Exhibit No. 36

Ameren Missouri – Exhibit 36
Andrew Meyer
Surrebuttal Testimony
File Nos. ER-2021-0240 & GR-2021-0241

Exhibit No.:	036
Issue(s):	Fuel Adjustment Clause
Witness:	Andrew Meyer
Type of Exhibit:	Rebuttal Testimony
Sponsoring Party:	Union Electric Company
File No.:	ER-2021-0240
Date Testimony Prepared:	November 5, 2021

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2021-0240

SURREBUTTAL TESTIMONY

OF

ANDREW MEYER

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
November 5, 2021

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SURREBUTTAL TESTIMONY

OF

ANDREW MEYER

FILE NO. ER-2021-0240

I. INTRODUCTION

Q. Please state your name and business address.

A. Andrew Meyer, Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company"), One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. Are you the same Andrew Meyer that filed direct and rebuttal testimony in this proceeding?

A. Yes, I am.

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

A. I will address issues raised in the rebuttal testimonies of the Office of the Public Counsel ("OPC") witness Lena Mantle and Staff witness Brooke Mastrogiannis relating to the Company's Fuel Adjustment Clause ("FAC").

II. RESPONSE TO MS. MANTLE'S REBUTTAL TESTIMONY

Q. Please address the first of Ms. Mantle's three recommendations.

A. Essentially, Ms. Mantle indicates that the changes the Company requested to its Purchased Gas Adjustment ("PGA") tariff arising from the impact of Winter Storm Uri last February on its natural gas costs prompted her to recommend an FAC tariff change. The change could become relevant if an extraordinary event were to impact net energy costs in the FAC in an extraordinary way like Winter Storm Uri affected natural gas costs.

Q. Does the Company agree with Ms. Mantle's recommendation?

A. Conceptually, yes. However, her proposed tariff provision should be modified to improve clarity and to make sure that it properly focuses on situations where the Commission determines that the impact of an extraordinary event warrants delaying the Company's cash flows, and increasing financing costs for customers caused by extending the recovery period in certain circumstances under the FAC. Set forth below is Ms. Mantle's proposed language, but with changes necessary to accomplish these objectives:[1]

> **Notwithstanding that an** ~~When~~ extraordinary **event has occurred that results in an impact to actual net energy costs** ~~net costs have been incurred~~ in an accumulation period, for good cause **shown,** the **Company may (subject to** Commission **approval** ~~may allow~~ (after **an** opportunity for **comment from** any party ~~to be heard~~) **defer** ~~the~~ recovery ~~period to extend~~ beyond eight months**, and up to twenty-four months, upon a finding that the magnitude of the impact on customers of recovering the difference between actual net energy costs and net base energy costs for that accumulation period should be mitigated.** The **difference** ~~amount~~ not recovered **within the eight-month recovery period applicable to the accumulation period at issue** will be added to subsequent recovery periods **until recovered** with a true-up ~~for the extraordinary cost~~ at the end of the Commission approved **extended** recovery ~~time~~ period ~~for the extraordinary cost~~.[2]

Q. Please explain in more detail the reasons for your suggested modifications.

A. Consistent with the recent PGA tariff changes, the trigger for the Commission's possible use of this provision is the occurrence of an extraordinary *event* that in turn causes an *impact* on the net energy costs in the FAC that the Commission determines *warrants mitigation* by extending the recovery period. Not all extraordinary events that may impact a cost element in

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[1] **Bold/underline material added to Ms. Mantle's proposal**; ~~Stricken material deleted.~~ The Company has also modeled this after an Actual Cost Adjustment ("ACA") tariff provision submitted in in File no. GT-2022-0031 that allows an extension of the ACA recovery period by up to 36 months (three times the default 12 months). The ACA tariff revision took effect on September 24, 2021. See *Notice That Tariff Will Be Allowed to Go into Effect,* issued by the Commission on September 23, 2021. Here, we have set the extended period at a maximum of 24 months, which is also three times the default eight month recovery period under the FAC.

[2] File No. ER-2021-0240, Rebuttal Testimony of Lena Mantle, p. 1, ll. 20-24, p. 2, ll. 1-2.

the FAC warrant mitigation. For example, it could be that an extraordinary event occurs that causes a very significant spike in a cost tracked in the FAC, but there could be other factors in that same accumulation period that overall, the difference between actual net energy costs and net base energy costs is not significant enough to warrant delaying recovery and causing customers to ultimately pay more due to financing costs. The revised language thus focuses on events that have an impact of sufficient magnitude to warrant extension of the recovery period. My reading of Ms. Mantle's reasons for suggesting a change suggests to me that this is what she was aiming for in making the recommendation.

