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Issues:	Power/Transmission Components of Fuel Adjustment Clause ("FAC"); Volatility and Uncertainty of FAC Components
Witness:	Andrew Meyer
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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2019-0335

DIRECT TESTIMONY

OF

ANDREW MEYER

ON

BEHALF OF

UNION ELECTRIC COMPANY d/b/a Ameren Missouri

St. Louis, Missouri
July, 2019

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DIRECT TESTIMONY

OF

ANDREW MEYER

CASE NO. ER-2019-0335

I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Andrew Meyer and my business address is 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. By whom are you employed and what is your position?

A. My employment is with Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company") as Senior Director, Energy Management & Trading.

Q. Please describe your employment and educational background.

A. I joined Ameren's independent marketing affiliate, Ameren Energy Inc., in 1999. Ameren Missouri assumed this corporate function in 2004. I have worked in several different capacities on the trading floor and in Regional Transmission Organization ("RTO") stakeholder relations. My trading responsibilities included long-term energy and capacity position management, financial hedging, congestion management, and real-time trading and scheduling. Since 2009, I have progressed through several managerial roles. These roles all included responsibility for wholesale energy marketing for Ameren Missouri's generation. Over time, my role has expanded on multiple occasions and now includes Gas Supply, RTO Real-Time Operations, Fossil

Fuel Procurement & Logistics, Nuclear Fuel Procurement, Generation Performance Monitoring and NERC Compliance.

I earned Bachelor of Science degrees in Business Administration (Management Emphasis) and Agricultural Economics from the University of Missouri – Columbia. I was employed by Continental Grain Co. prior to joining Ameren.

Q. What are your responsibilities in your current position?

A. As Senior Director of Energy Management & Trading, my responsibilities focus on three areas related to the Ameren Missouri generation fleet: (i) Fuel Procurement and Logistics; (ii) Real-Time Operations of the generation fleet; and (iii) Energy Marketing. My main role is providing guidance, oversight, and coordination of activities in these areas. I am responsible for establishing strategy, goal setting, staffing, budgeting, management reporting, and other tasks associated with these functions.

Q. What is the purpose of your direct testimony in this proceeding?

A. I will first discuss the establishment of the level of off-system sales revenues ("OSSR"),[1] net of the normalized capacity component of purchased power expense, to be included in the cost of service utilized for the purpose of setting Ameren Missouri's rates.

My testimony next addresses a modification to the methodology used to determine the level of transmission costs to be utilized in establishing the Net Base Energy Costs ("NBEC") (Factor B in the FAC tariff sheets) that form the base against which changes in Ameren Missouri's Actual Net Energy Costs ("ANEC") are tracked in the FAC. The calculation of NBEC and B is discussed in the direct testimony of Ameren

[1] Factor "OSSR" in the Company's FAC tariff sheets which in totality are called "Rider FAC."

Missouri witness Laura Moore, while the modeled fuel (including fuel-related transportation) and net purchased power components of NBEC are discussed in the direct testimony of Ameren Missouri witness S. Hande Berk. The change regarding the level of transmission costs is being made to more accurately ensure that an appropriate level of transmission costs related to off-system sales is properly accounted for in the FAC, while continuing to follow the Commission's prior decisions regarding transmission charges associated with what the Commission termed as "true purchased power" in its Report and Order in File No. ER-2014-0258.

The third purpose of my testimony is to demonstrate the continued volatility and uncertainty of market drivers which impact the costs and revenues tracked in the FAC. These drivers include commodity prices and volumetric fluctuations in the Company's commodity and transportation requirements.

Q. Please summarize your testimony and conclusions.

A. This direct testimony discusses the methodology and source data utilized to determine the appropriate level of normalized net off-system sales revenue. Appropriate adjustments are made when the level of net off-system sales experienced during the test year is not the result of normal conditions or does not properly reflect known and measurable changes.

The three largest components of Ameren Missouri's reported net off-system sales are energy, capacity, and ancillary services sales. The volume of energy sales is driven in large part by Ameren Missouri's load serving obligation to its retail customers, the availability of its generation resources, and the incremental cost of operating its generating resources relative to the market prices for energy. Ameren Missouri utilizes the PROSYM production cost model to determine the normalized level of the energy component of net off-system sales. This model output, along with values for the remaining components of net off-system sales revenue, are used to determine a normalized energy component of net off-system sales revenue as specified in Factor OSSR in the Company's FAC tariff.

Capacity revenue is another significant component of NBEC and my testimony will explain the methodology utilized to determine this value. I also explain the necessity of considering the capacity expense component of purchased power as specified in Factor PP in the Company's FAC tariff.

