Exhibit No. 3

Ameren – Exhibit 3
Andrew M. Meyer
Direct Testimony
File No. ER-2022-0337

Exhibit No.:	
Issues:	Fuel Adjustment Clause Continuation & Components; Rush Island Operations; Coal Inventory; High Prairie Conservation Mitigation
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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2022-0337

DIRECT TESTIMONY

OF

ANDREW M. MEYER

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
August, 2022

TABLE OF CONTENTS

DIRECT TESTIMONY

OF

ANDREW M. MEYER

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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. I am employed by 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 am responsible for Ameren Missouri's generation and load asset management in the wholesale energy markets. This includes real-time operation of the generation fleet within the applicable Regional Transmission Organization ("RTO"); procurement of nuclear fuel, fossil fuels, and emission control commodities; financial and physical hedging of any energy, capacity, congestion-rights, or related exposures; and RTO stakeholder relations. I am also responsible for gas supply procurement for the Local Distribution Company ("LDC"); generation performance monitoring; NERC[1] compliance oversight; and operational responsibility for the combustion turbine generator and renewable generator fleets.

[1] North American Electric Reliability Corporation.

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 is the purpose of your direct testimony in this proceeding?

A. My testimony sponsors the continuation of Ameren Missouri's Fuel Adjustment Clause ("FAC"), including providing the minimum filing requirements prescribed by the Commission's FAC rules and updating the net base energy costs ("B" in the FAC tariff sheets and sometimes referred to as "NBEC") that form the base against which changes in the Company's Actual Net Energy Costs ("ANEC") are tracked in the FAC.

I will also discuss the establishment of several components of NBEC, including the appropriate level of off-system sales revenues ("OSSR"),[2] net of the normalized capacity component of purchased power expense. The normalization approach addressing the impact of financial gains and losses and the removal of this component from the calculation of OSSR is also discussed below.

Another purpose of my testimony is to demonstrate the continued volatility and uncertainty of ANEC and of the 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.

I also discuss the appropriate level of coal inventory to use for setting the revenue requirement in this case.

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

Finally, I address the anticipated changes to operations at the Rush Island Energy Center over the next few years as it transitions to retirement.

II. FUEL ADJUSTMENT CLAUSE CONTINUATION

Q. Is the Company requesting to continue its FAC?

A. Yes. The key considerations that supported the Commission's approval of the FAC initially, and the Commission's continuation of it in the past seven rate review cases, support its continuation now.

Q. Please explain the basic structure of the Company's FAC?

A. The FAC rate (defined as the "Fuel Adjustment Rate" or "FAR" in the tariff), changes three times per year based upon changes in ANEC during each historical four-month accumulation period, as compared to the NBEC established in each rate review. After a rate adjustment filing is made, 95% of the difference between ANEC and NBEC for the subject accumulation period is recovered from (or returned to) customers over an eight-month recovery period. Interest is applied to the sums recovered or returned. Since the FAC's inception through April of this year, 39 such FAR filings have been made.

This core structure and operation of the FAC has not changed since it was first approved in late January 2009 in File No. ER-2008-0318, which became effective March 1, 2009. There have been some changes in its details, primarily to add more detail to the tariff sheets, and recently in File No. ER-2021-0240, to include all costs and benefits associated with renewable energy resources used for RES compliance in the RESRAM, instead of the FAC.[3]

[3] "RES" stands for Renewable Energy Standard, and "RESRAM" stands for Renewable Energy Standard Rate Adjustment Mechanism.

Q. What are the requirements for requesting or continuing an FAC?

A. Continuation of a FAC is governed by Section 386.266, RSMo, and Commission Rule 20 CSR 4240-20.090, in particular Rule 20 CSR 4240-20.090(2)(A), which prescribes the minimum filing requirements for continuation of an FAC. Information satisfying these minimum filing requirements is provided in the attached Schedule AMM-D1.

Q. For what specific reasons does the Company recommend continuation of the FAC?

A. Ameren Missouri's FAC should be continued because the nature of these costs and revenues meets the criteria for use of this Rider, and to minimize the negative impact on the Company in recovering these costs and revenues absent a FAC. These specific reasons include: 1) that all of the factors the Commission has generally considered in evaluating FACs favor continuation of the FAC; 2) that the FAC is reasonably designed to provide the Company a sufficient opportunity to earn a fair return; 3) that without an FAC, significant regulatory lag would be present and would prevent the Company from timely reflecting what can be and often are very significant changes in net energy costs in rates, whether those changes are up or down, and those changes can impact the Company's ability to earn a fair return; 4) that elimination or any significant modification of the FAC would reflect an inconsistent regulatory policy that would harm the Company's access to needed capital at the lowest reasonable cost; and 5) that Ameren Missouri's FAC is important to maintaining the Company's credit quality, primarily because virtually all other vertically integrated electric utilities with whom the credit rating agencies compare Ameren Missouri operate with FACs.

When the question of whether the FAC should be continued has been litigated, the Commission has consistently recognized that all of these reasons continued to demonstrate the appropriateness of the Company's FAC.[4] The Company's FAC was also continued in the last three general rate case proceedings by agreement of the settling parties, and each of those agreements were approved by the Commission.

Q. Please elaborate on why the nature of these costs and revenues meet the criteria for continuation of the Company's FAC.

A. There are three primary attributes of these costs and revenues that warrant the continuation of a FAC. These are the same attributes the Commission considered when approving Ameren Missouri's FAC initially, and in subsequent requests. Specifically, the nature of costs or revenues that would be included in the FAC should be:

1. Substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases;
2. Beyond the control of management, where the utility has little influence over experienced revenue or cost levels; and
3. Volatile in amount, causing significant swings in income and cash flows if not tracked.

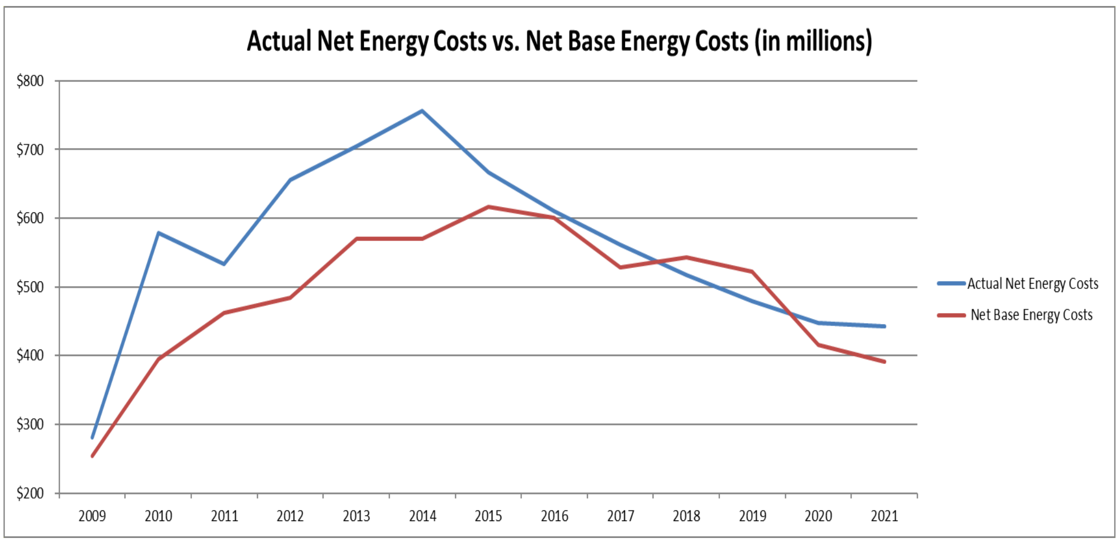
Q. Are the Company's fuel and purchased power costs substantial?

