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Witness:	Sarah L. Kliethermes
Sponsoring Party:	MO PSC Staff
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MISSOURI PUBLIC SERVICE COMMISSION

REGULATORY REVIEW DIVISION

SURREBUTTAL TESTIMONY

OF

SARAH L. KLIETHERMES

UNION ELECTRIC COMPANY d/b/a AMEREN MISSOURI

CASE NO. ER-2014-0258

Jefferson City, Missouri
February 2015

** **<u>Denotes Highly Confidential Information</u>** **

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BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service	)))	Case No. ER-2014-0258

AFFIDAVIT OF SARAH L. KLIETHERMES

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Sarah L. Kliethermes, of lawful age, on her oath states: that she has participated in the preparation of the following Surrebuttal Testimony in question and answer form, consisting of 33 pages of Surrebuttal Testimony to be presented in the above case, that the answers in the following Surrebuttal Testimony were given by her; that she has knowledge of the matters set forth in such answers; and that such matters are true to the best of her knowledge and belief.

Sarah L. Kliethermes

Sarah L. Kliethermes

Subscribed and sworn to before me this 6th day of February, 2015.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 28, 2018
Commission Number: 14942086

Susan L. Sundermeyer

Notary Public

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OF

SARAH L. KLIETHERMES

UNION ELECTRIC COMPANY d/b/a AMEREN MISSOURI

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SURREBUTTAL TESTIMONY

OF

SARAH L. KLIETHERMES

UNION ELECTRIC COMPANY d/b/a AMEREN MISSOURI

CASE NO. ER-2014-0258

EXECUTIVE SUMMARY

Q. Are you the same Sarah L. Kliethermes who contributed to Staff's Cost of Service Direct Report and Staff's Class Cost of Service and Rate Design Direct Report and filed Rebuttal Testimony?

A. Yes.

Q. What is the purpose of your Surrebuttal testimony?

A. Attached to my testimony is Staff's response to Ameren Missouri's proposal to enter into a wholesale contract with Noranda, and its request to obtain a Commission order approving that contract and ratemaking decisions concerning that contract.

My testimony responds to Mr. Brubaker's testimony on behalf of MIEC concerning Staff's direct-filed class cost of service ("CCoS") study, particularly concerning production cost allocation and off-system sales allocation. Mr. Brubaker generally makes factually incorrect statements concerning the steps of Staff's Detailed BIP method, and I attempt to clarify any resulting confusion his Rebuttal testimony may have caused concerning Staff's methodology.

I also (1) respond to Ameren Missouri's witness William Warwick concerning allocation of O&M expense, (2) update certain calculations concerning the cost of providing service to Noranda based on the Rebuttal testimony of Ameren Missouri witness Mark Peters,

(3) make minor corrections to values presented in my rebuttal testimony resulting from discussion with Ameren Missouri personnel, and (4) respond to Ameren Missouri's witness Steve Wills' request to reduce the level of billing units associated with the LTS class for purposes of setting rates.

RESPONSE TO BRUBAKER

Q. How did Staff allocate fixed production costs in its Detailed BIP study?

A. Staff allocated production capacity costs on the basis of class demands.[1] Staff's development of dollar-weighted capacity values is described extensively below, and was provided in its Cost of Service Report under the heading "C. Allocation of Production Costs." A summary of the calculations for developing the allocator are provided below:

BIP Installed Capacity Allocator							
	Total	Res	SGS	LGS/SPS	LPS	LTS	Lighting
Base Capacity	$2,822,815,026	$ 1,029,099,242	$ 267,307,031	$ 900,314,018	$ 290,350,520	$ 318,683,938	$ 17,060,278
Incremental Intermediate Capacity	$1,174,908,789	$ 708,022,668	$ 146,907,996	$ 292,286,025	$ 27,692,100	-	-
Incremental Peak Capacity	$296,884,272	$ 206,620,704	$ 30,862,301	$ 50,449,482	$ 8,951,786	-	-
Totals:	$4,294,608,087	$1,943,742,614	$445,077,327	$1,243,049,525	$326,994,406	$318,683,938	$17,060,278
BIP Installed Capacity Allocator:		45.26%	10.36%	28.94%	7.61%	7.42%	0.40%

Q. What is Mr. Brubaker's primary criticism of Staff's Detailed BIP study?

A. Although Staff did not allocate fixed production costs using energy, Mr. Brubaker states that Staff's study used energy to allocate fixed production capacity costs. Mr. Brubaker concludes that using energy to allocate fixed production capacity costs over-allocates production capacity costs to the LPS class.[2]

[1] Staff also allocated Fuel in Storage on class demands.

[2] It appears that Mr. Brubaker reached this conclusion by dividing the sum of Staff's **dollar-weighted** calculation of class base capacity requirements by the sum of the **dollar-weighted** calculated base, intermediate, and peak capacity requirements. This same error was repeated by Mr. Warwick in his "corrected" Rebuttal testimony filed January 28. Staff is not aware of any convention under which capacity would be denominated with a dollar sign ($).

Q. Did Staff allocate more production costs to the LPS class than was allocated by Mr. Brubaker.?

A. No. Not only are the overall results of Staff's Detailed BIP study quite consistent with Mr. Brubaker's results, Mr. Brubaker actually allocated approximately $6.6 million more in production costs to the LPS class than did Staff.

Q. Did Staff allocate any production costs using energy?

A. Of course. Staff, like Mr. Brubaker, Ameren, and OPC, allocated fuel costs using energy.[3] Staff's development of dollar-weighted energy values is described extensively below, and was provided in its Cost of Service Report under the heading "C. Allocation of Production Costs." A summary of the calculations for developing the allocator are provided below:

BIP Fuel for Energy Allocator (annual)							
	Total	Res	SGS	LGS/SPS	LPS	LTS	Lighting
Base Energy Usage	$597,229,001	$ 204,706,430	$ 55,266,720	$ 195,272,270	$ 65,437,461	$ 74,486,460	$ 2,059,660
Incremental Intermediate Usage	$81,278,803	$ 45,954,611	$ 9,437,315	$ 20,319,204	$ 2,693,029	$ 255,388	$ 2,619,255
Incremental Peak Usage	$6,497,677	$ 3,374,837	$ 667,847	$ 1,678,546	$ 776,447	-	-
Totals:	$685,005,481	$254,035,879	$65,371,883	$217,270,020	$68,906,937	$74,741,848	$4,678,916
BIP Fuel for Energy Allocator:		37.09%	9.54%	31.72%	10.06%	10.91%	0.68%

Q. In its CCoS Report, did Staff clearly identify that it allocated fixed asset costs using demand, and fuel expense using energy?

A. Yes. As stated in Staff's CCoS Report at page 14, lines 2 - 13, "Ameren Missouri's costs for plant investment and the production expenses appearing on its income statement are appropriately allocated by a production-capacity (demand) or a production-energy (energy) allocator. Ameren Missouri's generation facilities are predominantly considered fixed assets, and so the costs of these assets are considered demand-related and

[3] Staff also allocated O&M on class energy.

apportioned to the rate classes on the basis of the production-capacity allocator. Fuel expense related to running the generation plants and purchased power used to serve load are considered energy-related and allocated to rate classes on the basis of the production-energy allocator. The demand and energy characteristics of Ameren Missouri's load requirement are both important determinants of production cost and expense allocations, since load must be served efficiently over time throughout the day and year."

Q. Does Staff's method attribute the same capacity cost to a customer that takes all of its load at the system peak hour as it would to a class with the same amount of energy consumption taken steadily at the same amount every hour throughout the year?

A. No. Staff explicitly relied on the load factors and demands of each customer class to appropriately assign (1) the relatively expensive capacity costs of base generation on each class' base level of demand, (2) the relatively moderate capacity costs of intermediate generation on each class' intermediate level of demand, and (3) the relatively inexpensive capacity costs of peaking generation on each class' peak level of demand.[4,5]

Q. Between the BIP and the Average and Excess method, which method better recognizes the need to install plants to most cost-effectively serve load throughout the year?

A. The BIP most reasonably recognizes that some plants will run virtually year round at a high capacity factor (Base), only part of the year at a moderate capacity factor (Intermediate), and rarely during the year, at a low capacity factor (Peak). The BIP method

[4] Mr. Brubaker's statement at page 15, line 20 – page 16, line 4 is factually inaccurate. Mr. Brubaker there asserts that "[i]n Staff's Detailed BIP study, 100% of the fixed costs associated with plants designated as base load are allocated to customer classes using the customer class energy requirement factor as the basis for the allocation. By using the energy allocation factor, Staff does not include any consideration of the times that energy is consumed (i.e., when demands occur), and would therefore attribute the same capacity cost to a customer that takes all of its load at the system peak hour as it would to a class with the same amount of energy consumption taken steadily at the same amount every hour throughout the year."

[5] Staff's methods of fuel expense allocation, O&M allocation, and fuel in storage allocation also recognizes the difference in average costs associated with operation of Base, Intermediate, and Peak units.

also better recognizes the fact that Base plants tend to be more expensive to install, but have a lower average cost of energy, while Peak plants tend to be less expensive to install, but have a high average cost of energy, and that Intermediate plants tend to be somewhere between the two.

Q. Does designating a plant as "Base" or "Intermediate" imply that those plants will not operate at the time of system peak or that those plants' capacity will not be relied upon to meet system peak?

A. Not at all. Under Staff's method, the average prices used to assign intermediate capacity costs or energy costs assumes that all Base plants have already been dispatched to safe operational levels. Similarly, the average prices used to assign peak capacity costs or energy costs assumes that all Intermediate and Base plants have already been dispatched to safe operational levels.[6]

Q. Does Staff's Detailed BIP study conflict with any prior Commission ruling that the Staff is aware of, particularly those discussed by Mr. Brubaker?