I also present a proposed modification to Rider FAC which will more properly reflect the transmission costs the Commission has previously determined were (or were not) includable in an FAC. Specifically, I propose a modification so that transmission costs that are <u>not</u> "incurred to transport power from Ameren Missouri's own generation to serve its own native load"[2] will be included, while those that are incurred to serve its own native load will be excluded. The result will be that only transmission costs associated with what the Commission has termed as "true purchased power" will be included along with additional transmission costs to make off-system sales to third parties or to buy power from third parties.

Finally, in the latter part of this testimony I will demonstrate that the main FAC components – namely fuel, transportation, net purchased power, net energy sales, and net capacity sales – remain volatile and uncertain. Since cost is a function of both price and

[2] Report and Order, p. 114, para. 10, File No. ER-2015-0258.

volume, volatility and uncertainty in either the price or the volume necessarily results in volatility and uncertainty in the cost (or revenue) of these various FAC components.

II. NET OFF-SYSTEM SALES REVENUE AND CAPACITY COMPONENT OF NET PURCHASED POWER

Q. What is the meaning of "net off-system sales revenue" in the context of this testimony?

A. In the context of this proceeding, I use the term "net off-system sales revenue" in reference to the revenues and costs from transactions resulting from Ameren Missouri's trading activities after netting out the costs and revenues associated with purchasing energy from the Midcontinent Independent System Operator, Inc. ("MISO") market to meet the Company's load requirements.

Q. What is the appropriate level of net off-system sales revenues to include in Ameren Missouri's revenue requirement and to set NBEC?

A. I determined that the level of net off-system sales revenues that should be included in Ameren Missouri's revenue requirement and used to set NBEC in the FAC is approximately $302.1 million per year. This total is comprised of the following components, each of which I address in more detail later in this testimony:

1) $261.0 million of net energy sales revenues;

2) $22.6 million of gross capacity sales revenues;

3) $9.8 million of ancillary services revenues;

4) $5.3 million of real-time RSG MWP[3] margins; and

5) $3.5 million of other physical bilateral and swap margins.

[3] Real-time revenue sufficiency guarantee make-whole payments.

Q. What is the appropriate level of the capacity component of purchased power expense to include in Ameren Missouri's revenue requirement and to set the NBEC?

A. I determined that the level of the capacity component of purchased power expense that should be included in Ameren Missouri's revenue requirement and used to set NBEC in the FAC is $13.6 million.

A. Energy Sales Revenues

Q. How was the normalized level of net off-system sales of energy determined?

A. In accordance with well-established past practice, modeling using Ameren Missouri's PROSYM model was used so that net off-system energy sales more reasonably reflect a normal year, since no particular 12-month period reflects a normal year. The test year is affected by its unique weather, generation outages, fuel costs, transmission constraints, and energy prices, among many other things. In any given year, weather, prices, unit availability, and load characteristics can vary greatly from normal. Utilizing only actual data from one specific year in setting the revenue requirement would fail to account for this volatility. In order to assure that net off-system energy sales revenues utilized to determine the Company's cost of service and NBEC are consistent with normalized conditions, it is necessary to determine the energy component of net off-system sales based on production cost modeling using normalized loads and generation-related inputs. Modeling has been used by both the Company and the Commission Staff to determine the energy component of net off-system energy sales revenues in all the Company's general rate proceedings in recent history.

Q. How are net off-system sales of energy derived from the PROSYM model's output?

A. PROSYM simulates Ameren Missouri's interactions with the market. Ameren Missouri is a market participant within the MISO markets. The Company purchases energy for its entire load from the MISO market and it separately sells all the megawatt-hours ("MWhs") generated by its generating units to the MISO market. In accordance with FERC requirements, however, these amounts are netted against each other for each hour. This netting results in the recording of either a net off-system sale or a net power purchase for that hour depending on whether the volume of total sales exceeds the volume of total purchases (net off-system sale) or the volume of total sales is less than the volume of total purchases (net power purchase). The results of the Company's modeling reflect netted amounts for both off-system sales and purchased power.

The model utilizes the inputs described in Ms. Berk's testimony to simulate the dispatch of Ameren Missouri's system. In any given period, the model dispatches available generation that has dispatch costs below the hourly market price for energy. In any period where Ameren Missouri has a load requirement in excess of available generation that has a dispatch cost below the hourly market price for power, the model reports a net purchase equal to that difference. In any period where Ameren Missouri has a load requirement less than available generation that has a dispatch cost below the hourly market price for power, the model will report a net sale equal to that difference.