A. Yes. The Company's fuel and purchased power costs, including transportation (reflected in Factors FC and PP in the current FAC tariff), are one of the Company's largest operations and maintenance ("O&M") expenses, representing approximately 44% of its total O&M costs in 2021. In addition, the Company's ANEC (the sum of Factors FC, PP, E, and R less OSSR in the FAC tariff) have changed substantially since the FAC was first established, from a low of approximately $280 million in 2009 to a high of approximately $756 million in 2014 followed by a reduction to approximately

[4] File No. ER-2014-0258, *Report and Order*, pp. 102-104, issued on 4/29/15.

$443 million as of the end of 2021. Absent the FAC, those changes would have had an extremely material and detrimental impact on Ameren Missouri's financial performance between rate cases, and when decreases have occurred, those decreases would not have been timely passed through to customers.[5] The changes in ANEC through the end of 2021 are depicted in the Figure 1 below:

Figure 1



Q. Does the Company have influence or control over these costs and revenues?

A. No, the Company has very little influence. This was the case when the Company's FAC became effective in 2009, and nothing has changed with respect to the question of control over the past eight rate cases (with this being the ninth) in which the

[5] Customers receive 95% of the benefit between rate reviews, since the FAC includes a 95% / 5% sharing mechanism.

Commission approved the FAC and its continuation. The Company still lacks control over the national and international fuel and power markets that dictate what its ANEC will be.[6]

Q. Are volatility and uncertainty evident, and will volatility and uncertainty continue to exist?

A. Yes. The Company's ANEC history clearly shows the substantial changes (up and down) in the Company's ANEC over the past several years. And the forward value of ANEC will be greatly impacted by competing forces of generation fleet retirements and dramatic shifts in commodity market pricing. The currently elevated prices for fuel and energy will have large impacts on ANEC.

As Figure 1 above illustrates, ANEC has at times increased well over $100 million from a given year to the next and has also seen large year-to-year decreases, since the FAC was first established. These significant up and down year-over-year comparisons demonstrate the volatility and uncertainty of the Company's fuel and purchased power costs net of off-system sales, including transportation. It also continues to be true that the national and international markets that set the prices for fuel and power continue to be volatile. The volatility we see in the FAC could result in higher charges to customers, but it could result in a reduction of the FAC rates and lower charges to customers as well, as we have seen on several occasions, depending on volumes of fuel burned, prices for power,

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[6] The Commission has recognized this for years: File No. ER-2008-0318, *Report and Order*, p. 63, issued 1/27/2009, ("[M]ost of the costs that comprise [Ameren Missouri's] fuel costs, the costs that would be tracked in a fuel adjustment clause, are dictated by national and international markets, including competing purchases by China and India, far beyond the control of [Ameren Missouri]."); File No. ER-2014-0258, *Report and Order*, p. 103, issued 4/29/15 ("Those fuel and purchased power costs continue to be dictated by national and international markets and thus are outside the control of Ameren Missouri's management."); File No. ER-2019-0335, *Amended Report and Order,* p. 9 thru p.10, issued 7/15/20 ("Fuel costs are volatile and electric utilities do not have complete control over those fuel costs. In general, Ameren Missouri's net energy costs are set by markets for energy and fuel that are largely beyond Ameren Missouri's control" (footnotes omitted)).

etc. As the Commission knows, 95% of any such reduction as compared to the NBEC established in this case will be passed through to customers.

Q. Do the Company's hedging programs for ANEC components eliminate volatility and uncertainty?

A. No, they do not. While the Company's efforts to hedge commodity price exposure is intended to limit extreme price swings, it has very little control over the underlying market prices and over the volumetric components of ANEC. Later in this testimony I will discuss how the Company's fuel costs are a function of unit dispatch, which itself is a function of spot fuel and spot energy market prices. Additionally, off-system sales revenues are a function of that same unit dispatch and changes in native load obligations.

Q. The Company annually produces a forecast of ANEC for budget purposes. Does the comparison of budgeted to actual ANEC demonstrate the volatility and uncertainty of ANEC?

A. Yes. The following charts below show the variance between what we expected our ANEC to be (per our budget) and what they actually were since the inception of the FAC.

Figure 2

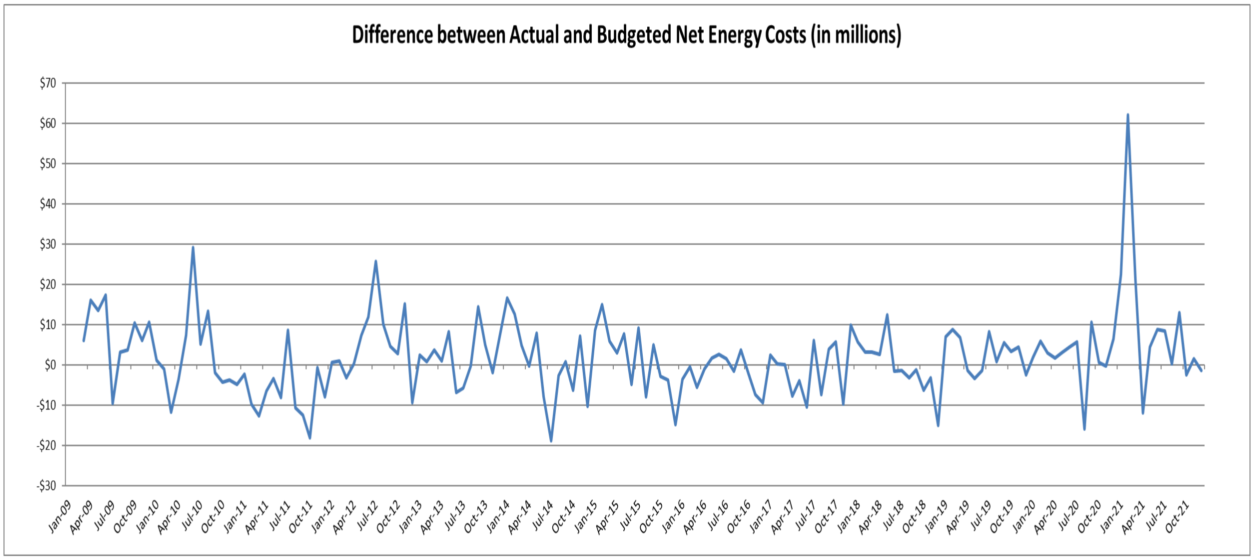
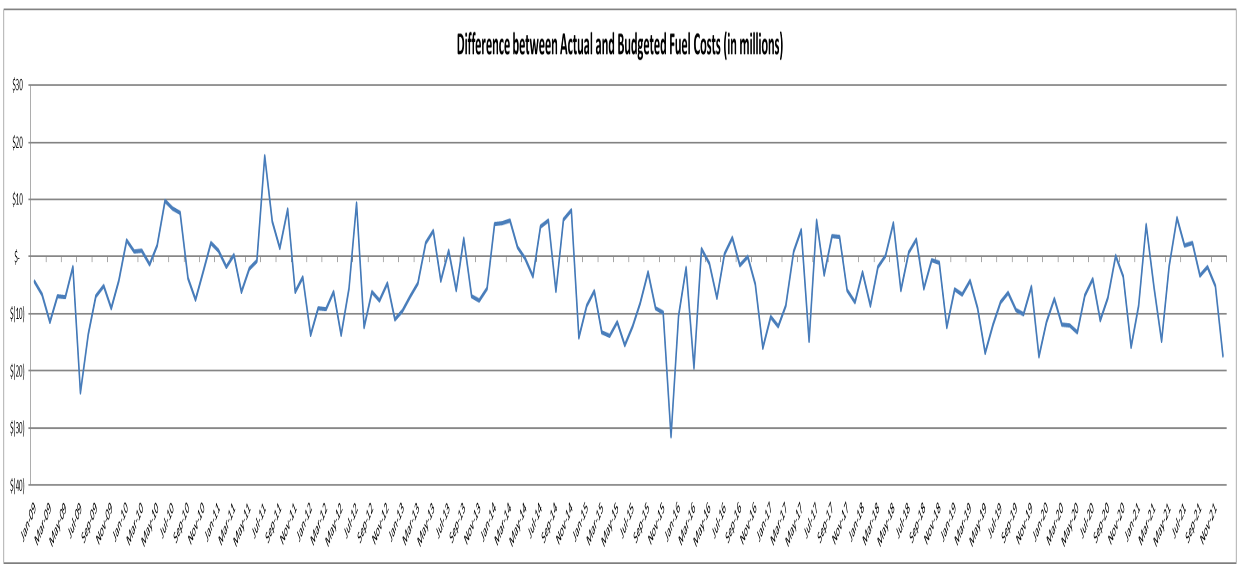