A. No. Mr. Brubaker's assertion at page 16, line 18 – page 17, line 10, is factually inaccurate in at least two respects. First, his statement is based on his factually inaccurate claim that Staff based its allocation of capacity costs on energy. Second, his statement is based on an assertion that the Commission's decision in Case No. ER-2010-0036 included a finding that the Commission rejected particular methods because they were

[6] Mr. Brubaker's testimony at page 16, lines 10 – 17 is factually inaccurate. Mr. Brubaker here asserts that "[t]he BIP approach attempts to assign only one purpose for each class of plant. In reality, when systems are planned, the utility attempts to install that combination of generation facilities which, giving consideration to fixed costs and variable costs, is expected to serve the needs of all customers, collectively, on a least-cost basis. All plants contribute to meeting peak demands, and the failure to allocate the fixed costs associated with base load plants on a measure of peak demand produces a biased result that over-allocates costs to high load factor customers and under-allocates costs to low load factor customers."

"heavily energy-weighted." In fact, the Commission's decision neither discusses nor even notes the degree of "energy-weighting" of the rejected methods.[7]

Q. Does Mr. Brubaker's claim that the BIP "lacks precedent for its use" conflict with any prior Commission decision?[8]

A. Yes. In its most recent ruling relying on an electric CCoS study, Case No. ER-2012-0175, the Commission stated that it relied on the BIP study performed by Mr. Paul Normand, on behalf of Kansas City Power & Light.

Q. Is Staff implying that the Commission's reliance on a particular methodology in a particular case is dispositive of what methodology should be used going forward?

A. No.

Q. Did Staff make the "implementation errors" as identified by Mr. Brubaker?

A. No. Mr. Brubaker identifies some items as "errors" that did not actually exist in Staff's study. For example, Mr. Brubaker states that Staff's Detailed BIP adjusted the costs of intermediate plants downward by shifting some of the cost to the base load category. However, Staff did not shift any cost into the base load category. While Staff did make an adjustment to a $/MW figure related to the Sioux scrubber, that basis for that adjustment was explained in Staff's Direct testimony and in no manner constitutes an "implementation error" as alleged by Mr. Brubaker.

Q. Did Staff ignore the cost of approximately 25% of Ameren's capacity when performing its calculations as Mr. Brubaker alleges?

[7] The Commission's rejection of Peak and Average method in Case No. ER-2010-0036 was due to a double-counting of demand. In contrast, the BIP method explicitly separates demand to avoid double-counting and to ensure reasonable recognition of each level of each class's demand.

[8] Brubaker rebuttal, page 15, lines 1 – 6.

A. No. Staff used the actual operating characteristics of all of Ameren Missouri's non-solar generating units to develop $/MWh fuel and O&M values. Staff used 92% (by dollar value), 83% (by maximum capacity), and 99% (by test year energy generation) of Ameren Missouri's generation fleet to develop $/MW capacity and fuel in storage values. The allocators calculated with these values were allocated to 100% of the costs associated with Ameren Missouri's generating units (including solar).

Q. Did Mr. Brubaker raise any points that warrant ongoing discussion or that Staff may address differently in a future study?

A. Yes. Mr. Brubaker suggested that class minimum demand may be a reasonable measure of class base demand. While Staff did consider use of class minimum demand in this case, Staff used class average demand as its measure of class base demand because of operational concerns specific to Ameren Missouri's generation fleet. However, going forward, Staff would like to explore whether a measure of minimum demand could be reasonable for determining class base demand.[9]

Q. What items do you discuss below in response to Mr. Brubaker's rebuttal testimony?

A. I discuss the following issues raised by Mr. Brubaker:

1. Staff's Development of Production-Related Allocators
2. Staff's Use of Surrogates for Intermediate Capacity
3. Staff's Calculation of Base Demands
4. The Unreasonableness of Mr. Brubaker's Conclusions
5. Staff's Allocation of Other Revenues
6. Staff's Market Price Study

[9] Mr. Brubaker also suggests at page 19, lines 4 – 11, that it would be more appropriate to use installed capacity costs to determine allocation, as opposed to net capacity costs. Staff will review this suggestion going forward, but is concerned that such an adjustment could over-allocate fixed capacity costs to customers with high load factors.

CORRECTIONS TO BRUBAKER'S DESCRIPTION OF STAFF'S STUDY

Q. In his summary of Staff's detailed BIP method, was Mr. Brubaker factually accurate?

A. No.

Q. Could reasonable minds disagree on whether Staff's Detailed BIP method reasonably allocated costs to Ameren Missouri's retail classes?

A. Of course.

Q. Can reasonable minds disagree on what mathematical calculations are contained in Staff's workpapers and described in Staff's testimony?

A. No. Mr. Brubaker is factually inaccurate in his description of virtually every aspect of Staff's method that he mentions in his testimony.

Q. What is the fundamental tenant of the detailed BIP Method?

A. Staff's BIP method focuses on the inverse relationship between the cost of capacity and the price of energy. Base energy tends to be less expensive, but it is generated from relatively expensive capacity. Peak energy tends to be more expensive, but it is generated from relatively inexpensive capacity. These relationships are inherently inter-related, and that is the reason Staff developed the separate Detailed BIP allocators for its primary study.[10]

1. Staff's Development of Production-Related Allocators

Q. How did Staff develop the BIP allocators?

A. While the detailed discussion of Staff's production-capacity and production-energy allocators can be found in Staff's direct case, a succinct summary of finding the class

[10] Mr. Brubaker's assertions at page 15, lines 7 – 16, are factually inaccurate.

BIP energy and demand components, and the system BIP energy costs per MWh and demand costs per MW is provided below.

Q. How did Staff develop the "BIP Installed Capacity Allocator"?

A. Staff found class demands and found Ameren Missouri's dollar-weighted capacity costs. These values were multiplied to assign Ameren Missouri's capacity costs to each type of demand of each class. Those assigned capacity costs were then summed and divided by the total to produce a capacity allocator that recognizes the variation in capital costs of plants that serve different levels of demand.[11]

<u>Finding Class Demands</u>

1. Staff found each class's average demand in MW. That MW of demand value is the "base demand" used for each class in the BIP calculation. For example, LPS has a base demand of 461 MW, while Residential has a base demand of 1,635 MW.

2. Staff found each class's demand in MW at the time of each month's system peak. Staff then averaged each class's 12 demands to a single MW value. That MW value is each class's intermediate demand. The difference between each class's base demand and its intermediate demand is its incremental peak demand. For example, LPS has an intermediate demand that is only 45 MW higher than its base demand, while Residential has an intermediate demand that is 1,145 MW higher than its base demand. LPS has a much higher load factor than Residential, so it is not surprising that LPS's incremental intermediate demand is only 10% of its base demand, while Residential's incremental intermediate demand is 70% of its base demand.

3. Staff found each class's demand in MW at the time of the four system peaks. Staff then averaged each class's 4 demands to a single MW value. That MW value is each class's peak demand. The difference between each class's intermediate demand and its peak demand is its incremental peak demand. For example, LPS has a peak demand that is only 28 MW higher than its intermediate demand, while Residential has a peak demand that is 655 MW higher than its base demand. LPS has a much higher load factor than Residential, so it is not surprising that LPS's incremental peak

[11] As stated in its CCoS Report, Ameren Missouri does not have the amount of intermediate generation one would expect if Ameren Missouri had designed its system to efficiently serve load over the course of a year. However, because in practice, Ameren Missouri participates in the MISO integrated energy market, its generation is dispatched as part of the larger MISO fleet. MISO's dispatch is ordered according to security-constrained economic merit, which results in price signals stacking in a manner consistent with those experienced by a utility with a generation fleet that includes the relative amounts of each base, intermediate, and peak generation units assumed in the NARUC Manual.

demand is only 5% of its total demand, while Residential's incremental peak demand is 19% of its total demand.

The BIP Demand Characteristics of each class are provided in the table below:

	Res	SGS	LGS/SPS	LPS	LTS	Lighting
Base	1,635 MW	425 MW	1,430 MW	461 MW	506 MW	27 MW
Incremental Intermediate	1,145 MW	238 MW	473 MW	45 MW	-	-
Incremental Peak	655 MW	98 MW	160 MW	28 MW	-	-

<u>Finding Dollar-Weighted Average Capacity Costs</u>

4. Staff summed each class's base demands to find a system base demand for CCoS purposes of 4,483,927 MW.[12]

5. Assuming that the available generating plants with the lowest operating costs would be the first plants called upon, Staff identified the Ameren Missouri plants that had the lowest $/MWh operating cost as modeled in Staff's fuel run, up to the capacity requirements of base demand (4,483,927 MW). Those plants were Keokuk, Osage, Callaway, Rush Island 2, Labadie 3, Labadie 2, and Labadie 4.

6. Staff found the capacity-weighted average $/MW of installed-capacity for the plants identified as meeting base capacity requirements. The combined capacity of those plants is 4,542.8 MW, and the net investment in those plants is $2,859,878,047. Dividing the investment by the capacity results in an average cost of base capacity of $629,540.82/MW.

7. Staff then identified the Ameren Missouri plants that had the next lowest $/MWh operating cost as modeled in Staff's fuel run, up to the capacity requirements of the sum of the class's intermediate demand (6,383,461 MW). Those plants were Rush Island 1, Sioux 1, Sioux 2, and Meramec 4.

8. Staff found the capacity-weighted average $/MW of installed-capacity for the plants identified as meeting intermediate capacity requirements. The combined capacity of those plants is 1,898 MW. After the Sioux adjustment, the net investment in those plants is $1,173,978,466.[13] Dividing the investment by the capacity results in an average cost of intermediate capacity of $618,534.49/MW.

[12] Mr. Brubaker's assertion that "Staff simply divides Ameren Missouri's total annual retail energy sales by the 8,760 hours in the year to arrive at approximately 4,500 megawatts as the amount of capacity to be considered base load" at page 18, lines 4 – 18, of his Rebuttal Testimony is factually inaccurate.