Q. What is Ms. Mantle's second recommendation?

A. Ms. Mantle expands on, or clarifies a recommendation made in her direct testimony and a similar recommendation made by the Staff in its Cost of Service Report regarding basemat coal. I responded to both recommendations in my rebuttal testimony. The difference in Ms. Mantle's recommendation now is that she desires to expand a prohibition on including "decommissioning costs" in the FAC beyond just basemat coal and she clarifies that she desires the recommendation to apply to all energy centers, not just the Meramec Energy Center, which will retire next year.[3]

Q. What is the Company's position on Ms. Mantle's expanded second recommendation?

A. The language proposed in Schedule AMM-R1 to my rebuttal testimony already properly addresses the issue Ms. Mantle is raising. That language is not limited to just the Meramec plant. It also already covers the only "decommissioning costs" that would be eligible for recovery

[3] File No. ER-2021-0240, Rebuttal Testimony of Lena Mantle, p. 3, ll. 6-9

in the FAC as fuel or power costs/revenues. Consequently, additional language is unnecessary.

Q. It is clear that the language you proposed is by its terms not limited to just the Meramec plant, but please explain why it already covers any decommissioning costs.

A. Costs to dismantle, secure, remediate, etc. a power plant once it closes does not fit the definitions of fuel, purchased power, off-system sales, or transportation provided for in the Company's Rider FAC or the Commission's FAC rules, *except that* the accounting for basemat coal would ordinarily be included in fuel costs. We agreed (and provided language that) the basemat coal costs should be excluded as long as a proper deferral occurs as is the practice employed with other utilities in the state.

Q. Why not just add something that says "no decommissioning costs ever"?

A. Because (a) it is improper to include language excluding a myriad of costs that are not eligible for the FAC in the first place; (b) such a provision is not necessary, for the reasons I just explained; and (c) such language may lead to confusion later. Let me explain why. In a case where useable fuel (not basemat coal but, e.g., <u>useable</u> coal in the coal pile) remains at the site of a plant that ceases operation at the time of the cessation, that fuel has value either for consumption at another plant that is still operating or by selling it for use by another entity. Today, if Ameren Missouri had to move coal from one plant to another, or if Ameren Missouri sold coal that it did not need, the coal and coal transportation costs for that coal would properly be included in the FAC.[4] Such fuel would also have value if a plant were to cease operations (e.g., unexpectedly due to damage to a major component that cannot be economically repaired). However, would someone

[4] Coal deliveries to one plant could be disrupted for some reason requiring coal from a different plant to be moved to the plant with the disruption, or fuel burn could be down significantly creating an excess of coal that can be sold economically for the benefit of customers.

attempt to claim that costs associated with that coal have now become a "decommissioning cost" if the coal happens to be at a plant that ceases operation?

Q. Please address Ms. Mantle's third recommendation.

A. Essentially, Ms. Mantle wants to be sure that all Renewable Energy Standard ("RES") benefits are included in the Company's RESRAM mechanism since all RES compliance costs are eligible for recovery in the RESRAM. Conceptually, I agree with Ms. Mantle's main point.

Q. How did the issue arise?

A. The Company established its RESRAM in 2018, outside of a general rate proceeding. Its existing FAC tariff was in place at that time. FAC's cannot be changed outside a general rate proceeding and under the FAC, energy and capacity revenues generated by a RES compliance asset were required to be reflected in the FAC. The Company (and the other parties to the docket where the RESRAM was established) recognized this, but also recognized that the sharing mechanism in the FAC would mean that 5% of the benefit of those energy and capacity revenues would not be passed on to customers. To remedy that issue, the Company proposed and the Commission approved a variance to the rules governing RESRAM's that allowed the energy and capacity benefits from the RES compliance assets to remain in the FAC and approved a mechanism that captured the 5% of benefits and passed them back to customers in the RESRAM. The end result was that customers got 100% of the RES-related benefits.

Q. Is Ms. Mantle recommending a continuation of that approach?

A. Her preferred recommendation is to include all RES-related costs and benefits in the RESRAM, and I agree that this is the preferred approach. As noted earlier, that was not an option until we had a rate review to rebase net base energy costs and to make changes to the FAC tariff, but since we are in a rate review at this time, we can implement such a solution now.