The simulated net off-system energy sales revenues are determined based on the hourly market price for the MWhs reported as net sales. The model effectively assumes that the dispatch of Ameren Missouri's generation is "perfect," meaning it assumes that available generation units will always operate at the optimal economic level in each hour.[4]

Q. What market energy price assumptions were utilized to model the dispatch of Ameren Missouri's generation?

A. Consistent with the approach used in the last several general rate proceedings, the price assumption used to model dispatch was the average hourly energy prices for the 36-month period ending December 31, 2019. These prices averaged $26.12 per MWh, on an around-the-clock basis. The energy prices for the period of December 1, 2016 through April 30, 2019 are the weighted average day-ahead locational marginal prices ("LMPs") in the MISO energy market received at the Ameren Missouri generating units. Consistent with past practice, the energy prices for the remaining months are basis-adjusted forward energy prices. These serve as a reasonable proxy until they are replaced with actual energy prices as part of the true-up in this case.

Q. Please explain why you chose to utilize day-ahead LMPs at the generator nodes.

A. The use of the day-ahead LMPs is consistent with longstanding practice. As mentioned before, the PROSYM model simulates the dispatch of the Company's generators based on a series of inputs. This dispatching logic is similar to the one followed by the MISO to determine its day-ahead commitment of all of the generators in its footprint. The result of the MISO process is, among other things, the determination of

[4] As noted in Ms. Berk's testimony, the Company has adopted Staff's approach from Ameren Missouri's last electric rate proceeding, File No. ER-2016-0179, for normalizing the generation output for Keokuk and Osage.

individual LMPs for each generator. It is most appropriate to use the historical prices applicable to Ameren Missouri generation for the day-ahead markets since day-ahead prices determined the generation levels that produced the vast majority of Ameren Missouri's historic net off-system energy sales. In fact, day-ahead prices determine about 97% of Ameren Missouri's generation commitment and dispatch.

B. Capacity Sales Revenues and Capacity Costs

Q. What is the level of gross capacity sales revenues and gross capacity purchase costs that is appropriate to include in total net off-system sales?

A. I have determined that \$22.6 million of gross capacity sales revenues and \$13.6 million of gross capacity purchase costs are the appropriate amounts to include in the determination of NBEC. These values represent the average annual sales revenues and purchase costs for the last three MISO Planning Years ("PY")[5] which cover the period of June 1, 2017 through May 31, 2020. The sales value includes both bilateral capacity sales revenue and MISO Planning Resource Auction sales revenue.

Q. What is the net impact of the gross capacity sales revenues and gross capacity purchase costs upon NBEC?

A. Netting capacity sales against capacity purchases results in net revenues used in determining NBEC of \$9.0 million, which lowers the NBEC.

Q. What was the corollary amount used to set NBEC in Ameren Missouri's last two electric rate proceedings, File Nos. ER-2014-0258 and ER-2016-0179?

A. \$5.8 million and \$44.9 million, respectively.

[5] PY 2017/18, PY2018/19, and PY2019/20. Planning years run from June 1 to May 31.

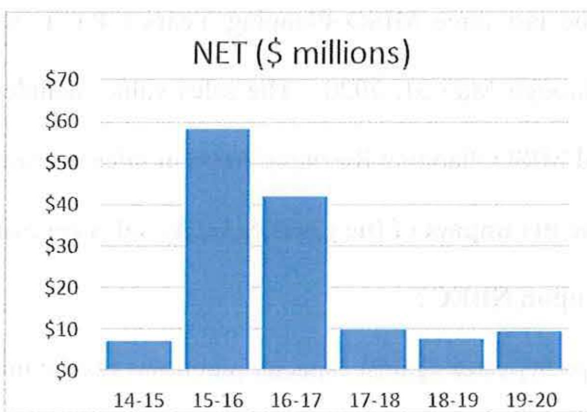
Q. You indicated that these values represent the average annual sales revenue and purchase costs for the of the last three MISO Planning Years (PY). Is this methodology the same as used in File No. ER-2016-0179?

A. No.

Q. Why has the Company changed the valuation methodology?

A. For the same reason it normalizes market energy prices using the PROSYM model, the Company recommends utilizing a three-year average of these revenue values to better normalize capacity revenues.

A review of the net impact of capacity sales and purchases over the past six MISO PYs, going back to June of 2014, reveals significant year-on-year changes, which warrant normalization.



These changes are a direct result of the volatility in the annual MISO Auction Clearing Price ("ACP"). The historical ACP table shows the volatility of ACP's over the same time period. Ameren Missouri's native load obligation resides in Zone 5 (MO), and generation resides in both Zone 4 (IL) and Zone 5 (MO).

