COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

APPLICATION OF BIG RIVERS ELECTRIC	)
CORPORATION FOR A GENERAL ADJUSTMENT	) **Case No. 2013-00199**
IN RATES	)

<u>PUBLIC VERSION</u>

DIRECT TESTIMONY

AND EXHIBITS

OF

PHILIP HAYET

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

October 28, 2013

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DIRECT TESTIMONY OF PHILIP HAYET

I. QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Philip Hayet, and 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 your business title?

A. I am an Electrical Engineer, and my title is Director of Consulting.

Q. Please summarize your education and professional experience.

A. I received a Bachelor of Electrical Engineering degree from Purdue University and a Master of Electrical Engineering degree from the Georgia Institute of Technology, with a specialization in Power Systems.

I have over thirty years of experience in the electric utility industry, in which I have worked in the areas of generation resource planning, economic analysis, and rate analysis. I began my career with Energy Management Associates ("EMA" now known as Venytx), an Atlanta based utility consulting firm, where I provided client support services and performed consulting studies using the firm's PROMOD IV™ ("PROMOD") and Strategist software. PROMOD and Strategist are production cost and planning models that are similar to the tools used in the Big Rivers Electric Corporation ("Big Rivers" or "the Company") studies performed in this proceeding.

In 1996, I began my own consulting firm, Hayet Power Systems Consulting ("HPSC"), and continued to work in the areas of generation resource planning and analysis, rate case support, and new generation technology analysis. In addition to working for HPSC, in July 2000, I joined Kennedy and Associates, where I perform similar analyses. A list of my specific regulatory appearances can be found in Exhibit___(PH-1).

Q. Have you previously filed testimony at the Kentucky Public Service Commission ("Commission" or "PSC")?

A. Yes, In July 2012, I filed testimony in Big Rivers' 2012 Environmental Compliance Plan case, Case No. 2012-00063. In April 2013, I filed testimony in Kentucky Power Company's Certificate of Public Convenience and Necessity case, Case No. 2012-00578, in which Kentucky Power sought approval to acquire a 50% interest in the Mitchell Generating Station. I have also filed testimony and testified before other state regulatory commissions and the Federal Energy Regulatory Commission, mostly concerning production cost and resource planning issues.

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

A. I am testifying on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC"), which is a group of large customers served by Big Rivers.

II. PURPOSE

Q. Please summarize your testimony.

A. The Company's requested rate increases in the pending Century rate case, Case No. 2012-00535 and in this proceeding ("Alcan rate case") were caused by the loss of smelter load that accounted for nearly 70% of the Company's energy requirements. The Company's response to the loss of this load and revenue is described in its so-called "Load Mitigation Plan", which calls for massive upfront rate increases before the resolution of any of its underlying problems of excess physical generating capacity and the related fixed costs. The Company's witnesses in the Century proceeding and in this case state their belief that these rate increases will be temporary based on their projections of replacement load and increasing profits from market sales. The Company has performed production cost and financial modeling analyses intended to predict the impacts of the Century and Alcan rate increases and the subsequent mitigation of those increases in the future if its Load Mitigation Plan is successful. This testimony concerns my review of the assumptions incorporated in and the results from the Company's production cost modeling analyses, and in particular, I evaluate the economics of the Wilson and Coleman plants, the risk of CO_2 and other environmental costs, and the Company's replacement load assumptions.[1]

Q. Please summarize your conclusions and recommendations.

A. My conclusions and recommendations are:

1. The Company's Load Mitigation Plan is premised on unrealistic or clearly erroneous assumptions, including:
   A. The addition of 800 MW and 5,256,000 MWH of unsubstantiated replacement load over a six year period in addition to its native load and MISO market sales;
   B. The failure to consider CO_2 impacts stemming from regulatory requirements, which will increase coal generation costs and market sales revenues. The impact on coal generation costs will far exceed the benefit of increased market sales revenues;
   C. The failure to consider other costs, including environmental capital and operating costs, in its modeling decision of whether it is economic to restart either Wilson or Coleman; and,
   D. The failure to consider selling Coleman or Wilson for fair market value, and instead requiring that the units be sold at [redacted]. This decision has artificially constrained the sales process by refusing to recognize that fair market value for these units [redacted].
2. Big Rivers' Load Mitigation Plan is based on nothing more than unfounded hope and speculation. It needs to be fundamentally reevaluated to consider other business options in order to right-size the Company and to avoid a complete bailout by the customers, who can ill afford to pay higher and higher rates. The

[1] While the Company supplied numerous production cost results spreadsheets, no written report summarizing input data, output results, findings or conclusions was developed and produced.

Company's Load Mitigation Plan is based on the hope that market capacity and energy prices will dramatically increase, incredible amounts of replacement load will be added, and CO_2 regulations will not be implemented or will have little impact on Big Rivers, which is a largely coal-fired utility. The Load Mitigation Plan builds on these hopes with the further expectation that Big Rivers will become a successful merchant generator, which has been a difficult endeavor for even the largest utility companies in the U.S, let alone a junk bond rated cooperative electric utility. Finally, the Company uses these highly speculative assumptions to claim that the proposed rate increases will only be temporary. The Company has supplied few studies, no written analyses, and little evidence supporting its assumptions regarding replacement load and its position that profits from market sales will lead it out of this quagmire and back to solid financial footing. The Commission should reject the Company's rate request, and should instead rely on KIUC's more sensible rate plan. The Commission should direct the Company to re-evaluate other options to right-size the Company. KIUC witness Kollen presents KIUC's Rate Plan and related recommendations to resolve the Company's underlying problems.

III. BIG RIVERS LOAD MITIGATION PLAN

Q. Please describe the Big River's System.

A. Big Rivers is a relatively small Rural Electric Generation and Transmission Cooperative Company, which had a peak demand and native load requirement in 2012 of approximately 1,500 MW and 10,700,000 MWH, respectively, consisting of rural, large industrial and smelter load.[2] Big Rivers principally serves the wholesale electricity requirements of its three distribution cooperative member-owners, which are Jackson Purchase Energy Corporation, Kenergy Corp., and Meade County Rural Electric Cooperative Corporation, collectively known as the "Members". Big Rivers operates four primarily coal-fired plants, Coleman, Green, Reid and Wilson, has an

[2] Peak demand derived from Big Rivers LTFC2011.xlsx, and energy from Financial Forecast (2014-2027) 5-16-2013.xlsx.

agreement with the City of Henderson to operate and receive power from the Station Two coal-fired units, and has an entitlement to capacity from the SEPA hydro project. Big Rivers generating capability is approximately [redacted] MW based on MISO's unforced capacity ("UCAP") rating.[3]

Q. What are the major events that led to this filing?

A. On January 31, 2013, Alcan Primary Products Corporation ("Alcan")[4] issued notice that it would discontinue service with Big Rivers on January 31, 2014. Prior to that, on August 20, 2012, Century Aluminum of Kentucky General Partnership ("Century") issued notice that it would discontinue service with Big Rivers effective August 20, 2013. As the result of the Smelter terminations, Big Rivers will lose 850 MW of demand, which amounts to 57% of Big Rivers 2012 total peak demand. The combined energy usage of the smelters was approximately 7,300,000 MWH, or 69% of the total 2012 native load energy requirements.[5] The smelters also represented 69% of Big Rivers' total native load revenue.[6] This loss of load and revenue led Big Rivers to begin implementing its Load Concentration Analysis and Mitigation Plan ("Load Mitigation Plan").

Q. Please discuss the Company's Load Mitigation Plan.

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[3] Big Rivers response to KIUC 1-2b

[4] Note that the Alcan Primary Products Corporation aluminum smelting facility was purchased by Century Aluminum Sebree, LLC on June 1, 2013. For purposes of this testimony, I continue to refer to this retail customer as Alcan.

[5] Response to KIUC 1 - 30(c-1)

A. Company witness Berry discusses the Load Mitigation Plan in his testimony, and he explains there are four steps in the plan, which are: 1) petition for a rate increase; 2) increase off-system sales; 3) idle or reduce generation when market prices do not support the cost of generation; and 4) either find replacement load for the 850 MW (7,300,000 MWH) lost smelter load or sell some of its generating units.

Q. Does Big Rivers express confidence that the Load Mitigation Plan will solve the Company's problems?

A. Yes. In his testimony, President and CEO, Mark Bailey claims that with the rate relief, Big Rivers will be in a more stable position, and will have begun the recovery process. Mr. Bailey states, "So, although Big Rivers is in a difficult transition period, if it can secure the needed rate relief, Big Rivers will be well-positioned for the future."[7] Mr. Berry, who lays out the Load Mitigation Plan in his testimony, responds to the question of whether "...Big Rivers' mitigation efforts have any chance of success given the low prices in the current short-term wholesale power market?", by expressing confidence in the Load Mitigation Plan based solely on his observation that "The Big Rivers generating units routinely achieve a 90% dispatch rate in the MISO market, which validates the competitive production cost of these units."[8] Generating energy at high dispatch rates, but then selling that energy at low margins in the MISO market provides little validation of the competitive position of

[6] Id.
[7] Bailey Direct, page 6, line 15.
[8] Berry Direct, page 12, line 2.

the Company's generating units and the reasonableness of its Load Mitigation Plan. But even if it did inspire confidence, what Mr. Berry is saying is that the solution to Big Rivers' problems is for it to become a Merchant Generator in the MISO market. Becoming a Merchant Generator has proven quite challenging for the most sophisticated and well financed companies, and it would be even more challenging for Big Rivers given its lack of investment grade credit rating and inability to borrow in the private debt markets. It would also be challenging for Big Rivers given its participation in the MISO market, which has an undeveloped capacity market that is dominated by vertically integrated utilities that operate in regulated jurisdictions and an energy market that is depressed due in large part to abundant wind generation and low natural gas prices. Finally, a merchant generator business plan would be particularly problematic for Big Rivers given its almost exclusive reliance on coal generation and the attendant environmental cost and risk, including expected CO_2 risk. As a policy matter, the Commission needs to decide if it is appropriate for Kentucky to maintain its large carbon footprint by encouraging a junk bond rated cooperative utility to become a coal based merchant generator.

Q. Are you advocating for the retirement of the Wilson and Coleman plants?

A. If a thorough evaluation was performed, and it was found to be uneconomic to continue to operate the plants, then I would most likely recommend retiring them. Unfortunately, no reliable evaluation based on updated assumptions has been performed, and I believe the Company should be required to perform such a study to determine what the proper disposition of the Coleman and Wilson plants should be. Another factor that I believe should be considered as part of that study is Kentucky's state policy related to carbon emissions. One of the goals expressly laid out in Governor Steve Beshear's energy plan is to mitigate carbon emissions and reduce Kentucky's carbon footprint.[9] Additionally, the Kentucky Climate Action Plan Council recommends that Kentucky should aim to achieve more than a 20% reduction in greenhouse gases ("GHG") below 1990 levels by 2010 (from about 136.7 to 109.4 million metric tons of carbon dioxide equivalent).[10] One way to further these goals would be to retire uneconomic coal units. Accordingly, when considering Big Rivers' request to act as a merchant generator by continuing to operate two potentially uneconomic coal plants, the Commission should ask itself whether approving that approach will further the energy goals of the Commonwealth.

Q. Other than the massive up-front rate increases in the Century rate case and in this proceeding, when does Big Rivers anticipate that the Load Mitigation Plan will yield results?

A. According to the Company, its efforts to enter into additional wholesale sales (Step 4 of the Load Mitigation Plan) have not yielded any results since the Company first

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[9] *Intelligent Energy Choices for Kentucky's Future: Kentucky's 7-Point Strategy for Energy Independence* (November 2008), *available at* http://eec.ky.gov/Documents/Kentucky%20Energy%20Strategy.pdf.
[10] *Final Report of the Kentucky Climate Action Plan Council* (November 2011), *available at* http://energy.ky.gov/carbon/Documents/KY%20Final%20Report%20Part%20I%20revised%2003-05-12.pdf.

began implementing the Load Mitigation Plan more than a year ago. Mr. Berry stated,

> To date, these efforts have not produced results; however, initiatives of this nature take time, and market conditions change over time, so the present circumstances are not indicative of future outcomes.[11]

This sounds much like the kind of legalistic cautionary remark a stock broker might say to a client to protect him or herself when an investment idea turns bad. In a further attempt to set expectations, Mr. Berry states that it is likely that it will take 3 - 4 years before any bilateral sales agreements will come to fruition.[12] Moreover, with regard to Step 2 of the Load Mitigation Plan, which is to increase off-system sales, the Company admits it is unlikely that it will see substantial energy margins from sales to the MISO market until 2019, which is over 5 years from now.

Q. Do you believe it would be reasonable for the Commission to set rates in this case on the hope that the increases will be temporary and speculation that market conditions will improve for Big Rivers over the next five years?