Q. What is necessary to implement that solution?

A. The implementation is relatively easy. Essentially, we need to modify the FAC tariff to exclude any RES compliance costs and benefits (energy and capacity revenues from the RES compliance projects) from the FAC. The RESRAM itself already provides for inclusion of RES compliance costs and RES benefits so it needs no modification. I have included the FAC tariff modifications necessary in Schedule AMM-S1 to my surrebuttal testimony. That schedule also includes the language set out above relating to extraordinary events.[5]

III. RESPONSE TO STAFF WITNESS MASTROGIANNIS' REBUTTAL TESTIMONY

Q. Are there any areas of disagreement between the Company and the Staff reflected in Ms. Mastrogiannis' rebuttal testimony?

A. Perhaps, but I should note that Ms. Mastrogiannis indicated the Staff had no opposition to several of the Company's proposed FAC tariff changes as outlined in my direct testimony. The one area of disagreement I already addressed in my rebuttal testimony — is that the Company and the Staff have not yet agreed on the percentage of transmission costs/revenues to include in the FAC or on the summer and winter base factors. However, I do not believe the disagreement is substantive and instead believe it is simply a function of the need to true-up the components of those items through September 30, 2021. With respect to transmission costs/revenues, we have used the true-up data and recalculated the percentage using the same approach historically approved by the Commission and agreed upon by Staff, resulting in a

[5] Schedule AMM-S1 is identical to Schedule AMM-R1 attached to my rebuttal testimony, except that I have highlighted in green the two additional changes discussed in my surrebuttal testimony, leaving the changes proposed in my rebuttal testimony highlighted in yellow, as I did in rebuttal testimony Schedule AMM-R1.

percentage of 1.85%. With respect to the base factors, we have also recalculated those factors as of the true-up, resulting in a summer base factor of 1.320 cents per kilowatt-hour and a winter base factor of 1.186 cents per kilowatt-hour. The above figures are included in Schedule AMM-R1.

Q. Ms. Mastrogiannis also comments on OPC's direct testimony relating to the basemat issue you discussed earlier, and to the research and development project which was also the topic of both Staff's Cost of Service Report and Ms. Mantle's direct testimony. Ms. Matrogiannis indicates Staff does not oppose Ms. Mantle's position on those two issues. What is the Company's position?

A. I addressed both issues in my rebuttal testimony, and the Company's position on them remains the same as expressed in my rebuttal testimony. Regarding the research and development project, Staff agreed on exactly how the FAC tariff was to be changed in the stipulation discussed in my rebuttal testimony – and that was approved by the Commission. OPC did not object to that stipulation and under the Commission's rules, it is thus treated as a unanimous stipulation. No further FAC changes on this topic should be made in this case, as they would be outside those agreements. With respect to the basemat coal issue, I addressed it in both my rebuttal testimony and in my surrebuttal testimony above.

Q. Were there any other issues of note in Ms. Mastrogiannis' rebuttal testimony?

A. She did indicate an openness to a stakeholder meeting regarding the extraordinary event issue I addressed earlier. Given that the Company is agreeable to an FAC tariff change as set out above, a stakeholder meeting would not be necessary.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

UNION ELECTRIC COMPANY ELECTRIC SERVICE

MO.P.S.C. SCHEDULE NO. 6 Original SHEET NO. 71.16

CANCELLING MO.P.S.C. SCHEDULE NO. SHEET NO.

APPLYING TO **MISSOURI SERVICE AREA**

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

APPLICABILITY

This rider is applicable to kilowatt-hours (kWh) of energy supplied to customers served by the Company under Service Classification Nos. 1(M), 2(M), 3(M), 4(M), 5(M), 6(M), 11(M), and 12(M).

Costs passed through this Fuel and Purchased Power Adjustment Clause (FAC) reflect differences between actual fuel and purchased power costs, including transportation and emissions costs and revenues, net of off-system sales revenues (OSSR) (i.e., Actual Net Energy Costs (ANEC)) and Net Base Energy Costs (B), calculated and recovered as provided for herein.

The Accumulation Periods and Recovery Periods are as set forth in the following table:

Accumulation Period (AP)	Recovery Period (RP)
February through May	October through May
June through September	February through September
October through January	June through January

AP means the four (4) calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purposes of determining the Fuel Adjustment Rate (FAR).

RP means the calendar months during which the FAR is applied to retail customer usage on a per kWh basis, as adjusted for service voltage. Notwithstanding that each RP covers a period of eight months, when an extraordinary an event has occurred that results in an impact to actual net energy costs in an accumulation period, for good cause shown, the Company may (subject to Commission approval after an opportunity for comment from any party) defer recovery beyond eight months, and up to 24 months, upon a finding that the magnitude of the impact on customers of recovering the difference between actual net energy costs and net base energy costs for that accumulation period should be mitigated. The difference not recovered within the eight-month recovery period applicable to the accumulation period at issue will be added to subsequent recovery periods until recovered with a true-up at the end of the Commission approved extended recovery period.

