COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

The Application of the Fuel Adjustment Clause of	)	
Kentucky Power Company From November 1, 2013	)	**Case No. 2014-00225**
Through April 30, 2014	)	

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC. AND
ATTORNEY GENERAL OF THE COMMONWEALTH OF KENTUCKY

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

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TABLE OF CONTENTS

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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 in Accounting degree and a Master of Business Administration degree from the University of Toledo. I also earned a Master of Arts degree in theology from Luther Rice University. I am a Certified Public Accountant ("CPA"), with a practicing license, a Certified Management Accountant ("CMA"), and a Chartered Global Management Accountant ("CGMA").

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

I have testified before the Kentucky Public Service Commission on dozens of occasions, including the most recent Kentucky Power Company ("Kentucky Power" or "Company") base rate proceedings, Case Nos. 2009-00459 and 2005-00341; the Company's Mitchell acquisition proceeding, Case No. 2012-00578; the Company's purchased wind power proceeding, Case No. 2009-00545; various Company Environmental Cost Recovery ("ECR") proceedings; and other proceedings involving the Company, Louisville Gas and Electric Company, Kentucky Utilities Company, Big Rivers Electric Corporation, and East Kentucky Power Cooperative, Inc. My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC"), a group of large customers taking electric service on the Kentucky Power Company system, and on behalf of the Attorney General of the Commonwealth of Kentucky ("AG"). The members of KIUC participating in this case are: Air Products & Chemicals, Inc., Air Liquide Large Industries U.S. LP, AK Steel Corporation, EQT Corporation, and Marathon Petroleum Company LP.

Q. Please describe the purpose of your testimony.

A. The purpose of my testimony is to address Kentucky Power's approach to allocating fuel costs between its native load customers and off-system sales customers during the November 1, 2013 through April 30, 2014 six-month review period. Throughout my testimony, I use the term "native load" to refer to Kentucky Power's retail customers, although I recognize that Kentucky Power also has two all-requirements wholesale native load customers.

I discuss why Kentucky Power's fuel cost allocation approach during the review period was improper, resulting in unfair, unjust, and unreasonable fuel adjustment clause ("FAC") rates for native load customers. My testimony focuses primarily on the January 1, 2014 through April 30, 2014 timeframe since: 1) the AEP Interconnection Agreement was no longer in effect at that time; and 2) Mitchell Units 1 and 2 began serving Kentucky Power's native load customers as of January 1, 2014. However, the rationale behind much of my testimony applies to the pre-January 1, 2014 portion of the review period as well.

Q. Please summarize your conclusions and recommendations.

A. Kentucky Power's fuel cost allocation approach during the review period was improper because it forced native load customers to pay unjust and unreasonable FAC rates in order to enhance the profitability of the Company's off-system sales.

The result of this improper fuel cost allocation approach was that the Company's native load customers paid more than the average costs for fuel while its off-system sales were allocated less than the average costs for fuel, rather than vice versa. During the period from January 1, 2014 through April 30, 2014, the Company's average fuel cost for all sales was $28.49/MWh, but the fuel cost allocated to the Company's native load customers was $31.67/MWh. In stark contrast, the average fuel cost allocated to off-system sales was only $24.13/MWh.

The primary reason for this anomalous result is that Kentucky Power improperly allocated 100% of its theoretical "no load" fuel costs (totaling $40.0 million during the six-month review period) for its six generating units to native load customers and none to off-system sales. The Company did so even though a portion of those "no load" costs were incurred to enable Kentucky Power to make off-system sales. After the Mitchell acquisition, the Company still assigned 100% of the Big Sandy 1 and 2 "no load" costs to native load even though the units no longer were necessary to serve native load. The allocation of 100% of "no load" fuel costs to native load customers is contrary to the principle of cost causation and results in cost shifting to native load customers in order to enhance the profitability of off-system sales.

No other utility in the Commonwealth uses the same fuel cost allocation approach as Kentucky Power. Instead, most utilities in Kentucky have adopted allocation methodologies that ensure their highest fuel costs are allocated to off-system sales for FAC purposes. Kentucky Power's fuel cost allocation approach also runs counter to the guidance provided by the Federal Energy Regulatory Commission ("FERC") in cases finding that native load customers are entitled to the utility's lowest cost generation and should not be forced to subsidize off-system sales or enhance the profitability of off-system sales.

Although I would characterize theoretical "no load" fuel costs as "variable" costs, Kentucky Power claims that the costs are "fixed." But even if the "no load" fuel costs are considered "fixed" costs, they still should be fairly allocated between native load customers and off-system sales customers. Such an approach is consistent with the Commission's precedent requiring Kentucky Power and the other Kentucky utilities to fairly allocate "fixed" environmental compliance costs between native load customers and off-system sales in the monthly environmental surcharge. The Commission required Kentucky Power to do so because the off-system sales could not have been made if the "fixed" costs had not been incurred. The same rationale is applicable to the "no load" fuel costs.

Moreover, in the Mitchell acquisition and transfer case (Case No. 2012-00578, the "Mitchell transfer case"), the Company failed to disclose the material fact that customers would be harmed through an increase in fuel costs due to the Company's allocation approach. Instead, the Company claimed, incorrectly, that customers would achieve $16.75 million in annualized fuel savings after the Mitchell units were transferred on January 1, 2014. The Commission relied on the Company's claimed savings in approving the transaction, as did the other parties who agreed to the Stipulation in that proceeding. The Company failed to disclose that it would assign 100% of an additional $38.252 million in annual theoretical "no load" fuel costs associated with the Mitchell units to native load customers through the FAC beginning January 1, 2014. In the Mitchell transfer case, Kentucky Power represented that the total rate increase to customers resulting from the asset transfer would be 5.3%. If the Company had included the effect of assigning the "no-load" costs of the Mitchell units to native load customers, then the total rate increase to customers resulting from the Mitchell acquisition would have been 12.81%.