A. No, I do not. There are reasons to be concerned that the Company's Load Mitigation Plan will not achieve the success that the Company assumes based on the meager amount of analysis that the Company provided. It would be inappropriate for the Commission to set rates at levels that would be harmful to customers on the hope

[11] Berry Direct, page 11, line 17
[12] Berry Direct, page 13 at 1.

that the high rates will be temporary and will ultimately decline when replacement load or market sales come through as the solution to all of the Company's problems.

IV. LOAD MITIGATION PLAN – UNREALISTIC AND ERRONEOUS ASSUMPTIONS

Q. What unrealistic or erroneous assumptions does the Company include in its Load Mitigation Plan?

A. They are as follows:

A. The addition of 800 MW and 5,256,000 MWH of unsubstantiated replacement load over a six year period in addition to its native load and MISO market sales;

B. The failure to consider CO_2 impacts stemming from regulatory requirements, which will increase coal generation costs and market sales revenues. The impact on coal generation costs will far exceed the benefit of increased market sales revenues;

C. The failure to consider other costs, including environmental capital and operating costs, in its modeling decision of whether it is economic to restart either Wilson or Coleman; and,

D. The failure to consider selling Coleman or Wilson for fair market value, and instead requiring that the units be sold at [redacted]. This decision has artificially constrained the sales process by refusing to recognize that fair market value for these units [redacted].

A. UNSUBSTANTIATED REPLACEMENT LOAD

Q. Please explain the assumptions the Company used in its modeling to study its Load Mitigation Plan.

A. In the Company's production cost analysis, it assumed that the Century and Alcan loads would be removed beginning September 1, 2013 and February 1, 2014, respectively. It also assumed that Wilson would be idled beginning September 2013 and would be returned to service May 2018. It assumed that the three Coleman units would be idled beginning February 2014 and would be returned to service July 2019. The Company also made the assumption that 800 MW, or 5,256,000 MWH, of replacement load would be added to its system by 2021, with the first block of capacity added in 2016. In addition, the Company assumed that the Replacement Load would be priced at a 25% premium to the market price of energy. The following provides the Company's assumed schedule when replacement load would be added.

Year	Incremental Amount Added Each Year (MW)	Cumulative Amount Added (MW)	Cumulative Amount Added (MWH)
2016	100	100	658,800
2017	100	200	1,314,000
2018	100	300	1,971,000
2019	100	400	2,628,000
2020	200	600	3,952,800
2021	200	800	5,256,000
2022		800	5,256,000

Q. What was the basis of the Company's 800 MW and 5,256,000 MWH replacement load assumption?

A. The Company did not conduct any studies to form the basis for this projection of replacement load or to determine the feasibility of achieving this magnitude of replacement load growth, according to its response to KIUC 2-7. It could not identify any specific loads that it would add and did not know what the lead time was for new large industrial load, according to its response to KIUC 2-35, which stated:

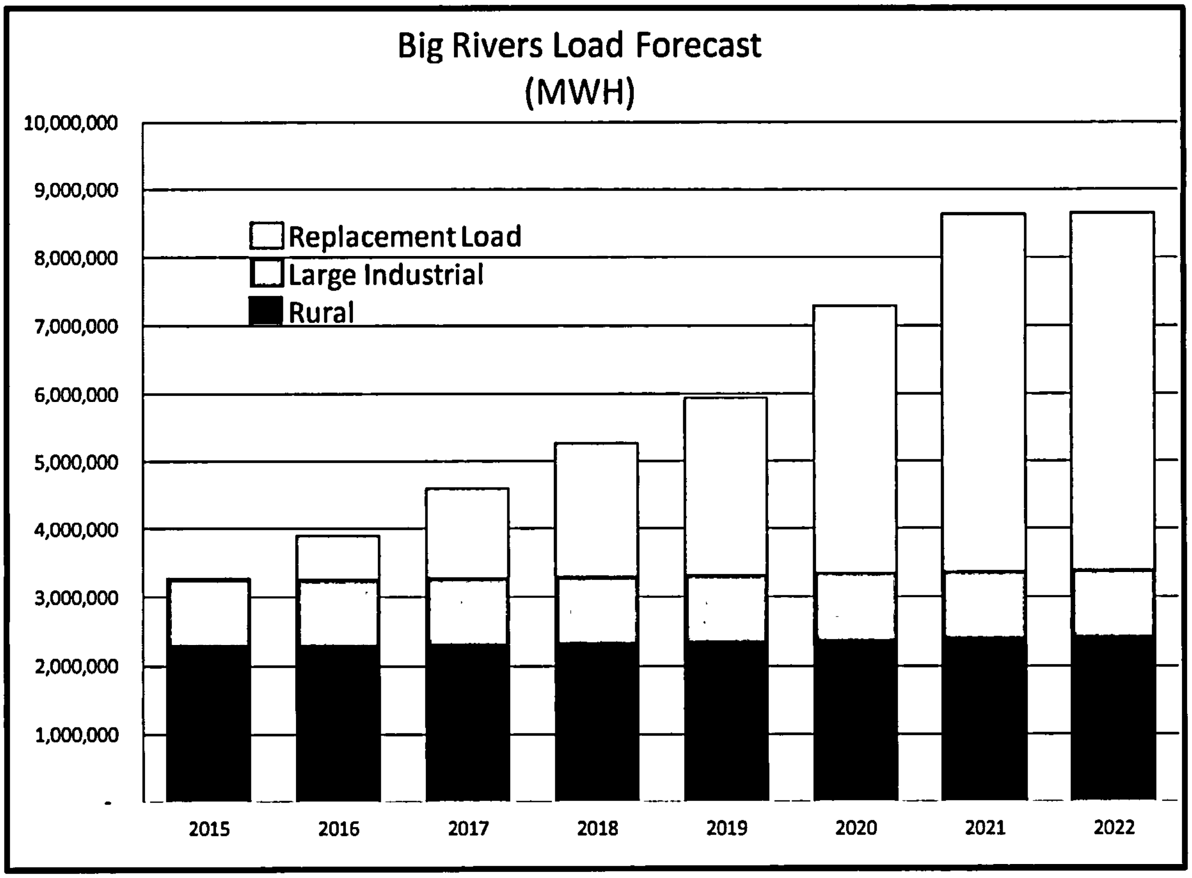
> "There are no such analyses; however, based on past experience, Big Rivers is aware that there is a significant lead time for new large industrial load site development."

In other words, the replacement load is nothing more than a speculative guess, even though the Company claimed that it was the result of "informed judgment" and declared that the replacement load assumption was "reasonable, reliable, made in good faith, and justified for use by management."[13] Yet, when the replacement load projections are critically examined, as they should be, they are not reasonable and are not reliable. They are nothing more than wishful conjecture and are unsupported by any objective analyses.

Q. Do you have any graphs evaluating the enormity of the replacement load assumption?

A. Yes, the following graph contains the native load energy requirements associated with the Rural, Large Industrial and Replacement Load, and depicts how the currently non-existent Replacement Load ultimately dwarfs the Rural and Large Industrial load in a short period of time.

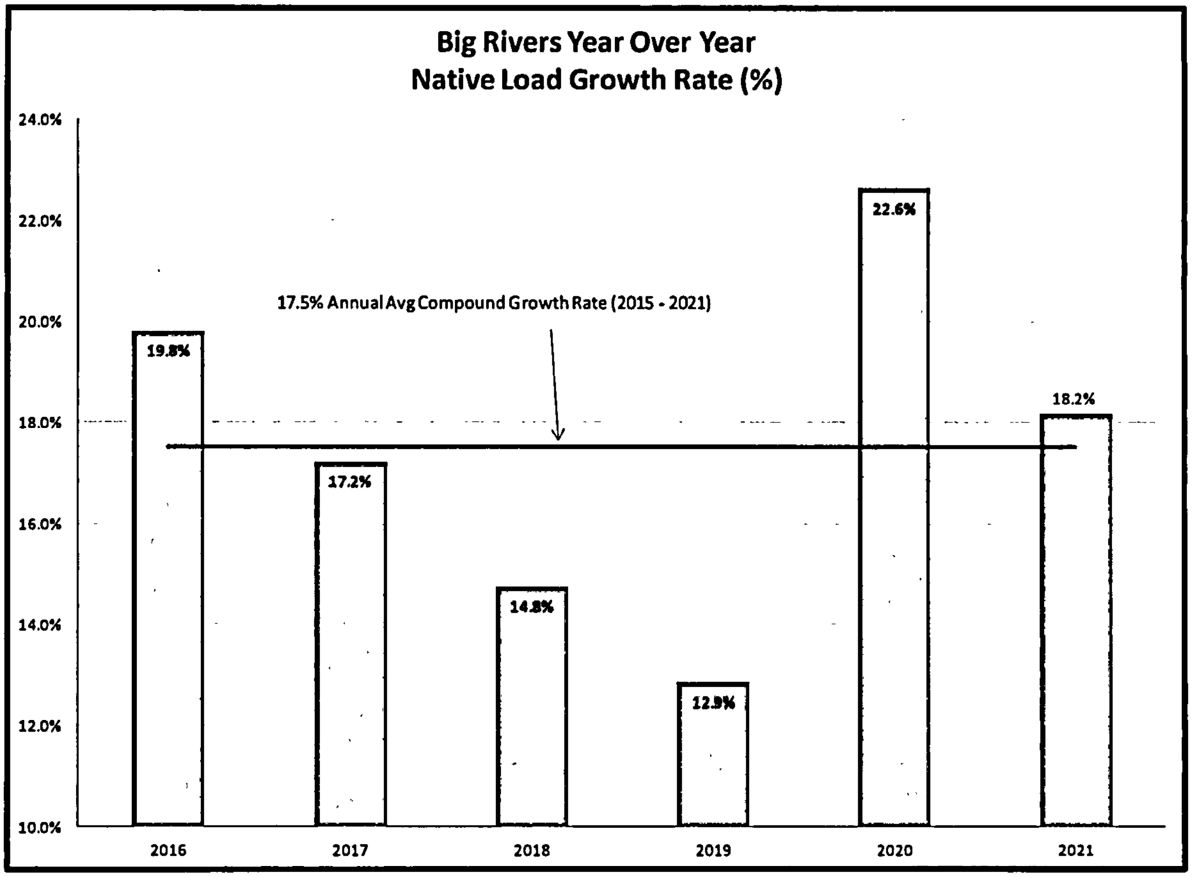
[13] KIUC DR 2-7b.



In 2015, Big Rivers native load energy requirement is 3.27 million MWH spread between Rural and Large Industrial customers. The Company assumes that Replacement Load will begin in 2016, and then four years later, in 2019, Big River's total native and replacement load will almost double to about 5.95 million MWH, and then two more years after that, in 2021, it will nearly triple to 8.63 million MWH. It is almost inconceivable that a utility's native and replacement load requirement will grow this much in such a short period of time, even with a focused effort on economic development. After all, other utilities in Kentucky and in other states are also engaged in focused economic development efforts, and the acquisition of new loads is an extremely competitive undertaking. The 5,256,000 MWH of replacement load assumed by Big Rivers eight years from now is the equivalent of adding 336,923 new residential customers, each using 1,300 kWh per month. That is close to the total number of residential customers currently on the Louisville Gas & Electric ("LG&E") system.[14]

The following chart indicates the underlying load growth rate, year-over-year, that Big Rivers assumes will occur from 2016 to 2021, and it compares that to the compound growth rate over the period. The lowest year-over-year growth rate occurs in 2019 and is still more than 12%, and in 2016, the first year that Replacement Load is expected - just 26 months away, the company is expecting to increase its load by about 659,000 MWH or a 19.8% increase over 2015. Overall, the Company's forecast assumes that load will grow at a 17.5% compound average annual growth rate over the period of 2015 to 2021, which is an extraordinary amount of growth for a typical utility.

[14] LG&E's 2012 FERC Form 1 indicates on average it has 346,445 residential customers.