Figure 3 shows the same thing for the fuel cost component of ANEC:

Figure 3



The volatility of ANEC is clearly visible in these charts. The differences swing from positive to negative. The budget values used in this comparison are frequently produced much closer to the actual timeframe that the Company is incurring these costs and revenues, as compared to when NBEC is reset in a general rate review. This budget process also utilizes projected costs, whereas the FAC rules adopted by the Commission require the use of historic costs for purposes of establishing NBEC. As such, one might expect the Company's budget forecast to not contain large variances. However, in actual practice we see tens of millions of dollars in differences between what we budget and what we actually experience, which demonstrates that these costs are volatile and uncertain.

In summary, the large fuel and purchased power costs and significant off-system sales revenues that we track in the FAC cannot be controlled by the Company and are volatile and uncertain. I will discuss the volatility of market factors impacting FAC components later.

Q. Please explain how operating with a FAC still allows for a lag in time between the incurrence of fuel-related costs and recovery of those costs.

A. Ameren Missouri's FAC recovery mechanism is designed to mitigate net energy cost-related rate impacts for customers. It accomplishes this by only allowing for updates three times per year, and also by spreading the recovery, or return, of any differences over an eight-month period. These two features contribute to a lag in recovery of fuel-related costs. Schedule AMM-D2 illustrates how it will take at least 12 months between the time when changes in ANEC occur and when those changes are fully[7] reflected in bills to customers.

[7] The FAC does not provide "full" recovery because only 95% of the changes in net energy costs are reflected in FAC adjustments.

Q. Do other reasons support the necessary and appropriate continuation of the Company's FAC, beyond the discussion of magnitude, control, and volatility/uncertainty?

A. Yes, most definitely. Ameren Missouri's FAC remains critical to maintaining the Company's credit quality and keeping the Company's risk profile (with regard to this issue) on par with virtually all of the vertically integrated electric utilities across the country that operate with an FAC (including the other electric utilities in Missouri). The Commission has previously recognized that "[i]ncreased financial risk results in an increase in a company's cost of borrowing, ultimately increasing costs that will be passed on to ratepayers,"[8] and continued its recognition of the importance of an FAC to the investors (both debt and equity) that provide capital to the Company in its last fully litigated rate case order.[9] The facts that supported those findings have not changed.

Q. Has the Company made any updates or changes to the Rider FAC tariff as filed in this case?

A. The Company is proposing the following changes, which are shown in redline in the attached Schedule AMM-D3:

a. Use of updated Base Factor ("BF") amounts using updated NBEC figures.

b. Consolidation of the various existing provisions containing language to exclude costs and revenues related to Renewable Choice and digital currency operations, and in that consolidated language includes a provision that excludes such costs and

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[8] File No. ER-2010-0036, *Report and Order*, p. 78, issued 5/28/2010.
[9] File No. ER-2014-0258, *Report and Order,* p. 103, issued 4/29/15 ("Ameren Missouri still must compete in the capital markets with other utilities and the vast majority of those utilities have fuel adjustment clauses. The continued existence of a fuel adjustment clause is important to maintaining Ameren Missouri's credit worthiness.").

revenues from any subsequent renewable subscription program if the Commission determines that they should be excluded from the FAC.

c. Language to make clear that "basemat coal," which is coal that is left when a coal plant retires, is not to be included in the FAC and should be deferred to a regulatory asset for future recovery consideration as the Commission previously ordered for Evergy and Empire.

d. Language to remove references to Schedule 11, since Schedule 11 deals with wholesale distribution charges associated with payments from entities such as municipalities for use of Company distribution assets. While Schedule 11 is nominally a Midcontinent Independent System Operator, Inc. ('MISO") "transmission" schedule, it really has nothing to do with transmission of electricity bought from the MISO market to serve Ameren Missouri's retail load, and it probably never belonged in the FAC. The revenues received from these wholesale customers have been stable and were always reflected in base rates, so customers have been getting credit for them via lower revenue requirements in rate reviews, and we believe that is the proper treatment of them for ratemaking purposes.

e. As addressed in the direct testimony of Mitch Lansford in File No. EA-2022-0245, language to make sure that capacity costs from Company facilities financed using tax equity financing are included just as capacity costs for other Company facilities are included.

f. Updating the "charge type" table for minor changes to Regional Transmission Organization charge types since the last rate review.

None of these changes fundamentally alter the components in the FAC as compared to what those components have generally been since the FAC was first approved in 2009.

Q. Has the Company also rebased the B used to calculate the BF[10] in the FAC tariff to reflect the current level of B?

A. Yes. When base rates are re-set in a rate case, the Commission updates all of the costs and revenues that comprise the revenue requirement. B is one of the elements of the cost of service that must be updated. Therefore, as with every other cost in a rate case, the base level of B has been updated to reflect more current levels of the costs and revenues reflected in the FAC.

