methodologies used by the other Commission-jurisdictional generating utilities (who, with the exception of KU and LG&E, all use different methodologies). The estimated impact of the change in methodology is $10.83 million and is highlighted on the attachment to this response. This attachment along with the working papers supporting it are provided on the CD accompanying this response.

Please note that Big Rivers' position regarding its current allocation methodology is unchanged. As Big Rivers explained in its response to KIUC's motion to compel this response and in its post-hearing brief in Case No. 2014-00230, Big Rivers' current allocation methodology is reasonable and consistent with Commission precedent, requiring Big Rivers to change methodologies outside of a general rate case would be unreasonable and contrary to traditional ratemaking principles, and ordering a refund because Big Rivers employed its current methodology rather than utilizing a stacked cost approach would be arbitrary and unreasonable.

BIG RIVERS ELECTRIC CORPORATION

AN EXAMINATION OF THE APPLICATION OF THE FUEL
ADJUSTMENT CLAUSE OF BIG RIVERS ELECTRIC CORPORATION
FROM NOVEMBER 1, 2013 THROUGH APRIL 30, 2014
CASE NO. 2014-00230

AN EXAMINATION OF THE APPLICATION OF THE FUEL
ADJUSTMENT CLAUSE OF BIG RIVERS ELECTRIC CORPORATION
FROM NOVEMBER 1, 2012 THROUGH OCTOBER 31, 2014
CASE NO. 2014-00455

Response to Item 1 of the Kentucky Industrial Utility Customers, Inc.'s
Request for Information
dated March 6, 2015

April 14, 2015

Witness) Lindsay N. Barron

Big Rivers Electric Corporation
Case No. 2014-00455 and Case No. 2014-00230

	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13
As Filed:						
Fuel Cost for Generation Allocated to Native Load (before F.O. generation adjustments)	$ 18,842,117	$ 19,143,174	$ 20,067,444	$ 18,336,444	$ 19,170,421	$ 17,120,121
Plus: Fuel (Assigned Cost During F.O.)[1]	$ 76,869	$ 1,002,426	$ 1,715,124	$ 238,161	$ 922,315	$ 254,108
Less: Fuel (Substitute Cost for F.O.)[1]	$ 66,794	$ 1,008,876	$ 1,642,999	$ 220,448	$ 809,142	$ 210,710
Total Fuel Cost for Generation Allocated to Native Load	$ 18,852,192	$ 19,136,724	$ 20,139,568	$ 18,354,157	$ 19,283,594	$ 17,163,519
Native Load Sales Volumes from Generation (MWh)	794,811,841	785,123,909	799,159,056	745,693,073	769,524,300	716,226,166
Total Fuel Cost for Generation Allocated to Native Load (As Filed) ($/MWh)	$ 23.72	$ 24.37	$ 25.24	$ 24.61	$ 25.06	$ 23.96
Proforma (Estimated) Fuel Cost Allocating Lowest Cost Gen to NL:						
Estimated Fuel Cost for Generation Allocated to Native Load (before F.O. generation adjustments)	$ 18,233,325	$ 18,582,873	$ 19,529,497	$ 17,812,180	$ 18,731,388	$ 16,477,810
Plus: Fuel (Assigned Cost During F.O.)[1]	$ 76,869	$ 1,002,426	$ 1,715,124	$ 238,161	$ 922,315	$ 254,108
Less: Fuel (Substitute Cost for F.O.)[1]	$ 66,794	$ 1,008,876	$ 1,642,999	$ 220,448	$ 809,142	$ 210,710
Total Estimated Fuel Cost for Generation Allocated to Native Load	$ 18,243,400	$ 18,576,423	$ 19,601,622	$ 17,829,893	$ 18,844,561	$ 16,521,208
Native Load Sales Volumes from Generation (MWh)	794,811,841	785,123,909	799,159,056	745,693,073	769,524,300	716,226,166
Estimated Fuel Cost for Generation Allocated to Native Load (Proforma) ($/MWh)	$ 22.95	$ 23.66	$ 24.53	$ 23.91	$ 24.49	$ 23.07
Difference:						
Difference (Total $)	$ 608,791	$ 560,301	$ 537,947	$ 524,264	$ 439,033	$ 642,310
Difference ($/MWh)	$ 0.77	$ 0.71	$ 0.67	$ 0.70	$ 0.57	$ 0.89

	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13
As Filed:						
Fuel Cost for Generation Allocated to Native Load (before F.O. generation adjustments)	$ 17,903,105	$ 19,090,919	$ 19,604,104	$ 15,721,751	$ 10,450,645	$ 10,711,624
Plus: Fuel (Assigned Cost During F.O.)[1]	$ 428,352	$ 1,545,665	$ 1,073,263	$ 909,204	$ 565,908	$ 568,654
Less: Fuel (Substitute Cost for F.O.)[1]	$ 419,917	$ 1,428,902	$ 1,029,789	$ 611,731	$ 223,585	$ 120,500
Total Fuel Cost for Generation Allocated to Native Load	$ 17,911,540	$ 19,207,682	$ 19,647,578	$ 16,019,224	$ 10,792,968	$ 11,159,778
Native Load Sales Volumes from Generation (MWh)	727,344,488	781,163,186	795,615,191	672,418,506	451,622,510	447,224,731
Total Fuel Cost for Generation Allocated to Native Load (As Filed) ($/MWh)	$ 24.63	$ 24.54	$ 24.69	$ 23.82	$ 23.90	$ 24.95
Proforma (Estimated) Fuel Cost Allocating Lowest Cost Gen to NL:						
Estimated Fuel Cost for Generation Allocated to Native Load (before F.O. generation adjustments)	$ 17,350,264	$ 18,554,249	$ 18,973,964	$ 15,367,806	$ 9,983,243	$ 10,124,947
Plus: Fuel (Assigned Cost During F.O.)[1]	$ 428,352	$ 1,545,665	$ 1,073,263	$ 909,204	$ 565,908	$ 568,654
Less: Fuel (Substitute Cost for F.O.)[1]	$ 419,917	$ 1,428,902	$ 1,029,789	$ 611,731	$ 223,585	$ 120,500
Total Estimated Fuel Cost for Generation Allocated to Native Load	$ 17,358,699	$ 18,671,012	$ 19,017,438	$ 15,665,279	$ 10,325,566	$ 10,573,101
Native Load Sales Volumes from Generation (MWh)	727,344,488	781,163,186	795,615,191	672,418,506	451,622,510	447,224,731
Estimated Fuel Cost for Generation Allocated to Native Load (Proforma) ($/MWh)	$ 23.87	$ 23.90	$ 23.90	$ 23.30	$ 22.86	$ 23.64
Difference:						
Difference (Total $)	$ 552,841	$ 496,670	$ 630,139	$ 353,946	$ 467,402	$ 586,678
Difference ($/MWh)	$ 0.76	$ 0.64	$ 0.79	$ 0.52	$ 1.04	$ 1.31