Because Kentucky Power's fuel cost allocation approach during the review period was improper, resulting in unreasonably high FAC charges to native load customers, I recommend that the Commission order Kentucky Power to refund over a six-month period $12.648 million in excessive fuel costs collected from native load customers since January 1, 2014 through April 30, 2014 plus $0.864 million in interest through December 31, 2014 calculated at the Company's weighted average cost of capital. Interest at the weighted cost of capital should continue to run until the refund is fully implemented. I also recommend that the Commission direct Kentucky Power to modify its fuel cost allocation approach by adopting the methodology used by East Kentucky Power Cooperative ("EKPC") on a going-forward basis.

II. KENTUCKY POWER'S FUEL COST ALLOCATION APPROACH DURING THE REVIEW PERIOD WAS IMPROPER.

Q. Please describe Kentucky Power's approach to allocating fuel costs during the review period.

A. Each month, Kentucky Power performs an after-the-fact reconstruction of its fuel costs for FAC purposes that allocates the costs between native load and off-system sales. This allocation does not change the actual dispatch of the Company's generating units or the sales to native load customers and off-system sales.

The after-the-fact reconstruction incorporates various methodologies that systematically assign and allocate the highest costs to native load sales rather than to off-system sales. The result is that the FAC rate charged to native load customers is excessive and unreasonable, while the Company's off-system sales margins are improperly enhanced. Every dollar in fuel costs that is shifted to native load customers represents an additional dollar in off-system sales margins. The Company retains the entirety of the off-system sales margins pursuant to the Stipulation in the Mitchell transfer case.

During the review period, Kentucky Power allocated its fuel and purchased power expense between native load and off-system sales as follows: First, Kentucky Power calculated the theoretical "no load" fuel costs for its units and assigned all of those costs to native load customers. During the six-month review period this amount totaled $40.045 million. The theoretical "no load" fuel costs for each unit are equivalent to the constant in the dispatch equation, which assumes no generation at that level for actual dispatch purposes. The assumption of no generation reflects the fact that none of the generating units actually physically operate at such a "no load" level.

Next, Kentucky Power assigned 100% of its other minimum segment costs (other than the "no-load" costs) to native load customers unless the sum of the minimum segment capacity in the hour was greater than the native load. In those hours, the Company allocated a portion of the other minimum segment costs to off-system sales. In other words, only in the hours where it had so much excess capacity that the minimum operating levels of its units exceeded its native load did Kentucky Power allocate a portion of its minimum segment costs (other than the "no-load" costs) to off-system sales.

Finally, Kentucky Power allocated the remaining fuel costs in excess of the "no-load" costs and the costs incurred to generate at the minimum segments by economically "stacking" those costs in dispatch order, assigning the next increments of available generation each hour first to native load and then the final increments to off-system sales. This last step resulted in the economic stacking of only part of the Company's fuel costs, not all of its fuel costs.

Although Kentucky Power claims that it adopted this allocation approach while the AEP Interconnection Agreement was in effect, the Company actually modified the allocation approach on January 1, 2014 to include the second step. As discussed in greater detail by KIUC/AG witness Mr. Philip Hayet, this second step was introduced to address the significant excess capacity caused by adding the Mitchell capacity without eliminating the Big Sandy capacity.

Q. Why is Kentucky Power's fuel cost allocation approach improper?

A. It is inherently unreasonable and illogical to charge native load customers more for fuel than is allocated to off-system sales for FAC purposes. Instead, Kentucky Power's native load customers should be allocated the lowest fuel costs and off-system sales should be allocated the highest fuel costs. There are two interrelated problems with Kentucky Power's allocation approach that lead to this unreasonable result.

The first problem lies in the step where the Company assigns 100% of the theoretical "no load" fuel costs to native load customers despite the fact that a portion of those costs were incurred to enable and support off-system sales. This approach 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 profits.

The second problem lies in the step where the Company assigns all other minimum segment costs to native load customers unless the generation from all of the minimum segments in an hour exceeds the native load requirements. Only in that circumstance and only for those hours does the Company allocate any minimum segment costs to off-system sales. The minimum segment cost per kWh is greater than the cost of incremental generation. The primary problem with this approach is similar to that of the "no-load" costs, i.e., the Company considers the minimum segment costs essentially as "fixed" costs. This problem was exacerbated starting January 1, 2014 when the Mitchell units were acquired.

By treating both no-load fuel costs (which never get assigned to off-system sales) and minimum segment fuel costs (which only sometimes get allocated to off-system sales) as "fixed," Kentucky Power charged its native load customers a disproportionate share of its total fuel costs. Although the Company considers these costs "fixed," the Company nevertheless considered the other minimum segment fuel costs (other than the "no-load" costs) as variable in the limited circumstance where the generation from all of the minimum segments in an hour exceeds the native load requirements.

Q. What are "no load" fuel costs?

A. The "no-load" fuel cost is a dispatch concept and represents the constant in the generating unit's incremental cost curve. PJM defines "no load" cost as the "[c]ost per hour to maintain the boiler operating and the turbine and generator spinning at synchronous speed, but not generating any output."[1] PJM characterizes "no load" costs as "theoretical"[2] because thermal generating units cannot operate at a "no load" state (i.e. producing zero net output). The Company considers the "no-load" fuel cost as a component of the minimum segment cost, but never allocates any of the "no-load" cost to off-system sales.

Q. Is it appropriate for Kentucky Power to segregate theoretical "no load" fuel costs from the other fuel costs it incurs for allocation purposes?

A. No. The concept of "no load" costs is used by PJM for purposes of dispatching generating units. But the theoretical "no load" concept is not relevant and not appropriately applied to fuel cost allocation for FAC purposes, which is outside of PJM's purview. No other utilities in Kentucky (including EKPC and Duke, both of which are members of PJM) segregate theoretical "no load" fuel costs from other fuel costs for purposes of the FAC fuel cost allocation between native load customers and off-system sales.