In the Company's previous rate case, the Commission set the BF at 1.323 cents per kilowatt-hour ("kWh") for the summer and 1.192 cents per kWh for the winter, based on the NBEC in the revenue requirement in that case. We are proposing to update the BF to 1.448 cents per kWh for the summer and 1.312 cents per kWh for the winter. The calculation of the NBEC that underlies these BF values is addressed in detail in the direct testimony of Company witness Mitchell Lansford.

Q. The FAC sharing percentage has been a topic of debate in prior rate reviews. Is the Company recommending any changes in this case?

A. No. The Company is recommending a continuation of the 95%/5% sharing ratio that has been in place since the Company first received a FAC, even though most utilities in other states with FACs do not have a sharing mechanism. The last time the ratio was an issue, in File No. ER-2019-0335, the Commission once again reaffirmed the appropriateness of the 95%/5% sharing mechanism: "(t)he Commission has found on

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[10] Factor BF is determined by dividing the B (which is expressed in dollars) by the total normalized net system load to produce a rate.

several occasions and, most recently, after a hearing on this question alone, that the 95/5 sharing ratio provides Ameren Missouri sufficient incentive to operate at optimal efficiency and still provides an opportunity for Ameren Missouri to earn a fair return on its investment."[11]

Q. Would a change to the FAC sharing percentage, such as if it were eliminated or changed to increase Company exposure, further incent the Company to efficiently manage net energy costs?

A. No. The Company has more than enough incentive to efficiently manage its net energy costs, as such costs are subject to regular prudence reviews and the possibility that the FAC could be discontinued completely.

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

Q. Please define "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 wholesale market exposure, after netting out the costs and revenues associated with purchasing energy from the 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

[11] File No. ER-2019-0335, *Amended Report and Order,* p. 12 thru p. 13, issued 7/15/20.

approximately $435.4 million per year. This total is comprised of the following components, each of which I address in more detail later in this testimony:

1) $189.8 million of net energy sales revenues;

2) $228.4 million of gross capacity sales revenues;

3) $6.8 million of ancillary services revenues;

4) $2.7 million of real-time RSG MWP[12] margins, with the calculation of this component discussed in the direct testimony of Company witness Mark J. Peters, and

5) $7.7 million of real-time load and generation deviation credit adjustment, also discussed in the testimony of witness Peters.

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

A. Ameren Missouri's normalized annual off-system sales of energy were calculated using the PowerSIMM production cost model. In accordance with well-established past practice, production cost modeling 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

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

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 PowerSIMM model's output?

A. PowerSIMM 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 market. In accordance with FERC requirements, however, these amounts are netted against each other for each hour.[13] 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 witness Peters' direct 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

[13] The only exception to this is that the energy from the Atchison wind facility is sold into the Southwest Power Pool ("SPP") market since that facility is connected to the transmission system under SPP's functional control.

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. The energy market price assumptions utilized in the model, and the rationale for use of Day-Ahead locational marginal prices (“LMPs”). is discussed in witness Peters' direct testimony.

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 $228.4 million of gross capacity sales revenues and $220.5 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”),[14] which cover the period of June 1, 2020, through May 31, 2023. A normalization adjustment has been made to the gross capacity sales revenues to remove the historic revenue associated with the Meramec units, since the plant's retirement at the end of 2022 is a known and measurable change. The revenue calculation was also normalized to exclude the historic revenue of High Prairie from this total, as it is now appropriately reflected in the RESRAM. Finally, a

[14] PY 2018/19, PY2019/20, and PY2020/21. Planning years run from June 1 to May 31.

normalization adjustment was made to the gross capacity purchase costs, to reduce that cost by the value of any Zonal Deliverability Benefit ("ZDB") credits.

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 revenues to include in total net off-system sales is $6.8 million. As was done in the prior case, we intend to true-up this level through the true-up cutoff date based upon data for the twelve-month period ending December 31, 2022.

Q. Have you included a normalized level of physical bilateral trading contract and swap margins in your recommended net off-system sales?

A. No. While a normalized level of such margins has been included in off-system sales in the past, it is inappropriate to do so in this case due to generating units that will be retired or impacted by a transition to retirement during the period when rates set in this case will be in effect.

Q. Please explain.

A. Physical bilateral transactions and financial swaps are hedging mechanisms used to mitigate some of the volatility in OSSR. However, they do not replace the off-system energy sales themselves. Given the material reduction in energy sales that the Company will experience once the Meramec Energy Center retires at the end of 2022, and due to modified operations at the Rush Island Energy Center associated with its transition to retirement, use of historical margins consistent with past practice would misstate these margins and net base energy costs.

Q. Why isn't the Company simply removing transactions associated with the Meramec and Rush Island Energy Centers from the calculation of physical bilateral transaction and financial swap margins, but instead taking margins for the other energy centers into account in developing its off-system sales recommendation?

A. Because the Company's off-system sales hedging program does not associate specific transactions with specific resources. When the Company develops its hedge programs, it begins with its net position. The net position for any given period is a comparison of the total volume of all available resources (generation in-the-money and purchases) to its total obligations (load and existing sales, including to Missouri municipalities). This will determine whether the Company is long generation (more resources than obligations) or short generation (less resources than obligations). Based on this volume of expected length, the Company contemplates entering hedge transactions. Neither this position reporting, nor the resulting hedge transactions, specifically link sales hedge volumes to individual generators at the time they occur, nor does the Company hedge 100% of the net position.

Since one cannot simply identify and remove from the calculations specific transactions that were associated with Meramec or the reduced output expected from Rush Island given its transition to retirement (which I discuss in greater detail below), the question is whether the Company could utilize some other means of making such an adjustment. In my opinion there is no reasonable means of doing so, indicating that such margins should be eliminated from setting NBEC in this case.

Q. Does this preclude including such an adjustment in future proceedings?

A. No. The appropriateness of including such an adjustment in future proceedings would be determined as part of that proceeding itself.

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.