Q. Did the Company make any other assumptions concerning the make-up of the Replacement Load?

A. Yes. The Company also assumed that it would be comprised of high quality load with a high load factor (75%), and would be charged a 25% premium above market prices. The Company described the Replacement Load as follows:[15]

> "Big Rivers forecasted replacement load assuming the replacement load could take many forms [...] The replacement load was not meant to be specific, but rather represented what Big Rivers' management believed was a reasonable expectation for load replacement given all of the information available to it at the time. The replacement load was assumed

[15] DR Response KIUC 2-32

> to have a 75% load factor because Big Rivers believed it was likely to be composed of a combination of rural, large industrial, and market transactions"

Q. What conclusions did you reach regarding the Company's modeling of the Replacement Load?

A. The Company's load factor assumption is another speculative and self-serving assumption for which the Company admittedly has no objective or analytical support. The Company states that the replacement load was not specific, but instead will be composed of a combination of rural, large industrial and market transactions. However, an average 75% load factor is extremely high and reflects what might be expected primarily from some type of high load factor industrial loads, certainly not from low load factor residential or commercial loads. Furthermore, the Company's reference to market transactions must mean municipal loads, cooperative loads, or bilateral sales, because the Company separately modeled its MISO economy market transactions, and those sales were not included in the replacement load assumptions. Even assuming the Replacement Load included additional MISO economy market sales, which I do not believe it should have, I also evaluated the load factor associated with the off-system sales that the Company specifically modeled using hourly results that were provided in response to KIUC 2-1. Based on this analysis I found that the off-system sales load factor never surpassed [redacted]% in the study period.

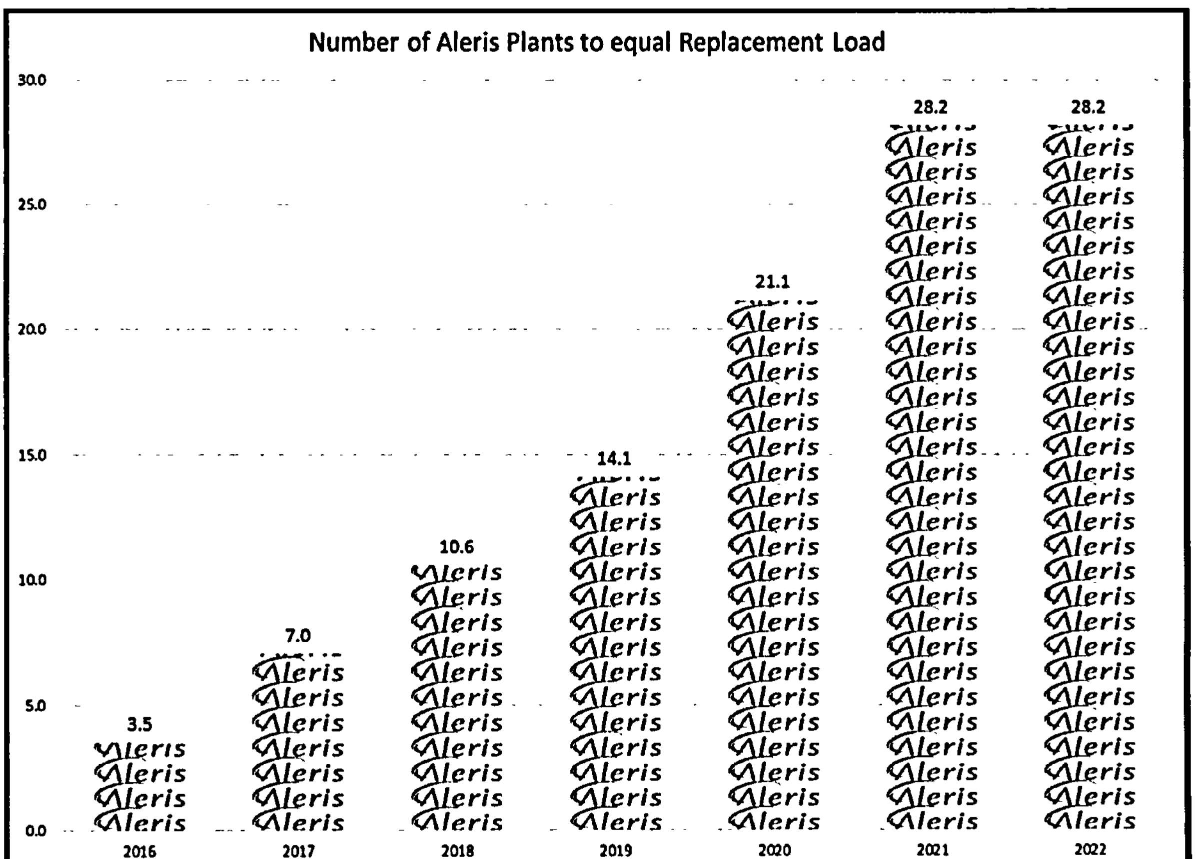
The Company's 75% average load factor assumption would require new loads with very high load factors to be added to the System, such as large industrial loads. This is unrealistic by comparison to the Company's own experience. Even the Company's large industrial load class has a load factor slightly less than 75%, and the Rural Class has a load factor that ranged between 49% and 51%.[16] Presumably any new municipal or cooperative load would have a load factor that is similar to that of the Company's Rural class, which is well below the Company's average 75% assumption.

In summary, the Company's average load factor assumption of 75% is unrealistic and cannot be attained unless the load is comprised primarily of large industrial loads with extremely high load factors, which is unlikely to occur. The Company has offered no evidence that it can or will be able to attract such loads when it is competing against other utilities in Kentucky and in other states for these loads.

Q. Assuming that the Replacement Load is composed of mostly new industrial load, can you put in perspective the amount of new industrial load that would be required by making a comparison to one of Big Rivers' existing industrial customers, such as Aleris?

[16] "Demand Energy Budget 2013-2017.xlsx" and "Demand Energy Budget 2018 thru 2026.xlsx"

A. Yes, Big Rivers is expecting 800 MW of capacity to be added to its system by 2021 as Replacement Load. As mentioned previously, that is an enormous amount of load, almost equivalent to the Alcan and Century Smelter load, which in 2012 was 57% of Big Rivers' total peak demand. It is hard to imagine that Big Rivers would be able to negotiate bilateral contracts or be able to entice new industrial load to its System through its economic development efforts, but if it could, it would have to find the equivalent of 28 new Aleris-sized plants that it could serve. The following graph indicates the number of Aleris-sized plants that Big Rivers would have to add to its System over time in order to match the Replacement Load assumption that it modeled.



It would simply be too far-fetched to expect that Big Rivers would be able to find this many new plants the size of Aleris over this time period. Even one new load the size of Aleris would be cause for rejoicing and a ribbon cutting ceremony. But assuming 28 such loads is not grounded in reality.

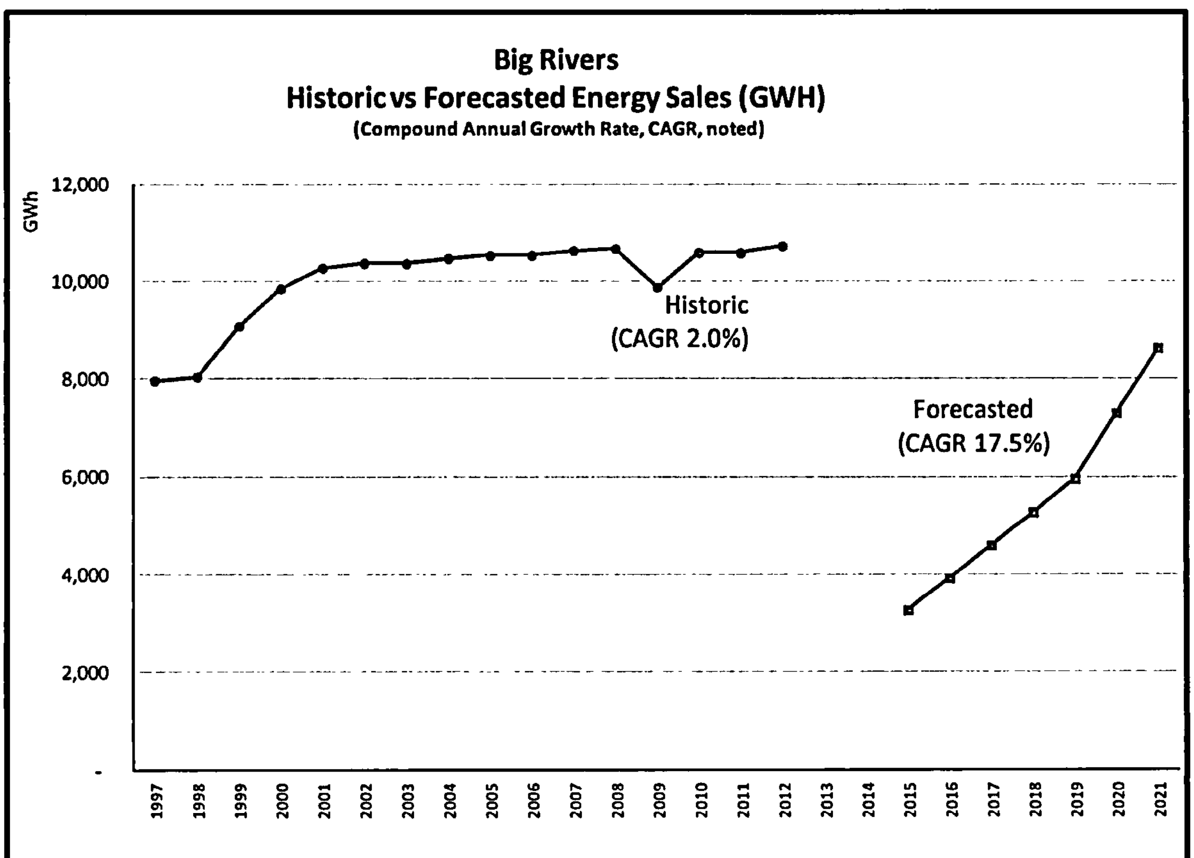
Q. Would it even be possible for 3.5 Aleris plants (659,000 MWH) to be constructed in Big Rivers service territory by 2016, given that 2016 is only about 26 months away?

A. Assuming that Big Rivers' replacement load projections contemplate new industrial load, it is hardly conceivable that this much industrial load could be added in such a short period of time. It takes several years for a large industrial customer to negotiate state economic development incentives, secure permits, design and construct its manufacturing facility, etc. In order for a large industrial customer to be taking service from Big Rivers in 2016 the facility would probably have to be in the construction process right now. I am not aware of any major industrial customer that has any current plans to build a new facility in Big Rivers' service territory much less any large industrial customer that is currently constructing a facility. Big Rivers has not identified any such prospective industrial customer either. Given that 2016 is only about 26 months away, Big Rivers' 2016 projections are most likely impossible. The same can be said for Big Rivers' 2017 projections of 1,314,000 MWH in replacement load. Unless there are multiple very large industrial customers that are actively planning to construct large new manufacturing facilities in Big

Rivers' service territory right now, it is probably impossible for any of the 2016 or 2017 replacement load projections to be achievable.

Q. Does the historic load growth on the System over about the past 15 years provide any basis to suggest that the Company would be able to grow at the rate assumed in the Replacement Load?

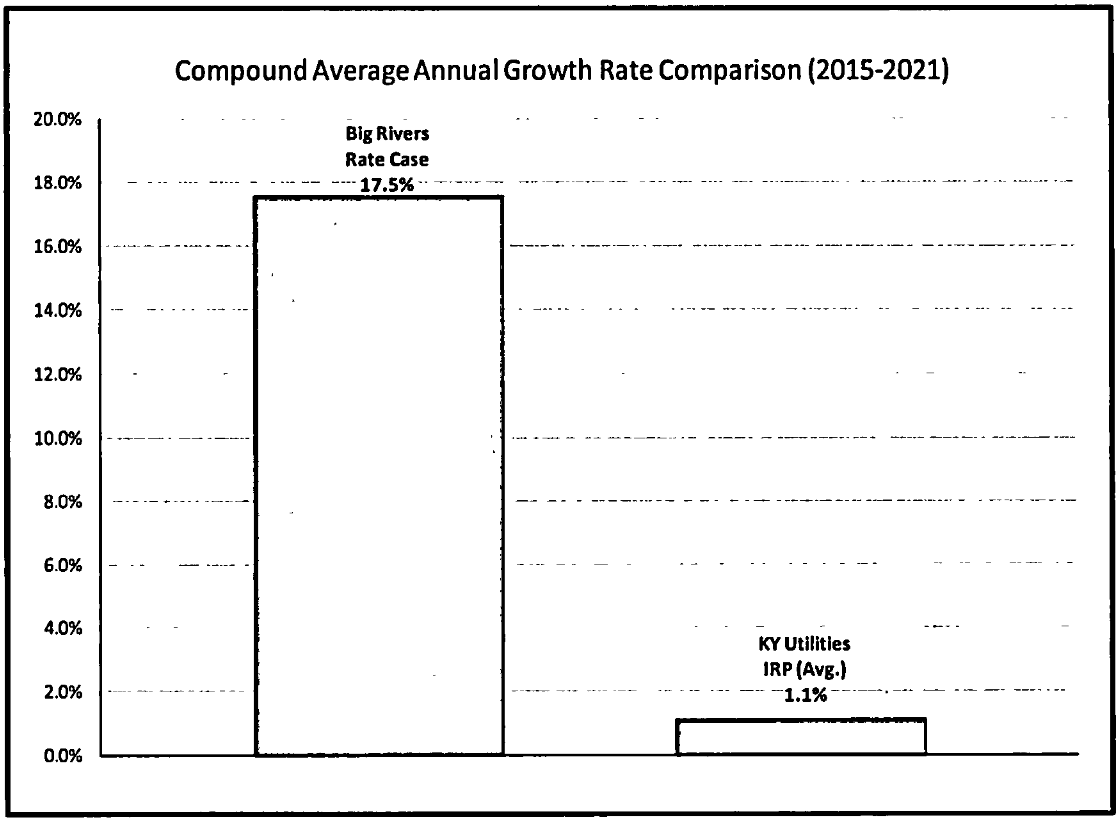
A. No it does not. The following graph compares Big Rivers' historic native load energy sales over the historic period of 1997 to 2012, and compares that to the Company's load forecast beginning in 2015 after the Smelters exit the System.