Historical Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
2014-2015	$3.29	$16.75						$16.44		N/A	N/A
2015-2016		$3.48		$150.00		$3.48		$3.29		N/A	N/A
2016-2017	$19.72	$72.00						$2.99			N/A
2017-2018	$1.50										N/A
2018-2019	$1.00	$10.00									N/A
2019-2020	$2.99						$24.30	$2.99			
Conduct Threshold	*24.24*	*23.88*	*23.95*	*24.22*	*24.65*	*24.05*	*24.34*	*23.23*	*22.37*	*23.12*	*24.65*
Cost of New Entry	*242.36*	*238.82*	*239.51*	*242.16*	*246.47*	*240.49*	*243.37*	*232.27*	*223.67*	*231.15*	*246.47*

- Auction Clearing Prices & are displayed as $/MW-day
- Conduct Threshold is 10% of Cost of New Entry (CONE)
- Conduct Threshold is $0 for a generator with a Facility Specific Reference Level

https://cdn.misoenergy.org/20190412_PRA_Results_Posting336165.pdf

Q. Why is Ameren Missouri purchasing capacity if it owns enough generation to meet the resource adequacy requirements imposed by MISO's tariff?

A. Consistent with past practice, Ameren Missouri self-schedules its capacity obligation in MISO's annual capacity auction. In doing so, Ameren Missouri offers its resources, up to the megawatt ("MW") amount needed to meet its load obligations, at $0.00/MW-day, ensuring that at least that amount of its resources will clear (i.e., be sold) in the capacity auction.

C. Ancillary Services Revenues

Q. What level of annual ancillary services revenues did you determine was appropriate to include in total net off-system sales?

A. Based upon actual test year values, I have concluded the level of annual ancillary services revenue to include in total net off-system sales is $9.8 million. As was done in the prior case, we intend to true-up this level through December 2019, based upon data for the twelve-month period ending December 31, 2019.

D. Revenue Sufficiency Guarantee Make-Whole Payment Margin

Q. What level of real-time revenue sufficiency guarantee make-whole payment margins did you determine was appropriate to include in net off-system sales?

A. $5.3 million. I determined this level of margin by multiplying the $6.6 million of RT RSG MWP in the test year by 80%, which was the ratio of the RT RSG MWP margin to total real-time RSG MWPs from the true up period in File No. ER-2016-0179. Consistent with the methodology employed in each of the last three rate cases, we intend to update this percentage as part of the true-up process to reflect actual amounts during the twelve months ending with the last day of the true-up period.

E. Physical Bilateral Trading Margins

Q. What level of physical bilateral trading contract and swap margins did you determine was appropriate to include in net off-system sales?

A. $3.5 million.

Q. What are the physical bilateral transaction and financial swap margins?

A. Physical bilateral transactions and financial swaps are hedging mechanisms used to mitigate some of the volatility in OSSR, but they do not replace the off-system energy sales themselves. Physical bilateral transactions and financial swaps margins of $2.7 million and $0.8 million, respectively, should be utilized for this component of net off-system sales revenues. These amounts will also be trued-up.

Q. How are the margins for physical bilateral transactions and financial swaps calculated?

A. The margin calculation for physical bilateral transactions and financial swaps is based on the difference between the fixed sale price and the floating index settlement price. This is the same approach utilized by the parties in the Company's last rate proceeding.

The margin was calculated by taking the difference between the actual price received and the price that would have been received had the transaction settled at the spot market for the CpNode[6] specified by the transaction and multiplying that difference by the volume. For a bilateral purchase, the calculation is reversed – it is a comparison of the fixed price paid to the spot price which would have been paid.

For the physical bilateral transactions, the underlying energy and the associated fuel has already been accounted for in the PROSYM production cost model. However, the model prices the energy at the day-ahead market price and not the price of the physical bilateral transaction. The margin calculation accounts for that difference.

III. <u>TRANSMISSION COSTS</u>

Q. What are the total transmission costs that you are recommending to be included in establishing the NBEC used to determine the BFs in the FAC.

A. $1.6 million.

[6] "CP" stands for "commercial pricing."

Q. Has Ameren Missouri changed the methodology used to determine the appropriate amount of transmission charges and revenues used in establishing the NBEC used to determine the Based Factors in the FAC?

A. Yes, as I addressed earlier.

Q. Why has Ameren Missouri made this change?

A. As I briefly explained earlier, this change is being made to more accurately reflect the level of transmission costs related to off-system sales but also to reflect an appropriate level of transmission costs associated with what the Commission termed as "true purchased power" in its Report and Order in File No. ER-2014-0258.