	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14
As Filed:						
Fuel Cost for Generation Allocated to Native Load (before F.O. generation adjustments)	$ 10,763,831	$ 10,918,883	$ 12,307,362	$ 5,384,111	$ 4,542,151	$ 3,939,896
Plus: Fuel (Assigned Cost During F.O.)[1]	$ 419,248	$ 1,199,264	$ 2,321,452	$ 310,637	$ 340,644	$ -
Less: Fuel (Substitute Cost for F.O.)[1]	$ 65,923	$ 440,550	$ 1,351,743	$ 54,704	$ 69,422	$ -
Total Fuel Cost for Generation Allocated to Native Load	$ 11,117,156	$ 11,677,597	$ 13,277,071	$ 5,640,044	$ 4,813,373	$ 3,939,896
Native Load Sales Volumes from Generation (MWh)	452,019,763	451,031,346	483,866,567	220,532,495	186,387,640	161,217,954
Total Fuel Cost for Generation Allocated to Native Load (As Filed) ($/MWh)	$ 24.59	$ 25.89	$ 27.44	$ 25.57	$ 25.82	$ 24.44
Proforma (Estimated) Fuel Cost Allocating Lowest Cost Gen to NL:						
Estimated Fuel Cost for Generation Allocated to Native Load (before F.O. generation adjustments)	$ 10,156,122	$ 10,290,754	$ 11,731,012	$ 5,041,756	$ 4,250,764	$ 3,742,670
Plus: Fuel (Assigned Cost During F.O.)[1]	$ 419,248	$ 1,199,264	$ 2,321,452	$ 310,637	$ 340,644	$ -
Less: Fuel (Substitute Cost for F.O.)[1]	$ 65,923	$ 440,550	$ 1,351,743	$ 54,704	$ 69,422	$ -
Total Estimated Fuel Cost for Generation Allocated to Native Load	$ 10,509,447	$ 11,049,468	$ 12,700,721	$ 5,297,689	$ 4,521,986	$ 3,742,670
Native Load Sales Volumes from Generation (MWh)	452,019,763	451,031,346	483,866,567	220,532,495	186,387,640	161,217,954
Estimated Fuel Cost for Generation Allocated to Native Load (Proforma) ($/MWh)	$ 23.25	$ 24.50	$ 26.25	$ 24.02	$ 24.26	$ 23.21
Difference:						
Difference (Total $)	$ 607,709	$ 628,129	$ 576,350	$ 342,355	$ 291,387	$ 197,226
Difference ($/MWh)	$ 1.34	$ 1.39	$ 1.19	$ 1.55	$ 1.56	$ 1.23

	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Total
As Filed:							
Fuel Cost for Generation Allocated to Native Load (before F.O. generation adjustments)	$ 4,003,820	$ 5,433,702	$ 5,429,157	$ 6,115,551	$ 4,888,209	$ 4,330,072	$ 284,178,615
Plus: Fuel (Assigned Cost During F.O.)[1]	$ 379,662	$ 974,712	$ 502,425	$ 339,872	$ 56,674	$ 308,737	$ 16,453,376
Less: Fuel (Substitute Cost for F.O.)[1]	$ 88,573	$ 476,379	$ 173,874	$ 255,947	$ 87	$ 9,436	$ 10,780,031
Total Fuel Cost for Generation Allocated to Native Load	$ 4,294,909	$ 5,932,035	$ 5,757,708	$ 6,199,476	$ 4,944,796	$ 4,629,373	$ 289,851,960
Native Load Sales Volumes from Generation (MWh)	157,356,187	200,707,278	218,597,953	252,257,217	204,649,002	173,305,470	11,647,855,829
Total Fuel Cost for Generation Allocated to Native Load (As Filed) ($/MWh)	$ 27.29	$ 29.56	$ 26.34	$ 24.58	$ 24.16	$ 26.71	$ 24.88
Proforma (Estimated) Fuel Cost Allocating Lowest Cost Gen to NL:							
Estimated Fuel Cost for Generation Allocated to Native Load (before F.O. generation adjustments)	$ 3,775,777	$ 4,982,075	$ 5,110,012	$ 5,760,277	$ 4,749,376	$ 4,035,938	$ 273,348,080
Plus: Fuel (Assigned Cost During F.O.)[1]	$ 379,662	$ 974,712	$ 502,425	$ 339,872	$ 56,674	$ 308,737	$ 16,453,376
Less: Fuel (Substitute Cost for F.O.)[1]	$ 88,573	$ 476,379	$ 173,874	$ 255,947	$ 87	$ 9,436	$ 10,780,031
Total Estimated Fuel Cost for Generation Allocated to Native Load	$ 4,066,866	$ 5,480,408	$ 5,438,563	$ 5,844,202	$ 4,805,963	$ 4,335,239	$ 279,021,425
Native Load Sales Volumes from Generation (MWh)	157,356,187	200,707,278	218,597,953	252,257,217	204,649,002	173,305,470	11,647,855,829
Estimated Fuel Cost for Generation Allocated to Native Load (Proforma) ($/MWh)	$ 25.84	$ 27.31	$ 24.88	$ 23.17	$ 23.48	$ 25.01	$ 23.95
Difference:							
Difference (Total $)	$ 228,043	$ 451,627	$ 319,145	$ 355,274	$ 138,832	$ 294,134	$ 10,830,535
Difference ($/MWh)	$ 1.46	$ 2.25	$ 1.46	$ 1.41	$ 0.68	$ 1.69	$ 0.93

Footnote: 1 - Note: For months when the Fuel (Assigned Cost During F.O.) is greater than the Fuel (Substitute Cost for F.O.), the fuel expense recovered through the FAC is reduced by the greater of (a) the amount which Assigned Cost During F.O. exceeded Substitute Cost for F.O. and (b) the cost of power purchased to substitute for lost generation due to forced outage. This reduction is included in the Purchases section on page 2 of Big Rivers' monthly Form A filings in the "Identifiable fuel cost substitute for Forced Outage" line. Because that reduction is not included in the Generation section of Big Rivers' monthly Form A filing, the reduction was not included in the calculations above.

Note: For months when the Fuel (Assigned Cost During F.O.) is greater than the Fuel (Substitute Cost for F.O.), the fuel expense recovered through the FAC is reduced by the greater of (a) the amount which Assigned Cost During F.O. exceeded Substitute Cost for F.O. and (b) the cost of power purchased to substitute for lost generation due to forced outage. This reduction is included in the Purchases section on page 2 of Big Rivers' monthly Form A filings in the "Identifiable fuel cost substitute for Forced Outage" line. Because that reduction is not included in the Generation section of Big Rivers' monthly Form A filing, the reduction was not included in the calculations above.

Note: For months when the Fuel (Assigned Cost During F.O.) is greater than the Fuel (Substitute Cost for F.O.), the fuel expense recovered through the FAC is reduced by the greater of (a) the amount which Assigned Cost During F.O. exceeded Substitute Cost for F.O. and (b) the cost of power purchased to substitute for lost generation due to forced outage. This reduction is included in the Purchases section on page 2 of Big Rivers' monthly Form A filings in the "Identifiable fuel cost substitute for Forced Outage" line. Because that reduction is not included in the Generation section of Big Rivers' monthly Form A filing, the reduction was not included in the calculations above.