The historic compound average growth rate is 2.0%. After the Smelters exit, load plunges from about 11,000 GWH to under 4,000 GWH. Again, it is simply hard to imagine that it would be possible for the Company to rebound so dramatically as it assumes, and as depicted in this graph. To do that, the Company would have to grow its load beginning in 2015 at a compound average growth rate of 17.5% over the period shown.

Q. How does the Company's projected load growth compare to other utilities in Kentucky?

A. The Company's projected load growth rate is significantly higher than that of other Kentucky Utilities. For purposes of a comparison, I calculated the Compound Average Growth Rate ("CAGR") projected by Big Rivers in this proceeding and compared it to the CAGR values for other Kentucky utilities, including East Kentucky Power Cooperative, Duke Kentucky, Kentucky Utilities, and Louisville Gas and Electric. I obtained information over the period of 2015 through 2021 from the most recent Integrated Resource Plans ("IRP") for each company filed with the Commission, including Big Rivers' 2010 IRP load forecast. Each of the utilities' IRPs, including Big Rivers' own IRP, reported fairly low and consistent growth rates, which are substantially lower than the growth rate Big Rivers is now assuming in its Load Mitigation Plan. As a result, I averaged the IRP data for each company (including Big Rivers' IRP data) to produce a single growth rate projection for all of the utilities. This seemed reasonable as all of the utilities (including Big Rivers' using its 2010 IRP data) had growth rate projections that were close to 1%, which was significantly less than the growth rate the Company has assumed in its Load Mitigation Plan analysis, which is 17.5%. The following graph provides the comparison.



To put this in perspective, the Energy Information Administration ("EIA") 2013 Annual Energy Outlook[17] forecasted total electricity load growth for the entire U.S. at .9% per year through 2040, and it references that an "offset by efficiency gains from new appliance standards and investments in energy efficient equipment" is built into the forecast. Big River's forecast with the Replacement load shows a

[17] 2013 Annual Energy Outlook, page 71, http://www.eia.gov/forecasts/aeo/pdf/0383(2013).pdf

dramatically higher load growth projection compared to any other utility in Kentucky, and it is dramatically higher than the load growth projection Big Rivers even assumed in its 2010 IRP. It is clear that the Company's assumption about load growth is completely inconsistent with the small amount of growth predicted by each utility in Kentucky or by other utilities in the U.S.

Q. How successful do you anticipate Big Rivers will be in attempting to locate new customers or encourage expansion within its service territory?

A. The combined effects of the Century and Alcan rate increases will be massive, amounting to a 72% rate increase for Rural and 112% increase for Large Industrial customers. In light of those increases, I do not believe Big Rivers can possibly grow load within its service territory anywhere close to what is suggested by the Replacement Load that it has assumed. The increase in rates will have a destructive effect on economic development, job retention, and job growth.

Studies have been conducted that have examined the impact of changes in the price of electricity on levels of employment. For example, one study performed in 2011 found that a onetime increase of 25% in the price of electricity led to a reduction in the long-run employment growth rate from an average of 3.0% to

2.49%.[18] The rate increase to Big Rivers' Large Industrial customers is more than four times greater than what this study even examined.

Q. What will be the impact on manufacturing as a result of such a large rate increase?

A. Manufacturing will be hit harder than any other sector of the economy according to another recent study that examined the relationship between employment and rate increases. The October 2012 study was entitled, "The Vulnerability of Kentucky's Manufacturing Economy to Increasing Electricity Prices" and was produced by the Kentucky Energy and Environment Cabinet Department for Energy Development and Independence, which is an office that was created by the Governor of Kentucky to oversee energy use and evaluate the energy needs of Kentucky citizens.[19] As opposed to the prior study, this study examined impacts on specific business sectors within the economy.

Q. What is the importance of manufacturing to the Kentucky economy?

A. Kentucky has had historically low and stable electricity prices that have led to the growth of an electricity intensive manufacturing economy, which is being threatened

[18] The Relationship between Electricity Prices and Electricity Demand, Economic Growth, and Employment, for Kentucky Department for Energy Development and Independence, October 19, 2011, Dr. John Garen, Dr. Christopher Jepsen, and James Saunoris, Center for Business and Economic Research, University of Kentucky. http://energy.ky.gov/Programs/Data%20Analysis%20%20Electricity%20Model/Gatton%20CBER%20Final%20Report%2010302011.pdf

by Big Rivers' rate increases. The study reports that manufacturing in Kentucky is responsible for the largest source of revenue, is a leading source of employment, and provides a unique economic function by bringing revenues to the Commonwealth from other economies. Compared to the rest of the country, manufacturing in Kentucky makes up a disproportionate amount of total electricity usage. For example, in 2011 49% of total electricity usage was used by industrial users compared to 26% for the United States as a whole. The report also found that in 2009, manufacturing accounted for 17% of the State Gross Domestic Product ("GDP"), and employed 213,330 people, which by comparison was 2.5 times more than the number of farmers and 11 times more than the number of coal miners employed in Kentucky.[20]

Q. What were the findings of the study concerning manufacturing?

A. The study found that electricity price increases alone would be destructive to the economy. The study found that over a forecast period of 2011 through 2025, a 25% rise in electricity price over that period would lead to a loss of 17,500 jobs in the Kentucky manufacturing sector, and a loss of 12,500 jobs in the four other sectors that were examined including retail services, hospitality, healthcare and government. The study concluded by saying:

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[19] The Vulnerability of Kentucky's Manufacturing Economy to Increasing Electricity Prices, Kentucky Energy and Environment Cabinet, October 2012. http://energy.ky.gov/Programs/Documents/Vulnerability%20of%20Kentucky%27s%20Manufacturing%20Economy.pdf

[20] id.

> This study demonstrated that electricity price increases alone may force businesses to seek ways to reduce costs, or close, causing substantial job losses in Kentucky's electricity-intensive manufacturing sector, and slowing overall long-term job creation in other sectors. The timing of this transition could exacerbate high unemployment and slow economic growth in the near-term. The Commonwealth's vulnerability to these dynamics could be worsened if leadership is unaware of them and inadequately prepared for the transition.

In the case of Big Rivers, the Commission should be aware of how devastating the rate increases can be on manufacturing and other sectors of the economy. Furthermore, price is not the only consideration, price volatility is also problematic as it makes it difficult for manufacturing businesses to plan ahead, and it discourages manufacturers to risk making capital investments. With the large rate increases that the Company is requesting, it is unlikely the Company will be able to add industrial load as incorporated in its Replacement Load forecast.

B. CO_2 IMPACTS

Q. Earlier you mentioned the second unrealistic assumption that the Company based its Load Mitigation Plan on was its failure to consider CO_2 impacts. Please discuss this further.

A. This concern arises because in its Load Mitigation Plan, the Company has chosen to ignore the likely impact that CO_2 regulations will have on the operation of its coal units. CO_2 impacts will likely result from regulatory requirements the

Environmental Protection Agency ("EPA") will finalize, presumably by June 2015.[21] The Company's position concerning why it ignored CO_2 was simply that it has only modeled "....what is known today."[22] This is rather curious logic considering the Company made up its speculative Replacement Load theory based on nothing more than just a simple statement that the Company considers it "reasonable, reliable, made in good faith, and justified for use by management." It is unfathomable that the Company believes its Replacement Load assumptions would pass the "reasonable, reliable, made in good faith, and justified for use by management" test, but a CO_2 assumption would not.

Q. What is the status of the EPA's CO_2 regulations?

A. On June 25, 2013, President Obama issued a directive to the EPA to issue new proposed Carbon Pollution Standards for *future* power plants by September 20, 2013, to issue proposed Carbon Pollution Standards for *existing* power plants by June 1, 2014, to issue *final* standards for existing power plants by June 1, 2015, with such standards requiring states to submit implementation plans by June 30, 2016.[23] While there is are still many details to be worked out and quite likely legal challenges to deal with, there is more certainty today than in the past that CO_2 will have to be dealt with, and Big Rivers should have at least performed a sensitivity study as part of its

[21] EPA Proposes Carbon Pollution Standards for New Power Plants / Agency takes important step to reduce carbon pollution from power plants as part of President Obama's Climate Action Plan http://yosemite.epa.gov/opa/admpress.nsf/0/da9640577ceacd9f85257beb006cb2b6!OpenDocument
[22] DR Response to KIUC 2-7

Load Mitigation Plan analysis in this proceeding to evaluate the impacts of CO_2. The result would have shown that Big Rivers is particularly vulnerable to CO_2 impacts because most of the energy it produces is derived from burning coal, which would be impacted by CO_2 most heavily.

I believe that if enacted, it is reasonable to expect that regulations would go into effect in the 2020 to 2022 time period. Apparently, Kentucky Power would agree with this, because in its Mitchell certification proceeding, Case No. 2012-00578, AEP's analyses included a reference case assumption that CO_2 would be priced at \$15.08/metric ton starting in 2022 and would increase over time to \$16.72 per metric ton in 2030.[24] Furthermore, in Georgia Power's recent 2013 IRP, it analyzed two sensitivity cases, one in which CO_2 costs would begin in 2017 and would be priced beginning at \$10/metric Ton, and another in which CO_2 costs would begin in 2020 and would be priced beginning at \$20/metric Ton.[25]

Q. Did you conduct any analyses of the impact that CO_2 costs would have on Big Rivers?

A. Yes. Since the Company's Load Mitigation Plan analyses did not consider CO_2 impacts, the benefits of bringing back the Wilson and Coleman plants, after being

[23] http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards
[24] Kentucky Power Case No. 2012-00578, Direct Testimony Mr. Scott Weaver, Exhibit SCW-3. http://psc.ky.gov/pscscf/2012%20cases/2012-00578/20121219_Kentucky%20Power%20Company_Application%20and%20Motion.pdf
[25] Georgia Power 2013 IRP, Docket No. 36498, January 31, 2013, Technical Appendix Volume 1, Resource Mix Study, Appendix I, page 6, http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=145981

layed-up for a period of time, were overstated. Since the Company did not provide a case with CO_2 impacts, and I did not have the Company's production cost model and database, I made a simplifying assumption that Big River's generation output would not change even if CO_2 costs were accounted for. This assumption is reasonable, since my only interest was to determine the magnitude of the impact of CO_2 regulations. The Company could have and still can perform its own analysis using reasonable assumptions to determine the impact of CO_2 regulations. The impacts that I accounted for were increases in the cost of generation and purchase power, and an increase in the amount of revenue derived from market sales as a result of higher market prices with CO_2 costs.

Q. How did you model the impact of CO_2 costs?

A. I performed two sensitivity analyses. In Sensitivity 1, I assumed that allowances would have to be bought for every ton of CO_2 produced. In Sensitivity 2, I assumed that each generator could emit a certain amount of CO_2 before having to buy allowances. In that analysis, I assumed the amount would be 1,500 lbs/MWh of CO_2 before allowances would have to be purchased.[26] In addition, for each sensitivity case I used AEP's CO_2 price forecast that I previously discussed, which was approximately $15/ton in 2022 escalated over time; however, I assumed that CO_2 impacts would begin in 2020 now that President Obama has issued his Carbon

[26] NRDC report: Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters http://www.nrdc.org/air/pollution-standards/files/pollution-standards-report.pdf

Pollution Standards directive. I converted the \$15/ton allowance cost to a \$/MWH cost using the unit's heat rate, and added that cost to the operating cost of the unit. As a result, a unit that is less efficient but produces the same amount of energy would have to purchase more allowances and would incur higher CO_2 costs, compared to a unit that has a lower heat rate and is more efficient.