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[1] "No-Load Definition: Educational Document," PJM, *available at* http://www.pjm.com/~/media/committees-groups/subcommittees/cds/20110620/20110620-item-03b-cds-educational-paper-for-no-load.ashx.
[2] Id.

Q. Were the "no load" fuel costs allocated to Kentucky Power's native load customers limited only to the costs associated with the generating units and generation necessary to serve those customers?

A. No. Kentucky Power allocated 100% of the theoretical "no load" fuel costs associated with all of its generating units to native load customers, even though not all of those units were necessary to serve native load customers. In its recent Integrated Resource Planning Report, the Company projected its 2014 reserve margin at 57.3%.[3] With the addition of the Mitchell units, Kentucky Power currently has a significant amount of excess capacity, which means that only the Rockport and Mitchell units are needed to serve native load customers in most hours. That means that the Big Sandy 1 and 2 units are "needed" only to serve off-system sales in most hours. Nevertheless, Kentucky Power still charged customers 100% of the "no-load" costs for its entire generation fleet during the review period.

Q. Does the fuel cost incurred by Kentucky Power for its entitlement to a portion of the output of the Rockport units lend itself to the Company's "no-load" allocation approach?

A. No. Kentucky Power is entitled to 15% of the output of each of the Rockport units through long-term purchase power agreements. The Rockport units are owned and operated by Indiana Michigan Power, an affiliate. Each month, Kentucky Power receives an invoice from AEP for the Rockport fuel costs associated with its entitlement. Those AEP invoices do not segregate Rockport "no load" fuel costs

[3] Integrated Resource Planning Report, Case No. 2013-00475 (December 20, 2013) at 14.

from other fuel costs. Rather, they simply charge Kentucky Power an overall cost for "Fuel." Kentucky Power performs an after-the-fact calculation to segregate out the theoretical "no load" fuel costs from the other Rockport fuel costs for FAC purposes.

This after-the-fact calculation results in Kentucky Power effectively "marking up" the Rockport fuel allocated to native load. For example, in February 2014, Kentucky Power purchased Rockport energy for $26.31/MWh. In the after the fact reconstruction for FAC purposes, it allocated a portion of that energy to native load customers at $28.76/MWh and allocated the rest to off-system sales at $23.463/MWh.[4] Marking up the Rockport fuel assigned to native load, and discounting the fuel assigned to off-system sales, allowed Kentucky Power to improperly profit from this affiliate purchase. I have attached a portion of the February 2014 invoice for Rockport to Kentucky Power as my Exhibit___(LK-2).

Q. Can you provide examples of how Kentucky Power's approach to allocating "no load" fuel costs harmed native load customers during the review period?

A. Yes. As a result of the Company's approach, the fuel cost per MWh allocated and charged to native load customers through the FAC was significantly greater than the cost per MWh charged to off-system sales during the review period. The following table compares the average April 2014 fuel cost for the Mitchell units with the cost per MWh allocated to native load and off-system sales:[5]

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[4] Kentucky Power Response to KIUC First Set of Data Requests, Item No. 5; Kentucky Power Response to Commission Staff's First Set of Data Requests, Item No. 29, Attachment 1.
[5] Kentucky Power Response to Commission Staff's First Set of Data Requests, Item No. 29, Attachment 1.

	April 2014 Fuel Cost ($/MWh)	Fuel Cost Allocated to Off-System Sales ($/MWh)	Fuel Cost Allocated to Native Load ($/MWh)
Mitchell 1	24.12	18.21	29.44
Mitchell 2	28.45	17.92	36.93

As the table demonstrates, during April of 2014, Kentucky Power allocated approximately 22% more than its average fuel cost for Mitchell Unit 1 to native load customers while allocating off-system sales approximately 24% less than the Mitchell Unit 1 average fuel cost. And Kentucky Power allocated approximately 30% more than its average fuel cost for Mi.tchell Unit 2 to native load customers while allocating off-system sales approximately 37% less than the Mitchell Unit 2 average fuel cost. This resulted in native load customers paying approximately 62% more in fuel costs for Mitchell Unit 1 and approximately 106% more in fuel costs for Mitchell Unit 2 than the cost allocated to off-system sales that month.

This pattern of allocating native load customers above-average costs for fuel while allocating off-system sales below-average costs for fuel costs occurred in other months as well and with respect to other generating units, as demonstrated below.

KENTUCKY POWER COMPANY
COMPARISON OF ACTUAL FUEL EXPENSE PER MWH, FUEL EXPENSE PER MWH CHARGED TO RETAIL NATIVE LOAD CUSTOMERS, AND FUEL EXPENSE PER MWH ALLOCATED TO OFF-SYSTEM SALES

	Nov. 2013	Dec. 2013	Jan. 2014	Feb. 2014	Mar. 2014	Apr. 2014
Rockport 1						
Fuel Cost $ Per MWH By Generating Plant	25.54	25.36	24.21	25.96	22.19	25.38
Fuel Cost $ Per MWH Allocated to Off-System Sales	23.33	23.21	22.13	23.59	22.41	22.88
Fuel Cost $ Per MWH Allocated to Native Load	25.94	26.62	25.73	28.55	22.07	28.95
Rockport 2						
Fuel Cost $ Per MWH By Generating Plant	25.35	25.15	23.94	26.66	22.23	26.13
Fuel Cost $ Per MWH Allocated to Off-System Sales	23.23	23.04	21.91	23.30	21.97	22.63
Fuel Cost $ Per MWH Allocated to Native Load	25.71	26.15	25.22	28.93	22.35	30.68
Mitchell 1						
Fuel Cost $ Per MWH By Generating Plant			31.91	37.66	30.64	24.12
Fuel Cost $ Per MWH Allocated to Off-System Sales			23.83	23.94	24.67	18.21
Fuel Cost $ Per MWH Allocated to Native Load			33.82	38.56	35.35	29.44
Mitchell 2						
Fuel Cost $ Per MWH By Generating Plant			29.17	29.46	25.34	28.45
Fuel Cost $ Per MWH Allocated to Off-System Sales			23.78	25.01	23.45	17.92
Fuel Cost $ Per MWH Allocated to Native Load			30.69	30.17	26.14	36.93
Big Sandy Plant						
Fuel Cost $ Per MWH By Generating Plant	57.88	34.82	31.18	29.54	31.38	30.22
Fuel Cost $ Per MWH Allocated to Off-System Sales	32.00	54.51	25.59	26.79	26.22	24.75
Fuel Cost $ Per MWH Allocated to Native Load	62.53	18.44	35.29	32.54	36.25	38.27