[13] Staff's Sioux adjustment was described in its CCoS Report and will be summarized for convenience below.

9. Staff then identified the Ameren Missouri plants that had the next lowest $/MWh operating cost as modeled in Staff's fuel run, up to the capacity requirements of the sum of the class's peak demand (7,324,774 MW). Those plants were Meramec 3, Meramec 2, Meramec 1, Pinckney 2, Pinckney 3, Pinckney 4, Pinckney 1, Venice 4, and Venice 3.

10. Staff found the capacity-weighted average $/MW of installed-capacity for the plants identified as meeting intermediate capacity requirements. The combined capacity of those plants is 1,008 MW and the net investment in those plants is $317,906,880. Dividing the investment by the capacity results in an average cost of intermediate capacity of $315,383.81/MW.

Assigning Class Capacity Costs

11. Staff multiplied each class's base demand (in MW) by the average cost of base capacity of $629,540.82/MW.

12. Staff multiplied each class's incremental intermediate demand (in MW) by the average cost of intermediate capacity of $618,534.49/MW.

13. Staff multiplied each class's incremental peak demand (in MW) by the average cost of peak capacity of $315,383.81/MW.

14. Staff summed the assigned capacity costs for each class. Not surprisingly, the capacity costs assigned to each class's base capacity requirements is higher than the capacity costs assigned to each class's peak capacity requirements. The assigned capacity cost for each class's intermediate capacity requirements is in between those two amounts.

	Res	SGS	LGS/SPS	LPS	LTS	Lighting
Base Capacity	$1,029,099,242	$267,307,031	$900,314,018	$290,350,520	$318,683,938	$17,060,278
Incremental Intermediate Capacity	$708,022,668	$146,907,996	$292,286,025	$27,692,100	-	-
Incremental Peak Capacity	$206,620,704	$30,862,301	$50,449,482	$8,951,786	-	-
Totals:	$1,943,742,614	$445,077,327	$1,243,049,525	$326,994,406	$318,683,938	$17,060,278

Determining the "Detailed BIP Installed Capacity Allocator"

15. Staff divided each class's assigned capacity cost by the total of all classes' assigned energy cost. The resulting factor is the allocator.

	Res	SGS	LGS/SPS	LPS	LTS	Lighting
BIP Installed Capacity Allocator:	45.26%	10.36%	28.94%	7.61%	7.42%	0.40%

Q. How did Staff develop the "BIP Fuel for Energy Allocator"

A. Staff found class loads at each level of demands and found Ameren Missouri's dollar-weighted fuel costs associated with the plants serving each level of demand. These values were multiplied to assign Ameren Missouri's fuel cost to the energy used at each level of demand by each class. Those assigned fuel costs were then summed and divided by the total, to produce a fuel allocator that recognizes the variation in fuel costs of plants that serve different levels of demand.

<u>Finding Class Energy Usage</u>

1. Staff analyzed each class's weather-normalized energy usage for each hour of the year. In a given hour, if a class had energy usage (MWh) equal to or below its base demand (MW), then Staff recorded that energy usage as base usage. If in that hour a class had energy usage in excess of its base demand, Staff recorded that hour's energy usage for that class as being equal to that class's base demand. For example, in a particular hour (hour 42), LPS had an hourly load of 415.54 MWh. Because that amount is lower than the LPS base demand of 461 MW, all 415.54 MWh are recorded as base energy usage. In that same hour, Residential had total usage of 2,911.51 MWh. Because Residential's base demand is only 1,635 MW, only 1,635 MWh were recorded as base energy usage.

2. Staff then analyzed if in each hour a class had energy usage in excess of its intermediate demand. If so, Staff recorded that hour's energy usage (less the previously allocated base usage) for that class as being equal to that class's intermediate demand. For example, because in hour 42, LPS had an hourly load that was less than its base demand, Staff did not record any intermediate usage. In that same hour, Residential had total usage of 2,911.51 MWh, with 1,635 MWh recorded as base energy usage. So for that hour, Staff recorded Residential's intermediate energy as 1,144.68 MWh, because that is the amount that is greater than Residential's base demand, but less than its intermediate demand.

3. Finally, Staff recorded all energy usage in excess of a particular class's intermediate demand as peak usage. For example, in hour 42, Staff recorded Residential peak energy usage of 132.15 MWh.

The BIP Energy Characteristics of each class are provided in the table below:

	Res	SGS	LGS/SPS	LPS	LTS	Lighting
Base	12,106,010 MWh	3,268,385 MWh	11,548,089 MWh	3,869,866 MWh	4,405,010 MWh	121,805 MWh
Incremental Intermediate	2,026,216 MWh	416,107 MWh	895,908 MWh	118,740 MWh	11,260 MWh	115,487 MWh
Incremental Peak	118,801 MWh	23,510 MWh	59,088 MWh	27,333 MWh	-	-

<u>Finding Dollar-Weighted Average Energy Costs</u>

1. Staff found the total fuel cost associated with each plant in Ameren Missouri's generation fleet identified as necessary to serve base demand. Staff also found the total MWh of energy generated by those plants in Staff's fuel run.

2. Staff divided the total fuel cost of the base-serving plants by the total MWh of generation of those plants, to produce a dollar-weighted average cost of a MWh of energy from a base-serving plant. Staff used this value for the $/MWh fuel cost of base energy in developing its "BIP Fuel for Energy Allocator."

3. Staff repeated this process using the generation and fuel cost of the intermediate-serving plants, and the peak-serving plants.
4. Staff found the average fuel cost of base energy to be $16.91, intermediate energy to be $22.68, and peak energy to be $28.41.

<u>Assigning Class Energy Costs</u>

5. Staff multiplied each class's base energy usage (in MWh) by the average cost of base fuel of $16.91/MWh.

6. Staff multiplied each class's intermediate energy usage (in MWh) by the average cost of intermediate fuel of $22.68/MWh.

7. Staff multiplied each class's peak energy usage (in MWh) by the average cost of peak fuel of $28.41/MWh.

8. Staff summed the assigned fuel costs for each class.

	Res	SGS	LGS/SPS	LPS	LTS	Lighting
Base Energy Usage	$204,706,430	$55,266,720	$195,272,270	$65,437,461	$74,486,460	$2,059,660
Incremental Intermediate Usage	$45,954,611	$9,437,315	$20,319,204	$2,693,029	$255,388	$2,619,255
Incremental Peak Usage	$3,374,837	$667,847	$1,678,546	$776,447	-	-
Totals:	$254,035,879	$65,371,883	$217,270,020	$68,906,937	$74,741,848	$4,678,916

<u>Determining the "Detailed BIP Fuel for Energy Allocator"</u>

9. Staff divided each class's assigned capacity cost by the total of all classes' assigned energy cost. The resulting factor is the allocator.

	Res	SGS	LGS/SPS	LPS	LTS	Lighting
BIP Installed Capacity Allocator:	37.09%	9.54%	31.72%	10.06%	10.91%	0.68%

2. Staff's Use of Surrogates for Intermediate Capacity (Sioux Adjustment)

Q. Do the capacity factors of the plants modeled in the fuel run confirm the reasonableness of Staff's designation of plants as providing Base, Intermediate, and Peak capacity?

A. Yes. In the fuel run the plants used to determine Base values operated with a capacity factor of almost 84% (if Keokuk and Osage are excluded, the Base plants operated at a capacity factor of over 85%). The plants used to determine Intermediate values operated with a capacity factor of 63%, and the peaking plants operated at a capacity factor of 21%. The plants that Staff did not directly assign in determining weighted-average values operated at a capacity factor of less than 3%.[14]

Q. Does Ameren Missouri have "intermediate" plants?

A. Ameren Missouri does not have any combined cycle units, and has very small percentage of small coal units. These are the physical plant types assumed to serve

[14] Excluding Taum Sauk, wind, and solar.

intermediate load both as a practical matter and under the BIP method as described in the NARUC Manual. Staff has developed a method to reasonably assign the capital cost of Ameren Missouri's generation assets to the BIP components for purposes of developing an allocator.[15] In practice, because Ameren Missouri participates in the MISO integrated energy market, its generation is dispatched as part of the larger MISO fleet. MISO's dispatch is ordered according to security-constrained economic merit, which results in price signals stacking in a manner consistent with those experienced by a utility with a generation fleet that includes the relative amounts of each base, intermediate, and peak generation units assumed in the NARUC Manual.

Q. Are the plants Staff used to develop its intermediate \$/MW and \$/MWh values actually intermediate plants?

A. Other than Meramec 4, they are not. Rush Island 1 and the Sioux units are textbook base-load coal plants. However, in Staff's fuel run, these plants generally operated at the lowest capacity factors of Ameren Missouri's coal units, which resulted in a higher-than-average fuel cost per MWh compared to the Ameren Missouri coal units operating at higher capacity factors.[16] The average energy prices resulting from using these plants as intermediate surrogates is entirely consistent with the operating costs one would associate with intermediate plants.

[15] As assumed under the NARUC Manual, base load units have high capital costs and have lower, constant running costs. Intermediate units have capital costs and operating characteristics between those of base-load units and peaking units, and are typically combined cycle gas units or very small coal thermal plants. Peaking units have low capital costs but are relatively more costly to run.

[16] Labadie 1 did operate at a lower capacity factor than Rush Island 1, but this is due to the method in which Ameren Missouri models its outages, and does not impact the reliability of Staff's results.

Q. How does the relative lack of intermediate plants relate to the Sioux capital adjustment Staff made in finding the average installed cost of capital for intermediate capacity?

A. Sioux dispatches at a higher operating cost than other coal units because of the increased station use of energy associated with operating the scrubber. Essentially, for the same amount of coal burned, Sioux will produce slightly less net energy than a comparable coal plant, because running the scrubber consumes energy.