Q. How did you model the impact of CO_2 costs on the market price forecasts?

A. Hourly market energy prices are driven by the highest incremental generation costs that occur in MISO. In some hours market prices reflect coal generation costs, while in other hours market prices reflect natural gas generation costs. Furthermore, market prices are influenced by the amount of renewable energy being produced in an hour, primarily including hydro and wind power. While individual coal units may be significantly impacted by the cost of CO_2 allowances, the impact of CO_2 costs on market prices would not be as significant. For purposes of this analysis, I assumed that the \$/MWH impact on market prices would be half of the \$/MWH impact on coal generating units. For example, a \$15/ton CO_2 allowance cost converts to approximately a \$15/MWH generating unit operating cost adder, and from that I assumed that the market price would increase by \$7.5\$/MWH each hour. In Sensitivity 2, in which utilities only have to purchase allowances for emissions above 1,500 lbs/MWH, the impact of a \$15/ton CO_2 allowance cost converts to about a \$5/MWH impact on coal generating units, and correspondingly, I assumed that the market price would increase by \$2.50/MWH.

Q. What results did you develop?

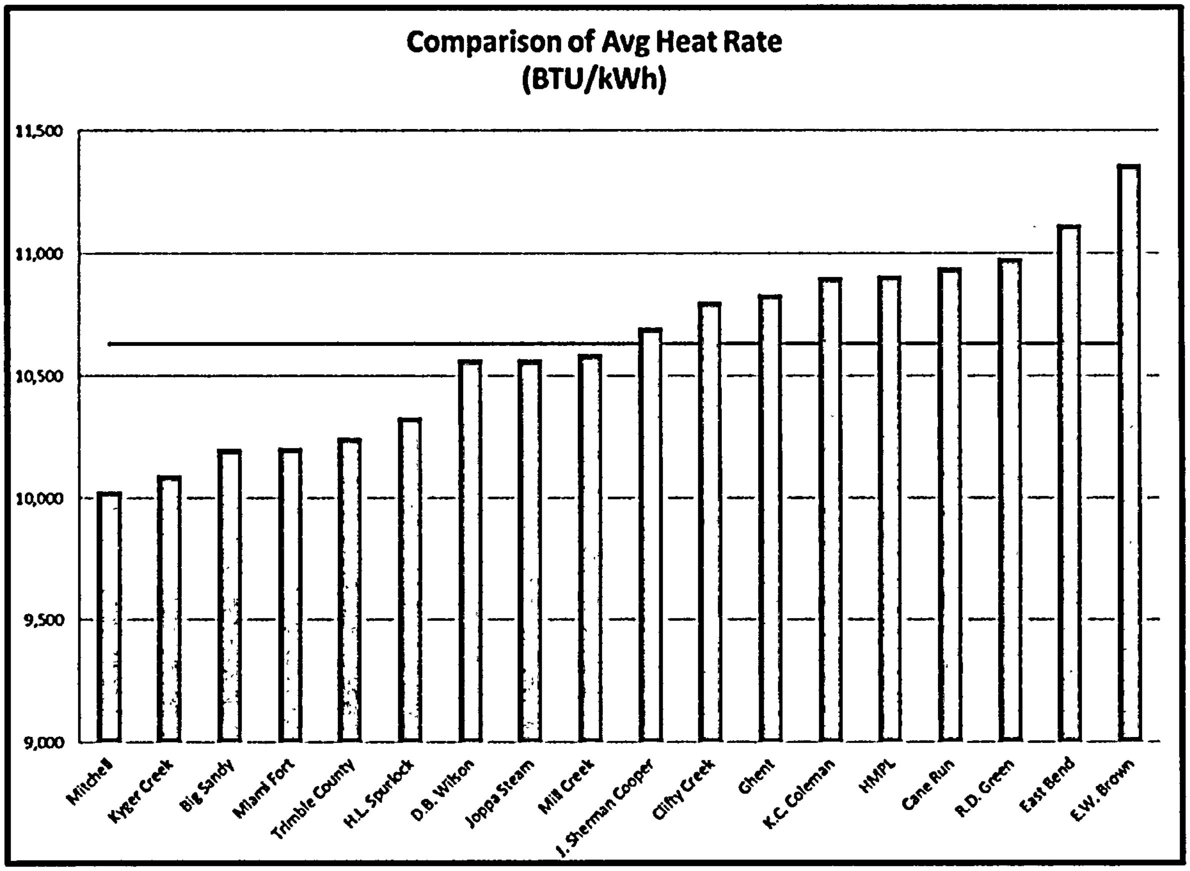
A. Based on the Company's production cost model analysis, I developed a production cost summary for the Company's base case, and for each sensitivity case, which appears below.

[redacted]

Sensitivity 1 demonstrates that with CO_2 costs, Big Rivers production costs increase on average about [redacted] million dollars per year, whereas market and replacement load revenues increase on average by only about [redacted] million per year. The net impact is an increase on average of about [redacted] million per year. Sensitivity 2 indicates that if less onerous CO_2 regulations are implemented, and utilities only have to pay for allowances based on a portion of the total CO_2 produced, then Big Rivers' production costs would increase on average about [redacted] million per year, whereas market and replacement load revenues would increase on average by only about [redacted] million per year. The net impact is an increase on average of about [redacted] million per year. The results show that the impact of CO_2 costs on the cost of operating Big Rivers' generating units is significantly greater than the added benefit derived from higher market priced revenues.

Q. How does the efficiency of a unit affect the CO_2 impact?

A. The amount of CO_2 emitted by a unit is influenced by the unit's efficiency (heat rate). The more efficient a unit is, the less CO_2 will be emitted for each MWH of generation. The Coleman units are smaller and less efficient than the Wilson unit, and therefore, the CO_2 allowance cost impact at Coleman will be greater than at Wilson. The chart below compares coal unit heat rates at a selection of coal units and indicates that Coleman has a heat rate that is above the average of the units shown, while Wilson is close to but below the average.[27] .



Q. What are your conclusions regarding CO_2 impacts?

A. These results demonstrate that regardless of what the final regulations will be, once imposed, Big Rivers' customers will be exposed to significant additional CO_2 costs. Because the Company did not consider CO_2 impacts in its Load Mitigation Plan, it

[27] 2012 EIA 923 data, http://www.eia.gov/electricity/data/eia923/

has greatly understated the costs that will be incurred once it re-starts the Coleman and Wilson units. In 2020, Sensitivity 1 indicates that total production costs will increase by [redacted] million with CO_2 impacts included. Of this [redacted] million increase, the Coleman and Wilson units are responsible for [redacted] million or about [redacted] of the total impact caused by inclusion of CO_2 costs. Given the magnitude of these impacts, CO_2 should have been considered in the Company's analysis.

C. OTHER EXCLUDED COSTS

Q. What is the third unrealistic or erroneous assumption that the Company included in its Load Mitigation Plan Analysis?

A. The Company's third erroneous assumption was that certain capital and operating costs would not be incorporated in the Load Mitigation Plan analysis of when to restart the idled Wilson or Coleman plants. Before either plant can be restarted major capital investments must be made, and after they are restarted ongoing capital investments and increased operating costs for environmental compliance and other reasons will be incurred. Assuming that Big Rivers will be able to find lenders willing to fund its merchant generation business (which is questionable given its inability to access the private debt markets), ignoring the return of and return on the increased capital investments in its financial modeling is erroneous.

Q. What was the basis for the Company's modeling decision to re-start Wilson and Coleman in 2018 and 2019, respectively?

A. Every party asked this, and the Company was somewhat evasive in its response to the question. Ultimately, when pressed for an answer in the second round of data requests, the Company still did not produce specific workpapers, but responded by referring parties to view the production cost and financial model spreadsheets (e.g. KIUC 2-56), and by providing the following narrative explanation of how the decision to re-start the units was made (KIUC 2-14):

> The PCM run determines the gross margins the generating station earns on the variable cost side. These gross margins can be compared with the fixed cost savings from idling a generating station. If the fixed cost savings are greater than the variable cost net margins, then the generating station should remain idled. If the variable cost gross margins are greater, then the generating station should be restarted.

The Company's response to KIUC 1-67 indicates that the Coleman and Wilson plants would each save about $[redacted] million per year in labor and non-labor fixed departmental expenses ("FDE") while layed-up. In order to re-start them, it appears that the Company believes it would have to earn margins from off-system sales exceeding $[redacted] million, otherwise, it would not make sense for the units to be re-started.

Q. Do you agree with the Company's assessment of when it would be economic to re-start the units?

A. No I do not, but even if I did, it does not appear that Wilson and Coleman should be re-started by May 2018 and July 2019, respectively, as the Company assumes in its

Load Mitigation Plan modeling analyses. The following table contains variable cost gross margin results that were derived from the Company's production cost results.

[redacted]

According to the Company's explanation in KIUC 2-14 included above, the gross margin would have to exceed the fixed cost savings, which for each plant is approximately $[redacted] million. The Company's assumption that this would occur in 2018 for Wilson and 2019 for Coleman appears to be erroneous. The first year that the net margin exceeds $[redacted] million is not until 2021 for each unit. The Company's analysis does not justify the earlier restart dates. If there is an explanation, the Company should supplement its various discovery responses and address the issue when it files its next round of testimony.

Q. You also indicated that the Company's analysis of when to re-start the units is flawed because it has excluded other costs that you believe should have been captured in the analysis. What are those costs?

A. In addition to the variable production costs associated with operating the units, there are also other revenue requirements that are avoidable as long as the units are not re-started. Once the units re-start, then additional costs will have to be incurred at

Coleman and Wilson. The Company has already determined that it would have to make capital investments at the units to comply with the Mercury and Air Toxics Standard ("MATS"). Also, if CO_2 regulations go into effect, then the cost of CO_2 allowances would have to be accounted for and it is likely that other environmental regulations will be implemented, and capital investments associated with those regulations would also have to be accounted for. With regards to MATS, the Company's current plan is to hold off on those upgrades until one year prior to when it plans to re-start the units. The MATS capital expenditures are expected to be approximately $40 million for the two plants according to Robert Berry's testimony in the Environmental Compliance Case (Case No. 2012-00063).[28] The revenue requirement associated with this $40 million capital cost needs to be included in the economic analysis to determine if and when a restart of either Wilson or Coleman is justified, which the Company did not do. In addition, there are other EPA environmental regulations currently being modified or promulgated that should have also been factored into the Wilson/Coleman restart analysis, including CO_2 regulations for existing plants, National Ambient Air Quality Standards (NAAQS), a successor to the Cross State Air Pollution Rule ("CSAPR"), Section 316(b) of the Clean Water Act regarding Cooling water intake structures, and the Resource Conservation and Recovery Act (RCRA)'s Coal Combustion Residuals (CCRs) specifications. Estimates for the costs of compliance with other regulations are found in the study that was performed by Sargent and Lundy on behalf of the

[28] Robert Berry Direct Testimony, Case No. 2012-00063, April 2, 2012, Exhibit Berry-2. Wilson is assumed to

Company for its Environmental Compliance Plan. At Coleman, the Company may have to spend up to $42 million to comply with the Coal Combustion Residual (CCR) ($38 million[29]) regulation and the Cooling Water Intake Rule 316(b) ($4 million[30]).

Q. Have you determined the additional revenue requirements the Company would incur by incorporating costs associated with CO_2, MATS, and the other environmental regulations?

A. Yes, I have. To be conservative, I used the CO_2 Sensitivity Analysis 2 that I performed above, in which CO_2 costs would only be imposed on a portion of the CO_2 produced. In addition, I assumed that $40 million would have to be spent at Wilson and Coleman to comply with MATS requirements and that $42 million would have to be spent at Coleman to comply with the CCR and the Cooling Water Intake Rule. For purposes of deriving revenue requirements associated with capital investments, I relied on the interest rate assumption that the Company used in the environmental proceeding (Case No. 2012-00063), which was 5.5%, a TIER of 1.24, and a reasonable assumption that the capital costs would be depreciated over a 20 year remaining life. The following table contains the additional costs that should be included in the Coleman and Wilson restart analysis to incorporate costs associated with CO_2, MATS, CCR and the Cooling Water Intake Rule.

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cost $11.24 million and Coleman is $28.5 million.