Note: For months when the Fuel (Assigned Cost During F.O.) is greater than the Fuel (Substitute Cost for F.O.), the fuel expense recovered through the FAC is reduced by the greater of (a) the amount which Assigned Cost During F.O. exceeded Substitute Cost for F.O. and (b) the cost of power purchased to substitute for lost generation due to forced outage. This reduction is included in the Purchases section on page 2 of Big Rivers' monthly Form A filings in the "Identifiable fuel cost substitute for Forced Outage" line. Because that reduction is not included in the Generation section of Big Rivers' monthly Form A filing, the reduction was not included in the calculations above.

	SOURCE	Nov-12	As Adjusted in Feb-13 Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	As Adjusted in Jul-13 Jun-13	Jul-13	W/ Adj. Losses & Interchange Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	As Adjusted in Feb-14 Jan-14
Inputs:																
(+) Total Fuel Cost of Generation	Form A, p.2	$ 23,987,316	$ 23,979,447	$ 24,428,767	$ 22,518,861	$ 22,512,623	$ 20,972,238	$ 21,475,966	$ 21,651,345	$ 23,516,951	$ 19,978,449	$ 15,767,092	$ 17,573,206	$ 14,065,770	$ 17,078,728	$ 17,439,186
(-) MISO Make Whole Payments (for start up costs)	Form A, p.2	$ 8,780	$ -	$ 2,193	$ -	$ -	$ 6,663	$ 6,634	$ 2,191	$ 6,556	$ 6,544	$ 4,377	$ 6,552	$ 26,097	$ 6,875	$ 4,904
(+) Fuel (Assigned Cost During F.O.)	Form A, p.2	$ 76,869	$ 1,002,426	$ 1,715,124	$ 238,161	$ 922,315	$ 254,108	$ 428,352	$ 1,545,665	$ 1,073,263	$ 909,204	$ 565,908	$ 568,654	$ 419,248	$ 1,199,264	$ 2,321,452
(-) Fuel (Substitute Cost for FO)	Form A, p.2	$ 66,794	$ 1,008,876	$ 1,642,969	$ 220,448	$ 809,142	$ 210,710	$ 419,917	$ 1,428,902	$ 1,029,789	$ 611,731	$ 223,585	$ 120,500	$ 65,923	$ 440,550	$ 1,361,743
(-) Fuel (Supp. & Back-Up Energy to Smelters)	Form A, p.2	$ 70,103	$ 102,163	$ 55,168	$ 69,173	$ 146,289	$ 99,407	$ 104,537	$ 4,031	$ 5,656	$ 35,598	$ 7,149	$ 58,458	$ 195,581	$ 276,852	$ 308,161
(-) Fuel (Domtar Back-Up/ Imbalance Generation)	Form A, p.2	$ 28,278	$ 42,140	$ 40,028	$ 73,721	$ 66,596	$ 26,314	$ 6,426	$ 16,331	$ 22,835	$ 38,049	$ 128,209	$ 54,794	$ 3,263	$ 5,690	$ 3,487
Sub-Total Generation Fuel Costs		**$ 23,890,220**	**$ 23,828,694**	**$ 24,403,483**	**$ 22,403,680**	**$ 22,412,711**	**$ 20,884,252**	**$ 21,367,794**	**$ 21,745,555**	**$ 23,525,378**	**$ 20,193,731**	**$ 15,969,680**	**$ 17,901,560**	**$ 14,184,154**	**$ 17,548,225**	**$ 18,092,343**
(+) Net Energy Cost - Economy Purchases	Form A, p.2	$ 1,451,002	$ 2,587,877	$ 2,946,508	$ 1,859,073	$ 3,274,306	$ 3,226,803	$ 3,978,038	$ 2,714,452	$ 2,849,181	$ 1,834,643	$ 876,466	$ 1,039,050	$ 1,479,228	$ 2,010,542	$ 2,896,587
(+) Identifiable Fuel Cost - Other Purchases	Form A, p.2	$ 584,916	$ 592,900	$ 636,187	$ 405,945	$ 782,463	$ 715,846	$ 1,438,947	$ 1,447,289	$ 2,033,874	$ 2,482,539	$ 1,802,627	$ 1,829,799	$ 1,159,700	$ 876,728	$ 2,828,313
(+) Identifiable fuel cost - Forced Outage purchases	Form A, p.2	$ -	$ 52,787	$ 74,978	$ -	$ 131,789	$ -	$ -	$ 54,627	$ -	$ 267,917	$ 328,166	$ 593,075	$ 434,340	$ 1,304,390	$ 2,667,071
(-) Identifiable fuel cost (substitute for Forced Outage)	Form A, p.2	$ 10,075	$ 52,787	$ 74,978	$ 17,713	$ 131,789	$ 43,398	$ 8,436	$ 116,763	$ 43,474	$ 297,473	$ 342,323	$ 593,075	$ 484,340	$ 1,304,390	$ 2,667,071
(-) Less Purchases for Supp. & Back-Up energy to Smelters	Form A, p.2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(-) Less Purchases for Domtar back up	Form A, p.2	$ 584,916	$ 516,572	$ 504,037	$ 384,373	$ 513,733	$ 647,241	$ 140,801	$ 181,153	$ 189,788	$ 519,063	$ 969,227	$ 820,825	$ 69,991	$ 75,596	$ 366,534
(-) Less Purchases Above Highest Cost Units	Form A, p.2	$ -	$ 24,189	$ 43,110	$ 7,637	$ 181,071	$ 51,057	$ 37	$ 31,460	$ -	$ -	$ -	$ 34,270	$ 18,695	$ -	$ 924,169
Sub-Total		**$ 1,440,927**	**$ 2,640,016**	**$ 3,035,548**	**$ 1,875,295**	**$ 3,361,965**	**$ 3,200,753**	**$ 5,267,712**	**$ 3,886,992**	**$ 4,639,593**	**$ 3,618,563**	**$ 1,695,709**	**$ 2,013,754**	**$ 2,556,242**	**$ 2,911,675**	**$ 4,434,177**
Total Energy Cost of Purchased Power	Power Trans. Summ.	$ 2,035,918	$ 3,233,583	$ 3,657,671	$ 2,265,919	$ 4,188,558	$ 3,942,449	$ 5,410,985	$ 4,216,368	$ 5,562,360	$ 4,875,104	$ 3,263,712	$ 3,756,383	$ 3,413,593	$ 4,896,528	$ 10,345,651
Purchases for Inter-System Sales (Total Energy $)	Power Trans. Summ.	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,297,744	$ 1,237,289	$ 2,513,391	$ 2,321,678	$ 1,089,854	$ 1,187,995	$ 1,313,914	$ 1,308,002	$ 3,012,066
Purchases for Inter-System Sales (kWh)	Power Trans. Summ.	-	-	-	-	-	-	37,200,000	36,000,000	74,400,000	74,400,000	36,000,000	37,200,000	42,880,000	37,200,000	41,200,000
Inter-system Sales of Generation (Fuel $)	Power Trans. Summ.	$ 5,038,028	$ 4,691,970	$ 4,263,914	$ 4,049,523	$ 3,129,117	$ 3,720,734	$ 3,458,254	$ 2,577,873	$ 3,877,800	$ 4,174,507	$ 5,176,712	$ 6,741,782	$ 3,076,963	$ 5,870,628	$ 4,815,272
Inter-system Sales of Generation (kWh)	Power Trans. Summ.	212,413,700	192,435,800	169,789,100	164,681,700	125,606,800	155,601,100	140,366,900	105,689,500	157,320,600	165,039,402	223,816,049	281,306,064	128,901,112	242,347,599	169,234,943
Net Generation (before losses) (kWh)	Form A, p.3	1,027,844,434	1,001,859,223	992,560,838	934,553,934	925,070,282	893,015,897	889,734,859	905,243,758	979,326,267	870,247,794	701,032,246	749,004,193	806,887,961	725,802,466	709,596,296
System Losses (kWh)	Form A, p.3	16,470,928	18,421,104	19,851,174	16,774,797	21,377,655	15,972,806	17,567,637	17,536,244	25,236,382	29,878,254	19,946,703	15,747,827	16,437,138	20,556,811	24,247,348
Back-Up & Supp. Sales to Smelters (from Gen) (kWh)	SmelterFuelCost	2,956,692	4,180,102	2,197,581	2,406,372	5,872,227	4,115,383	4,245,491	165,278	229,478	1,407,375	308,802	2,439,122	8,193,256	11,426,816	12,110,410
Domtar Back-Up Power Sales (from Gen) (kWh)	DomtarFuelCost	1,192,273	1,726,308	1,593,927	2,997,992	2,869,300	1,100,442	220,343	869,550	926,410	1,504,257	5,538,182	2,286,329	136,692	234,892	137,027
Interchange In (kWh)	Form A (Inputs)	289,187,000	350,907,000	374,049,000	434,332,000	404,179,000	303,394,000	307,253,000	286,251,000	349,617,000	362,792,000	388,515,000	374,235,000	331,436,000	420,364,000	424,352,000
Interchange Out (kWh)	Form A (Inputs)	278,127,000	337,693,000	356,323,000	419,229,000	386,970,000	293,941,000	296,357,000	274,691,000	330,630,000	339,533,000	373,520,000	362,460,000	319,285,000	404,650,000	404,012,000
Net Interchange (kWh)		11,060,000	13,214,000	14,726,000	15,103,000	17,209,000	9,453,000	10,896,000	11,560,000	18,987,000	23,259,000	14,995,000	11,775,000	12,151,000	15,714,000	20,340,000
Total Purchased Power (kWh)	Power Trans. Summ.	79,772,100	131,782,100	148,773,101	98,180,201	153,603,000	133,488,200	189,427,600	143,918,500	194,677,200	171,827,353	120,392,688	120,008,913	116,345,231	160,700,898	175,815,341
(-) Purchases for Domtar Back-up (kWh)	Power Trans. Summ.	16,461,662	15,859,453	16,675,501	12,044,362	14,973,231	16,855,044	3,876,530	5,507,110	6,113,729	16,175,883	31,796,673	21,992,510	2,096,765	2,048,854	2,192,021
(-) Purchases for Inter-system Sales	Power Trans. Summ.	-	-	-	-	-	-	37,200,000	36,000,000	74,400,000	74,400,000	36,000,000	37,200,000	42,880,000	37,200,000	41,200,000
Total Purchased Power for Native Load (kWh)		63,310,438	115,922,647	132,097,600	86,135,839	138,629,769	116,633,156	148,351,070	102,411,390	114,163,471	81,251,470	52,596,015	60,816,403	71,368,516	121,451,844	132,423,320