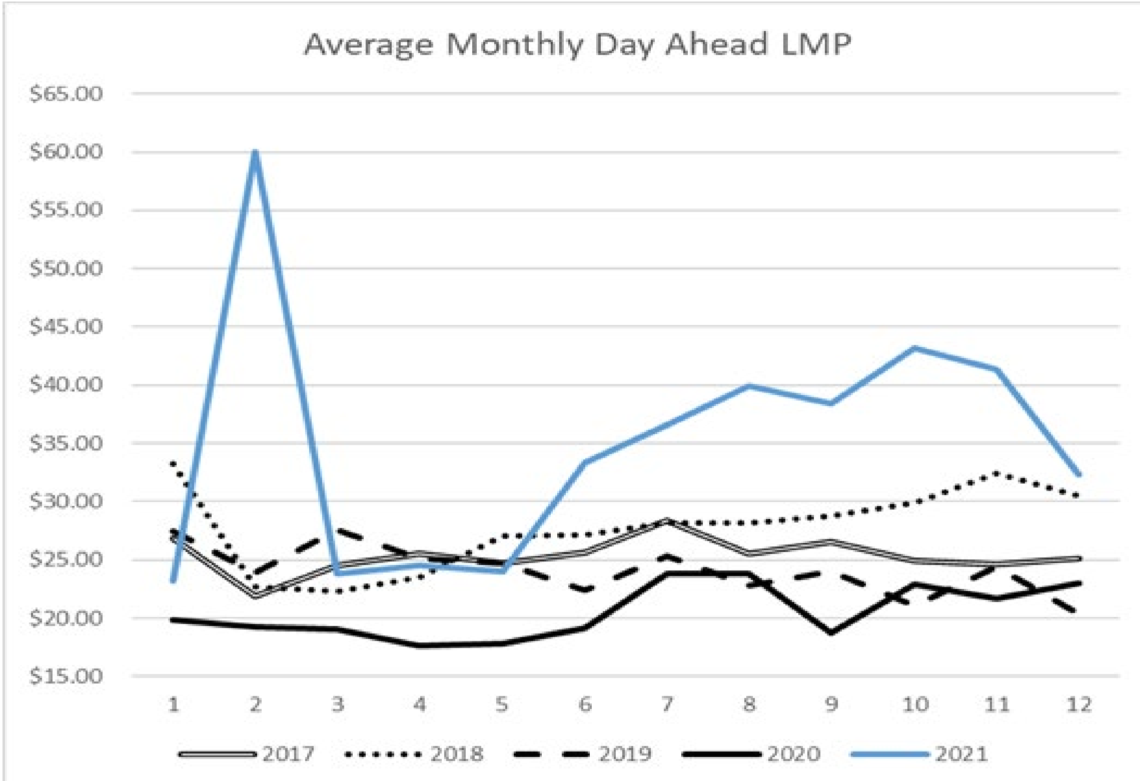
The Company's fuel costs (which includes significant coal costs), off-system sales, and spot market prices for fuel commodities and energy are inexorably linked together. The volume of coal (and natural gas) which Ameren Missouri consumes in any given year is a function of the market dispatch of its 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. Table 1 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 show significant inconsistency from year-to-year. It is important to note the shape of the 2021 line of the chart. In February of that year the Company experienced the impacts of Winter Storm Uri, and in the second half of 2021 experienced a sustained surge in commodity prices. The latter pricing surge was evident in natural gas, where lower year-over-year inventories, record international gas prices, and stagnant U.S. production all drove the price strength. Similar drivers led to price spikes in oil and refined fuels, spot coal, nuclear fuel components, and generally all commodities used as fuel for electric generation. Driven by higher fuel inputs, energy prices are dramatically elevated since fourth quarter of 2021.

Table 1



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. Please illustrate the volatility and uncertainty in the volume of coal consumed by Ameren Missouri's Energy Centers.

A. As shown in Table 2 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.

Table 2

AMEREN MISSOURI ANNUAL COAL CONSUMPTION							
	Actual	Actual	Actual	Actual	Actual	Actual	Actual
	2015	2016	2017	2018	2019	2020	2021
Total Burn TONS	17,609,000	16,232,000	17,975,000	17,474,000	14,320,000	15,439,000	16,505,000
Y/Y Change		-1,377,000	1,743,000	-501,000	-3,154,000	1,119,000	1,066,000
AMEREN MISSOURI COAL COMMODITY AND TRANSPORTATION							
Cost	$ 678,213,385	$ 627,925,199	$ 671,421,565	$ 599,223,417	$ 428,863,656	$ 450,643,799	483,068,545.30
Y/Y Change		$ (50,288,187)	$ 43,496,366	$ (72,198,148)	$ (170,359,761)	$ 21,780,143	$ 32,424,747

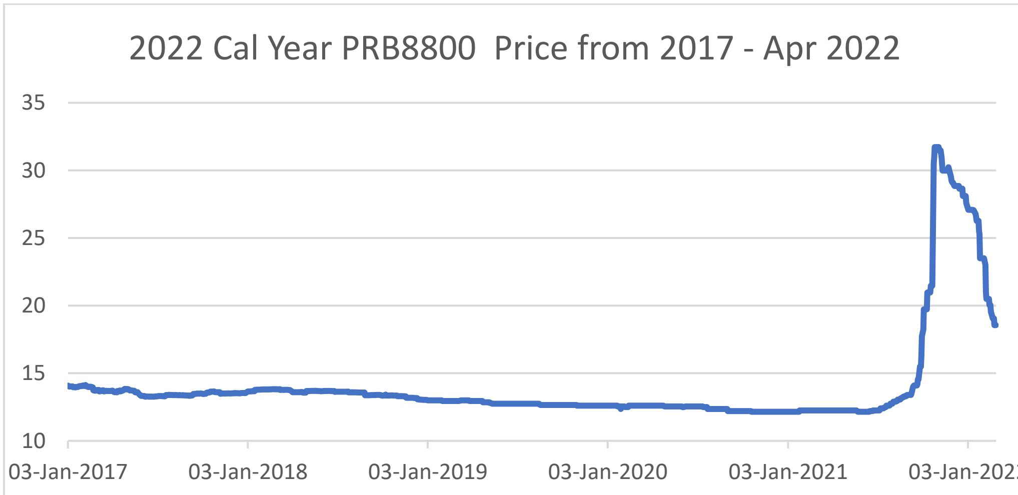
Q. Is this variability expected to continue?

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

Q. Please illustrate the volatility and uncertainty in the price component affecting coal consumed by Ameren Missouri's energy centers.

A. 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") coal and Illinois Basin thermal coal. The following chart in Figure 4 shows the change in the 2022 delivery PRB 8800 forward price curve for the five years preceding the 2022 delivery window. It is important to note that the value of 2022 delivered PRB routinely fluctuated in a few dollar range for several years before the latest price spike. Those $1 per ton fluctuations still have significant impact to the Company's coal expenses, as the Company has routinely burned more than 14 million tons per year.

Figure 4



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 adjustment provisions in Ameren Missouri's rail transportation agreements.

A. Rail surcharges 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 prices and 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?

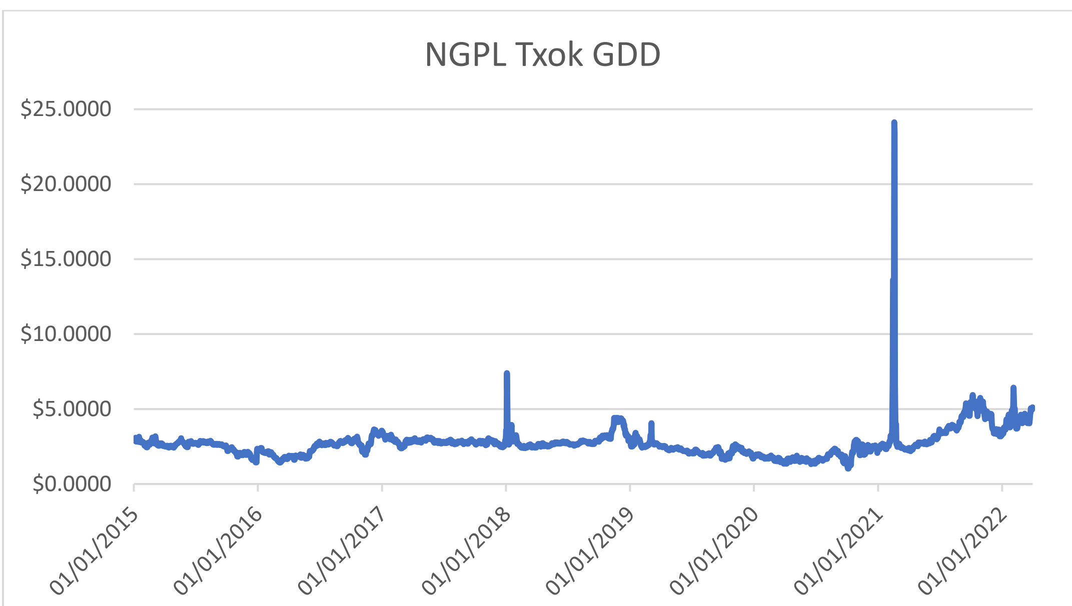
A. Yes, because the volume of these items is a function of generator output, which itself is volatile and uncertain.