This treatment results in the Sioux generating facility being treated as an intermediate plant under Staff's BIP capacity assignment. However, because Sioux is the only Ameren Missouri production plant with scrubbers, including an unadjusted value for Sioux as the basis for the determination of intermediate capacity cost allocation would create an inappropriate price signal that intermediate capacity is more costly than base capacity. Staff adjusted Sioux's net plant value used in the assignment of plant to BIP components to smooth the capacity cost curve, by removing the net value of the scrubbers.[17]

3. Staff's Calculation of Base Demands

Q. After Mr. Brubaker's misstatement of fact at page 18, lines 4 – 18, of his Rebuttal Testimony, does he raise a concern upon which reasonable minds could disagree?

A. Yes. Mr. Brubaker states that conceptually under the BIP method, the "base load" should be regarded as that load that is present at all times, and not the average demand.

Q. In developing the Detailed BIP as used in this case, did Staff consider use of a measure of minimum demand for establishing the Base component?

[17] Contrary to Mr. Brubaker's assertion at page 18, line 19 – page 19, line 3, the need for the Sioux adjustment is not "completely at odds with Staff's theory," because Staff never theorized that Sioux was anything other than a base-load plant with recently-installed environmental equipment.

A. Yes. Staff considered use of a measure of minimum demand, but for purposes of this case, Staff did not proceed with developing a measure of minimum demand for a number of reasons. First, and for purposes of this case, determinative, Staff was concerned that use of a minimum demand amount would not reasonably recognize the safe ramp rates of Ameren Missouri's generating fleet. For example, if minimum demand were found to be at a level that assumes that all of Ameren Missouri's coal fleet shuts off every evening and fires back up every morning to be running at full capacity by 2 in the afternoon, that result is not reasonable in that it is not practical or even possible.

Q. In early iterations of researching the Detailed BIP method, did Staff "play around" with observing the impacts of using some measure of minimum demand for establishing the level of base generating capacity requirements?

A. Yes. However, counter to the assertions of Mr. Brubaker, as Staff recalls, the lower the measure of minimum demand used, the higher the costs allocated to classes with high load factors. This appeared to relate to the high capacity, O&M, and fuel in storage costs associated with the Callaway nuclear facility. The seeming unreasonableness of this result of over-allocating costs to high load-factor classes is consistent with Staff's concerns related to ramp rates.

Q. Does use of average demand as opposed to minimum demand render Staff's Detailed BIP unreasonable or unreliable?

A. Not at all. Staff's use of each class's average demand to determine the Base component is reasonable, particularly in light of the limited ramp rates of the Ameren Missouri generating units assigned to the Base component. Staff assumed that unless there is a required outage, the generating units assigned to the Base component will run year round.

This assumption is reasonable. Staff further assumed that the generating units assigned to the Base component will run at some amount greater than 50% of their capacity, but less than 100% of their capacity. This assumption is also reasonable. Both assumptions are consistent with Staff's decision to use each class's average demand to determine the Base component.

Q. Is Staff open to discussion with the parties as to whether it may be reasonable to incorporate some measure of minimum demand into future Detailed BIP studies, assuming that concerns with ramp rate abilities can be addressed?

A. Absolutely. Staff recognizes the value of the experience and knowledge of the experts retained by the other parties, and welcomes the opportunity to develop a class cost of service study method that is as accurate as is practicable.

Q. Is each class's energy usage less than the average demand in 57% of the hours of each year, as stated by Mr. Brubaker at page 18, line 4 – 18 of his Rebuttal Testimony?

A. No. The following table identifies the percentage of hours of the year that each class's energy usage (in MWh) is less than that class's base level of demand (in MW):

Res	SGS	LGS/SPS	LPS	Noranda	Lighting
43%	44%	45%	46%	56%	49%

These results are consistent with the expectations one would have for each class based on its load factor. For example, because the Residential class has relatively more peak energy usage than other classes, one would expect that it would have relatively few hours of the year when its hourly demand did not exceed its average demand - the opposite being true for the LPS class.

4. The Unreasonableness of Mr. Brubaker's Conclusions

Q. Is Mr. Brubaker's repeated concern that Staff's Detailed BIP over-allocates capacity costs to high load-factor customers at odds with his own study results?

A. Yes. Mr. Brubaker alleges that Staff's Detailed BIP overallocates production capacity costs to high load-factor classes, however, his study allocates more production capacity costs to these classes than does Staff's study.

Q. What percent of production costs does Mr. Brubaker allocate to the LPS class?

A. Mr. Brubaker allocated about 7.74% of production costs to the LPS class.

Q. What percent of production costs did Staff allocate to the LPS class in its Detailed BIP study?

A. Staff allocated about 7.61% production costs to the LPS class.

Q. Did Mr. Brubaker allocate a greater percentage of production costs to the LPS class than Staff allocated to the LPS class?

A. Yes. While Mr. Brubaker asserts that Staff's approach over-allocates production costs to the LPS class, the LPS production cost allocator used in Staff's study is approximately 2% less than Mr. Brubaker's LPS class production cost allocator.

Q. Is the dollar value of the production costs allocated by Staff comparable to the dollar value of the production costs allocated by Mr. Brubaker?

A. Yes. Staff allocated $5,235,196,827 of production costs, and Mr. Brubaker allocated $5,235,601,000. Mr. Brubaker allocated approximately $404,173 of production costs more than was allocated by Staff.

Q. Is the dollar value of the production costs allocated by Staff to the LPS class comparable to the dollar value of the production costs allocated by Mr. Brubaker to the LPS class?

A. Combining the impact of Mr. Brubaker allocating a greater percentage of a greater amount of costs to LPS than was allocated by Staff, Mr. Brubaker's production costs allocation to the LPS class is noticeably larger than the amount allocated by Staff. Mr. Brubaker allocated $405,207,000 in production costs to the LPS class, while Staff allocated only $398,611,477 to the LPS class. The difference between these two amounts is approximately $6.6 million dollars.

Q. Does the prior answer indicate that in spite of Mr. Brubaker devoting eleven pages of his rebuttal testimony to assertions that Staff's Detailed BIP study over-allocates production costs to the LPS class, that Mr. Brubaker himself allocated $6.6 million more dollars of production costs to the LPS class than was allocated by Staff?

A. Yes.

Q. Are the other classes' production cost allocators used by Mr. Brubaker comparable to the allocators used by Staff?

A. Yes. As discussed in my rebuttal testimony, Staff's CCoS results and MIEC's CCoS results are quite consistent, particularly in the allocation of production capacity results.

	Residential	SGS	LGS/SPS	LPS	LTS	Lighting	Total
Allocator Percent Difference	0%	3%	0%	2%	-14%	43%	
Allocator Difference	0.076%	0.308%	0.104%	0.125%	-0.917%	0.303%	0.000%
Brubaker Production Cost Allocators	45.34%	10.67%	29.05%	7.74%	6.50%	0.70%	100.00%
Brubaker Production Cost	$2,373,622,000	$ 558,742,000	$1,520,835,000	$ 405,207,000	$ 340,526,000	$ 36,670,000	$5,235,601,000
Staff Detailed BIP Production Cost Allocators	45.26%	10.36%	28.94%	7.61%	7.42%	0.40%	100.00%
Staff Detailed BIP Production Cost	$2,369,453,734	$ 542,556,471	$1,515,297,507	$ 398,611,477	$ 388,480,882	$ 20,796,755	$5,235,196,826
Allocated Cost Difference	$ 4,168,266	$ 16,185,529	$ 5,537,493	$ 6,595,523	$ (47,954,882)	$ 15,873,245	$ 404,174
Percent Allocated Cost Difference	0%	3%	0%	2%	-12%	76%	0%

Q. Is it fair to say that Staff's dollar value of assigned base capacity is equivalent to class load factors or average class energy usage?

A. Not at all. Staff's sum of base capacity costs is the product of a reasonable estimate of each class's minimum demand, multiplied by the average $/MW value of Ameren Missouri's base capacity.

Q. Have you compared the allocator Staff actually used for production-capacity to the class load-factor allocator that Mr. Brubaker asserts Staff used for production capacity?

A. Yes. The two allocators are not similar, as shown below:

	Res	SGS	LGS/SPS	LPS	LTS	Lighting
BIP Installed Capacity Allocator:	45.26%	10.36%	28.94%	7.61%	7.42%	0.40%
Class Load Factors:	36.46%	9.47%	31.89%	10.29%	11.29%	0.60%
Difference:	8.80%	0.89%	-2.95%	-2.67%	-3.87%	-0.21%

Q. Have you compared the allocator Staff actually used for production-capacity to a simple class energy allocator that Mr. Brubaker alternatively asserts Staff used for production energy?

A. Yes. The two allocators are not similar, as shown below:

	Res	SGS	LGS/SPS	LPS	LTS	Lighting
BIP Installed Capacity Allocator:	45.26%	10.36%	28.94%	7.61%	7.42%	0.40%
Class % of kWh:	36.42%	9.48%	31.95%	10.26%	11.29%	0.61%
Difference:	8.84%	0.89%	-3.01%	-2.65%	-3.87%	-0.21%

Q. How does Staff's production-capacity allocator compare to the allocators that Mr. Brubaker claims Staff used to allocate production-capacity?

A. Staff's production-capacity allocator allocated 2.65% - 3.87% less to the LGS, SPS, LPS, and LTS classes than the allocators Mr. Brubaker asserts Staff used.

Q. Did Mr. Brubaker allocate fuel and purchased power cost by class energy consumption?

A. Yes. Mr. Brubaker used a class energy consumption to allocate fuel and purchased power cost. He did not weight this allocator in any way to reflect that peak energy tends to be more expensive than base energy.

Q. Did Staff allocate fuel and purchased power cost by class energy usage?

A. As discussed above, Staff's BIP method focuses on the inverse relationship between the cost of capacity and the price of energy. Base energy tends to be less expensive, but it is generated from relatively expensive capacity. Peak energy tends to be more expense, but it is generated from relatively inexpensive capacity. These relationships are inherently inter-related, and that is the reason Staff developed the separate Detailed BIP allocators for its primary study.