SOURCE	Nov-12	As Adjusted in Feb-13 Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	As Adjusted in Jul-13 Jun-13	Jul-13	W/ Adj. Losses & Interchange Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	As Adjusted in Feb-14 Jan-14
Generation - Native Load															
Total Fuel Cost of Generation	23,987,316	23,979,447	24,428,767	22,518,861	22,512,823	20,972,238	21,475,956	21,651,345	23,516,951	19,976,449	15,767,092	17,573,208	14,065,770	17,078,728	17,439,186
Less: Make Whole Payments	8,790	-	2,193	-	-	6,663	6,634	2,191	6,556	6,544	4,377	6,552	26,097	5,675	4,904
Plus: Fuel (Assigned Cost During F.O.)	76,869	1,002,426	1,715,124	238,161	922,315	254,108	428,352	1,645,665	1,073,263	909,204	565,908	588,654	419,248	1,109,264	2,321,452
Less: Fuel (Substitute Cost for F.O.)	66,794	1,008,876	1,642,999	220,448	809,142	210,710	419,917	1,428,902	1,029,789	811,731	223,585	120,500	65,923	440,560	1,351,743
Less: Fuel (Supp. and Back-Up Energy to Smelters)	70,103	102,163	56,188	59,173	146,289	98,407	104,537	4,031	5,656	35,598	7,149	58,456	195,681	278,852	308,161
Less: Domtar Back-Up/ Imbalance Generation	28,278	42,140	40,028	73,721	66,996	26,314	5,426	16,331	22,836	38,049	128,209	54,784	3,263	5,690	3,487
Less: Fuel Cost of Generation for OSS	5,038,028	4,691,970	4,263,914	4,049,523	3,129,117	3,720,734	3,456,254	2,577,873	3,877,800	4,174,507	5,176,712	6,741,782	3,076,998	5,870,628	4,815,272
Total Cost of Fuel for Generation Allocated to Native Load	18,852,192	19,136,724	20,139,569	18,354,157	19,263,594	17,163,519	17,911,540	19,167,682	19,647,578	16,018,224	10,792,968	11,159,778	11,117,156	11,677,597	13,277,071
Native Load Sales Volumes from Generation (kWh)	794,811,841	785,123,909	799,159,056	745,693,073	769,524,300	716,226,168	727,344,488	781,163,186	795,615,191	672,418,506	451,622,510	447,224,731	452,019,783	461,031,346	483,856,567
Generation Fuel Cost for Native Load ($/MWH)	23.72	24.37	25.20	24.61	25.06	23.96	24.63	24.54	24.69	23.82	23.90	24.96	24.59	25.28	27.44
Generation - OSS															
Fuel Cost of Generation for OSS	5,038,028	4,691,970	4,263,914	4,049,523	3,129,117	3,720,734	3,456,254	2,577,873	3,877,800	4,174,507	5,176,712	6,741,782	3,076,998	5,870,628	4,815,272
OSS Volumes from Generation	212,413,700	192,435,800	169,789,100	164,681,700	125,606,800	155,601,100	140,366,900	105,689,500	157,320,800	165,039,402	223,616,049	281,306,084	128,901,112	242,347,599	189,234,943
Generation Fuel Cost for OSS ($/MWH)	23.72	24.38	25.11	24.59	24.91	23.91	24.62	24.39	24.65	25.29	23.16	23.97	23.87	24.22	25.45
Purchased Power - Native Load															
Total Energy Cost of Purchased Power	2,035,918	3,233,563	3,657,671	2,265,019	4,188,568	3,942,449	5,416,985	4,216,368	5,582,360	4,875,104	3,263,712	3,758,383	3,413,593	4,696,528	10,345,651
Less: Total Energy Cost of Purchased Power for OSS	-	-	-	-	-	-	1,297,744	1,237,289	2,513,391	2,321,878	1,089,854	1,187,995	1,313,914	1,306,002	3,012,055
Less: Identifiable Fuel Cost (Substitute for F.O.)	10,075	52,787	74,976	17,713	131,789	43,398	8,435	116,763	43,474	297,473	342,323	593,075	484,340	1,304,390	2,657,071
Less: Purchases for Supp. & Back-Up Energy to Smelters	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Less: Purchases for Domtar Back-Up Power	584,916	516,572	504,037	364,373	513,733	647,241	140,801	181,153	199,788	519,063	969,227	820,825	69,991	75,595	366,534
Less: Purchases Above Highest Cost Units	-	24,189	43,110	7,637	181,071	51,057	37	31,460	-	-	-	34,270	18,695	-	924,189
Energy Cost of Purchased Power for Native Load Recovered through FAC	1,440,927	2,640,015	3,035,548	1,875,296	3,361,965	3,200,753	3,969,968	2,649,703	2,805,708	1,736,689	862,309	1,122,218	1,526,653	2,010,542	3,385,802
Native Load Volumes from Purchased Power (kWh)	63,310,438	115,822,647	132,097,600	86,135,839	138,629,769	116,633,156	148,351,070	102,411,390	114,163,471	81,251,470	52,596,015	60,816,403	71,368,516	121,451,844	132,423,320
Total Energy Cost of Purchased Power for Native Load ($/MWH)	22.76	22.79	22.98	21.77	24.25	27.44	26.76	25.87	24.58	21.37	16.39	18.45	21.39	16.55	25.57
Purchased Power - OSS															
Total Energy Cost of Purchased Power for OSS	-	-	-	-	-	-	1,297,744	1,237,289	2,513,391	2,321,878	1,089,854	1,187,995	1,313,914	1,306,002	3,012,055
OSS Volumes from Purchased Power	-	-	-	-	-	-	37,200,000	36,000,000	74,400,000	74,400,000	36,000,000	37,200,000	42,880,000	37,200,000	41,200,000
Total Energy Cost of Purchased Power for OSS ($/MWH)	-	-	-	-	-	-	34.89	34.37	33.78	31.21	30.27	31.94	30.64	35.11	73.11
OSS - Total $/MWH in FAC	23.72	24.38	25.11	24.59	24.91	23.91	26.77	26.93	27.68	27.13	24.14	24.90	25.56	25.67	33.97
NATIVE LOAD - Total $/MWH in FAC	23.65	24.17	24.89	24.32	24.94	24.45	24.99	24.69	24.88	23.56	23.12	24.18	24.16	23.91	27.04
Difference (OSS vs. NL $/MWH)	0.07	0.21	0.22	0.27	(0.03)	(0.54)	1.78	2.24	2.80	3.57	1.02	0.72	1.40	1.76	6.93
Error Checks/ Reconciliations to Form A Filings:															
Total Member Fuel & Purchased Power Recoverable from Above:	20,293,119	21,776,740	23,175,117	20,229,453	22,645,560	20,364,272	21,881,508	21,817,385	22,453,285	17,755,914	11,655,277	12,281,996	12,643,809	13,688,139	16,662,873
Less: Over/(Under) Recovery — *Form A Filing, p. 2, O/(U)*	22,931	107,454	79,142	(606,085)	287,764	(268,171)	157,767	30,509	(156,585)	(518,066)	(667,225)	1,688	42,327	136,805	102,048
(A) Recalculated Total Fuel Recovery from Detail Above	20,270,188	21,669,286	23,095,975	20,835,538	22,357,796	20,632,443	21,723,741	21,786,877	22,609,870	18,273,980	12,322,502	12,280,308	12,601,482	13,551,334	16,560,825
Form A Filing - Total Fuel Recovery — *Form A Filing, p. 1, Fuel "Fm"*	20,270,188	21,408,349	23,095,975	20,835,537	22,357,795	20,632,442	21,723,741	21,525,940	22,609,870	18,273,980	12,322,502	12,280,309	12,601,482	13,551,334	16,775,524
Adjmts. Incl. in subsequent month filing(s)	-	260,937	-	-	-	-	-	260,937	-	-	-	-	-	-	(214,700)
(B) Adjusted Total Fuel Recovery per Filing	20,270,188	21,669,286	23,095,975	20,835,537	22,357,796	20,632,442	21,723,741	21,786,877	22,609,870	18,273,980	12,322,502	12,280,309	12,601,482	13,551,334	16,560,824
Difference (A) - (B)	(0)	(0)	0	1	1	1	0	0	0	(0)	0	(1)	-	(0)	1
Total Member Sales from Above (MWH)	858,122,279	900,946,556	931,256,656	831,828,912	908,154,069	832,859,322	875,695,558	883,574,576	909,778,662	753,669,976	504,218,525	508,041,134	523,388,279	572,483,190	616,289,887
Total Sales per Form A Filing — *Form A Filing, p. 1, Sales "Sm"*	869,182,279	914,160,556	945,982,655	846,931,911	925,363,069	842,312,322	886,591,558	895,134,576	928,765,662	776,928,976	519,213,524	519,816,134	535,539,280	588,197,190	636,629,886
Difference	(11,060,000)	(13,214,000)	(14,725,999)	(15,102,999)	(17,209,000)	(9,453,000)	(10,896,000)	(11,560,000)	(18,987,000)	(23,259,000)	(14,994,999)	(11,775,000)	(12,151,001)	(15,714,000)	(20,339,999)
Net Interchange (kWh)	11,060,000	13,214,000	14,726,000	15,103,000	17,209,000	9,453,000	10,896,000	11,560,000	18,987,000	23,259,000	14,995,000	11,775,000	12,151,000	15,714,000	20,340,000
Remaining Difference	-	-	1	1	-	-	-	-	-	-	1	-	(1)	-	1