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

A. Yes. The units in Ameren Missouri's generation fleet which utilize natural gas as a fuel (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 which we have procured but did not consume.

As a result, Ameren Missouri frequently procures natural gas supplies for its CTGs 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 years, we have more recently seen increased volatility generally, and even when prices are lower there is still significant gas market volatility on a daily and locational basis, especially on peak days. Figure 5 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 (covering January 2015 through March 2022) span a range of $1.03 to $24.13, with an average of $2.71.

Figure 5

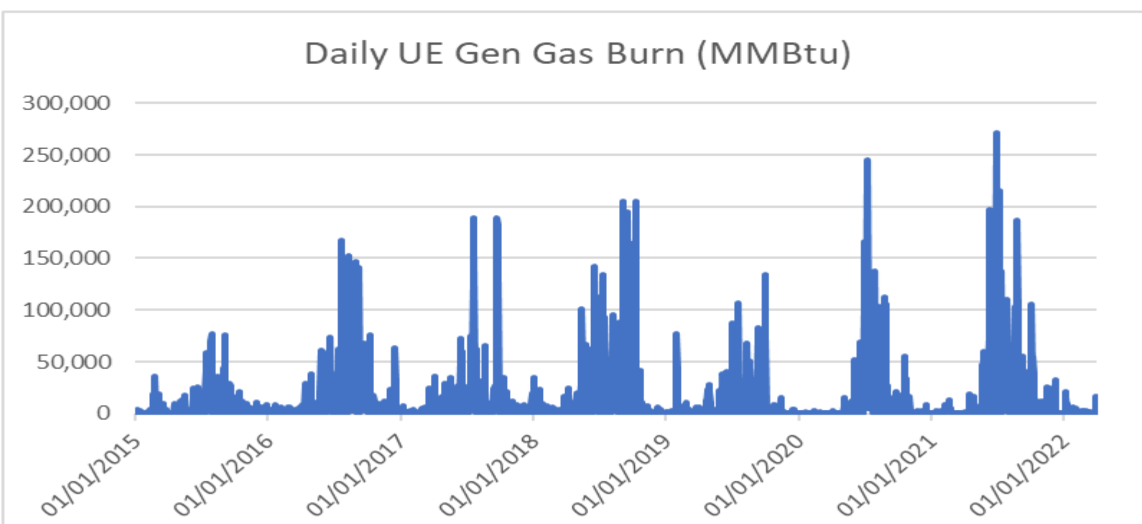


Q. Are the volumes of natural gas consumed for electrical generation relatively certain and easy to predict?

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. Of course, these commitments for units located in Illinois are now subject to the limits established in the recently passed Illinois Clean Energy Jobs Act.

As noted previously, these units are not baseload units and operate infrequently. The following Figure 6 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.

Figure 6



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" RTO wholesale market.[15] As a function of the MISO market, all the generation which is cleared for a given hour is sold into the 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.

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

A. Yes. This is true for both net purchased power costs arising from our activity in the market, and purchases made under the Pioneer Prairie Purchased Power Agreement ("PPA"). The retirement of Meramec, the anticipated significantly reduced operation of Rush Island, and the intermittent generation from new renewable energy centers all increase the frequency of events when the Company is a net purchaser of energy in the

[15] As noted earlier, the output of the Atchison Energy Center is sold into the SPP market, but all other generation sold into the MISO market.

wholesale market. 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.

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.

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 3 shows ancillary services costs and revenues for regulation, spinning reserve, and supplemental reserve services from January 2016 to March 2022, reflecting a (full year) range from a net of about $2.8 million in a given year to a net of about $8 million in another year during this period:

Table 3

Ancillary Services	2016	2017	2018	2019	2020	2021	2022 (through March)	Avg.
Cost	$2.82	$3.27	$3.26	$2.39	$2.09	$4.07	$0.91	$3.76
Revenue	($8.29)	($10.00)	($11.31)	($5.51)	($6.34)	($6.84)	($1.98)	($10.05)
Net	($5.47)	($6.72)	($8.05)	($3.11)	($4.26)	($2.77)	($1.08)	($6.29)

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. 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. Also, while the

Company's forecasted demand plus reserve margin is more certain, the accreditation process that MISO uses to determine how much capacity from each generator can be sold in the auction can yield very different results year-over-year.

Q. Have the results of past MISO annual Planning Resource Auctions demonstrated volatility in the Auction Clearing Price ("ACP")?

A. Yes. Table 4 shows the volatility of ACP's over the last several auctions. Ameren Missouri's native load obligation resides in Zone 5 (Missouri), and generation resides in both Zone 4 (Illinois) and Zone 5 (Missouri). The volatility and uncertainty of the MISO auction settlement are easily apparent, considering the most recent YOY change from $5 per MW-day to the scarcity pricing of $236.66 per MW-day.

Table 4

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
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			
2020-2021	$5.00						$257.53	$4.75	$6.88	$4.75	$4.89-$5.00
2021-2022	$5.00							$0.01			$2.78-$5.00
2022-2023	$236.66							$2.88			$133.70-236.66
IMM Conduct Threshold	25.01	24.52	23.67	24.74	26.63	24.40	25.69	23.10	22.88	22.84	26.67
Cost of New Entry	250.05	245.18	236.66	247.40	266.27	243.95	256.90	230.99	228.82	228.44	266.68

- Auction Clearing Prices shown in $/MW-Day
- Conduct Threshold is 10% of Cost of New Entry (CONE)

V. COAL INVENTORY

Q. Witness Lansford notes in his direct testimony that coal inventories during the test year are not representative of levels expected once rates set in this case take effect. Please explain.

A. Recent rail transportation challenges, which ultimately impact the volume of coal shipped, have impacted the volume of PRB coal received and coal-fired energy center inventories during the test year. More specifically, Ameren Missouri utilizes the Union Pacific Railroad to deliver coal to Labadie and Meramec Energy Centers, and the Burlington Northern Santa Fe Railway to deliver coal to Rush Island and Sioux Energy Centers. The quality of service on both railways has declined, as they respond to a post-Covid economic rebound, a recent surge in commodity prices and coal demand, and struggle to hire and retain crews in rural areas. Due to these circumstances, both railroads are experiencing slow system velocity, particularly for such an extended timeframe.