Recognizing this relationship, Staff allocated fuel and purchase power cost by **dollar-weighted** class energy usage. The difference between the dollar-weighted energy allocator and the non-weighted allocator are provided below:

	Res	SGS	LGS/SPS	LPS	LTS	Lighting
BIP Fuel for Energy Allocator:	37.09%	9.54%	31.72%	10.06%	10.91%	0.68%
Class % of kWh:	36.42%	9.48%	31.95%	10.26%	11.29%	0.61%
Difference:	0.67%	0.07%	-0.23%	-0.20%	-0.37%	0.08%

Q. What does this show about Staff's allocation of fuel and purchased power costs versus Mr. Brubaker's allocation of fuel and purchased power costs?

A. Staff's method allocated less fuel and purchased power expenses to the LGS, SPS, LPS, and LTS classes than Mr. Brubaker allocated to these classes.

Q. Is it unreasonably inconsistent for Mr. Brubaker to criticize only one side of these highly inter-related allocators?

A. Yes. If Mr. Brubaker objects to recognizing the higher capacity costs of base capacity (particularly as base capacity costs are increasing to accommodate environmental compliance-related retrofits), then it follows that Mr. Brubaker should not expect recognition of the lower cost of energy provided by base capacity units.

Q. Taken together, in this case do the lower energy costs of base energy and higher capacity costs of base capacity "cancel out" to approximately the same allocator as used by Ameren and MIEC?

A. Yes. This is also true of the peak capacity's low capacity cost yet high energy price, and the intermediate capacity's moderate capacity costs and moderate energy costs.

5. Staff's Allocation of Other Revenues

Q. Is Staff's allocation of Other Revenues (primarily off-system sales revenues, including off-system sales margin revenues) inconsistent with Case No. ER-2010-0036, as alleged by Mr. Brubaker at page 9, lines 1 – 6?

A. No. Mr. Brubaker badly misrepresents the language he quotes from the KCP&L case, Case No. ER-2006-0314. That language was from the section of the Report and Order concerning allocation of off-system sales margins between Missouri, Kansas, and the FERC.

Q. What method did the Commission reject in the language quoted by Mr. Brubaker regarding this *jurisdictional* allocation method, in Case No. ER-2006-0314?

A. KCPL proposed an “unused energy allocator” which was calculated “by subtracting the actual energy usage from the ‘available energy.’ The available energy is defined as the average of the 12 coincident peak demands multiplied by the total hours in the test period.”[18]

Q. Are both the issue decided and the allocator rejected in the language quoted by Mr. Brubaker completely distinct from the issue and proposals in this case?

A. Yes. Mr. Brubaker is providing language deciding a different issue, rejecting an approach no party in this case has recommended. It is concerning that Mr. Brubaker does not identify these distinctions in his testimony.

Q. Is Mr. Brubaker’s criticism of Mr. Marke’s allocation of off-system sales revenues essentially identical to Mr. Brubaker’s criticism of Ms. Meisenheimer’s off-system sales revenues allocator in Case No. ER-2006-0314?

A. Yes. In both cases Mr. Brubaker states that it is inappropriate to allocate the fuel for off-system sales to a class on one basis, but to allocate the fuel-related portion of off-system sales revenue on a different basis.

Q. Does Staff agree with this criticism?

[18] Report and Order in Case No. ER-2006-0314, page 38.

A. Yes. In fact, Mr. Brubaker essentially outlined Staff's method of allocating off-system sales in his criticism of Mr. Marke's off-system sales allocation. Staff weighted its "other revenue" allocator to return fuel for off-system sales to the classes in the amount that each class provided the expense associated with that fuel.

Q. Did Staff allocate all fuel costs to the classes on the basis of class energy, including those used to produce off-system sales?

A. Yes. Staff did allocate all of Ameren Missouri's fuel and purchase power expenses to classes based on the dollar-weighed annual energy usage of each class in kWh. Those fuel costs include the fuel used to generate energy sold as off-system sales.

Q. Did Staff specifically adjust the allocator it uses for "other revenue" to ensure that each class is credited back pro-rata the share of fuel allocated to that class for off-system sale generation?

A. Yes. To determine its allocator, Staff first found the percentage of total fuel and purchase power expense as modeled in the Staff fuel run that is related to off-system sales. Staff's weighted allocator allocates off-system sales revenues in an amount equal to the off-system sales fuel is allocated to the retail classes using the energy allocator. This compensates each class for the share of fuel and purchase power expense that were used to generate the off-system sales energy that were allocated to each class as discussed above.

Q. Are off-system sales margins variable consistent with the amount of energy sold to a particular retail class?

A. No. While in reality, under the MISO integrated marketplace, the level of off-system sales margin realized by Ameren Missouri is inversely related to the cost of the energy consumed by Ameren Missouri's load as a whole, there are other factors in place that mitigate this relationship. In any case, there is no reasonable argument to be made that the level of off-system sales margin realized by Ameren Missouri is directly related to the kWh of energy consumed by a particular retail class relative to other retail classes.

6. Staff's Market Price Study

Q. Did Staff allocate any production costs in its market price study on "energy?"

A. No. Staff allocated costs on dollar-weighted energy.

Q. Is Mr. Brubaker's criticism that "[b]ecause the LMPs are higher than embedded energy cost, there is a disproportionately large allocation of these costs to high load factor customers" a fair criticism?[19]

A. No. First, the LMPs are not noticeably higher than the embedded cost of energy, they are largely consistent with the embedded cost of energy. This is indicated by the consistency of Staff's market study with its other two studies, and in fact, those of all other parties. Mr. Brubaker's complaint appears to be related to the fact that Staff's market study recognizes that customers with high load factors do consume energy in hours when the market price of energy is high, not just in hours when the market price of energy is low. That the price of energy is high in some hours and low in others is reality.

Q. Accounting for voltage levels, does it cost Ameren Missouri exactly the same amount to obtain a kWh on a weekday afternoon in July for an industrial customer as it does to obtain a kWh on a weekday afternoon in July for a residential customer?

A. Yes.

[19] Brubaker Rebuttal, page 22, lines 1 – 17.

RESPONSES TO AMEREN MISSOURI

Q. Has Staff prepared a response to Ameren Missouri's offer presented in Matt Michels' testimony to enter into a wholesale contract with Noranda?

A. Yes. Please find attached to this surrebuttal testimony Appendix 1, "Staff Response to Ameren Missouri's Noranda Proposal."

Q. In summary, what does Staff recommend concerning Ameren Missouri's proposal to enter into a wholesale contract with Noranda, with the gains or losses on such contract to flow through Ameren Missouri's FAC?

A. Staff does not object to a commercially reasonable wholesale contract between Ameren Missouri and Noranda. However, to Staff's knowledge, no such contract has been agreed upon to date. If such a contract is agreed upon between Ameren Missouri and Noranda, it is likely that Staff will recommend adjustments to aspects of this case – particularly the Missouri-jurisdictional cost of service calculation for Ameren Missouri, and the Fuel Adjustment Clause tariff sheets. Staff also recommends rejection of Ameren Missouri's request that the Commission in this case determine that such contract is prudent and that the gains and losses on such contract be flowed through the FAC to Ameren Missouri's captive retail ratepayers.

Q. Do you agree with Mr. Warwick's characterization that Staff allocated non-fuel Operations & Maintenance ("O&M") expenses as fixed, and that Staff allocated those expenses on its fixed production plant allocator?[20]

A. No. Staff did calculate an average $/MW value of the O&M associated with serving each level of demand (base, intermediate, and peak), but it only used this value to "scale" the amount of generation at each type of plant to the amount of energy actually

[20] Warwick Rebuttal, page 8, line 16 – page 9, line 5.

needed from each type of plant. Staff developed its O&M allocator by multiplying these base, intermediate, and peak O&M $/MWh amounts by the amount of each type of energy consumed by each class.

Q. Has Ameren Missouri alerted you to an error in two of your graphs and the language describing that graph?

A. Yes. Following a conversation with Ameren Missouri, I became aware that I had mistakenly pulled in Ameren Missouri's revenue recommendation instead of its revenue requirement calculation in compiling Tables 1 and 2 of my Rebuttal testimony. The corrected versions of My Rebuttal Tables 1 & 2 (and the associated graphs) are provided below.