[29] Rachel Wilson Direct Testimony, Case No. 2012-00063, July 23, 2012, page 16, table 6 and Sargent & Lundy report page ES-9 table ES-7

ADDITIONAL COSTS - MATS, CO2 SENSITIVITY 2, AND OTHER COSTS										
(millions $)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
WILSON MATS (O&M + CAP EX)	$4.3	$4.4	$4.4	$4.5	$4.5	$4.6	$4.6	$4.7	$4.7	$4.6
COLEMAN MATS (O&M + CAP EX)	$0.0	$7.1	$7.1	$6.9	$7.2	$7.2	$7.3	$7.3	$7.3	$7.2
CO2 ADJUSTMENT (SENSITIVITY 2)	$0.0	$0.0	$17.6	$18.4	$18.0	$19.2	$18.6	$19.8	$19.7	$20.7
COLEMAN CCR	$0.0	$4.5	$4.4	$4.3	$4.3	$4.2	$4.1	$4.0	$3.9	$3.8
COLEMAN RULE 316(b)	$0.0	$0.5	$0.5	$0.5	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4
Total Additional Costs	**$4.3**	**$16.4**	**$34.0**	**$34.6**	**$34.4**	**$35.6**	**$35.0**	**$36.1**	**$36.0**	**$36.7**

I also assessed the additional costs that would have to be included in the Coleman and Wilson re-start analysis under a more stringent environmental scenario. For this, I assumed that a successor to CSAPR would be implemented by the EPA, and it would result in the Company having to spend $139 million at Wilson, which was the amount the Company previously determined it would have to spend when it developed its Environmental Compliance Plan in Case No. 2012-00063. Furthermore, for this scenario, I used the CO_2 Sensitivity Analysis 1 that I performed earlier, in which CO_2 costs would be imposed on all of the CO_2 produced by the Company's generating units. The following table contains the additional costs that should be included under a more stringent environmental scenario in the Coleman and Wilson restart analysis to incorporate costs associated with significant CO_2, MATS, CCR, Cooling Water Intake Rule, and a successor to CSAPR.

[30] Id. at page 17, table 7

ADDITIONAL COSTS (SENSITIVITY) - MATS, CSAPR, CO2 SENSITIVITY 1, AND OTHER COSTS										
(millions $)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
WILSON MATS (O&M + CAP EX)	$4.3	$4.4	$4.4	$4.5	$4.5	$4.6	$4.6	$4.7	$4.7	$4.6
COLEMAN MATS (O&M + CAP EX)	$0.0	$7.1	$7.1	$6.9	$7.2	$7.2	$7.3	$7.3	$7.3	$7.2
CO2 ADJUSTMENT (SENSITIVITY 1)	$0.0	$0.0	$55.1	$58.2	$57.1	$61.8	$59.5	$63.2	$62.9	$66.0
COLEMAN CCR	$0.0	$4.5	$4.4	$4.3	$4.3	$4.2	$4.1	$4.0	$3.9	$3.8
COLEMAN RULE 316(b)	$0.0	$0.5	$0.5	$0.5	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4
WILSON CSAPR (O&M + CAP EX)	$17.2	$16.9	$16.7	$16.4	$16.1	$15.8	$15.4	$15.1	$14.7	$14.3
Total Additional Costs	$21.5	$33.4	$88.2	$90.8	$89.6	$93.9	$91.3	$94.7	$93.9	$96.3

The results of an analysis including these costs would likely indicate that the re-start of the Coleman and Wilson plants should be delayed for several years beyond what the Company has assumed as part of its Load Mitigation Plan, and possibly should be delayed indefinitely.

In summary, Big Rivers' aging coal fleet will require significant additional capital investments to remain in operation. In order to re-start Coleman and Wilson the Company must include all costs that will be incurred, which the Company did not do. Based on current plans, the Company knows with certainty that MATS costs will be incurred and those costs should have been incorporated in the Company's re-start decision analysis. In addition, it is highly likely that other environmental costs will have to be incurred including CO_2, CCR and Cooling Water Intake compliance costs, and possibly a successor to CSAPR. A basic financial analysis requires considering such costs when making the decision about whether it is economic to restart Wilson and/or Coleman as merchant plants. Because it ignored additional capital costs, Big Rivers' modeling is inaccurate and unreliable.

D. ARTIFICIAL CONSTRAINTS ON THE SALES PROCESS

Q. What is the final unrealistic or erroneous assumption that the Company included in its Load Mitigation Plan?

A. The final unrealistic assumption is the Company's refusal to consider selling Coleman or Wilson for fair market value, and instead requiring that the units to be sold at [redacted]. This decision has artificially constrained the sales process by refusing to recognize that market value for these [redacted] This is an unrealistic assumption because an arm's length buyer would only be willing to pay market value, [redacted]

Q. Would customers be better off if the Company were able to sell at [redacted]

A. Certainly they would be, if there was a reasonable chance that the Company could sell the units above fair market value. But just as it would not be realistic to attempt to sell a house for more than fair market value, it would not be reasonable to insist on receiving more than fair market value for the idled plants. Furthermore, the longer the units sit idle, the less value they will likely have because as time goes by CO_2 and other environmental regulations will be imposed, and coal units will be hardest hit by the regulations. Furthermore, there is a cost to ratepayers just to keep the units off-line. As Mr. Kollen discusses, it will cost the Company and its customers more than $[redacted] million per year in fixed costs if the Company retains the Wilson and Coleman power plants rather than selling them or otherwise divesting them.

V. RE-EVALUATION OF THE COMPANY'S LOAD MITIGATION PLAN

Q. What do you believe the likely outcome will be if the Company continues to pursue its existing Load Mitigation Plan?

A. Contrary to the confidence the Company has expressed in its existing Load Mitigation Plan, the likely outcome would be that the Company's proposed rate increases would not be temporary, and most likely, the Company would continue to need its customers to bail it out based on further rate increases. Existing manufacturing customers will not thrive under this environment, and new manufacturing load would be reluctant to locate within Big Rivers' service territory given the probability that higher rates will occur in the future. Rural customers may find the rate increases will cause them considerable hardship, and some rural customers may be forced into having to make unfortunate sacrifices in order to pay their electric bills. This is unsustainable, as customers cannot continue to bail out the Company, and the Commission should not accede to the Company's rate request.

Q. What would you recommend the Company do to re-evaluate its Load Mitigation Plan?

A. As I mentioned already, Big Rivers' Load Mitigation Plan is based on flawed assumptions, and I recommend that the Company re-evaluate its Load Mitigation Plan using more realistic assumptions. First, the Company should reduce the amount of replacement load it assumes it will acquire substantially. Second, the Company should incorporate CO_2 costs in its analysis. Third, the Company should reconsider when it might be economic to re-start the Coleman and Wilson units, and as part of that analysis, the Company should incorporate the additional environmental compliance costs that I discussed including MATS, and other potential environmental compliance costs. Fourth, the Company should revise its strategy for marketing the Coleman and Wilson units, such that it would evaluate selling the units at fair market value.

Q. What do you believe the likely outcome would be of this re-evaluated Load Mitigation Plan?

A. I believe the results of this analysis would provide evidence that the Company's rate increases will not be temporary and would show that additional rate increases would be required in the future. I believe that these results would provide convincing evidence that the Company should pursue more fundamental steps to right size the utility than it is already pursuing.

Q. In addition to your recommendation for the Company to re-evaluate its Load Mitigation Plan, what else are you recommending?

A. I also recommend that the Commission should reject the Company's rate request, and instead should rely on KIUC's more sensible rate plan, and the Commission should direct the Company to re-evaluate other business options to right-size the Company. Mr. Kollen discusses further about KIUC's Rate Plan and related recommendations to resolve the Company's underlying problems.

Q. Does this complete your testimony?

A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

PHILIP HAYET, 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.

Philip Hayet

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

Jessica K. I

Notary Public

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

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:		
APPLICATION OF BIG RIVERS ELECTRIC	)	
CORPORATION FOR A GENERAL ADJUSTMENT	)	**Case No. 2013-00199**
IN RATES	)	

EXHIBITS

OF

PHILIP HAYET

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

October 28, 2013

RESUME OF PHILIP HAYET

EDUCATION/CERTIFICATION

M.S., Electrical Engineering, Georgia Institute of Technology, 1980
B.S., Electrical Engineering, PurdueUniversity, 1979
Cooperative Education Certificate, PurdueUniversity, 1979
Registered as a Professional Engineer in the State of Georgia, 1987
Member National Professional Engineering Society

EXPERIENCE

Mr. Hayet has provided consulting services to Public Utility Commissions, State Energy Offices, Consumer Advocate Offices, Electric Utilities, Global Power Developers, and Industrial Companies for over thirty years. Mr. Hayet's expertise covers a number of areas including utility system planning and operations, market price forecasting, Integrated Resource Planning, renewable resource evaluation, transmission planning, demand-side analysis, and economic analysis. In 1995, Mr. Hayet began his own utility consulting firm, Hayet Power Systems Consulting ("HPSC"), and has worked for customers in the United States, and internationally in Australia, Japan, Singapore, Malaysia, the United Kingdom, and Vietnam. In addition to continuing to work for HPSC, in 2000, Mr. Hayet also joined the consulting firm of J. Kennedy & Associates, Inc. to provide support for projects requiring utility resource planning analysis and software modeling expertise.

Prior to 1995, Mr. Hayet worked for fifteen years at Energy Management Associates, now Ventyx, where he provided consulting services and client service support for the widely used utility system planning software models, PROMOD IV and STRATEGIST. Clients included various electric utilities, governmental agencies, and private industry. Mr. Hayet helped to design some of the features that exist within the PROMOD IV and STRATEGIST systems, such as the competitive market modeling features in STRATEGIST.

Mr. Hayet has conducted numerous consulting studies in the areas of Renewable Resource Evaluation, Renewable Portfolio Standards Evaluation, Green Pricing Tariff Development, Electric Market Price Forecasting, Generating Unit Cost/Benefit Analysis, Integrated Resource Planning, Demand-Side Management, Load Forecasting, Rate Case Analysis and Regulatory Support. A list of recent projects is included below.

RESUME OF PHILIP HAYET

SPECIFIC EXPERIENCE

Projects Since 2000 - J. Kennedy and Associates, Inc. Atlanta, GA – Director of Consulting

- Filed Direct Testimony (July 2013) at the Louisiana Public Service Commission regarding Entergy's request for certification of a 8.5 MW PPA for renewable energy capacity (Agrilectric rice hull) in accordance with the LPSC's Renewable Energy Pilot (Docket U-32785), on behalf of the Louisiana Public Service Commission Staff.
- Filed Direct Testimony (April 2013) at the Kentucky Public Service Commission regarding Kentucky Power Company's Mitchell Certificate of Public Convenience and Necessity filing (Case No. 2012-00578) on behalf of the Kentucky Industrial Utility Customers, Inc.
- Filed Cross Answering Testimony (March 2013) at FERC regarding the Louisiana Public Service Commission's harm calculation stemming from Entergy's violation of its System Agreement (Docket No. EL09-61-002), on behalf of the Louisiana Public Service Commission.
- Filed Direct Testimony (December 2012) in Entergy's retail proceeding at the LPSC regarding termination of Cross-PPAs (Docket No. U-29764).
- Filed Direct Testimony (December 2012) regarding Entergy's request for certification of a 28 MW PPA for renewable energy capacity (RAIN CII waste heat) in accordance with the LPSC's Renewable Energy Pilot (Docket U-32557), on behalf of the Louisiana Public Service Commission Staff.
- Filed Direct Testimony (December 2012) at FERC regarding the Louisiana Public Service Commission's harm calculation stemming from Entergy's violation of its System Agreement (Docket No. EL09-61-002), on behalf of the Louisiana Public Service Commission.
- Filed Direct Testimony (September 2012) regarding Dixie Electric Member Cooperative's Ten year Power Supply AgreementU-32275.
- Filed Direct Testimony (March 2012) regarding Entergy's change of control filing to move to the Midwest ISO in LPSC Docket 32148.
- Filed Direct Testimony (September 2011) in support of a settlement agreement at the Louisiana Public Service Commission regarding the reasonableness of Cleco's CCPN to upgrade its Madison 3 coal unit to accommodate biomass fuel in accordance with the LPSC's Renewable Energy Pilot in Docket U-31792.
- Filed Direct (January 2011) and Cross-Answering (February 2011) Testimony at FERC regarding the reasonableness of Entergy's 2009 production costs that were used to develop bandwidth payments in Docket ER09-1350.
- Testified at FERC regarding an LPSC complaint that Entergy violated provisions of its System Agreement related to individual operating company sales in FERC Docket EL09-61.