	SOURCE	Feb-14	Mar-14	Apr-14	As Adjusted in Jun-14 May-14	As Adjusted in Jul-14 Jun-14	As Adjusted in Sep-14 Jul-14	As Adjusted in Sep-14 Aug-14	Sep-14	Oct-14
Inputs:										
(+) Total Fuel Cost of Generation	Form A, p.2	$ 17,565,646	$ 19,212,416	$ 18,288,530	$ 12,832,399	$ 11,826,308	$ 16,497,979	$ 18,049,572	$ 16,346,838	$ 15,781,204
(-) MISO Make Whole Payments (for start up costs)	Form A, p.2	$ 15,276	$ 9,148	$ -	$ 2,226	$ 4,453	$ -	$ 2,197	$ 3,957	$ -
(+) Fuel (Assigned Cost During F.O.)	Form A, p.2	$ 310,837	$ 340,644	$ -	$ 379,662	$ 974,712	$ 502,425	$ 339,872	$ 56,674	$ 308,737
(-) Fuel (Substitute Cost for FO)	Form A, p.2	$ 54,704	$ 69,422	$ -	$ 88,573	$ 476,379	$ 173,874	$ 255,947	$ 87	$ 9,436
(-) Fuel (Supp. & Back-Up Energy to Smelters)	Form A, p.2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(-) Fuel (Domtar Back-Up/ Imbalance Generation)	Form A, p.2	$ 10,235	$ 6,349	$ 27,257	$ 13,773	$ 23,641	$ 27,558	$ 31,395	$ 61,644	$ 26,668
Sub-Total Generation Fuel Costs		**$ 17,796,068**	**$ 19,468,141**	**$ 18,261,273**	**$ 13,107,487**	**$ 12,296,547**	**$ 16,798,972**	**$ 18,099,905**	**$ 16,337,824**	**$ 16,053,839**
(+) Net Energy Cost - Economy Purchases	Form A, p.2	$ 1,345,202	$ 1,829,194	$ 971,508	$ 1,182,583	$ 1,290,437	$ 832,581	$ 764,887	$ 640,627	$ 477,865
(+) Identifiable Fuel Cost - Other Purchases	Form A, p.2	$ 557,539	$ 463,529	$ 407,670	$ 529,576	$ 393,749	$ 2,560,168	$ 2,214,601	$ 2,330,520	$ 2,273,900
(+) Identifiable fuel cost - Forced Outage purchases	Form A, p.2	$ 370,699	$ 660,308	$ -	$ 412,903	$ 929,022	$ 452,236	$ 57,056	$ 91,405	$ 385,536
(-) Identifiable fuel cost (substitute for Forced Outage)	Form A, p.2	$ 370,699	$ 660,308	$ -	$ 412,903	$ 929,022	$ 452,236	$ 83,925	$ 91,405	$ 385,536
(-) Less Purchases for Supp. & Back-Up energy to Smelters	Form A, p.2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(-) Less Purchases for Domtar back up	Form A, p.2	$ 161,683	$ 88,174	$ 187,770	$ 158,422	$ 207,567	$ 135,782	$ 126,231	$ 489,157	$ 187,397
(-) Less Purchases Above Highest Cost Units	Form A, p.2	$ 82,196	$ 155,353	$ 41,800	$ 46,505	$ 16,187	$ 8,673	$ 17,412	$ 3,187	$ 40,544
Sub-Total		**$ 1,658,862**	**$ 2,049,196**	**$ 1,149,608**	**$ 1,507,242**	**$ 1,460,432**	**$ 2,848,284**	**$ 2,608,976**	**$ 2,478,893**	**$ 2,523,814**
Total Energy Cost of Purchased Power	*Power Trans. Summ.*	$ 2,273,441	$ 2,963,031	$ 1,379,379	$ 2,125,071	$ 2,813,208	$ *4,702,360*	$ *4,167,976*	$ 4,007,271	$ 4,097,297
Purchases for Inter-System Sales (Total Energy $)	*Power Trans. Summ.*	$ -	$ -	$ -	$ -	$ -	$ 3,342,655	$ 3,170,868	$ 2,551,202	$ 2,798,902
Purchases for Inter-System Sales (kWh)	*Power Trans. Summ.*	-	-	-	-	-	88,000,000	84,000,000	67,200,000	73,600,000
Inter-system Sales of Generation (Fuel $)	*Power Trans. Summ*	$ 12,156,024	$ 14,664,768	$ 14,321,377	$ *8,812,576*	$ 6,364,512	$ 11,041,264	$ 11,900,429	$ 11,393,028	$ 11,424,466
Inter-system Sales of Generation (kWh)	*Power Trans. Summ.*	496,508,754	600,162,466	566,078,982	*346,161,437*	234,887,500	444,584,800	490,153,176	476,576,100	457,253,000
Net Generation (before losses) (kWh)	*Form A, p.3*	736,225,365	810,875,091	766,338,214	*523,106,071*	469,041,661	685,648,409	764,901,702	701,225,247	650,243,189
System Losses (kWh)	*Form A, p.3*	16,766,064	23,884,934	17,927,852	*19,047,424*	22,574,382	21,356,123	21,198,213	17,421,565	18,617,450
Back-Up & Supp. Sales to Smelters (from Gen) (kWh)	*SmelterFuelCost*	-	-	-	-	-	-	-	-	-
Domtar Back-Up Power Sales (from Gen) (kWh)	*DomtarFuelCost*	418,052	260,031	1,115,426	541,023	872,501	1,109,623	1,293,096	2,576,590	1,067,269
Interchange In (kWh)	*Form A (inputs)*	340,321,000	384,708,000	421,080,000	*294,856,000*	146,620,000	254,232,000	291,398,000	267,480,000	256,212,000
Interchange Out (kWh)	*Form A (inputs)*	325,952,000	368,731,000	404,370,000	278,517,000	130,653,000	239,749,000	276,408,000	254,442,000	242,738,000
Net Interchange (kWh)		14,369,000	15,977,000	16,710,000	16,339,000	15,967,000	14,483,000	14,990,000	13,038,000	13,474,000
Total Purchased Power (kWh)	*Power Trans. Summ*	74,518,987	86,935,194	50,513,702	82,399,811	70,673,201	146,771,700	128,137,578	118,094,900	128,119,301
(-) Purchases for Domtar Back-up (kWh)	*Power Trans. Summ*	1,647,990	2,023,719	3,979,222	3,874,755	4,244,550	4,213,500	3,862,838	15,312,581	6,030,024
(-) Purchases for Inter-system Sales	*Power Trans. Summ.*	-	-	-	-	-	88,000,000	84,000,000	67,200,000	73,600,000
Total Purchased Power for Native Load (kWh)		72,870,997	84,911,475	46,534,480	78,525,056	66,428,651	54,558,200	40,274,740	35,582,319	48,489,277