Table 1

Relative Cost of Service Net of OSSMR By Class in Dollars per MWh						
	Residential	SGS	LGS/SPS	LPS	LTS	Lighting
Staff Detailed BIP	$91.52	$80.91	$63.01	$52.14	$41.27	$169.71
Staff Modified BIP	$92.85	$81.12	$62.35	$50.93	$40.44	$157.37
Staff Market Study	$91.99	$81.33	$62.51	$53.38	$40.76	$149.62
Brubaker Table 3 (Unfactored)	$97.10	$83.70	$63.70	$51.50	$39.50	$172.30
Brubaker Table 3 Factored	$103.46	$89.35	$68.17	$53.03	$41.60	$185.09
OPC A&E Factored	$91.80	$84.22	$62.52	$53.68	$40.02	$124.19
OPC A&4CP Factored	$88.03	$81.62	$63.45	$58.59	$48.26	$105.08
Ameren Missouri A&E (Unfactored)	$99.54	$85.54	$64.94	$54.79	$41.01	$175.49
Ameren Missouri A&E Factored	$93.99	$80.78	$61.32	$51.74	$38.73	$165.72

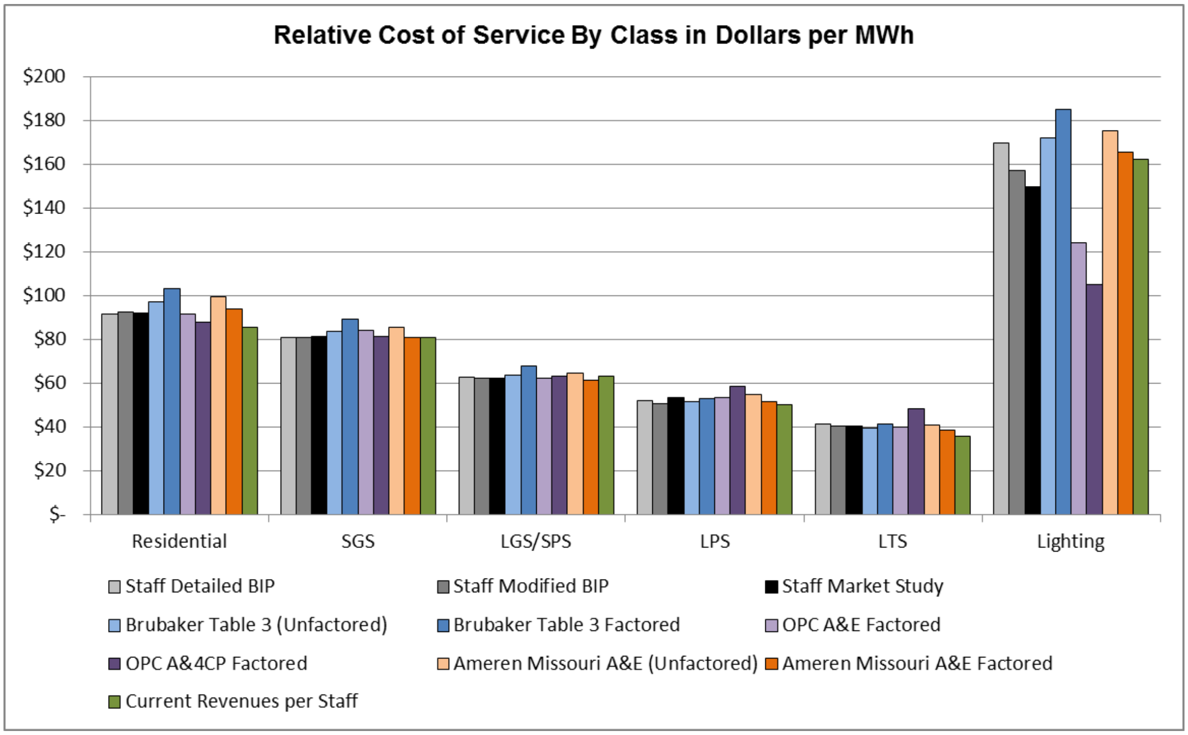
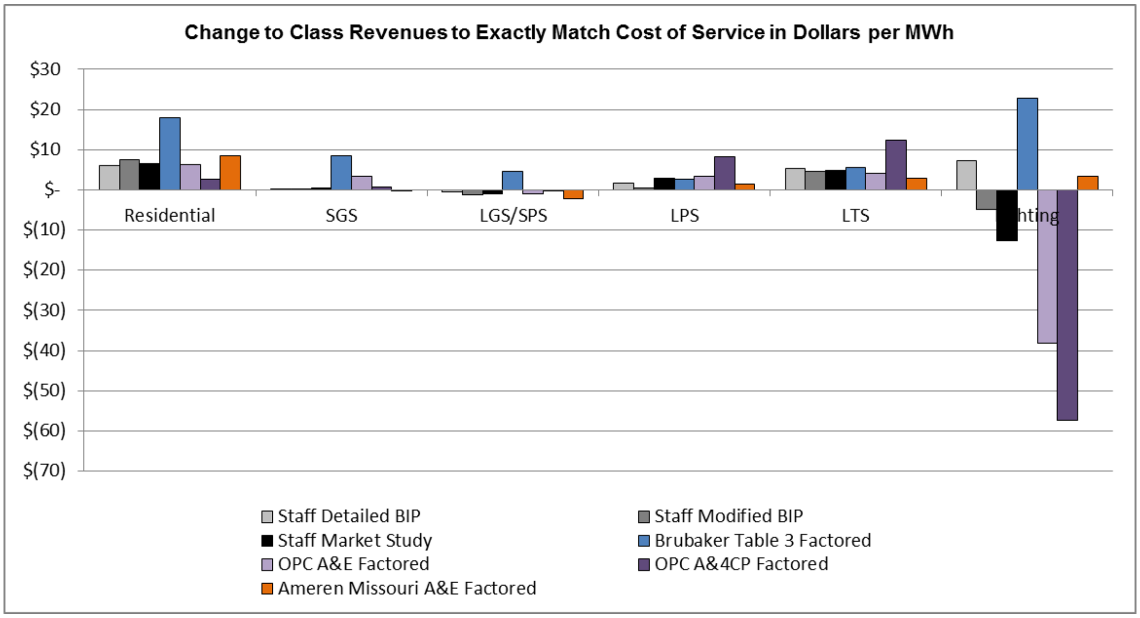


Table 2

Change to Class Revenues to Exactly Match Cost of Service in Dollars per MWh						
	Residential	SGS	LGS/SPS	LPS	LTS	Lighting
Staff Detailed BIP	$6.0683	$0.0045	($0.4841)	$1.7091	$5.3324	$7.3288
Staff Modified BIP	$7.3954	$0.2076	($1.1398)	$0.4927	$4.4974	($5.0047)
Staff Market Study	$6.5342	$0.4225	($0.9768)	$2.9441	$4.8192	($12.7574)
Brubaker Table 3 Factored	$18.0136	$8.4453	$4.6804	$2.5936	$5.6625	$22.7139
OPC A&E Factored	$6.3440	$3.3082	($0.9680)	$3.2421	$4.0783	($38.1888)
OPC A&4CP Factored	$2.5827	$0.7169	($0.0403)	$8.1537	$12.3248	($57.2950)
Ameren Missouri A&E Factored	$8.54	($0.1268)	($2.1689)	$1.3057	$2.7899	$3.3432
Current Revenues per Staff	$85.4514	$80.9074	$63.4893	$50.4338	$35.9397	$162.3792



With this correction to my summary of Ameren Missouri's study results, the non-MIEC studies are consistent in identifying that the LGS/SPS classes are over-contributing to cost of service.

Q. Have you updated certain values presented in your Rebuttal testimony based on new purchased-power-related information related to the updated Staff fuel run prepared in response to Mr. Mark Peters' testimony?

A. Yes. I have updated the level of wholesale power costs assumed in Staff's revenue requirement calculation, to coincide with the values associated with Staff's most recent fuel run.[21]

Q. Have you compared these updated wholesale power costs with the recommended rates for Noranda?

A. Yes. Notably, Noranda's requested rate would fall below the estimated power cost resulting from the "12-month ending 7/1/2014 Wholesale Energy with Transmission and

[21] Ameren Missouri alerted me to an error in the value I provided as Ameren Missouri's recommended rate design for Noranda. I have also corrected that error in this updated table.

Other Costs to Serve" calculation, and is only a dollar per MWh in excess of the "Average Wholesale Cost of Noranda Energy Found in Case No. EC-2014-0224, with Transmission and Other Costs to Serve" calculation.

Q. Using this revised wholesale power cost information, what is the benefit to other ratepayers of service to Noranda at a rate of $32.50, based on the wholesale cost of power assumed in Staff's updated fuel run, with an allocation for transmission-related costs to serve?

A. Using the wholesale cost of power assumed in Staff's fuel run, Noranda would contribute approximately $40,595,593 in excess of what Ameren Missouri would spend to procure that energy, at a rate of $32.50/MWh.

Q. Is Staff implying that $118,777,387 is the cost Ameren Missouri incurs to provide energy to Noranda?

A. No. Among other things, this value is based on the market prices Ameren Missouri receives for its generation, not the market prices Ameren Missouri incurs to serve load. However, this calculation is useful as a point of reference to relate the Ameren Missouri request to Staff's revenue requirement calculation.

Q. Has Staff calculated what the cost to other ratepayers would be, all else being equal, if Noranda ceased receiving service from Ameren Missouri?

A. Yes. Using the wholesale cost of power assumed in Staff's fuel run, other ratepayers rates would increase approximately $37,094,896 if Noranda ceased receiving service from Ameren Missouri, compared to what those rates would be if Noranda paid a rate of $32.50/MWh.

Q. For purposes of setting rates, does Staff recommend use of the normalized LTS billing units Staff included in its direct case, or use of the reduced level presented by Mr. Wills in his Rebuttal testimony?

A. Staff recommends use of the normalized LTS billing units included in Staff's direct case, reflecting an assumption that reduction in energy consumption during the update period is not normal and should not be expected to continue going forward.

Q. Has Noranda stated publicly that they expect to resolve the pot failure issue related to the reduction in its energy usage that began around July of 2014?

A. Yes.

Q. Is Ameren Missouri aware that Noranda has stated publicly that they expect to resolve the pot failure issue related to the reduction in its energy usage that began around July of 2014?

A. Yes. In Response to a Staff-issued Data Request, Ameren Missouri provided the same public information that Staff was aware of, which was provided by Noranda to investors on November 3, 2014, during Noranda's latest earnings call.

Q. Has Noranda provided any additional information to Staff?

A. Yes. ** ____ ____ **

Q. Even if it were appropriate to reduce Noranda's usage to reflect an ongoing pot failure, do you agree with Ameren Missouri's calculation of an annualized level?