The Company will make a FAR filing no later than sixty (60) days prior to the first day of the applicable Recovery Period above. All FAR filings shall be accompanied by detailed workpapers supporting the filing in an electronic format with all formulas intact.

DATE OF ISSUE March 31, 2021 DATE EFFECTIVE April 30, 2021

ISSUED BY Martin J. Lyons Chairman & President St. Louis, Missouri
NAME OF OFFICER TITLE ADDRESS

FAR DETERMINATION

Ninety five percent (95%) of the difference between ANEC and B for each respective AP will be utilized to calculate the FAR under this rider pursuant to the following formula with the results stated as a separate line item on the customers' bills.

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FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
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FAR DETERMINATION (Cont'd.)

For each FAR filing made, the FAR_{RP} is calculated as:

$$FAR_{RP} = [(ANEC - B) \times 95\% \pm I \pm P \pm TUP]/S_{RP}$$

Where:

ANEC = FC + PP + E ± R – OSSR

FC = Fuel costs and revenues associated with the Company's generating plants consisting of the following:

1) For fossil fuel plants:

A. the following costs and revenues (including applicable taxes) arising from steam plant operations recorded in FERC Account 501: coal commodity, gas, alternative fuels, Btu adjustments assessed by coal suppliers, quality adjustments related to the sulfur content of coal assessed by coal suppliers, railroad transportation, switching and demurrage charges, railcar repair and inspection costs, railcar depreciation, railcar lease costs, similar costs associated with other applicable modes of transportation, fuel hedging costs, fuel oil adjustments included in commodity and transportation costs, fuel additive costs included in commodity or transportation costs, oil costs, ash disposal costs and revenues, and expenses resulting from fuel and transportation portfolio optimization activities; provided that costs otherwise included in the foregoing associated with coal remaining at a coal plant after the coal plant ceases coal-fired generation shall be excluded from Factor FC and instead deferred on the Company's books to a regulatory asset for consideration of recovery in a general rate proceeding over a reasonable amortization period as determined by the Commission;

B. the following costs and revenues reflected in FERC Account 502 for: consumable costs related to Air Quality Control System (AQCS) operation, such as urea, limestone, and powder activated carbon; and

C. the following costs and revenues (including applicable taxes) arising from non-steam plant operations recorded in FERC Account 547: natural gas generation costs related to commodity, oil, transportation, storage, capacity reservation, fuel losses, hedging, and revenues and expenses resulting from fuel and transportation portfolio optimization activities, but excluding fuel costs related to the Company's landfill gas generating plant known as Maryland Heights Energy Center; and

2) The following costs and revenues (including applicable taxes) arising from nuclear plant operations, recorded in FERC Account 518: nuclear fuel commodity expense, waste disposal expense, and nuclear

fuel hedging costs.

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APPLYING TO **MISSOURI SERVICE AREA**

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

PP = Purchased power costs and revenues and consists of the following:

1) The following costs and revenues for purchased power reflected in FERC Account 555, excluding (a) amounts associated with the subscribed portions of Power Purchase Agreements dedicated to specific customers under the Renewable Choice Program tariff or any subsequent renewable subscription program that is approved by the Commission in an order that acknowledges that such program's impacts should be excluded from Factor PP,(b) all charges under Midcontinent Independent System Operator, Inc. ("MISO") Schedules 10, 16, 17 and 24 (or any successor to those MISO Schedules), (c) generation capacity charges for contracts with terms in excess of one (1) year, (d) amounts associated with energy purchased from the MISO market to serve digital currency mining by the Company, and (e) amounts for Renewable Energy Standard compliance that are included in Rider RESRAM. Such costs and revenues include:

A. MISO costs or revenues for MISO's energy and operating reserve market settlement charge types and capacity market settlement clearing costs or revenues associated with:

i. Energy;

ii. Losses;

iii. Congestion management:
   a. Congestion;
   b. Financial Transmission Rights; and
   c. Auction Revenue Rights;

iv. Generation capacity acquired in MISO's capacity auction or market; provided such capacity is acquired for a term of one (1) year or less;

v. Revenue sufficiency guarantees;

vi. Revenue neutrality uplift;

vii. Net inadvertent energy distribution amounts;

viii. Ancillary Services:
   a. Regulating reserve service (MISO Schedule 3, or its successor);
   b. Energy imbalance service (MISO Schedule 4, or its successor);
   c. Spinning reserve service (MISO Schedule 5, or its successor);and
   d. Supplemental reserve service (MISO Schedule 6, or its successor); and

ix. Demand response:
   a. Demand response allocation uplift; and
   b. Emergency demand response cost allocation (MISO Schedule

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30, or its successor);

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FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
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FAR DETERMINATION (Cont'd.)