	SOURCE	Feb-14	Mar-14	Apr-14	As Adjusted in Jun-14 May-14	As Adjusted in Jul-14 Jun-14	As Adjusted in Sep-14 Jul-14	As Adjusted in Sep-14 Aug-14	Sep-14	Oct-14
Generation - Native Load										
Total Fuel Cost of Generation		$ 17,565,646	$ 19,212,416	$ 18,288,530	$ 12,832,399	$ 11,826,308	$ 16,497,979	$ 18,049,572	$ 16,346,838	$ 15,781,204
Less: Make Whole Payments		$ 15,276	$ 9,148	$ -	$ 2,228	$ 4,453	$ -	$ 2,197	$ 3,957	$ -
Plus: Fuel (Assigned Cost During F.O.)		$ 310,637	$ 340,644	$ -	$ 379,662	$ 974,712	$ 502,425	$ 339,872	$ 56,674	$ 308,737
Less: Fuel (Substitute Cost for F.O.)		$ 54,704	$ 69,422	$ -	$ 88,573	$ 476,379	$ 173,674	$ 255,947	$ 87	$ 9,436
Less: Fuel (Supp. and Back-Up Energy to Smelters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Less: Domtar Back-Up/ Imbalance Generation		$ 10,235	$ 6,349	$ 27,257	$ 13,773	$ 23,641	$ 27,558	$ 31,395	$ 61,644	$ 26,666
Less: Fuel Cost of Generation for OSS		$ 12,156,024	$ 14,654,768	$ 14,321,377	$ 8,812,578	$ 6,364,512	$ 11,041,264	$ 11,900,429	$ 11,393,028	$ 11,424,466
Total Cost of Fuel for Generation Allocated to Native Load		$ 5,640,044	$ 4,813,373	$ 3,939,896	$ 4,294,909	$ 5,932,035	$ 6,757,708	$ 6,199,476	$ 4,944,796	$ 4,629,373
Native Load Sales Volumes from Generation (kWh)		220,532,495	186,387,640	161,217,954	157,356,187	200,707,278	218,597,953	252,257,217	204,649,002	173,305,470
Generation Fuel Cost for Native Load ($/MWH)		$ 25.57	$ 25.82	$ 24.44	$ 27.29	$ 29.56	$ 26.34	$ 24.58	$ 24.16	$ 26.71
Generation - OSS										
Fuel Cost of Generation for OSS		$ 12,156,024	$ 14,654,768	$ 14,321,377	$ 8,812,578	$ 6,364,512	$ 11,041,264	$ 11,900,429	$ 11,393,028	$ 11,424,466
OSS Volumes from Generation		496,508,754	600,162,486	586,076,982	346,161,437	234,887,500	444,584,800	490,153,176	476,576,100	457,253,000
Generation Fuel Cost for OSS ($/MWH)		$ 24.48	$ 24.42	$ 24.44	$ 25.46	$ 27.10	$ 24.84	$ 24.28	$ 23.91	$ 24.99
Purchased Power - Native Load										
Total Energy Cost of Purchased Power		$ 2,273,441	$ 2,953,031	$ 1,379,379	$ 2,125,071	$ 2,613,208	$ 4,702,360	$ 4,167,976	$ 4,007,271	$ 4,097,297
Less: Total Energy Cost of Purchased Power for OSS		$ -	$ -	$ -	$ -	$ -	$ 3,342,855	$ 3,170,868	$ 2,551,202	$ 2,798,902
Less: Identifiable Fuel Cost (Substitute for F.O.)		$ 370,699	$ 660,308	$ -	$ 412,903	$ 929,022	$ 452,236	$ 83,925	$ 91,405	$ 385,538
Less: Purchases for Supp. & Back-Up Energy to Smelters		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Less: Purchases for Domtar Back-Up Power		$ 161,683	$ 88,174	$ 187,770	$ 158,422	$ 207,567	$ 135,782	$ 126,231	$ 489,157	$ 187,397
Less: Purchases Above Highest Cost Units		$ 82,196	$ 155,353	$ 41,800	$ 46,505	$ 16,187	$ 8,673	$ 17,412	$ 3,187	$ 40,544
Energy Cost of Purchased Power for Native Load Recovered through FAC		$ 1,658,863	$ 2,049,196	$ 1,149,809	$ 1,507,241	$ 1,460,432	$ 762,814	$ 769,541	$ 872,320	$ 684,918
Native Load Volumes from Purchased Power (kWh)		72,870,997	84,911,475	46,534,480	78,525,056	66,428,651	54,558,200	40,274,740	35,582,319	48,489,277
Total Energy Cost of Purchased Power for Native Load ($/MWH)		$ 22.76	$ 24.13	$ 24.71	$ 19.19	$ 21.98	$ 13.98	$ 19.11	$ 24.52	$ 14.13
Purchased Power - OSS										
Total Energy Cost of Purchased Power for OSS		$ -	$ -	$ -	$ -	$ -	$ 3,342,855	$ 3,170,868	$ 2,551,202	$ 2,798,902
OSS Volumes from Purchased Power		-	-	-	-	-	88,000,000	84,000,000	67,200,000	73,600,000
Total Energy Cost of Purchased Power for OSS ($/MWH)		$ -	$ -	$ -	$ -	$ -	$ 37.98	$ 37.75	$ 37.96	$ 38.05
OSS - Total $/MWH in FAC		$ 24.48	$ 24.42	$ 24.44	$ 25.46	$ 27.10	$ 27.01	$ 26.25	$ 25.64	$ 26.79
NATIVE LOAD - Total $/MWH in FAC		$ 24.88	$ 25.30	$ 24.50	$ 24.60	$ 27.67	$ 23.87	$ 23.82	$ 24.21	$ 23.96
Difference (OSS vs. NL $/MWH)		$ (0.40)	$ (0.88)	$ (0.06)	$ 0.86	$ (0.57)	$ 3.14	$ 2.43	$ 1.43	$ 2.83
Error Checks/ Reconciliations to Form A Filings:										
Total Member Fuel & Purchased Power Recoverable from Above		$ 7,298,907	$ 8,862,569	$ 5,089,705	$ 5,802,150	$ 7,392,467	$ 6,520,523	$ 6,969,017	$ 5,817,116	$ 5,314,291
Less: Over/(Under) Recovery	*Form A Filing, p. 2, O/(U)*	$ (1,567,534)	$ (161,429)	$ (220,978)	$ 75,723	$ 56,423	$ 20,869	$ 51,158	$ 301,568	$ (8,820)
(A) Recalculated Total Fuel Recovery from Detail Above		$ 8,866,441	$ 7,023,998	$ 5,310,683	$ 5,726,427	$ 7,336,044	$ 6,499,654	$ 6,917,859	$ 5,425,548	$ 5,323,111
Form A Filing - Total Fuel Recovery	*Form A Filing, p. 1, Fuel "Fm"*	$ 8,866,440	$ 7,023,998	$ 5,310,682	$ 5,727,959	$ 7,334,385	$ 6,760,991	$ 7,179,196	$ 5,425,548	$ 5,323,111
Adjmts. Incl. in subsequent month filing(s)		$ -	$ -	$ -	$ (1,531)	$ 1,659	$ (261,338)	$ (261,338)	$ -	$ -
(B) Adjusted Total Fuel Recovery per Filing		$ 8,866,440	$ 7,023,998	$ 5,310,682	$ 5,726,428	$ 7,336,044	$ 6,499,653	$ 6,917,858	$ 5,425,548	$ 5,323,111
Difference (A) - (B)		$ 1	$ -	$ 1	$ (1)	$ (0)	$ 1	$ 1	$ (0)	$ (0)
Total Member Sales from Above (MWH)		293,403,492	271,299,115	207,752,434	235,881,243	267,135,929	273,156,153	292,531,957	240,231,321	221,794,747
Total Sales per Form A Filing	*Form A Filing, p. 1, Sales "Sm"*	307,772,493	287,276,116	224,462,434	252,220,243	283,102,928	287,639,154	307,521,958	253,269,321	235,268,747
Difference		(14,369,001)	(15,977,001)	(16,710,000)	(16,339,000)	(15,966,999)	(14,483,001)	(14,990,001)	(13,038,000)	(13,474,000)
Net Interchange (kWh)		14,369,000	15,977,000	16,710,000	16,339,000	15,967,000	14,483,000	14,990,000	13,038,000	13,474,000
Remaining Differences		(1)	(1)	-	-	1	(1)	(1)	-	-