A. No. Staff and Ameren Missouri agreed on the calculation of Noranda energy usage (with AECI line losses) for a test year amount of 4,345,485,999 kWh. ** ________ ____

** At current Noranda revenues, this results in an understatement of Ameren Missouri revenues of $9.8 million.

Q. Does this conclude your Surrebuttal testimony?

A. Yes.

<u>Staff Response to Ameren Missouri's Noranda Proposal</u>

In his rebuttal, Mr. Michels testifies that Ameren Missouri is willing to enter into a contract with Noranda under the following conditions:

- Noranda and Ameren Missouri would have to agree to price and terms of a wholesale contract to be effective concurrent with the change in retail rates established in this case, so that retail billing units could be adjusted to reflect Noranda's transition to a wholesale customer. As indicated, Ameren Missouri is willing to enter into such an agreement with market-based prices for a five-year term, subject to the other conditions described in my testimony;

- Noranda and Ameren Missouri would have to agree to terminate the current contract for service to Noranda to be effective concurrent with the change in retail rates established in this case;

- The Commission would have to cancel or suspend the certificate of convenience and necessity which established Ameren Missouri's retail service to Noranda in File No. EA-2005-0180;

- The Commission would have to approve the agreement between Noranda and Ameren Missouri;

- The Commission would have to specifically find that Ameren Missouri's decision to enter into the agreement was a prudent one; and

- The Commission would have to find that the wholesale contract between Noranda and Ameren Missouri would be treated like other wholesale contracts, as off-system sales subject to inclusion in Ameren Missouri's FAC.

Staff does not object to Ameren Missouri and Noranda reaching a **reasonable** agreement at a **reasonable** price on **reasonable** terms. However, under Ameren Missouri's proposal, all risk of the contract price not covering Ameren Missouri's actual cost to provide wholesale service to Noranda would fall on Ameren Missouri's captive retail customers. Specifically, Staff objects to Ameren Missouri's proposal to flow a Noranda wholesale contract through the FAC, unless the price, length, and terms of that agreement are commercially reasonable. To date, Ameren Missouri has not provided the sort of specific contract terms that are necessary for Staff to evaluate the reasonableness of such an agreement.

The specific terms of the agreement are perhaps the most important aspect of Mr. Michels' proposal. A properly-designed escalator provision could protect all parties. For example, Ameren Missouri could index Noranda's wholesale price to the market price of energy for Noranda - **including transmission and other expenses** - and periodically adjust Noranda's rate accordingly. Absent such an adjustment mechanism, a reasonable rate for Ameren Missouri to serve Noranda at wholesale pursuant to a long-term contract would possibly be higher than the fully allocated cost of service calculated by Staff and other parties, as the cost-of-service calculations are directed at a snapshot in time and reflective of current energy and transmission costs. In other words, whatever the market price of energy is at the moment Ameren Missouri and Noranda enter into their wholesale power contract, that price *will change* over the five-year life of the contract. If the market price rises above the contract price, who will pay the difference? Under Ameren Missouri's proposal, the ratepayers will pay the difference. Staff objects to that outcome.

Without having identified either the actual market prices that are contemplated in the agreement or the terms of any escalator, Mr. Michels seeks from the Commission both a pre-determination that Ameren Missouri's decision to enter into this agreement is prudent and pre-approval to run this proposed 5-year transaction through the FAC. Until Ameren Missouri has provided to Staff an analysis that takes into consideration all necessary cost aspects associated with the proposed agreement, Staff can only recommend that the Commission not approve the transaction.

Staff Recommendation Concerning Mr. Michels' Proposal:

Staff cannot provide specific recommendations until Noranda and Ameren Missouri have permitted Staff to review the actual terms of their proposed wholesale contract. However, Staff recommends that should Noranda become a wholesale customer of Ameren Missouri, due to the size of Noranda's load, it will likely be necessary to allocate the cost of service of Noranda to the wholesale jurisdiction.[1] If this is necessary, Staff recommends that the Ameren Missouri Missouri-jurisdictional revenue requirement otherwise found in this case be reduced by this wholesale jurisdictional amount. Staff does not recommend that any such contract be flowed through the FAC, thus slight modifications to the Ameren Missouri FAC tariffs will be necessary if Ameren Missouri and Noranda do enter into a wholesale contract.

Staff Expert / Witness: Sarah L. Kliethermes

Treatment of Wholesale Jurisdiction:

In previous Ameren Missouri rate cases (Case No. ER-2010-0036 and earlier), the Staff used a traditional method of allocating costs to the retail jurisdiction when there was also a wholesale jurisdiction. Several years ago, Ameren Missouri served several municipalities that bought power from Ameren Missouri through wholesale contracts to resell to their citizens. The traditional method for determining the costs allocated to the retail jurisdiction to determine the retail cost of service was accomplished by applying a retail jurisdictional allocation factor to Ameren Missouri's total amount of investment and expense. The retail cost of service was then compared to retail revenues generated by the current effective retail rates to determine the additional revenue and incremental rate increase for retail customers. Staff allocated rate base and expense to the retail and wholesale jurisdictions. All wholesale revenue that Ameren

[1] Noranda's load is approximately 10% of Ameren Missouri's current retail load.

Missouri received from the municipalities was excluded from the determination of Ameren Missouri's retail revenues.

As part of Ameren Missouri rate cases Nos. ER-2011-0028 and ER-2012-0166, Ameren Missouri had significantly reduced the number of wholesale commitments[2] and both the Staff and Ameren Missouri ultimately determined that revenue that was received from serving these customers exceeded the costs of serving them. In these two rate cases, Staff performed an analysis that determined that it was reasonable to reflect the revenues that Ameren Missouri received from serving the municipalities as off-system sales ("OSS") and flowing those OSS revenues as well as the additional generation costs (fuel expense and purchased power expense) to serve these wholesale customers to Ameren Missouri's fuel adjustment clause ("FAC"). This analysis was accomplished by fuel modeling that included the municipal customers and comparing that to modeling that excluded those municipal customers. The results of the analysis in both of these cases demonstrated that it was reasonable to include the costs to serve the wholesale customers and the revenues generated by the wholesale customers as part of the cost-of-service calculation by reflecting OSS revenue from the generation used to serve the customers and including the fuel costs to make those off-system sales. Essentially, this treatment did not recognize the existence of wholesale customer contracts and wholesale customers' generation requirements on Ameren Missouri's system.

As part of the current rate case, Case No. ER-2014-0258, Ameren Missouri reduced its wholesale commitment to just two small municipalities who currently receive a combined load of only 11,949 MWh annually. Staff determined that because the quantity of power that these two small municipalities take on an annual basis was small, that an extensive and time-

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[2] This was largely due to the fact Ameren Missouri declined to continue serving these wholesale customers and, as a result, when the contracts for these customers expired they entered into contracts with Ameren Missouri affiliate, Ameren Energy Marketing Company.

consuming fuel-modeling comparison was not warranted. Instead, the Staff compared the wholesale power price charge per MWh as reflected in the contracts to an average generation cost. This comparison revealed that it was still reasonable to reflect the OSS revenue and the generation cost to serve those two customers as a pass-through in the FAC.

In direct testimony found in the Staff's *Revenue Requirement Cost of Service Report* in Case No. ER-2012-0166, on page 66, lines 16-19, Staff indicated that:

> In general, the Staff is not opposed to departing from the traditional jurisdictional allocation method of determining the retail cost of service. However, the Staff will continue to analyze this treatment on a case by case basis going forward in all future Ameren Missouri rate proceedings.

Based on the proposal that Ameren Missouri witness Matt Michels explains in his rebuttal testimony, the Staff believes that performing an assessment of the need for jurisdictional allocation factors will likely be necessary. However, the Staff is unable to perform such an analysis at this time since no specific information has been provided.

Staff Expert / Witness: John P. Cassidy

Revenue Requirement Adjustment Required for Ameren Missouri Proposal:

If Ameren Missouri were to treat Noranda as a wholesale customer, the most reasonable available cost basis for determining the jurisdictional allocation to Noranda-wholesale is Staff's class-cost-of-service study. For purposes of jurisdictional allocations, it is most appropriate to remove both the costs and revenues associated with Ameren Missouri making off-system sales from the Noranda-wholesale cost-to-serve calculation. Adjusting Staff's Noranda-retail CCoS results to remove Ameren Missouri's off-system sales activities results in a Noranda-wholesale cost-to-serve of $46.79/MWh.[3] Therefore, if Noranda is removed from retail service and treated as a wholesale customer as proposed by Mr. Michels, it is necessary to remove $196,453,357 from Ameren Missouri's cost of service in conjunction with the Noranda revenues.

FAC Tariff Modification Required for Ameren Missouri Proposal:

As discussed above, Ameren Missouri's other wholesale contracts are of such small magnitude that they are flowed through the FAC. The contemplated Noranda contract is of such a large magnitude that it would be necessary to adjust the FAC to remove this contract. To accomplish this, the FAC tariff would be modified to remove an amount equal to Noranda's usage in each period multiplied by the jurisdictional allocator from the numerator of the Actual Net Energy Cost ("ANEC") calculation. Because Noranda would no longer be a retail customer, it would not be necessary to remove Noranda's usage from the description of the denominator of the ANEC calculation. This process would hold customers harmless from Ameren Missouri's decision to enter into a wholesale contract with Noranda.