Q. What are the impacts of this railroad performance?

A. The low system velocity has caused one carrier to reduce a significant number of operating railcar sets from the Company's service, beginning March, 2022. Rush Island and Sioux Energy Centers both subsequently experienced a sharp decline in inventory, which was stabilized by coal conservation measures. The carrier for Labadie has also seen slow system velocity despite maintaining a consistent volume of railcar sets and, as a result, the Labadie coal inventory has slowly declined since September 2021, the end of the 13-month period used to establish the Company's revenue requirement in File No. ER-2021-0240.

The Company has regular discussions with both carriers regarding their performance improvement plans. Both carriers have also submitted recovery plans to the Surface Transportation Board, detailing their efforts to recruit and train workers and improve system velocities.

As such, the 13-month average of coal inventory levels, ending in March 2022, is not appropriate for use in establishing the Company's revenue requirement in this rate review, since that period is not representative of what we expect coal inventories to be when rates set in this case are in effect.

Q. What is the appropriate timeframe to use for averaging the coal inventory levels for purposes of establishing the revenue requirement in this rate case?

A. The Company recommends using the 13-month average ending September 30, 2021. This approach will exclude the coal transportation delivery challenges experienced thus far in 2022 which will extend through the true-up period. The 13-month average, ending September 2021, of the Company's total coal stockpile was 3,341,456 tons. In comparison, the 13-month average, ending March 2022, was 3,079,671 tons.

VI. OPERATIONS AT RUSH ISLAND

Q. Ameren Missouri has publicly announced the retirement of the Rush Island Energy Center. How is Rush Island modeled in PowerSimm for purposes of setting the net base energy costs you recommend in this case?

A. Witness Peters modeled the Rush Island station consistent with operating parameters reflected in the below-referenced recommendation to the District Court. These operating parameters were selected because we expect, starting later this year, that the operations at Rush Island will be different than they were historically, given the units' transition to retirement over the next two to three years.

Q. Why are the units transitioning to retirement?

A. As discussed in the testimony of Company witnesses Mark Birk and Matt Michels, the Company has announced the retirement of the Rush Island units in the next few years, since retirement is in the best interest of the Company's customers given the final outcome of the New Source Review litigation, which has been ongoing for many years. Based on this decision, the Company filed an Attachment Y retirement study request with MISO. The results of this retirement study determine whether the units could be retired as of the date specified in the study request (the request specified a retirement date of September 1, 2022), or if the units should remain in operation to ensure the reliability of the transmission system. If the units are required to maintain transmission system reliability, MISO will designate them as System Support Resources ("SSR") until such time that transmission upgrade projects needed to ensure grid reliability in the absence of the units are completed.

Q. What is the status of the Attachment Y request?

A. MISO's Attachment Y analysis determined that both Rush Island units should be designated as SSRs pending completion of several transmission system projects that are needed to ensure reliability post-Rush Island's retirement. The Attachment Y Report has been submitted to the Commission in File No. EO-2022-0215. We expect Rush Island to begin its operation as SSR on or around September 1 of this year.

Q. What transmission projects are necessary, and what is the expected timeframe for completing them?

A. Figure 7 identifies the transmission projects that are needed to address reliability concerns identified in MISO's Attachment Y report along with estimated completion dates based on planning estimates. The STATCOM devices require the longest lead time and vendor bids will provide estimated manufacturing and delivery dates. Such bids are expected after the filing date of my testimony.

Figure 7

Project	Estimated Completion Date
Installation of a Capacitor Bank at the Overton Substation to address voltage issues	Spring/Fall 2023
Replacement of a Transformer at the Wildwood Substation in St. Louis County to address overload concerns	Spring 2024
Upgrading of a bus bar tie position at a substation adjacent to Rush Island to address voltage issues	Spring/Fall 2023
Installation of four (4) STATCOMs in the St. Louis Metropolitan area to provide reactive power support; installations to occur as equipment becomes available 2024-2025	Final STATCOM Fall 2025, perhaps earlier

Q. How will the Rush Island units be operated as an SSR?

A. The precise details of how Rush Island will be operated are still being discussed with MISO and ultimately will be reflected in an SSR Agreement and operating guide. On July 29, 2022, Ameren Missouri filed with the District Court a Proposed Draft Order along with a declaration from Andrew Witmeier, Director of MISO's Resource Utilization group, that describes the general conditions under which Rush Island would operate, subject to the District Court's approval. A copy of the Proposed Draft Order is attached to my testimony as Schedule AMM-D4. The Proposed Draft Order describes how

Rush Island could be operated consistent with maintaining transmission system reliability, as determined by the Attachment Y study, pending completion of transmission system upgrades necessary for the system's reliability once Rush Island retires.[16] Ameren Missouri anticipates there will be significant periods when the units will not need to operate at full load, and times when neither unit will need to operate at all, absent an emergency or system reliability concerns identified by MISO. The District Court has set a hearing for August 17, 2022 to consider Ameren Missouri's proposal but based on our understanding of the reliability needs of the system we believe that the recommendation is reasonable, as is the production cost modeling underlying the revenue requirement submitted in this case. Once the District Court makes a final decision and to the extent operations vary in some way from our recommendation, we will capture any such difference in the true-up phase of the case.

Q. How were the operating parameters outlined in the recommendation to the District Court used in the preparation of the Company's case in this rate review?

A. As noted, the operating regime recommended to the District Court was modeled by witness Peters in support of the Company's PowerSimm production cost modeling, the output of which is used along with other non-modeled items like those discussed in my testimony to develop the Company's recommended net base energy costs.

VII. HIGH PRAIRIE CONSERVATION MITIGATION

Q. In his surrebuttal testimony in the ER-2021-0240 docket, Company witness Ajay Arora outlined steps being taken by the Company to test and ultimately implement mitigation measures to deter, detect, or avoid endangered bats at night during bat season

[16] See Affidavit of Tim Lafser filed June 8, 2022 in the United States District Court for the Eastern District of Missouri, Civil Action No. 4:11-cv-00077-RWS.

as a means to improve the year-round capacity factor at the High Prairie Energy Center. Please update the Commission on High Prairie's current operations.

A. As explained previously, the Company has elected to curtail High Prairie's operations at night, to avoid taking any additional protected bats covered under the Habitat Conservation Plan ("HCP"). The most recent voluntary curtailment began on March 21st of this year and, subject to some increased nighttime operations as we test the mitigation measures discussed in more detail below, is expected to continue through roughly the end of October. It should be noted, however, that all 175 turbines are operational and High Prairie is consistently producing energy and production tax credits and is providing 1.25 renewable energy credits ("RECs") for each megawatt-hour of energy produced that are being retired to comply with the Missouri Renewable Energy Standard.

Q. Please update the Commission on the status of the Company's efforts to implement technological applications designed to mitigate the impact of bats on the facility's long-term operations.

A. As generally described in Schedule AAR-S1 to witness Arora's surrebuttal testimony in File No. ER-2021-0240, Ameren Missouri has undertaken three distinct mitigation projects, the goal of which is to allow greater operation of the turbines at night during the bat season and thus increase production from the facility. The projects are as follows: (1) a Detection and Active Response Curtailment ("DARC") system; (2) a Bat Deterrent System; and (3) a Modeled Curtailment study.