B. Non-MISO costs or revenues as follows:
   i. If received from a centrally administered market (e.g. PJM/SPP), costs or revenues of an equivalent nature to those identified for the MISO costs or revenues specified in subpart A of part 1 above;

   ii. If not received from a centrally administered market:
      a. Costs for purchases of energy; and
      b. Costs for purchases of generation capacity, provided such capacity is acquired for a term of one (1) year or less; and

C. Realized losses and costs (including broker commissions and fees) minus realized gains for financial swap transactions for electrical energy that are entered into for the purpose of mitigating price volatility associated with anticipated purchases of electrical energy for those specific time periods when the Company does not have sufficient economic energy resources to meet its native load obligations, so long as such swaps are for up to a quantity of electrical energy equal to the expected energy shortfall and for a duration up to the expected length of the period during which the shortfall is expected to exist.

2) One and _85/100 percent (1.85%) of transmission service costs reflected in FERC Account 565 and one and 85/100 percent (1.85%) of transmission revenues reflected in FERC Account 456.1 (excluding (a) amounts associated with the subscribed portions of Purchased Power Agreements dedicated to specific customers under the Renewable Choice Program tariff or any subsequent renewable subscription program that is approved by the Commission in an order that acknowledges that such program's impacts should be excluded from this Factor PP, (b) costs or revenues under MISO Schedule 10, or any successor to that MISO Schedule), and (c) for Renewable Energy Standard compliance included in Rider RESRAM . Such transmission service costs and revenues included in Factor PP include:

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FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
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FAR DETERMINATION (Cont'd.)

3)A. MISO costs and revenues associated with:

i. Network transmission service (MISO Schedule 9 or its successor);

ii. Point-to-point transmission service (MISO Schedules 7 and 8 or their successors);

iii. System control and dispatch (MISO Schedule 1 or its successor);

iv. Reactive supply and voltage control (MISO Schedule 2 or its successor);

v. MISO Schedule 11 or its successor;

vi. MISO Schedules 26, 26A, 26C, 26D, 37 and 38 or their successors;

vii. MISO Schedule 33; and

viii. MISO Schedules 41, 42-A, 42-B, 45 and 47;

B. Non-MISO costs and revenues associated with:

i. Network transmission service;

ii. Point-to-point transmission service;

iii. System control and dispatch; and

iv. Reactive supply and voltage control.

E = Costs and revenues for SO_2 and NO_X emissions allowances in FERC Accounts 411.8, 411.9, and 509, including those associated with hedging.

R = Net insurance recoveries for costs/revenues included in this Rider FAC (and the insurance premiums paid to maintain such insurance), and subrogation recoveries and settlement proceeds related to costs/revenues included in this Rider FAC.

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FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

OSSR = Costs and revenues in FERC Account 447 (excluding (a) amounts associated with portions of Power Purchase Agreements dedicated to specific customers under the Renewable Choice Program tariff or any subsequent renewable subscription program that is approved by the Commission in an order that acknowledges that such program's impacts should be excluded from Factor OSSR, (b) amounts associated with generation assets dedicated, as of the date BF was determined, to specific customers under the Renewable Choice Program tariff or any subsequent renewable subscription program that is approved by the Commission in an order that acknowledges that such program's impacts should be excluded from Factor OSSR, (c) amounts associated with generation assets that began commercial operation after the date BF was determined and that were dedicated to specific customers under the Renewable Choice Program tariff or any subsequent renewable subscription program that is approved by the Commission in an order that acknowledges that such program's impacts should be excluded from Factor OSSR when it began commercial operation, or (d) for Renewable Energy Standard compliance included in Rider RESRAM) for:

1. Capacity;
2. Energy;
3. Ancillary services, including:
   A. Regulating reserve service (MISO Schedule 3, or its successor);
   B. Energy Imbalance Service (MISO Schedule 4, or its successor;
   C. Spinning reserve service (MISO Schedule 5, or its successor); and
   D. Supplemental reserve service (MISO Schedule 6, or its successor);
4. Make-whole payments, including:
   A. Price volatility; and
   B. Revenue sufficiency guarantee; and
5. Hedging.