System Fuel Costs - October 2014									Units Serving Load, MWh	
Unit	Net kWh	Coal	Pet Coke	Oil	Gas	Total	$/MWh	$/MWh w/losses		
R1	-1,521,000	$ -	$ -	$ -		$ -	$ -	$ -	-	6
C1	-253,000	$ -			$ -	$ -	$ -	$ -	-	
C2	-259,000	$ -			$ -	$ -	$ -	$ -	-	
C3	-263,000	$ -			$ -	$ -	$ -	$ -	-	
CT	0			$ -	$ -	$ -	$ -	$ -	-	7
W1	304,540,275	$ 5,914,838.76	$ 918,395.07	$ 55,842.21		$ 6,889,076.04	$ 22.621	$ 23.288	180,752	1
H1(net)	77,413,206	$ 1,853,474.16		$ 45,560.45		$ 1,899,034.61	$ 24.531	$ 25.254	-	3
H2(net)	80,177,574	$ 2,010,582.75		$ 14,581.77		$ 2,025,164.52	$ 25.258	$ 26.003	-	4
G1	150,127,530	$ 3,035,616.96	$ 687,750.15	$ 55,532.11		$ 3,778,899.22	$ 25.171	$ 25.913	-	2
G2	40,283,604	$ 776,192.78	$ 233,293.29	$ 179,543.48		$ 1,189,029.55	$ 29.516	$ 30.386	-	5
System	650,243,189	$ 13,590,705.41	$ 1,839,438.51	$ 351,060.02	$ -	$ 15,781,203.94	$ 24.270	$ 24.985	180,752	
Losses	18,617,450							$ 23.288	Fuel Costs - w/o FAC fuel adjustments	
System w/Losses	631,625,739									