Q. Please describe the DARC system.

A. The DARC system interfaces with the environment via 35 installed microphones, located strategically throughout the wind farm which are tuned to listen for bat echolocation calls.[17] The system then interfaces with the Vestas turbine control system. If bat calls are detected by the DARC system, it will send a pause command to the turbine control system, and the control system will automatically signal turbines to pitch the blades, or rotate the blades, so they no longer catch incoming wind. The affected turbines are then curtailed for 10 minutes and, assuming additional bat calls are not detected, the turbines are then put back into production mode. The system is thus designed to only curtail turbine operation at night during the bat season as needed to avoid taking bats, but otherwise allows the turbines to generate electricity.

Q. What is the status of implementing the DARC system?

A. The installation of microphones is complete, the DARC server has been installed, and virtual testing of the DARC system to confirm functionality of the logic has been completed. More specifically, we have virtually operated the DARC system at night as if the turbines were running to see if it accurately detected bats and sent the proper signal to the turbines. The virtual testing was successful, and the system is operating as designed. The Company is now working to ensure a reliable communication link between the DARC system and the Vestas control system. Development of a SCADA[18] screen, or similar tool, to monitor the DARC system operation is still being finalized and tested. However, all bat loggers are now communicating, and bat calls are being logged.

We expect to begin live operation of the DARC system soon, starting with the operation of one turbine at night. After we collect data from that turbine's nighttime operation, we will incrementally start operating additional turbines at night through the remainder of bat season

[17] During the initial testing phase of the system, we are operating the system based on bat calls from all bat types but as we refine the system it would operate only when it detects bat calls from species covered by the facility's Habitat Conservation Plan.
[18] Supervisory Communications and Data Acquisition system.

this year and into the beginning of the bat season in spring of 2023. Specifically, we intend to expand use of the DARC system to ten turbines operated at 30 days after the first turbine was operated, then increase the operation to 20 turbines two weeks after that, with continued incremental increases in the number of turbines operated at night. The plan is to expand use of the DARC system to 90 turbines by mid-April, 2023.

Q. Will further tuning of the DARC system be possible after live operation begins?

A. Yes, there will be some operational improvements initiated as part of the test plan, but the goal of the program is continued refinement designed to increase energy center production. The initial deployment of the DARC system will trigger curtailments for *any* bat calls detected by the microphones. The first improvement involves only curtailing the testing turbines when bat calls are detected by microphones in a defined zone surrounding the testing turbines. In addition, curtailment instructions will be tuned to be triggered by sound above 21 kilohertz (kHz), thus filtering out noise at slightly lower frequencies than that of echolocation calls. Further refinement of curtailment frequencies, or more narrowly-focused turbine curtailment, would only occur after technical reviews and risk evaluations have taken place.

Q. Please provide details of the second project, the Bat Deterrent System.

A. The Bat Deterrent System uses constant ultrasonic noise to create an acoustic field in the same frequency range as the bat calls. When a bat enters the airspace where the deterrent units are operating, the ultrasound from the deterrent units will interfere with the echo return the bat is listening for. This makes it difficult for the bat to forage and orient itself, prompting it to choose airspace without the ultrasonic noise and away from the turbine's rotor swept zone.

Q. What is the status of the Company's implementation of the Bat Deterrent System?

A. Ultrasonic equipment is in place at 15 turbine nacelles, and 5 additional ultrasonic units have been mounted lower on select towers. We will evaluate the system's effectiveness for the remainder of the 2022 bat season by using thermal cameras to monitor turbines with and without deterrents installed. We will compare the quantity of bat passes in the cameras' fields of view with the deterrents on, versus with them off. This comparison will aid in determining the effectiveness of the two deterrent approaches; nacelle-only or a combination of nacelle and lower mounted deterrents (the combination covers more of the Rotor Swept Zone). If the system proves effective, we expect to expand use of the ultrasonic equipment to additional turbines.

Q. **You mentioned a third project, a modeled curtailment study. What is modeled curtailment?**

A. Modeled curtailment involves curtailing wind turbines based on real time weather conditions when bats are known to be active, using logic developed from a study of site-specific data derived from a minimum period of one full bat season. The model curtailment describes the conditions under which bats are active and thus can help inform operational decisions (favorable conditions for bats = high risk to operate) and allows us to understand bat activity specifically at our site.

Q. What is the status of the modeled curtailment system study?

A. We are gathering appropriate data through the end of this year's bat season. Data on bat activity is being collected from 20 different turbine locations with 2 acoustic monitors at each turbine, one at nacelle height and one mounted on the tower at a 26-meter height, as well as from 12 thermal cameras. Additionally, weather data such as ambient temperatures, wind speed, precipitation, etc., will be collected from the existing meteorological towers at site and ground weather stations at each thermal camera. Also, two Light Detecting and Ranging ("LIDAR") units will be deployed to collect data on wind profiles at different elevations.

Q. More specifically, what will be done with the data?

A. We will use the data collected from the study to correlate weather information, wind data, and other environmental conditions to bat activity at High Prairie. The results of the study will provide information related to the risk of bat take for various ambient conditions, specifically for the covered species under the HCP. The results of this study are expected in 2023. Based on the study, our consultants will develop curtailment action logic and design the modeled curtailment system for future bat activity seasons.

Q. Are the three projects intended to work together?

A. Ultimately, yes. The efficacy of the first two projects will be evaluated through the remainder of the 2022 bat season and into the early part of the spring of 2023 and as noted, data for the modeled curtailment system is being collected as well. We will carefully study the performance of the first two systems to make decisions on how we will operate prospectively after that. We will refine the role of the first two projects during the 2023 bat season and, we would currently expect to use a combination of all three mitigation measures by 2024. We will continue refinement of these measures as we gain additional operating experience and collect more data, with the goal of improving production over time.

Q. Is it premature to estimate the impact of these measures on the facility's production?

A. Yes. We cannot speculate on what the facility's ultimate production will be until we have fully studied, tested, and implemented these measures since we are in the early stages of those efforts.

As was done for the trued-up revenue requirement established in the settlement of File No. ER-2021-0240, we have modeled High Prairie production at a level that is greater than if we were to continue all nighttime voluntary curtailments during bat season but that is less than full, un-curtailed operations. Specifically, and consistent with the normalization practice utilized in the true up period in File No. ER-2021-0240, the output of High Prairie was modeled by Company witness Peters using a 50%/50% average of two operating profiles. These two profiles are the original operating profile, from the High Prairie project's inception, and an alternate profile that reflects the voluntary bat curtailments of the generators to mitigate bat fatalities, that was in place for the summer/early fall periods of 2021.

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 Adjust Its Revenues for Electric Service.	)))	Case No. ER-2022-0337

AFFIDAVIT OF ANDREW MEYER

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

Andrew Meyer, being first duly sworn states:

My name is Andrew Meyer, and on my oath declare that I am of sound mind and lawful age; that I have prepared the foregoing *Direct Testimony*; and further, under the penalty of perjury, that the same is true and correct to the best of my knowledge and belief.

/s/ Andrew Meyer
Andrew Meyer

Sworn to me this 1st day of August, 2022.