Q. How did Kentucky Power's average fuel cost compare to the fuel cost allocated to native load customers and to off-system sales for the January 2014 through April 2014 portion of the review period in this proceeding?

A. From January through April 2014, Kentucky Power's average fuel cost was \$28.49/MWh. But the average fuel cost allocated to native load customers during that period was \$31.67/MWh. In contrast, the average fuel costs allocated to off-system sales customers during that period was \$24.13/MWh. Consequently, Kentucky Power allocated approximately 31% more in fuel costs on a per MWh basis to native load customers than to off-system sales during that period. These figures are included in my attached Exhibit___ (LK-3).

Q. Why is the disparity in fuel costs allocated to native load customers and off-system sales greater in the lower usage months such as April?

A. Kentucky Power's current fuel cost allocation approach results in higher FAC charges to native load customers during lower usage months because the same amount of "no load" and other minimum segment costs are being allocated to native load customers, but collected over a smaller number of kilowatt hour sales. This results in a greater disparity between the costs allocated to native load customers and off-system sales and illustrates the problems with Kentucky Power's improper fuel cost allocation approach.

Q. What other problems are highlighted by the information in the chart above?

A. The chart demonstrates that in the Company's after the fact reconstruction a significant portion of the Rockport 1 and 2 generation was allocated to off-system sales instead of being retained by native load customers. The chart above reflects that the Rockport generating units generally have the lowest fuel costs on Kentucky Power's system, averaging \$24.77/MWh for Rockport Unit 1 and \$24.91/MWh for Rockport Unit 2 (\$24.64/MWh and \$24.73/MWh respectively on a weighted average basis) during the review period. The 390 MW provided by the Rockport units alone is sufficient to meet approximately 40% of Kentucky Power's native load energy requirements. Yet Kentucky Power allocated a significant amount of the low cost Rockport generation to off-system sales, allocating an average of 44% of the Rockport generation and related fuel costs to off-system sales from January through

April 2014.[6] Under the economic dispatch principles used by EKPC and other utilities for FAC purposes, Rockport would be at the bottom of the generation stack and assigned to native load first as the least-cost resource.

The chart also demonstrates that a significant portion of the Big Sandy fuel costs were allocated to native load customers from January through April 2014. The chart above reflects that the Big Sandy generating units generally have the highest fuel costs on Kentucky Power's system, averaging \$35.84/MWh (\$31.59/MWh on a weighted average basis) during the review period. With the Rockport and Mitchell units operating, neither of the Big Sandy units generally is needed to meet the Company's native load energy needs, based on the hourly data provided in response to KIUC 1-11. Even at the Company's winter peak, Big Sandy 1 and a significant portion of Big Sandy 2 were not needed to meet the native load energy needs. Yet Kentucky Power allocated a significant amount of those high Big Sandy fuel costs to native load customers in all hours they were available and operating, assigning an average of approximately 56% of Big Sandy Unit 1 and 47% of Big Sandy Unit 2 to native load customers from January through April 2014.[7] Under the economic dispatch principles used by EKPC and other utilities for FAC purposes, the Big Sandy units would be at the top of the generation stack and rarely assigned to native load as the last resource.

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[6] Kentucky Power Response to Commission Staff's First Set of Data Requests, Item No. 29, Attachment 1.
[7] Kentucky Power Response to Commission Staff's First Set of Data Requests, Item No. 29, Attachment 1.

Q. How much "no load" cost did Kentucky Power collect from native load from January 1, 2014 through April 30, 2014?

A. Native load customers paid more than $40 million in no-load fuel costs during the entire review period, and paid $31.649 million in "no load" fuel costs from January through April 2014.[8] This represents 25% of the total fuel costs ($124,284,693) charged during that period. Additionally, native load customers were allocated more fuel costs than their proportionate share of Kentucky Power's sales during the January 1, 2014 through April 30, 2014 period. As demonstrated in my attached Exhibit___(LK-3), native load customers were allocated 64% of Kentucky Power's fuel costs. But native load only represented 58% of Kentucky Power's sales during that period. Kentucky Power's fuel cost allocation approach therefore resulted in disproportionate fuel charges to native load customers.