Relevant calculations for evaluation of Noranda's request and Ameren Missouri Proposal

In evaluating the reasonableness of either a retail or wholesale rate for Noranda, Staff recommends that any rate considered must exceed the cost of energy for Noranda, including transmission and other costs to serve. The lowest reasonable calculation of that amount is $118,777,387 annually, or approximately $28.29 $/MWh at Noranda's meter. This calculation is derived from the values of energy at generation as calculated in Staff's surrebuttal fuel run for the 12 months ending December 31, 2015. Staff continues to recommend a retail rate for Noranda of $39.78/MWh, subject to FAC. Staff, Ameren Missouri, OPC, and MIEC filed CCoS

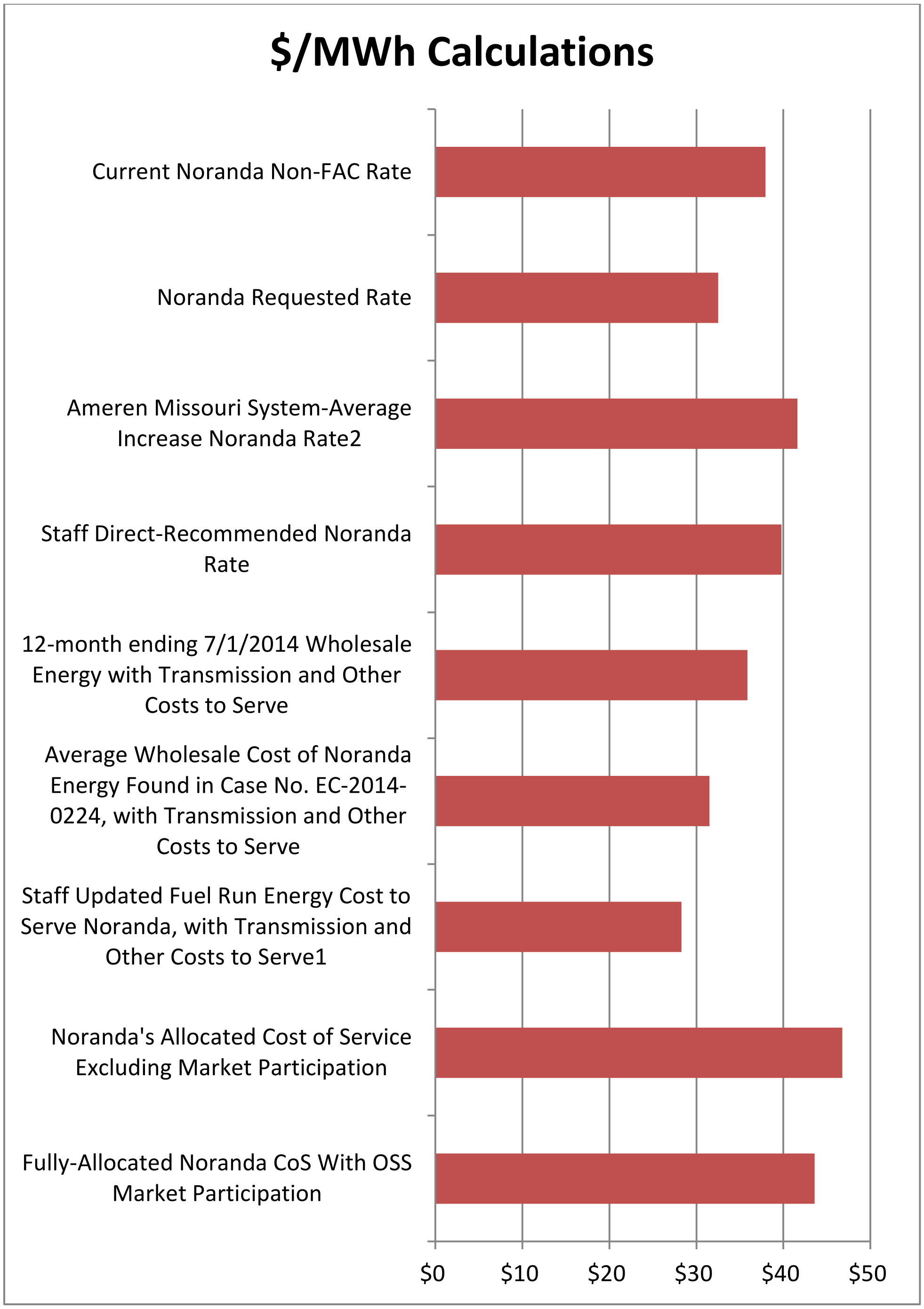
[3] On a $/MWh basis, Staff calculated a fully-allocated cost of service for Noranda of $41.27. Mr. Brubaker, on behalf of Noranda and MIEC calculated the fully-allocated cost of service for Noranda to be $39.50/MWh, while Ameren Missouri calculated approximately $41.01/MWh. However, these calculations reflect charging Noranda for the cost of Ameren Missouri to make off-system sales, as well as the profits earned by Ameren Missouri in making off-system sales, and other revenues, such as profits on rents of company facilities.

studies indicating that Noranda is contributing less revenue to Ameren Missouri than Ameren Missouri's fully-allocated cost to serve Noranda. Staff's recommended rate design includes a modest move towards aligning class revenues with class cost of service.[4]

The values provided below, unless otherwise indicated, are for the 12 months ending September 30, 2015. Staff has not attempted to predict what future market energy or transmission costs will be. For the protection of Ameren Missouri's retail ratepayers, it is necessary that any rate at which Noranda is provided service be subject to adjustment to account for market price changes, either through a reasonable adjustment mechanism or the general rate case process.

[4] Staff recommends Noranda remain subject to the FAC, and that its potential future rate increase not be subject to the 1% cap proposed by Mr. Brubaker.

	Dollar Value	At Noranda's Meter
Fully-Allocated Noranda CoS With OSS Market Participation	$183,019,389	$43.59
Noranda's Allocated Cost of Service Excluding Market Participation	$196,453,357	$46.79
Staff Updated Fuel Run Energy Cost to Serve Noranda, with Transmission and Other Costs to Serve[1]	$118,777,387	$28.29
Average Wholesale Cost of Noranda Energy Found in Case No. EC-2014-0224, with Transmission and Other Costs to Serve	$132,253,922	$31.50
12-month ending 7/1/2014 Wholesale Energy with Transmission and Other Costs to Serve	$150,651,903	$35.88
Staff Direct-Recommended Noranda Rate	$167,032,790	$39.78
Ameren Missouri System-Average Increase Noranda Rate[2]	$174,694,353	$41.61
Noranda Requested Rate	$136,452,459	$32.50
Current Noranda Non-FAC Rate	$159,372,980	$37.96
Noranda Allocation of Interchange-related Cost	$13,224,969	$3.15
Noranda Allocation of Gross OSSM	$29,247,095	$6.97
Noranda Allocation of OSSM Net of Interchange Costs	$16,022,126	$3.82
Staff Direct Fuel Run Average Energy-Only Cost to Serve Noranda	$117,878,282	$28.08
Average Noranda Transmission and Other Costs to Ameren Missouri	$3,882,027	$0.92
1. Reflecting fuel run filed in response to Mark Peter's Rebuttal Testimony.		
2. Per Ameren Missouri email of 1/28/2015 requested Noranda rate. Reflects Ameren Missouri's quantification of LTS billing units.		



Staff Expert / Witness: Sarah Kliethermes

Ameren Missouri Fuel Adjustment Clause Base Factor Scenarios:

The table below is a summary of Staff's scenarios that reflect the effect on Ameren Missouri's FAC base factor ("BF"):[5]

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Table 2 Has Been Deemed Highly Confidential In Its Entirety

Scenario 1 is Staff's calculation of Ameren Missouri's FAC summer and winter BF that includes the fuel and purchased power costs net off-system sales revenue and kWh sales with Noranda. Scenario 2 is Staff's calculation of Ameren Missouri's BF without Noranda's kWh sales but with fuel and purchased power costs net off-system sales revenue as Missouri Industrial Energy Consumer witness Mr. Brubaker proposes on behalf of Noranda. Scenario 3 is Staff's calculation of Ameren Missouri's BF without Noranda's fuel and purchased power costs net off-system sales revenue and without kWh sales. If the Commission adopts scenario 2, the BF increases ** ____ ** percent, shifting the risk to Ameren Missouri's other customers. If the Commission adopts scenario 3 (without Noranda), the BF decreases ** ____ ** percent with no shift in risk to Ameren Missouri's other customers.

Staff Expert / Witness: Matthew J. Barnes

[5] The Base Factors in Table 2 will be updated in True-up Direct testimony to be filed March 17, 2015.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service	)))	File No. ER-2014-0258

AFFIDAVIT OF MATTHEW J. BARNES

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Matthew J. Barnes, of lawful age, on oath states: that he participated in the preparation of the foregoing Appendix 1 attached to Sarah Kliethermes' Surrebuttal Testimony, to be presented in the above case; that the information in the Appendix 1 attached to Sarah Kliethermes' Surrebuttal Testimony was provided to him; that he has knowledge of the matters set forth in such Appendix 1 attached to Sarah Kliethermes' Surrebuttal Testimony; and that such matters are true to the best of his knowledge and belief.

Matthew J. Barnes

Matthew J. Barnes

Subscribed and sworn to before me this 6th day of February, 2015.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 28, 2018
Commission Number: 14942086

Susan L. Sundermeyer

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service	)))	File No. ER-2014-0258

AFFIDAVIT OF JOHN P. CASSIDY

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

John P. Cassidy, of lawful age, on oath states: that he participated in the preparation of the foregoing Appendix 1 attached to Sarah Kliethermes' Surrebuttal Testimony, to be presented in the above case; that the information in the Appendix 1 attached to Sarah Kliethermes' Surrebuttal Testimony was provided to him; that he has knowledge of the matters set forth in such Appendix 1 attached to Sarah Kliethermes' Surrebuttal Testimony; and that such matters are true to the best of his knowledge and belief.

John P. Cassidy

John P. Cassidy

Subscribed and sworn to before me this 6th day of February, 2015.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D. Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service	)))	File No. ER-2014-0258

AFFIDAVIT OF SARAH L. KLIETHERMES

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Sarah L. Kliethermes, of lawful age, on oath states: that she participated in the preparation of the foregoing Appendix 1 attached to Sarah Kliethermes' Surrebuttal Testimony, to be presented in the above case; that the information in the Appendix 1 attached to Sarah Kliethermes' Surrebuttal Testimony was provided to her; that she has knowledge of the matters set forth in such Appendix 1 attached to Sarah Kliethermes' Surrebuttal Testimony; and that such matters are true to the best of her knowledge and belief.

Sarah L Kliet

Sarah L. Kliethermes

Subscribed and sworn to before me this 6th day of February, 2015.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 28, 2018
Commission Number: 14942086

Susan L Sundermeyer
Notary Public