RESUME OF PHILIP HAYET

- Testified at FERC regarding the reasonableness of Entergy's 2008 production costs that were used to develop bandwidth payments in Docket ER08-1224.
- Filed testimony at the Public Utilities Commission of the State of Colorado, in October 2009 concerning Black Hills/Colorado's CPCN application to construct two LMS 100 natural gas combustion turbine units. Docket No. 09A-415E
- Testified in front of the Minnesota Public Service Commission, September 2009 concerning Minnesota Power's Request for Approval to Purchase Square Butte's 500 kV DC transmission line, and to restructure a coal based power purchase agreement. MPUC Docket No. E015/PA-09-526
- Testified in front of FERC, July 2009, concerning the Louisiana Public Service Commission's complaint regarding Entergy's 2007 rough production cost equalization compliance filing in the System Agreement Case in FERC Docket No. ER08-1056.
- Worked with the Louisiana Public Service Commission in a collaborative effort to implement a Green Pricing Tariff for Entergy Gulf States Louisiana, Entergy Louisiana, CLECO, and SWEPCO. Coordination is required between the utility, power developers, other customers, and Commission Staff. (Docket No. R-28271)
- Assisted the Louisiana Public Service Commission Staff with a rulemaking to design Integrated Resource Planning ("IRP") rules. (Docket No. R-30021)
- Assisted the Louisiana Public Service Commission Staff with a rulemaking for the opportunity to implement a Renewable Portfolio Standard in Louisiana. (Docket No. R-28271 Sub-Docket B)
- Filed Testimony at FERC in Jan 2009, concerning the 2007 System Agreement Rough Production Cost Equalization production cost equalization compliance filing in the System Agreement Case in FERC Docket No. ER08-1056.
- Testified in front of the Wisconsin Public Service Commission in 2008 regarding WPL's certification proceeding concerning the Nelson Dewey CFB coal-fired generating unit. (6680-CE-170).
- Testified at FERC in July 2008, concerning the Louisiana Public Service Commission's complaint regarding Entergy's 2006 rough production cost equalization compliance filing in the System Agreement Case in FERC Docket No. ER07-956.
- Testified in front of the Wisconsin Public Service Commission in 2008 regarding WEPCO's request to implement environmental upgrades at its Oak Creek Power Plant in Docket 6630-CE-299.
- Assisting the Louisiana Public Service Commission Staff with the review and evaluation of Cleco Power's 2008 Short Term RFP and its 2010 Long-Term RFP.

- Provided regulatory support on behalf of the Louisiana Public Service Commission Staff concerning jurisdictional separation of Entergy Gulf States in Docket No. U-21453.
- Provided regulatory support on behalf of the Louisiana Public Service Commission Staff concerning the potential benefit of Transmission upgrades in Docket No. U-25116.
- Provided regulatory support on behalf of the Louisiana Public Service Commission concerning a FERC complaint regarding power purchase contracts in FERC Docket No. ER03-753-000.
- Provided regulatory support on behalf of the Louisiana Public Service Commission Staff in a retail proceeding evaluating the benefits of possibly retiring some of Entergy's gas-fired units. Docket No. U-27136 (Subdocket A).
- In 2002 – 2003, provided regulatory support on behalf of the Louisiana Public Service Commission's FERC complaint regarding cost allocation issues between the Entergy Operating Companies in the FERC Docket No. EL01-88-000.
- In 2002 – 2003, provided regulatory support on behalf of the Louisiana Public Service Commission Staff in a retail proceeding concerning Entergy's billing practices. Docket No. U-25888
- In 2000 – 2001, provided regulatory support on behalf of the Louisiana Public Service Commission's intervention in Entergy's proposed System Agreement modifications in the FERC Docket No. ER00-2854-000.

Projects Since 2000 - Hayet Power Systems Consulting, Atlanta, GA – President

- Filed Direct testimony August 2013 at the Georgia Public Service Commission concerning Georgia Power's Eighth Semi-Annual Vogtle Construction Monitoring Report (Docket 29849-U).
- Filed Direct testimony May 2013 at the Georgia Public Service Commission concerning Georgia Power's 2013 IRP and its request to decertify over 2,000 MW of coal-fired capacity (Docket No. 36498).
- Filed Direct testimony December 2012 at the Georgia Public Service Commission concerning Georgia Power's Seventh Semi-Annual Vogtle Construction Monitoring Report (Docket 29849-U).
- FiledDirect Testimony July 2012 at the Kentucky Public Service Commission regarding Big Rivers Certification to perform environmental upgrades in compliance with MATS and CSAPR EPA regulations. (Case No. 2012-00063).
- Submitted Direct Testimony May 2012 at the Georgia Public Service Commission concerning Georgia Power's Sixth Semi-Annual Vogtle Construction Monitoring Report (Docket 29849).

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- Submitted Direct Testimony May 2012 at the Georgia Public Service Commission concerning Georgia Power's Fuel Cost Recovery Filing (FCR-23 - Docket 35277).
- Assisted in the evaluation of Rocky Mountain Power's request for certification of environmental upgrades at the Naughton 3 unit in Wyoming on behalf of the Wyoming Industrial Energy Consumers (Docket No. 20000-EA-400-11).
- Submitted Direct Testimony November 2011 at the Georgia Public Service Commission concerning Georgia Power's evaluation of environmental upgrades pertaining to MATS EPA regulations, to decertify two aging coal units, to acquire PPA resources, and to have approved its IRP Update, on behalf of the Georgia Public Service Commission Staff (Docket 34218).
- Submitted Direct Testimony November 2011 at the Georgia Public Service Commission concerning Georgia Power's request to certify the reacquisition of wholesale block capacity, on behalf of the Georgia Public Service Commission Staff (Docket 26550).
- Submitted an Initial and Rebuttal Expert Report (April and June 2011, respectively) on behalf of the Department of Justice in US District Court, Civil Action No. 2:10-cv-13101-BAF-RSW.
- Filed Direct Testimony June 2011 at the Georgia Public Service Commission concerning Georgia Power's Fourth Semi-Annual Vogtle Construction Monitoring Report Period Ending December 31, 2011 (Docket 29849-U).
- Filed Direct testimony April 2011 at the Georgia Public Service Commission concerning Georgia Power's Fuel Cost Recovery Filing (FCR-22) (Docket 33302).
- Filed Direct testimony December 2010 at the Georgia Public Service Commission concerning Georgia Power's Third Semi-Annual Vogtle Construction Monitoring Report Period Ended June 30, 2010 (Docket 29849-U).
- Filed Direct testimony June 2010 at the Georgia Public Service Commission concerning Georgia Power's Second Semi-Annual Vogtle Construction Monitoring Report Period Ended December 31, 2009 (Docket 29849-U).
- Filed Direct testimony January 2010 at the Georgia Public Service Commission concerning Georgia Power's Fuel Cost Recovery Filing (FCR-21) (Docket 28945).
- Filed Direct testimony October 2009 at the Georgia Public Service Commission concerning Georgia Power's First Semi-Annual Vogtle Construction Monitoring Report Period Ended June 30, 2009 (Docket 29849-U).
- Filed Direct and Sur-rebuttal testimony in September and October 2009, respectively at the Utah Public Service Commission concerning PacifiCorp's 2009 Rate Case with regard to net power costs (Docket 09-035-23).

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- Assisted the Utah Office of Consumer Services to evaluate PacifiCorp's 2008 IRP (Docket 09-2035-01).
- Assisting the Georgia Public Service Commission Staff to investigate the acquisition of additional coal and combustion turbine capacity currently wholesale capacity (Docket 26550).
- Testified on Georgia Public Service Commission Staff concerning Georgia Power's Certification request for the Vogtle 3 and 4 Nuclear units (Docket 27800).
- Testified on behalf of the Utah Committee of Consumer Services concerning PacifiCorp's 2008 request to acquire the Chehalis Combined Cycle Power Plant based on a waiver of the RFP solicitation process (Docket 08-035-35).
- Submitted testimony on behalf of the Utah Committee of Consumer Services concerning PacifiCorp's 2007 Rate Case with regard to net power costs (Docket 07-035-93).
- Testified in April 2008 in front of the Georgia Public Service Commission regarding Georgia Power's November 2006 Fuel Cost Recovery filing (Docket 26794-U).
- Assisted the Georgia Public Service Commission Staff to evaluate Georgia Power's 2007 IRP filings (Docket 24505-U).
- Conducted an investigation of the Southern Company interchange accounting and fuel accounting practices on behalf of the Georgia Public Service Commission (Docket 21162-U).
- Testified in January 2007 in front of the Georgia Public Service Commission regarding Georgia Power's November 2006 Fuel Cost Recovery filing (Docket 23540-U).
- Assisted the Utah Committee of Consumer Services to evaluate PacifiCorp's 2007 IRP.
- Provided regulatory support to the Utah Committee of Consumer Services concerning PacifiCorp's 2006 Rate Case with regard to net power costs (Docket 06-35-01).
- Testified in May 2006 in front of the Georgia Public Service Commission regarding Georgia Power and Savannah Electric's March 2006 Fuel Cost Recovery filing (Docket 22403-U).
- Assisted the Utah Committee of Consumer Services by evaluating PacifiCorp's 2005 IRP and assisted in writing comments that were filed with the Commission.
- Assisted the Utah Committee of Consumer Services by participating in a collaborative process to develop an avoided cost tariff for large QFs.

Other Projects Conducted Since 1996

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- Provided assistance in 2004 to the Utah Committee of Consumer Services to analyze a series of power purchase agreements and special contracts between PacifiCorp and several of its industrial customers.
- Assisted the Georgia Public Service Commission Staff to evaluate Georgia Power and Savannah Electric's 2004 IRP filings. Also, testified in front of the Georgia Public Service Commission in that proceeding.
- Provided regulatory support to the Utah Committee of Consumer Services regarding PacifiCorp's 2003 Utah General Rate Case Docket # 03-2035-02.
- Worked on behalf of the Oregon Public Utility Commission to Audit PacifiCorp's Net Power Costs per a Settlement Agreement accepted by the Public Utility Commission of Oregon in its Order No. 01-787. Audit report in Docket No. UE-116 filed July 2003.
- Worked on behalf of the Utah Committee of Consumer Services to provide guidance and assist in the analysis of PacifiCorp's 2002 Integrated Resource Plan.
- Worked on behalf of the Utah Committee of Consumer Services to help analyze PacifiCorp's restructuring proposals.
- Testified in front of the Utah Public Service Commission in regards to PacifiCorp's Utah General Rate Case Docket # 010-035-010
- Submitted an expert report in August 2002 in the United States District Court for the Middle District of North Carolina in the Civil Action No. 1:00 CV 1262, United States v. Duke Energy Corporation. The case concerned compliance with the 1977 Clean Air Act and the report concerned generation resource planning and production cost modeling issues.
- Provided general rate case assistance in other hearings in Oregon, Washington and Wyoming
- Modeled the Singapore Power Electricity System and analyzed the benefits of dispatching a new oil-fired unit within the system.
- Modeled the Australian National Energy Market to develop market based energy price forecasts on behalf of an Independent Power Producer in Australia
- Analyzed the benefit of purchasing existing gas-fired steam turbine units within the Australian market
- Developed market price forecasts for South Australia as part of the evaluation of a new gas fired combined cycle unit
- Modeled the Vietnam Electricity System as part of a project to develop Least Cost Expansion plans for Vietnam
- Assisted in the evaluation of a large gas-fired combined cycle plant in Vietnam

- Assisted in the development of Market Price Forecasts in several regions of the US. These forecasts were used as the basis for stranded cost estimates, which were filed in testimony in a number of jurisdictions across the country.
- Helped to analyze the rate structure and develop an electricity price forecast for the Metropolitan Atlanta Rapid Transit Authority (MARTA) in Atlanta, Georgia
- Testified regarding the reasonableness of PacifiCorp's determination of Net Power Cost as part of a rate case proceeding in Utah
- Provided rate case support opposing PacifiCorp's rate increases in both Oregon and Washington State. Performed alternative power cost modeling using software simulations
- Critiqued the IRP filings of 5 utilities in South Carolina on behalf of the South Carolina State Energy Office
- Conducted research regarding ISO Tariffs and Operations for the PJM Power Pool, the California ISO, and the Midwest ISO on behalf of a Japanese Research.
- Performed research on numerous electric utility issues for 3 Japanese research organizations. This was primarily related to deregulation issues in the US in anticipation of deregulation being introduced in Japan.

1991 to 1996: **EDS Utilities Division, Atlanta, GA**
Lead Consultant, PROSCREEN (Now STRATEGIST) Department

- Managed a client services software team that supported approximately 75 users of the STRATEGIST electric utility strategic planning software.
- Participated in the development of STRATEGIST's competitive market modeling features and the Network Economy Interchange Module
- Provided client management direction and support, and developed new consulting business opportunities.
- Performed system planning consulting studies including integrated resource planning, DSM analysis, marketing profitability studies, optimal reserve margin analyses, etc.
- Based on experience with PROMOD IV, converted numerous PROMOD IV databases to STRATEGIST, and performed benchmark analyses of the two models.

1988 to 1991: **Energy Management Associates (EMA), Atlanta, GA**
Manager, Production Analysis Department

- Served as Project Manager of a database modeling effort to create an integrated utility operations and generation planning database. Database items were automatically fed into PROMOD IV.
- Supervised and directed a staff of five software developers working with a 4GL database programming language.
- Interfaced with clients to determine system software specifications, and provide ongoing client training and support

1980 to 1988: **Energy Management Associates (EMA), Atlanta, GA**
Senior Consultant, PROMOD IV Department

- Provided client service support to EMA's base of over 70 electric utility customers using the PROMOD IV probabilistic production cost simulation software.
- Provided consulting services in a number of areas including generation resource planning, regulatory support, and benchmarking.