Q. Do any other utilities in Kentucky use the "no load" cost allocation approach adopted by Kentucky Power?

A. No. The other utilities in Kentucky do not recognize theoretical "no load" costs for fuel cost allocation purposes. Under EKPC's 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. The process of stacking and assigning the highest cost resources to off-system sales protects EKPC's native load from having no-load cost assigned

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[8] Kentucky Power Response to Commission Staff's First Set of Data Requests, Item No. 29, Attachment 2.

inappropriately."[9] EKPC "does not track no-load cost and does not segregate no-load cost in its energy accounting for the fuel clause."[10]

Duke Energy Kentucky, Inc. ("Duke") described its fuel cost allocation process as follows: "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."[11] Duke "doesn't track how much of the total energy cost consumed in a month is related to no-load costs." [12]

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] LG&E and KU "[do] not utilize the term 'No load costs' in the dispatch and operation of [their] system[s]."[14]

Big Rivers Electric Corporation ("Big Rivers") uses a form of system average cost allocation between native load and off-system sales, but "[t]he no-load cost is a cost Big Rivers does not quantify because Big Rivers does not operate at a no-load state."[15] According to Big Rivers "there is no distinction made in the allocation of

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[9] EKPC Response to Commission Staff's Information Request Dated 08/13/014, Case No. 2014-00226, Request 29.
[10] EKPC Response to Commission Staff's Information Request Dated 08/13/014, Case No. 2014-00226, Request 29.
[11] Duke Kentucky Response to Staff First Set of Data Requests, Case No. 2014-00229, Staff-DR-01-029.
[12] Duke Kentucky Response to Staff First Set of Data Requests, Case No. 2014-00229, Staff-DR-01-029.
[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.
[14] LG&E Response to Information Request in Appendix of Commission's Order Dated August 13, 2014, Case No. 2014-00228, Question No. 27; KU Response to Information Request in Appendix of Commission's Order Dated August 13, 2014, Case No. 2014-00227, Question No. 27.
[15] Big Rivers Response to Commission Staff's Request for Information Date August 13, 2014, Case No. 2014-00230, Item No. 29.

these theoretical costs between native-load and off-system sales."[16]

Data responses from the other Kentucky utilities regarding their fuel cost allocation approaches, as well as a presentation on KU/LG&E's joint dispatch approach, are attached as Exhibit___(LK-4).

Q. Is there another reason that you believe Kentucky Power's fuel cost allocation approach is improper?

A. Yes. Counsel informs me that Kentucky's FAC regulation, 807 K.A.R. 5:056, is modeled upon the FERC's fuel regulation, 18 C.F.R. §35.14.[17] 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.

The FERC has told Appalachian Power Company ("APCO"), a Kentucky Power affiliate company, 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*

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[16] Big Rivers Response to Commission Staff's Request for Information Date August 13, 2014, Case No. 2014-00230, Item No. 29.
[17] 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.*").

lower fuel cost resources are reserved for the benefit of the APCO native load customers who, through their rates, provide for the construction and operation of the generating facilities."[18] Additionally, the FERC has rejected a fuel cost allocation approach that assigned system average fuel costs to both native load and off-system sales (which is the approach taken by Big Rivers) because it forced native load customers to subsidize off-system sales by paying higher incremental fuel costs associated with those sales.[19] Thus, even an approach that allocates fuel costs *equally* to native load and off-system sales customers was not found satisfactory by the FERC.

The rationale set forth in the FERC cases reinforces my opinion that Kentucky Power's fuel cost allocation approach is improper. Kentucky Power's fuel cost allocation approach harms native customers even more than the system average allocation approach rejected by the FERC. Instead of allocating the same fuel cost to native load and off-system sales, Kentucky Power assigns native load *above*-average fuel costs.

Q. Why is it especially important that Kentucky Power allocate its fuel costs between native load customers and off-system sales properly?

A. As mentioned above, Kentucky Power currently has a very high reserve margin (57.3%) as a result of the transfer of the Mitchell assets to the Company on January

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[18] Order Accepting Rates for Filing, Granting Intervention and Terminating Docket, Docket No. ER83-63-000 (December 17, 1982) at 2.

[19] 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.

1, 2014.[20] Because Kentucky Power currently has a significant amount of excess capacity, it can make a substantial amount of off-system sales. In fact, off-system sales constituted 42% of Kentucky Power's total sales from January 1, 2014 through April 30, 2014. Thus, it is especially important that native load customers are not harmed in order to enhance the profitability of the Company's substantial off-system sales.

III. KENTUCKY POWER'S "NO LOAD" AND MINIMUM SEGMENT COSTS SHOULD BE TREATED SIMILARLY TO "FIXED" ENVIRONMENTAL COSTS AND ALLOCATED FAIRLY BETWEEN NATIVE LOAD CUSTOMERS AND OFF-SYSTEM SALES

Q. How would you characterize Kentucky Power's "no load" and other minimum segment costs?

A. I would characterize Kentucky Power's "no load" and other minimum segment costs as "variable" fuel costs. The costs of fuel and consumables generally are considered by the utilities in Kentucky to be "variable" costs; they are not segregated into fixed and variable components in cost-of-service studies. For base ratemaking purposes, Kentucky Power treats all of its fuel costs as variable. I have attached a Kentucky Power cost-of-service study treating the costs of fuel and consumables in this manner in my Exhibit___(LK-5).

Q. How does Kentucky Power characterize "no load" costs?

A. Kentucky Power alleges that its "no load" costs are "fixed" costs. The Company

[20] Integrated Resource Planning Report, Case No. 2013-00475 (December 20, 2013) at 14.

states that "'[n]o load' costs are essentially 'fixed fuel.' Because they are independent of unit output, they cannot be utilized in an economic dispatch."[21]

Q. Does Kentucky Power's characterization of "no load" costs as "fixed" change your recommendation?

A. No. Even if Kentucky Power's "no load" costs could properly be characterized as "fixed," that characterization would not change my recommendation that the Company's off-system sales should be allocated the portion of the "no load" costs incurred to enable off-system sales.

Q. Does Kentucky Power allocate any other "fixed" costs between native load customers and off-system sales?

A. Yes. Kentucky Power allocates some of its "no load" environmental costs to its off-system sales customers in the monthly environmental surcharge filings, even though those costs are similarly "fixed." So do all of the other utilities in Kentucky. In response to a Commission Staff data request, Kentucky Power indicated that "[a] portion of environmental consumable costs is also classified as 'no load costs' and is recovered through base rates or the environmental surcharge."[22] The other portion of those "fixed" "no load" environmental costs (i.e. costs of low NO_X burners, Continuous Emission Monitors, etc.) are allocated to Kentucky Power's off-system sales in the environmental surcharge.