For purposes of factors FC, E, and OSSR, “hedging” is defined as realized losses and costs (including broker commissions and fees associated with the hedging activities) minus realized gains associated with mitigating volatility in the Company’s cost of fuel, off-system sales and emission allowances, including but not limited to, the Company’s use of futures, options and over-the-counter derivatives including, without limitation, futures contracts, puts, calls, caps, floors, collars, and swaps.

UNION ELECTRIC COMPANY ELECTRIC SERVICE

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APPLYING TO **MISSOURI SERVICE AREA**

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FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
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FAR DETERMINATION (Cont'd.)

Should FERC require any item covered by factors FC, PP, E or OSSR to be recorded in an account different than the FERC accounts listed in such factors, such items shall nevertheless be included in factor FC, PP, E or OSSR. In the month that the Company begins to record items in a different account, the Company will file with the Commission the previous account number, the new account number and what costs or revenues that flow through this Rider FAC are to be recorded in the account.

B = BF x S_{AP}

BF = The Base Factor, which is equal to the normalized value for the sum of allowable fuel costs (consistent with the term FC), plus cost of purchased power (consistent with the term PP), and emissions costs and revenues (consistent with the term E), less revenues from off-system sales (consistent with the term OSSR) divided by corresponding normalized retail kWh as adjusted for applicable losses. The normalized values referred to in the prior sentence shall be those values used to determine the revenue requirement in the Company's most recent rate case. The BF applicable to June through September calendar months (BF_{SUMMER}) is $1.320 per kWh. The BF applicable to October through May calendar months (BF_{WINTER}) is $1.186 per kWh.

S_{AP} = kWh during the AP that ended immediately prior to the FAR filing, as measured by taking the most recent kWh data for the retail component of the Company's load settled at its MISO CP node (AMMO.UE or successor node), but excluding kWh for digital currency mining operations by the Company, plus the metered net energy output of any generating station operating within its certificated service territory as a behind the meter resource in MISO, the output of which served to reduce the Company's load settled at its MISO CP node (AMMO.UE or successor node).

S_{RP} = Applicable RP estimated kWh representing the expected retail component of the Company's load settled at its MISO CP node (AMMO.UE or successor node) but excluding kWh for digital currency mining operations by the Company, plus the metered net energy output of any generating station operating within its certificated service territory as a behind the meter resource in MISO, the output of which served to reduce the Company's load settled at its MISO CP node (AMMO.UE or successor node).

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RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

I = Interest applicable to (i) the difference between ANEC and B for all kWh of energy supplied during an AP until those costs have been recovered;

(ii) refunds due to prudence reviews ("P"), if any; and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the true-up filings ("TUP") provided for herein. Interest shall be calculated monthly at a rate equal to the weighted average interest rate paid on the Company's short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence.

P = Prudence disallowance amount, if any, as defined below.

TUP = True-up amount as defined below.

The FAR, which will be multiplied by the Voltage Adjustment Factors (VAF) set forth below is calculated as:

FAR = The lower of (a) PFAR and (b) RAC.

where:

FAR = Fuel Adjustment Rate applied to retail customer usage on a per kWh basis starting with the applicable Recovery Period following the FAR filing.

FAR_{RP} = FAR Recovery Period rate component calculated to recover under- or over-collection during the Accumulation Period that ended immediately prior to the applicable filing.

$FAR_{(RP-1)}$ = FAR Recovery Period rate component for the under- or over-collection during the Accumulation Period immediately preceding the Accumulation Period that ended immediately prior to the application filing for FAR_{RP}.

PFAR = The Preliminary FAR, which is the sum of FAR_{RP} and $FAR_{(RP-1)}$

RAC = Rate Adjustment Cap: applies to the FAR rate and shall apply so long as the rate caps provided for by Section 393.1655, RSMo. are in effect, and shall be calculated by multiplying the rate as determined under Section 393.1655.4 by the 2.85% Compound Annual Growth Rate compounded for the amount of time in days that has passed since the effective date of rate schedules published to effectuate the Commission's Order that approved the Stipulation and Agreement that resolved File No. ER-2016-0179, and subtracting the then-current RESRAM rate under Rider RESRAM and the average base rate determined from the most recent general rate proceeding as calculated pursuant to Section 393.1655, and dividing that result by the weighted average voltage adjustment factor 1.0455%.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
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FAR DETERMINATION (Cont'd.)