Date	HE	C1	C2	C3	G1	G2	H1(Gross)	H2(Gross)	H1 (Net)	H2 (Net)	R1	R-CT	W1	Native Load	SEPA-BREC	Purchases
						Real Time Generation - MISO										
		-	-	-	152,484	42,150	101,988	105,745	79,558	80,786	-	-	304,432	235,271	10,065	44,454
01-Oct-14	1	-	-	-	167	224	132	133	101	102	-	-	419	281.20	-	32.30
01-Oct-14	2	-	-	-	165	224	131	132	100	101	-	-	419	268.15	-	53.00
01-Oct-14	3	-	-	-	164	224	131	132	100	101	-	-	400	262.35	-	-
01-Oct-14	4	-	-	-	166	224	131	132	100	101	-	-	384	254.37	-	-
01-Oct-14	5	-	-	-	185	224	136	132	105	101	-	-	420	255.23	-	13.90
01-Oct-14	6	-	-	-	229	224	151	139	118	107	-	-	420	279.38	-	40.00
01-Oct-14	7	-	-	-	231	224	153	152	138	117	-	-	420	313.60	-	50.60
01-Oct-14	8	-	-	-	231	224	153	152	117	117	-	-	419	306.60	-	39.40
01-Oct-14	9	-	-	-	231	224	153	152	117	116	-	-	419	310.56	-	25.30
01-Oct-14	10	-	-	-	231	224	152	152	115	115	-	-	419	320.00	-	30.30
01-Oct-14	11	-	-	-	231	224	153	152	115	115	-	-	420	341.48	-	25.80
01-Oct-14	12	-	-	-	231	224	153	152	115	114	-	-	420	358.50	-	29.80
01-Oct-14	13	-	-	-	231	224	153	152	113	112	-	-	420	390.81	-	43.00
01-Oct-14	14	-	-	-	231	224	153	152	111	110	-	-	419	408.92	74	46.80
01-Oct-14	15	-	-	-	231	224	153	152	110	110	-	-	420	426.31	74	56.10
01-Oct-14	16	-	-	-	230	224	153	152	110	109	-	-	420	434.99	74	55.60

Date	HE	Native Load less SEPA less Purch.	HMP'L Load Meter	HMP'L SEPA	HMP'L Load Less		W1	G1	H1	H2	G2	R1	R-CT
							Units Serving Load						
		180,752	48,449	600	47,849	-	180,752	-	-	-	-	-	-
01-Oct-14	1	248.90	62	-	62		248.90	0.00	0.00	0.00	0.00	0.00	0.00
01-Oct-14	2	215.15	63	-	63		215.15	0.00	0.00	0.00	0.00	0.00	0.00
01-Oct-14	3	262.35	63	-	63		262.35	0.00	0.00	0.00	0.00	0.00	0.00
01-Oct-14	4	254.37	62	-	62		254.37	0.00	0.00	0.00	0.00	0.00	0.00
01-Oct-14	5	241.33	63	-	63		241.33	0.00	0.00	0.00	0.00	0.00	0.00
01-Oct-14	6	239.38	65	-	65		239.38	0.00	0.00	0.00	0.00	0.00	0.00
01-Oct-14	7	263.00	70	-	70		263.00	0.00	0.00	0.00	0.00	0.00	0.00
01-Oct-14	8	267.20	71	-	71		267.20	0.00	0.00	0.00	0.00	0.00	0.00
01-Oct-14	9	285.26	73	1	72		285.26	0.00	0.00	0.00	0.00	0.00	0.00
01-Oct-14	10	289.70	76	2	74		289.70	0.00	0.00	0.00	0.00	0.00	0.00
01-Oct-14	11	315.68	78	3	75		315.68	0.00	0.00	0.00	0.00	0.00	0.00
01-Oct-14	12	328.70	81	5	76		328.70	0.00	0.00	0.00	0.00	0.00	0.00
01-Oct-14	13	347.81	85	5	80		347.81	0.00	0.00	0.00	0.00	0.00	0.00
01-Oct-14	14	288.12	88	4	84		288.12	0.00	0.00	0.00	0.00	0.00	0.00
01-Oct-14	15	296.21	89	4	85		296.21	0.00	0.00	0.00	0.00	0.00	0.00
01-Oct-14	16	305.39	89	4	85		305.39	0.00	0.00	0.00	0.00	0.00	0.00