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[21] Kentucky Power Response to KIUC First Set of Data Requests, Item No. 3.
[22] Kentucky Power Response to Commission Staff's First Set of Data Requests, Item No. 29.

The rationale behind this practice is that but for the "fixed" environmental costs, the off-system sales could not be made. The same rationale applies in this case to Kentucky Power's "fixed" "no load" fuel costs, as well as its other "fixed" minimum segment fuel costs.

The Commission has previously required Kentucky Power to allocate "fixed" environmental compliance costs between native load customers and off-system sales customers in the environmental surcharge. In response to arguments by Kentucky Power that most of its "fixed" environmental compliance surcharge costs should be assigned only to its native load customers and all-requirements wholesale customers, but not to off-system sales, the Commission stated:

> Kentucky Power's generating facilities are currently used to make off-system sales and the cost of environmental improvements should be allocated to both retail and off-system sales. Kentucky Power has failed to demonstrate that the allocation of the surcharge to off-system sales would lower the margins on those sales to the point they would be uneconomical. To the extent that Kentucky Power is able to sell power off-system, proper cost allocation requires that the costs attributable to those sales, including environmental costs, be assigned to such sales, rather than being charged to retail sales.[23]

The Franklin Circuit Court affirmed the decision of the Commission with respect to the allocation of "fixed" environmental compliance costs to off-system sales, ruling:

> Because Kentucky Power's system is currently operated to supply wholesale sales for resale, a representative cost allocation must be made to these sales....Despite the huge blocks of power sold off-system, Kentucky Power maintains that Kentucky ratepayers should pay for 98.6% of all its new environmental costs. The Commission disagreed and ruled that costs should be allocated to the cost causer. The Commission held that there is some relationship between the energy consumed and the pollution caused by generating that energy. That decision is reasonable and should be affirmed.[24]

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[23] Order, Case No. 96-489 (May 27, 1997).
[24] *Commonwealth of Kentucky v. Kentucky Public Service Commission*, Franklin Circuit Court, Consolidated

In 2001, when Kentucky Power again tried to allocate the vast majority of its fixed environmental costs to native load customers, the Commission again rejected such an approach, stating:

> We further agree with the arguments of KIUC, which notes that significant levels of Kentucky Power's sales are made to off-system customers. Under these conditions, it is neither appropriate nor reasonable to allocate a greater share of Kentucky Power's environmental costs to its jurisdictional ratepayers, and in effect subsidize off system sales customers.[25]
>
> ***
>
> The Commission has consistently rejected the argument that since a utility's generating facilities were installed to meet the needs of its jurisdictional customers, all environmental costs should be borne by those customers, even when the utility is also making off-system sales. Kentucky Power has offered nothing new here, but instead has simply repeated arguments which have already been rejected in this proceeding. Rather than not recovering the environmental costs assigned to off-system sales, regardless of whether these sales are to affiliates or non-affiliates, what will happen is that the margins made on the sale will be lower.[26]

Accordingly, even if the Commission considers Kentucky Power's "no load" and other minimum segment fuel costs to be "fixed" costs, those costs should be treated similarly to Kentucky Power's "fixed" environmental compliance costs, i.e. fairly allocated between native load customers and off-system sales.

Case Nos. 97-CI-114, 97-CI-01138, and 97-CI-01319 (April 30, 1998) at 19.
[25] Order, Case No. 2000-107 (February 8, 2001).
[26] Order, Case No. 2000-107 (February 8, 2001).

IV. KENTUCKY POWER FAILED TO ACCOUNT FOR THE HARMFUL IMPACTS OF ITS IMPROPER FUEL COST ALLOCATION APPROACH WHEN IT CLAIMED THAT THERE WOULD BE $16.75 MILLION IN FUEL SAVINGS TO NATIVE LOAD CUSTOMERS FROM THE MITCHELL ASSET TRANSFER.

Q. Please provide a brief background on Kentucky Power's representations regarding fuel savings in the Mitchell transfer case.

A. In the Mitchell transfer case, Kentucky Power represented that transferring 50% of Mitchell Units 1 and 2 to the Company would result in approximately $16.75 million in fuel savings to native load customers. Specifically, the Stipulation in that case (attached as my Exhibit___(LK-6)) provided:

> Because of the anticipated lower fuel costs of Mitchell Units 1 and 2 vis-a-vis the anticipated fuel costs of the Big Sandy units, the transfer of the Mitchell units to Kentucky Power is expected to provide Kentucky Power customers with the benefit of reduced fuel costs of approximately $2.50/MWh. Based on 2012 jurisdictional kWh sales of 6.7 GWh, the benefits are estimated to total $16.75 million annually.[27]

In its Order approving the Stipulation in that case, the Commission cited the anticipated $16.75 million in fuel savings.[28]

Q. Have native load customers actually obtained $16.75 million in fuel savings as a result of the Mitchell asset transfer?

A. No. Kentucky Power's representations in the Mitchell Asset transfer case were in incorrect. Instead of $16.75 million in fuel savings, the Mitchell asset transfer

[27] Stipulation and Settlement Agreement, Case No. 2012-00578 (July 2, 2013)("Mitchell Stipulation") at 5.
[28] Order, Case No. 2012-00578 (October 7, 2013) at 33.

resulted in additional "no load" and minimum segment costs being allocated to native load customers beginning January 1, 2014. Specifically, from January 1, 2014 through April 30, 2014, Kentucky Power's native load customers were charged $13.155 million in Mitchell "no load" costs in addition to the "no load" costs associated with the Company's other generating units. The Company has estimated the annual Mitchell no-load costs at $38.252 million.