Q. What change has been made to the methodology?

A. The new methodology identifies the transmission costs reflected in FERC Account 565 that are associated with the Company's network integrated transmission service ("NITS") reservations separately from those that are associated with off-system sales and third-party transmission service providers. The transmission costs associated with off-system sales and third party transmission service providers are included in their entirety, while those associated with NITS and transmission revenues reflected in FERC Account 456.1 will continue to be adjusted by a factor equal to the ratio of purchased power volumes to total load volumes established in the PROSYM modeling results (i.e., "true purchased power").

Consistent with prior practice, RTO administrative costs are excluded from the FAC.

Q. Please explain further.

A. In its Report and Order in File No. ER-2014-0258, the Commission found that there are three reasons Ameren Missouri incurs transmission costs: 1) to transmit electric power it did not generate to its own load (true purchased power); 2) to transmit excess wholesale electric power sold to third parties other than in the MISO market; and 3) for electric power it generated that the Commission concluded was being transmitted to serve its own load. While the Company is not taking issue in this case with the Commission's prior decision, a change in the current methodology needs to be made to be consistent with the Commission's views on transmission costs in the FAC because the historical methodology used to set a base level of transmission costs in the FAC fails to adequately reflect the costs which the Commission found to be properly includable in the FAC. Specifically, by solely focusing on the ratio of purchased power volumes to total load volumes, that methodology essentially ignores transmission expense for off-system sales. It also does not adequately reflect transmission costs associated with power purchased outside of MISO.

Q. Is Ameren Missouri able to identify the transmission costs that are associated with its MISO NITS separately from those that are associated with off-system sales and third-party transmission service providers?

A. Yes. Ameren Missouri can identify its transmission costs by transmission service reservation. By doing so, it can readily distinguish those transmission costs which are associated with NITS from all other transmission costs.

Q. What is the significance of NITS in this discussion?

A. NITS is the transmission service within MISO by which energy is delivered to Ameren Missouri's load, including both what the Commission has termed as "true purchased power" and that which has been described as transmitting energy Ameren Missouri generated to its own load. NITS is not used to make off-system sales, nor is it used on non-MISO, third party systems to move purchased power out of those third-party systems into MISO.

By segregating the costs associated with NITS from all other transmission costs, we have necessarily identified all the costs which are not associated with NITS. These non-NITS costs are only associated with off-system sales, or the transmission of purchased power from outside of MISO, both of which fall squarely within the definition of the costs which the Commission found are properly includable in the FAC.

Q. Are you recommending that the costs associated with NITS be excluded from the FAC then?

A. No, not in their entirety. Continuing to follow the Commission's "true purchased power" approach, I am recommending that the FAC continue to include that portion of NITS costs which reflect costs for transmitting this "true purchased power."

Q. How would you determine what portion of NITS costs would be included in establishing the NBEC used to determine the BFs?

A. Consistent with the approach used in the Company's last two electric rate proceedings, I recommend using the ratio of purchased power volumes to total load from the PROSYM modeling results. That ratio is 1.65% (as compared to 1.71% used in File No. ER-2016-0179). This figure will be trued-up.

Q. What ratio of transmission revenues reflected in FERC Account 456.1 should be included in the determination of NBEC used to determine the BFs?