The Initial Rate Component For the Individual Service Classifications shall be determined by multiplying the FAR determined in accordance with the foregoing by the following Voltage Adjustment Factors (VAF):

Secondary Voltage Service (VAF_{SEC})	1.0539
Primary Voltage Service (VAF_{PRI})	1.0222
High Voltage Service (VAF_{HV})	1.0059
Transmission Voltage Service (VAF_{TRANS})	0.9928

Customers served by the Company under Service Classification No. 11(M), Large Primary Service, shall have their rate capped such that their FAR_{LPS} does not exceed RAC_{LPS}, where

RAC_{LPS} = Rate Adjustment Cap Applicable to LPS Class: applies to the FAR rate applicable to customers in the LPS class and shall apply so long as the rate caps provided for by Section 393.1655, RSMo. are in effect, and shall be calculated by multiplying the class average overall rate as determined under Section 393.1655.6 by the 2.00% Compound Annual Growth Rate compounded for the amount of time that has passed in days since the effective date of rate schedules published to effectuate the Commission's Order that approved the Stipulation and Agreement that resolved File No. ER-2016-0179, and subtracting the then-current RESRAM rate under Rider RESRAM and the class average base rate determined from the most recent general rate proceeding as calculated pursuant to Section 393.1655.

FAR_{LPS} = The lesser of (a) the Combined Initial Rate Component for RAC_{LPS} Comparison or (b) RAC_{LPS}.

Combined Initial Rate Component for RAC_{LPS} Comparison = The sum of the products of each of the Primary, High Voltage, and Transmission Initial Rate Components for the Individual Service Classifications and the applicable LPS Weighting Factors (WF):

Primary Voltage LPS Weighting Factor (WF_{PRI})	0.1587
High Voltage LPS Weighting Factor (WF_{HV})	0.3967
Transmission Voltage LPS Weighting Factor (WF_{TRANS})	0.4446

The Weighting Factors are the ratios between each voltage's annual kWh and total annual LPS kWh. The above Combined Initial Rate Component is developed for the purposes of determining if the statutory RAC_{LPS} has been exceeded, and if it has, calculating the FAR Shortfall Adder to be applied across all non-LPS service classifications in the immediately concluded AP.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

Where the Combined Initial Rate Component for RAC_{LPS} Comparison is greater than FAR_{LPS}, then a Per kWh FAR Shortfall Adder shall apply to each of the respective Initial Rate Components to be determined as follows:

Per kWh FAR Shortfall Adder = (((Combined Initial Rate Component For RAC_{LPS} Comparison – FAR_{LPS}) x SLPS) / (SRP – SRP-LPS))

Where:

SLPS	=	Estimated Recovery Period LPS kWh sales at the retail meter
SRP-LPS	=	Estimated Recovery Period LPS kwh sales at the Company’s MISO CP Node (AMMO.UE or successor node)

The FAR Applicable to the Non-LPS Individual Service Classifications shall be determined as follows:

FARSEC	=	Initial Rate Component For Secondary Customers + (Per kWh FAR Shortfall Adder x VAFSEC)
FARPRI	=	Initial Rate Component For Primary Customers + (Per kWh FAR Shortfall Adder x VAFPRI)
FARHV	=	Initial Rate Component For High Voltage Customers + (Per kWh FAR Shortfall Adder x VAFHV)
FARTRANS	=	Initial Rate Component For Transmission Customers + (Per kWh FAR Shortfall Adder x VAFTRANS)

The FAR Applicable to the LPS Individual Service Classifications shall be determined as follows:

LPSFARPRI	=	Initial Rate Component For Primary Customers x LPS RAC Cap Multiplier
LPSFARHV	=	Initial Rate Component For High Voltage Customers x LPS RAC Cap Multiplier
LPSFARTRANS	=	Initial Rate Component For Transmission Customers x LPS RAC Cap Multiplier

Where the LPS RAC Cap Multiplier is the FAR_{LPS} divided by the Combined Initial Rate Component for RAC_{LPS} Comparison.

The FAR applicable to the individual Service Classifications, including the calculations on Lines 24 through 29 of Rider FAC, shall be rounded to the nearest $0.00001 to be charged on a $/kWh basis for each applicable kWh billed.

TRUE-UP

After completion of each RP, the Company shall make a true-up filing on the same day as its FAR filing. Any true-up adjustments shall be reflected in TUP above. Interest on the true-up adjustment will be included in I above.

The true-up adjustments shall be the difference between the revenues billed and the revenues authorized for collection during the RP.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

GENERAL RATE CASE/PRUDENCE REVIEWS

The following shall apply to this FAC, in accordance with Section 386.266.4, RSMo. and applicable Missouri Public Service Commission Rules governing rate adjustment mechanisms established under Section 386.266, RSMo:

The Company shall file a general rate case with the effective date of new rates to be no later than four years after the effective date of a Commission order implementing or continuing this FAC. The four-year period referenced above shall not include any periods in which the Company is prohibited from collecting any charges under this FAC, or any period for which charges hereunder must be fully refunded. In the event a court determines that this FAC is unlawful and all moneys collected hereunder are fully refunded, the Company shall be relieved of the obligation under this FAC to file such a rate case.