Q. What were the actual rate impacts of the Mitchell asset transfer?

A. Rather than the receiving the 5.33% rate increase projected by Kentucky Power in the Mitchell Asset transfer case, the actual rate increase to customers, including the effects of the transfer was 15.0%.[29] A large portion of that increase was the result of the additional $38.252 million in "no load" costs associated with the Mitchell units that were allocated entirely to native load customers beginning January 1, 2014. Including those Mitchell "no load" fuel costs in the Company's Mitchell transfer case rate impact calculation increases the projected rate increase from 5.33% to 12.81%.[30] If the other minimum segment fuel costs from Mitchell were included, the projected rate increase would be even greater.

I would also note that in estimating the $16.75 million fuel savings figure, the Company assumed that the lower Mitchell fuel cost would be allocated 100% to native load customers under the assumption that the units would serve native load customers 100% of the time. However, under the Company's allocation approach, the Company allocated the 30% of the Mitchell generation and lower fuel costs to

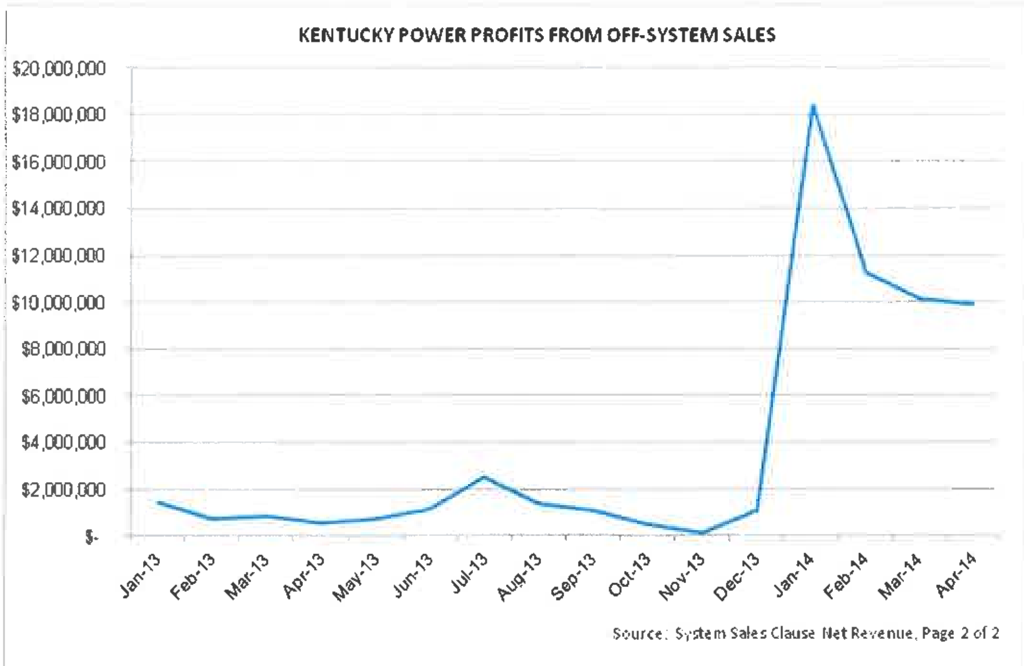
[29] Kentucky Power Response to Commission Staff's Third Set of Data Requests, Item No. 11, Attachment 1.
[30] Kentucky Power Response to Commission Staff's Third Set of Data Requests, Item No. 9

off-system sales since January 1, 2014 through the end of the review period.[31] Reducing the claimed $16.75 million in fuel savings by 30% results in estimated fuel savings to native load customers of approximately $11.725 million, a $5.025million reduction.

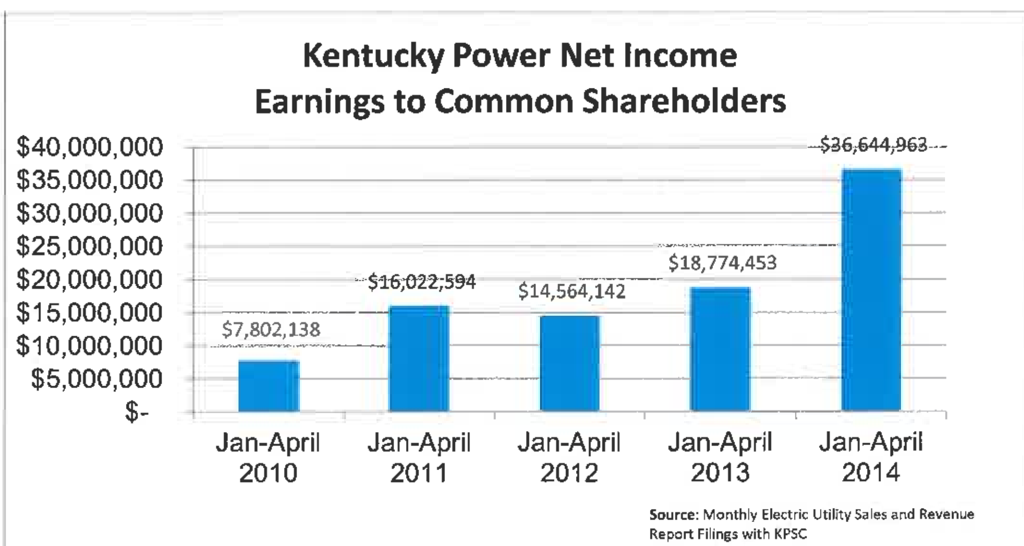
Q. How did the Mitchell asset transfer impact Kentucky Power?