PUBLICATIONS

Authored "The Developing Vietnamese Power System", which will appear in an upcoming addition of Power Value Magazine

Co-Authored "The European Electricity Market", which appeared in the June 2000 edition of Hart's Energy Markets

Authored "Singapore's Developing Power Market", which appeared in the July/August 1999 edition of Power Value Magazine

Co-authored "The New Energy Services Industry – Part 1", which appeared in the January/February 1999 edition of Power Value Magazine.

Co-authored and Presented "Evaluation of a Large Number of Demand-Side Measures in the IRP Process: Florida Power Corporation's Experience", Presented at the 3rd International Energy and DSM Conference, Vancouver British Columbia, November 1994

Co-authored "Impact of DSM Program on Delmarva's Integrated Resource Plan", Published in the 4th International Energy and DSM Conference Proceedings, held in Berlin, Germany, 1995

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TESTIMONY AND EXPERT WITNESS APPEARANCES

Filed Direct testimony August 2013 at the Georgia Public Service Commission concerning Georgia Power's Eighth Semi-Annual Vogtle Construction Monitoring Report (Docket 29849-U).

Filed Direct Testimony (July 2013) at the Louisiana Public Service Commission regarding Entergy's request for certification of a 8.5 MW PPA for renewable energy capacity (Agrilectric rice hull) in accordance with the LPSC's Renewable Energy Pilot (Docket U-32785), on behalf of the Louisiana Public Service Commission Staff.

Filed Direct testimony May 2013 at the Georgia Public Service Commission concerning Georgia Power's 2013 IRP and its request to decertify over 2,000 MW of coal-fired capacity (Docket No. 36498).

Filed Direct Testimony (April 2013) at the Kentucky Public Service Commission regarding Kentucky Power Company's Mitchell Certificate of Public Convenience and Necessity filing (Case No. 2012-00578) on behalf of the Kentucky Industrial Utility Customers, Inc.

Filed Cross Answering Testimony (March 2013) at FERC regarding the Louisiana Public Service Commission's harm calculation stemming from Entergy's violation of its System Agreement (Docket No. EL09-61-002), on behalf of the Louisiana Public Service Commission.

Filed Direct testimony December 2012 at the Georgia Public Service Commission concerning Georgia Power's Seventh Semi-Annual Vogtle Construction Monitoring Report (Docket 29849-U).

Filed Direct Testimony (December 2012) inEntergy's retail proceeding at the LPSC regarding termination of Cross-PPAs (Docket No. U-29764).

Filed Direct Testimony (December 2012) regarding Entergy's request for certification of a 28 MW PPA for renewable energy capacity (RAIN waste heat) in accordance with the LPSC's Renewable Energy Pilot (Docket U-32557).

Filed Direct Testimony (December 2012) at FERC regarding the Louisiana Public Service Commission's harm calculation stemming from Entergy's violation of its System Agreement (Docket No. EL09-61-002), on behalf of the Louisiana Public Service Commission.

Filed Direct Testimony (September 2012) regarding Dixie Electric Member Cooperative's Ten year Power Supply AgreementU-32275.

FiledDirect Testimony July 2012 at the Kentucky Public Service Commission regarding Big Rivers Certification to perform environmental upgrades in compliance with MATS and CSAPR EPA regulations. (Case No. 2012-00063).

Filed Direct testimony May 2012 at the Georgia Public Service Commission concerning Georgia Power's Sixth Semi-Annual Vogtle Construction Monitoring Report (Docket 29849-U).

Filed Direct Testimony (May 2012) at the Georgia Public Service Commission concerning

Georgia Power's Fuel Cost Recovery Filing (FCR-23 - Docket 35277).

Filed Direct Testimony (March 2012)regarding Entergy's change of control filing to move to the Midwest ISO in LPSC Docket 32148.

Submitted Direct testimony November 2011 at the Georgia Public Service Commission concerning Georgia Power's request to decertify two aging coal units, to acquire PPA resources, and to have approved its IRP Update, on behalf of the Georgia Public Service Commission Staff (Docket 34218).

Submitted Direct testimony November 2011 at the Georgia Public Service Commission concerning Georgia Power's request to certify the reacquisition of wholesale block capacity, on behalf of the Georgia Public Service Commission Staff (Docket 26550).

Filed Direct Testimony (September 2011) in support of a settlement agreement at the Louisiana Public Service Commission regarding the reasonableness of Cleco's CCPN to upgrade its Madison 3 coal unit to accommodate biomass fuel in accordance with the LPSC's Renewable Energy Pilot in Docket U-31792.

Submitted an Initial and Rebuttal Expert Report (April and June 2011, respectively), on behalf of the Department of Justice in US District Court, Civil Action No. 2:10-cv-13101-BAF-RSW.

Filed Direct testimony June 2011 at the Georgia Public Service Commission concerning Georgia Power's Fourth Semi-Annual Vogtle Construction Monitoring Report Period Ending December 31, 2011 (Docket 29849-U).

Filed Direct testimony April 2011 at the Georgia Public Service Commission concerning Georgia Power's Fuel Cost Recovery Filing (FCR-22) (Docket 33302).

Filed direct testimony (January 2011) and Cross Answering Testimony (February 2011) at FERC regarding the reasonableness of Entergy's 2009 production costs that were used to develop bandwidth payments in Docket ER09-1350.

Filed direct testimony December 2010 at the Georgia Public Service Commission concerning Georgia Power's Third Semi-Annual Vogtle Construction Monitoring Report Period Ended June 30, 2010 (Docket 29849-U)

Filed direct testimony June 2010 at the Georgia Public Service Commission concerning Georgia Power's Second Semi-Annual Vogtle Construction Monitoring Report Period Ended December 31, 2009 (Docket 29849-U)

Testified at FERC in 2010 regarding an LPSC complaint that Entergy violated provisions of its System Agreement related to individual operating company sales in FERC Docket EL09-61.

Filed direct testimony January 2010 at the Georgia Public Service Commission concerning Georgia Power's Fuel Cost Recovery Filing in Docket No. 28945.

Filed testimony at FERC December 2009 regarding the reasonableness of Entergy's 2008

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production costs that were used to develop bandwidth payments in Docket ER08-1224.

Filed Direct testimony December 2009 at the Georgia Public Service Commission concerning Georgia Power's First Semi-Annual Vogtle Construction Monitoring Report Period Ended June 30, 2009 (Docket 29849-U)

Filed Direct and Surrebuttal testimony in September and October 2009, respectively at the Utah Public Service Commission concerning PacifiCorp's 2009 Rate Case with regard to net power costs (Docket 09-035-23)

Filed testimony at the Public Utilities Commission of the State of Colorado, in October 2009 concerning Black Hills/Colorado's CPCN application to construct two LMS 100 natural gas combustion turbine units. Docket No. 09A-415E

Testified in front of the Minnesota Public Service Commission, September 2009 concerning Minnesota Power's Request for Approval to Purchase Square Butte's 500 kV DC transmission line, and to restructure a coal based power purchase agreement. MPUC Docket No. E015/PA-09-526

Filed testimony on behalf of the LPSC Staff in July 2009, concerning SWEPCO and CLECO's application to acquire the Oxbow Mine to supply the Dolet Hills Power Station in LPSC Docket No.U-30975.

Testified at FERC in July 2009, concerning the Louisiana Public Service Commission's complaint regarding Entergy's 2007 rough production cost equalization compliance filing in the System Agreement Case in FERC Docket No. ER08-1056.

Filed Testimony December 2008 at the Georgia Public Service Commission concerning Georgia Power's Certification request for the Vogtle 3 and 4 Nuclear units (Docket 27800)

Filed Testimony November 2008 at the West Virginia Public Service Commission concerning their fuel cost recovery filing (Docket 08-15-11-E-61)

Testified in front of the Wisconsin Public Service Commission in September 2008 regarding WPL's certification proceeding concerning the Nelson Dewey CFB coal-fired generating unit. (6680-CE-170).

Testified at FERC in July 2008, concerning the Louisiana Public Service Commission's complaint regarding Entergy's 2006 rough production cost equalization compliance filing in the System Agreement Case in FERC Docket No. ER07-956.

Testified in front of the Wisconsin Public Service Commission in 2008 regarding WEPCO's request to implement environmental upgrades at its Oak Creek Power Plant in Docket 6630-CE-299.

Filed direct testimony April 2008 at the Georgia Public Service Commission concerning Georgia Power's Fuel Cost Recovery Filing in Docket No. 26794 (FCR-20).

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Testified in October 2007 in front of the Louisiana Public Service Commission regarding ClecoPower's 2008 Short Term RFP in Docket No.U-30334.

Testified in June 2007 in front of the Georgia Public Service Commission regarding Georgia Power's 2007 Integrated Resource Planning Study.

Testified on behalf of the Georgia Public Service Commission Staff.in Docket No. 24505-U.

Filed testimony in Apr 2007 regarding the reasonableness of PacifiCorp's determination of Utah jurisdictional Net Power Costs in PacifiCorp's General Rate Case Docket 07-035-93.

Testified in January 2007 in front of the Georgia Public Service Commission concerning Georgia Power's November 2006 fuel Cost Recovery Filing in Docket No. 23540-U.

Testified in November 2006 in front of the Louisiana Public Service Commission concerning transmission issues associated with the audit of Entergy Louisiana's Fuel Adjustment Clause Filings (Docket U-25116).

Filed Testimony in August 2006 in front of the Louisiana Public Service Commission concerning jurisdictional separation of EntergyGulf States in Docket No. U-21453

Testified in May 2006 in front of the Georgia Public Service Commission regarding Georgia Power and Savannah Electric's March 2006 Fuel Cost Recovery filing (Docket 22403-U).

Testified in Apr 2006 in front of the Utah Public Service Commission regarding PacifiCorp Certification request to expand the Blundell Geothermal Power Station (Docket -05-035-54). Related to Mid-American Energy Holding's Acquisition of PacifiCorp.

Filed Testimony in July 2005 regarding PacifiCorp's Avoided Cost proceeding (03-035-14).

Filed Testimony in December 2005 regarding the reasonableness of PacifiCorp's determination of Utah jurisdictional Net Power Costs in PacifiCorp's General Rate Case (Docket 04-035-42).

Testified in March 2005 in front of the Utah Public Service Commission regarding whether the Stipulation that had previously been agreed to concerning PacifiCorp's Schedule 38 avoided cost tariff was still valid for the remaining unsubscribed capacity available under the Stipulation's cap.

Testified in November 2004 in front of the Utah Public Service Commission regarding an industrial customer's request for both a special economic development tariff and a large QF tariff. Testimony was provided on behalf of the Utah Committee of Consumer Services in Docket No. 03-035-19 (Special Contract) and No. 03-035-38 (QF proceeding).

Testified in August 2004 in front of FERC on behalf of the Louisiana Public Service Commission concerning a complaint that had been filed against Entergy concerning a series of affiliate power purchase agreements FERC Docket ER03-583-000.

Testified in June 2004 in front of the Georgia Public Service Commission regarding Georgia

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Power and Savannah Electric's 2004 Integrated Resource Planning Studies. Testimony was provided on behalf of the Georgia Public Service Commission Staff. Georgia Docket Nos. 17687 and 17688.

Testified in May 2004 in front of the Utah Public Service Commission concerning the development of a large QF avoided cost methodology. Testimony was provided on behalf of the Utah Committee of Consumer Services in Docket 03-035-14.

Testified in July 2003 in front of FERC in support of the Louisiana Public Service Commission's complaint regarding cost allocation issues amongst the Entergy Operating Companies in the FERC Docket Number EL01-88-000.

Submitted an expert report in August 2002 in the United States District Court for the Middle District of North Carolina in the Civil Action No. 1:00 CV 1262, United States v. Duke Energy Corporation.

Testified in July 2002 on behalf of the Utah committee for consumer services regarding a special contract for an industrial consumer in support of a settlement agreement in a PacifiCorp Utah proceeding in Docket Number 02-035-02.

Provided testimony in the Fall of 2001 in front of FERC on behalf of the Louisiana Public Service Commission's intervention in Entergy's proposed System Agreement modifications in the FERC Docket No. ER00-2854-000.

Testified in July 2001 regarding the reasonableness of PacifiCorp's determination of Utah jurisdictional Net Power Costs in PacifiCorp's General Rate Case Docket 01-035-01

Testified in September 1998 regarding the reasonableness of PacifiCorp's determination of Utah jurisdictional Net Power Costs as part of a Settlement Proceeding in Pacificorp's rate case Docket Number 97-035-01.