A. The same 1.65%, also consistent with past practice.

IV. VOLATILITY AND UNCERTAINTY OF MARKET FACTORS IMPACTING FAC COMPONENTS

Q. Do the various cost components of the FAC continue to be volatile and uncertain?

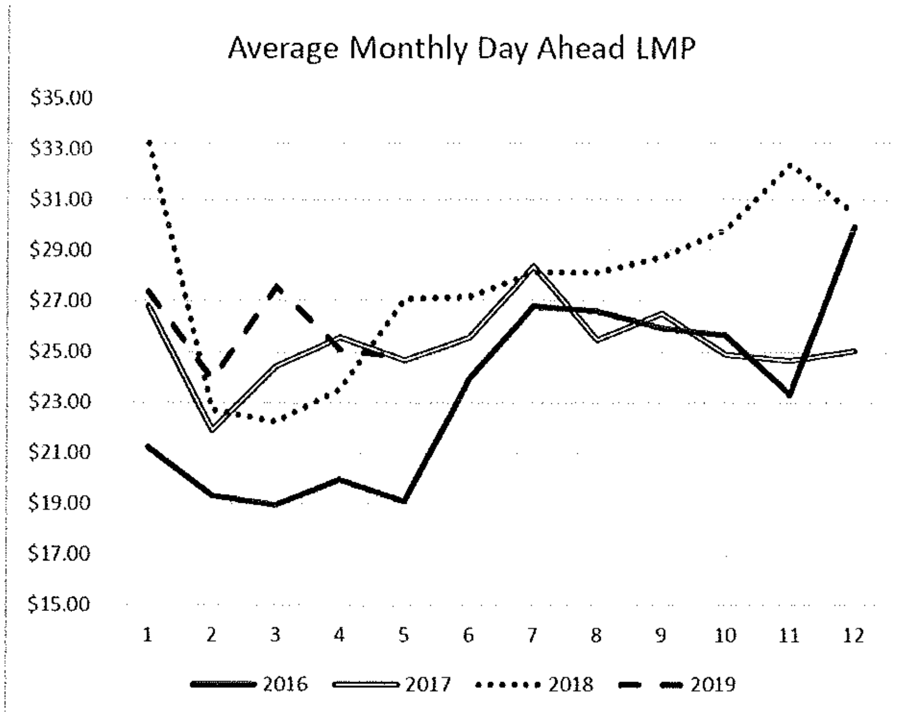
A. Yes, all the cost and revenue components of the FAC – fuel, purchased power, transportation, and off-system sales – continue to be volatile and uncertain. This includes nuclear fuel, coal, natural gas, coal transportation, transmission charges, energy, ancillary services, and net capacity revenues. This is because the costs and revenues associated with all these components are a function of both price and volume. Both price and volume can be significantly impacted by what is occurring in the markets.

It must be kept in mind that the volume of the Company's fuel costs (which includes significant coal costs), off-system sales, and spot market prices for fuel commodities and energy are inexorably linked together. The volume of coal (and natural gas) which Ameren Missouri consumes in a given year is a function of the market dispatch of its generating units. That dispatch in the MISO market is a function of the offer price of the unit (based on its incremental fuel cost) and the market price available to the unit for a given hour.

Any volatility or uncertainty in either the incremental fuel cost or the market price available to the units will necessarily result in volatility and uncertainty in the unit output which impacts fuel consumption, net purchased power expense, and net off-system sales revenues.

Q. Please discuss the volatility and uncertainty of market energy prices.

A. The table below illustrates the variability in the LMPs against which the Company's units are committed. The values are simply monthly averages of the day-ahead LMP for the MOGEN1 aggregate pricing node in MISO. This node is made up of the Labadie, Rush Island, and Sioux Energy Centers. As this table clearly shows, these LMPs are not consistent year-on-year.



A. <u>Coal and Coal Transportation</u>

Q. Do Ameren Missouri's coal and coal transportation expenses remain volatile and uncertain?

A. Yes, both the price and volume components of these costs remain volatile and uncertain.

The volume component is driven by the market dispatch of these units, which is itself a function of the incremental cost of fuel and market prices, while the price component is driven by the contracts for coal commodity and transportation.

Q. Can you illustrate the volatility and uncertainty in the volume of coal consumed by Ameren Missouri's Energy Centers?

A. Yes. As shown in the table below, the Company's annual consumption of coal, and the associated cost at its energy centers, varies significantly year-over-year – by tens of millions of dollars.

AMEREN MISSOURI ANNUAL COAL CONSUMPTION (in Tons)					
	2014	2015	2016	2017	2018
Total Burn TONS	19,943,000	17,981,000	16,616,000	18,619,000	18,058,000
Y/Y Change		-1,962,000	-1,365,000	2,003,000	-561,000

AMEREN MISSOURI COAL COMMODITY AND TRANSPORTATION (in Dollars)					
	2014	2015	2016	2017	2018
Cost	$ 736,337,348	$ 678,213,385	$ 627,925,199	$ 671,421,565	$ 599,223,417
Y/Y Change		$ (58,123,962)	$ (50,288,187)	$ 43,496,366	$ (72,198,148)

Q. Is this variability expected to continue?

A. Yes. The factors which affect the future dispatch of these units continue to be volatile and uncertain.

Q. Can you illustrate the volatility and uncertainty in the price component affecting coal consumed by Ameren Missouri's Energy Centers?

A. Yes. As noted above, the price of coal commodity and transportation impacts cost in two ways. First, the incremental cost is used to develop the offers for the Company's generating units in the MISO market, which affects dispatch and thus the volume of coal consumed. Second, the accounting expense is based on the actual contract prices.

Ameren Missouri utilizes a cost-averaging approach to coal procurement, making several fixed-priced purchases for a given delivery year across several years preceding the delivery year that are price-averaged together. As such, Ameren Missouri's price exposure is tied to the forward curves for both Powder River Basin ("PRB") 8800 British thermal unit ("Btu") and Illinois Basin thermal coal. The following chart shows the change in the 2020 delivery PRB 8800 forward price curve for the five years preceding the 2020 delivery window. Given that Ameren Missouri consumes in excess of 18 million tons of coal annually, each $1 change in the price results in a change in cost of around $18 million.