A. While the Mitchell asset transfer resulted in an additional $38.252 million in annual theoretical "no load" fuel costs and other increased minimum segment costs for its native load customers in addition to a rate increase from the Asset Transfer Rider, Kentucky Power has reaped significant benefits as a result of the transfer. Pursuant to the Stipulation in the Mitchell transfer case, Kentucky Power has retained 100% of its profits from off-system sales since January 1, 2014.[32] And those off-system sales profits were significant. Kentucky Power's off-system sales profits jumped from $1,117,310 in December 2013 to $18,397,861 in January 2014, $11,262,678 in February 2014, $10,109,741 in March 2014, and $9,865,627 in April 2014. Kentucky Power's off-system sales profits from January 2013 through April 2014 are set forth in the following chart. The detail is provided in my Exhibit___(LK-7).

[31] Kentucky Power Response to Commission Staff's First Set of Data Requests, Item No. 29, Attachment 1.
[32] Mitchell Stipulation at 7.



These significant off-system sales margins, which were substantially enhanced by an improper fuel allocation, contributed to significant total Company profits during the first four months of 2014. The chart below compares the Company's January-April profits over the last five years. Exhibit___(LK-8).



One factor contributing to Kentucky Power's high profits from January 1, 2014 through April 30, 2014 was that the Company was able to make substantial off-system sales during that period and keep all of the profits from those sales. As mentioned above, off-system sales constituted 42% of Kentucky Power's total sales from January 1, 2014 through April 30, 2014. And by assigning 100% of its "no load" fuel costs and an excessive portion of its other minimum segment fuel costs to native load customers, it was able to reduce the fuel costs allocated to off-system sales and thus unreasonably increase its profit margins on those sales.

V. THE COMMISSION SHOULD REQUIRE KENTUCKY POWER TO REFUND $12.648 MILLION IN IMPROPERLY COLLECTED FUEL COSTS TO KENTUCKY RETAIL NATIVE LOAD CUSTOMERS PLUS INTEREST OF $0.864 MILLION AND TO MODIFY ITS FUEL COST ALLOCATION FOR FAC PURPOSES GOING-FORWARD.

Q. What actions do you recommend that the Commission take in this case?

A. I recommend that the Commission order Kentucky Power to refund the excessive fuel costs that were improperly allocated to native load customers and recovered through the FAC, with interest. Mr. Hayet quantifies the amount of the excessive FAC fuel costs that should be refunded. Mr. Hayet recalculated the fuel costs that should have been allocated to native load customers during the January through April period using the same methodology as used by EKPC. I believe that the EKPC method which allocates the lowest fuel costs to native load each hour is reasonable and should be adopted here. The interest on those unreasonable costs should be calculated at Kentucky Power's weighted average cost of capital. This would result in a total refund of $13.512 million ($12.648 million excess fuel costs + $0.864 million in interest through December 31, 2014) as shown in the following table.

Kentucky Power Company Fuel Adjustment Clause
Refund of Excess Fuel Costs Plus Interest at Weighted Cost of Capit
January 1, 2014 through April 30, 2014

Month/Year		Excess Fuel Refund	Interest @ Wtd COC	Total Refund
1	2014	3,700,388	12,458	
2	2014	2,108,574	32,099	
3	2014	1,639,056	44,932	
4	2014	5,200,089	68,260	
5	2014		86,226	
6	2014		86,807	
7	2014		87,391	
8	2014		87,980	
9	2014		88,572	
10	2014		89,168	
11	2014		89,769	
12	2014		90,373	
Total Refund		12,648,107	864,034	13,512,141

Given Kentucky Power's significant off-system sales profits since January 1, 2014, the Company still will retain substantial profits after this refund. The refund should take place over a six-month period. The Commission also should require Kentucky Power to modify its fuel cost allocation approach on a going-forward basis.

Q. Why is your recommended refund limited to excess fuel costs collected only during the January 1, 2014 through April 30, 2014 period?

A. To be clear, it is my opinion that any "no load," excessive minimum segment, and all other excessive fuel costs that Kentucky Power improperly allocated and charged to native load customers during the entire review period should be refunded to customers. However, the excessive costs allocated to native load customers in November and December 2013 were collected while the AEP Interconnection Agreement was still in effect. The inter-company cost sharing arrangement set forth in the AEP Interconnection Agreement makes calculation of any excessive fuel costs collected in those months more difficult. It would be appropriate to address the calculation of those excessive costs during Kentucky Power's upcoming two-year FAC review case.

Q. How should Kentucky Power modify its fuel cost allocation approach going-forward?

A. I recommend that Kentucky Power be required to adopt the fuel cost allocation approach used by EKPC for FAC purposes. Like Kentucky Power, EKPC is also is a member of PJM. Economically "stacking" costs every hour and assigning the highest cost resources to off-system sales protects customers from disproportionate or unreasonably high FAC charges.

VI. THE COMPANY HAS ACKNOWLEDGED AN ERROR THAT OVERSTATED PURCHASED POWER COSTS

Q. Please describe the error identified by the Staff and acknowledged by the Company that overstated its purchased power costs.

A. The Company incorrectly included the actual cost of non-economy purchased power expense in the FAC during the review period based on an erroneous interpretation of Commission orders for another utility. Instead, the Company should have re-priced the cost of this purchased power at the lower of actual cost or the cost of generation using the peaking unit equivalent methodology in accordance with the Commission's Order in Case No. 2000-00495-B addressing this issue specifically for the Company. The Company acknowledged this error in its response to Staff 3-1.

Q. Has the Company provided a quantification of this error in response to Staff discovery?

A. Yes. The Company quantified the effects of this error at $0.084 million in response to Staff 3-8. The Company's response to Staff 3-8 revised an earlier quantification that it provided in response to Staff 2-1.

Q. Should the Commission direct the Company to correct this error if the Company has not already done so?

A. Yes.

Q. Does this complete your testimony?

A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

LANE KOLLEN, being duly sworn, deposes and states: that the attached are his sworn Testimony and Exhibits 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
9th day of October 2014.

Notary Public

LEAH J WELLBORN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
MAY 28, 2017
FULTON COUTY, GEORGIA