Q. Are there other factors which impact the volatility and uncertainty of Ameren Missouri's coal and transportation costs?

A. Yes. The Company's coal commodity contracts include adjustment provisions for Btu and sulfur dioxide ("SO_2") content. The various transportation agreements include provisions for rail surcharges (based on the price of diesel fuel), escalators tied to railroad cost indices, and in some instances, adjustment factors tied to MISO LMPs.

Q. Please discuss the coal quality adjustment provisions of the coal commodity contracts.

A. Each of Ameren Missouri's coal contracts include price adjustment mechanisms based on the difference between contract quality specifications and actual delivered quality. The two quality specifications identified in the coal contracts that result in price adjustments are Btu/lb and pounds of SO_2/MMBtu. Variations in the delivered quality result in price adjustments which impact our cost.

Q. Please discuss the adjustment provisions in Ameren Missouri's rail transportation agreements.

A. Rail surcharge charges are variable costs of rail transportation which compensate the railways for their diesel fuel expenditures. This surcharge is based on On-Highway Diesel Fuel pricing, and if applicable, is also based upon car-miles traveled.

Ameren Missouri's rail transportation contracts also include escalators tied to a railroad cost index (the all-inclusive index less fuel ("AII-LF")). This index is published by the Association of American Railroads and measures the changes in price level inputs to railroad operations: labor, materials and supplies, and other operating expenses. These price adjustments happen quarterly or annually depending upon contract.

Adding even more volatility and uncertainty to the cost of Ameren Missouri rail transportation is a feature in some transportation contracts which indexes freight rates to MISO LMPs. While this structure creates a logical association between higher prices and higher coal burn, it also adds to the uncertainty of the overall expense.

Q. Aside from the adjustment provisions discussed above, are Ameren Missouri's PRB rail transportation expenses volatile and uncertain with the Company's multi-year contracts in place?

A. Yes, for the reasons given earlier since cost is a function of price and volume.

Q. Are the costs for fuel additives and emissions volatile and uncertain?

A. Yes, because the volume of these items is a function of generator output, which itself is volatile and uncertain.

B. Natural Gas & Transportation and Impacts to Generator Dispatch

Q. Are Ameren Missouri's natural gas costs, including transportation, volatile and uncertain?

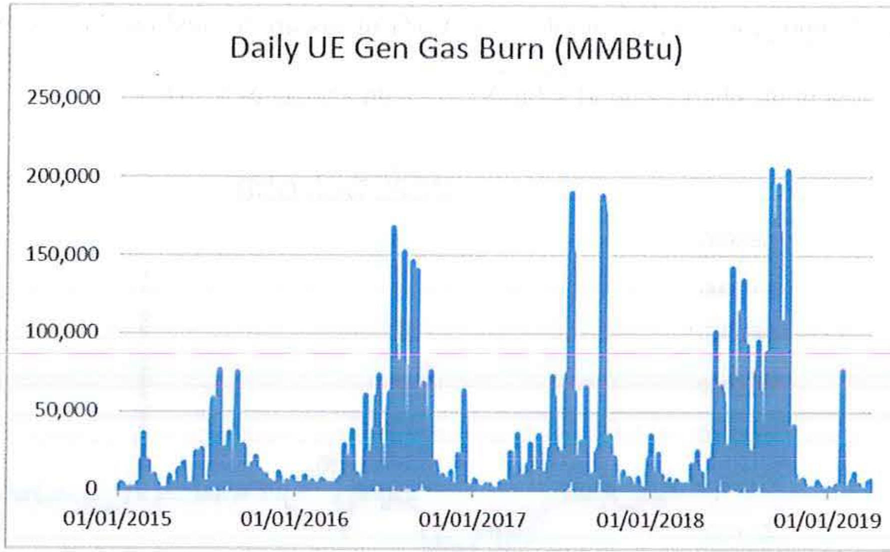
A. Yes. The units in Ameren Missouri's gas generation fleet (also referred to as combustion turbine generators or "CTGs") are peaking units. Their output is much less certain and predictable than that of baseload units, such as those at the Labadie, Rush Island, and Sioux Energy Centers. Additionally, we have limited resources for storing natural gas commodity which we have procured but did not consume.

As a result, Ameren Missouri frequently procures natural gas supplies in the next-day or same-day gas markets, after first having cleared the unit in the MISO market. While gas prices have been relatively low in recent months, there is still significant gas market volatility on a daily and locational basis, especially on peak days. The chart below shows the daily settlement price for the Natural Gas Pipeline Company's TxOk receipt point. This natural gas receipt point is key to Ameren Missouri's gas generation fuel supply, as several simple cycle CTG plants are located on this supply path. Daily prices in the chart range $1.43 to $7.40, with a mean of $2.67.

Q. Are the volumes of natural gas consumed for electrical generation relatively certain and easy to predict?

A. No. In addition to the Company's natural gas-fired units being subject to the economic dispatch provisions of the MISO market, the Company experiences a significant number of unit starts based on MISO commitment instructions issued for system reliability reasons. These non-economic based unit commitments compound the already difficult task of attempting to forecast unit output.

As noted previously, these units are not baseload units and operate infrequently. The following figure visually illustrates the large variability of Ameren Missouri's generation natural gas consumption. Since the natural gas generation fleet is largely committed during peak conditions, the Company is frequently procuring significant amounts of natural gas on volatile pricing days.



C. Net Off-System Sales Revenues

Q. Are Ameren Missouri's net off-system sales revenues volatile and uncertain?

A. Yes, for all the reasons outlined above. This volatility and uncertainty is further compounded by the fact that the volume of sales is a function of the amount of customer demand which is bid into the MISO market. The Company's demand is also volatile and uncertain, being dependent to a significant degree on weather.

Q. Please explain how the volume of off-system sales is a function of the amount of customer demand bid into the MISO market.

A. As I discussed earlier, Ameren Missouri operates in a "buy all – sell all" wholesale market. As a function of the MISO market, all the generation which is cleared for a given hour is sold into the MISO market. At the same time, the Company must purchase from the MISO market all the energy needed to meet its load obligations. FERC Order 668 requires that these sales and purchases be netted against each other in each given hour. When the volume of purchases exceeds the volume of sales in a given hour, a net purchase is recorded. When the opposite occurs, a net sale is recorded.

D. Net Purchased Power Costs

Q. Are Ameren Missouri's net purchased power costs volatile and uncertain?

A. Yes. This is true for both purchases made under the Pioneer Prairie Purchased Power Agreement ("PPA") and net purchased power costs arising from our activities in the MISO market.

Purchases under the Pioneer Prairie PPA are driven by the amount of energy produced at the facility, which is a function of weather. Weather is, and is expected to remain, both volatile and uncertain.

Net purchased power costs arising from activities in the MISO market are volatile and uncertain for the same reasons that our off-system sales revenues are volatile and uncertain.

E. Ancillary Services

Q. Are ancillary services revenues and costs volatile and uncertain?

A. Yes.

Ancillary services revenues arise through the Company's participation in the MISO market. This market is a spot market – settling both day-ahead and in the real time. The following table shows ancillary services costs and revenues for regulation, spinning reserve, and supplemental reserve services over the past five years, reflecting a range from a net of about $5 million in a given year to a net of about $8 million in another year during this period:

($ Millions)					
Ancillary Services	2014	2015	2016	2017	2018
Cost	$ 3.10	$ 2.41	$ 2.82	$ 3.27	$ 3.26
Revenue	$ (10.19)	$ (7.45)	$ (8.27)	$ (9.96)	$ (11.27)
Net	$ (7.09)	$ (5.04)	$ (5.45)	$ (6.68)	$ (8.01)

Ancillary services costs are a function of how much load the Company settles in the MISO market. This load is volatile and uncertain, being dependent to a significant degree on weather.

Q. Are capacity revenues and costs volatile and uncertain?

A. Yes. While Ameren Missouri has less uncertainty regarding the volume of capacity sales and purchases that will be required for a given period, the price at which these volumes will settle is volatile and uncertain, as I illustrated above in my discussion of why Ameren Missouri is recommending the use of a multi-year normalization period for these costs and revenues.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Decrease Its Revenues for Electric Service.	)))	File No. ER-2019-0335

AFFIDAVIT OF ANDREW MEYER

STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)

Andrew Meyer, being first duly sworn on his oath, states:

1. My name is Andrew Meyer. I work in the City of St. Louis, Missouri, and I am employed by Union Electric Company d/b/a Ameren Missouri as Senior Director, Energy Management & Trading.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Union Electric Company d/b/a Ameren Missouri consisting of 26 pages and Schedule(s) no schedules, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Andrew Meyer
Andrew Meyer

Subscribed and sworn to before me this 26th day of June, 2019.

Geri A. Best
Notary Public

My commission expires:

GERI A. BEST
Notary Public - Notary Seal
State of Missouri
Commissioned for St. Louis County
My Commission Expires: February 15, 2022
Commission Number: 14839811