Prudence reviews of the costs subject to this FAC shall occur no less frequently than every eighteen months, and any such costs which are determined by the Commission to have been imprudently incurred or incurred in violation of the terms of this rider shall be returned to customers. Adjustments by Commission order, if any, pursuant to any prudence review shall be included in the FAR calculation in P above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in I above.

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

FAC CHARGE TYPE TABLE

MISO Energy & Operating Reserve Market Settlement Charge Types and Capacity Market Charges and Credits

DA Asset Energy Amount;
DA Congestion Rebate on Carve-out GFA;
DA Congestion Rebate on Option B GFA;
DA Financial Bilateral Transaction Congestion Amount;
DA Financial Bilateral Transaction Loss Amount;
DA Loss Rebate on Carve-out GFA;
DA Loss Rebate on Option B GFA;
DA Non-Asset Energy Amount;
DA Ramp Capability Amount;
DA Regulation Amount;
DA Revenue Sufficiency Guarantee Distribution Amount;
DA Revenue Sufficiency Guarantee Make Whole Payment Amount;
DA Spinning Reserve Amount;
DA Supplemental Reserve Amount;
DA Virtual Energy Amount;
FTR Annual Transaction Amount;
FTR ARR Revenue Amount;
FTR ARR Stage 2 Distribution;
FTR Full Funding Guarantee Amount;
FTR Guarantee Uplift Amount;
FTR Hourly Allocation Amount;
FTR Infeasible ARR Uplift Amount;
FTR Monthly Allocation Amount;
FTR Monthly Transaction Amount;
FTR Yearly Allocation Amount;
FTR Transaction Amount;

RT Asset Energy Amount;
RT Congestion Rebate on Carve-out GFA;
RT Contingency Reserve Deployment Failure Charge Amount;
RT Demand Response Allocation Uplift Charge;
RT Distribution of Losses Amount;
RT Excessive Energy Amount;
RT Excessive\Deficient Energy Deployment Charge Amount;
RT Financial Bilateral Transaction Congestion Amount;
RT Financial Bilateral Transaction Loss Amount;
RT Loss Rebate on Carve-out GFA;
RT Miscellaneous Amount;
RT Ramp Capability Amount;
Real Time MVP Distribution;
RT Net Inadvertent Distribution Amount;
RT Net Regulation Adjustment Amount;
RT Non-Asset Energy Amount;
RT Non-Excessive Energy Amount;
RT Price Volatility Make Whole Payment;
RT Regulation Amount;
RT Regulation Cost Distribution Amount;
RT Resource Adequacy Auction Amount;
RT Revenue Neutrality Uplift Amount;
RT Revenue Sufficiency Guarantee First Pass Dist Amount;
RT Revenue Sufficiency Guarantee Make Whole Payment Amount;
RT Schedule 49 Distribution
RT Spinning Reserve Amount;
RT Spinning Reserve Cost Distribution Amount;
RT Supplemental Reserve Amount;
RT Supplemental Reserve Cost Distribution Amount;
RT Virtual Energy Amount;

MISO Transmission Service Settlement Schedules

MISO Schedule 1 (System control & dispatch);
MISO Schedule 2 (Reactive supply & voltage control);
MISO Schedule 7 & 8 (point to point transmission service);
MISO Schedule 9 (network transmission service);
MISO Schedule 11 (Wholesale Distribution);
MISO Schedules 26, 26A, 37 & 38 (MTEP & MVP Cost Recovery);
MISO Schedules 26-C & 26-D - (TMEP Cost Recovery);
MISO Schedule 33 (Black Start Service);

MISO Schedule 41 (Charge to Recover Costs of Entergy Strom Securitization);
MISO Schedule 42A (Entergy Charge to Recover Interest);
MISO Schedule 42B (Entergy Credit associated with AFUDC);
MISO Schedule 45 (Cost Recovery of NERC Recommendation or Essential Action);
MISO Schedule 47 (Entergy Operating Companies MISO Transition Cost Recovery);

MISO Charge Types Which Appear On MISO Settlement Statements Represent Administrative Charges And Are Specifically Excluded From The FAC

DA Market Administration Amount;
DA Schedule 24 Allocation Amount;
FTR Market Administration Amount;
Schedule 10 - ISO Cost Recovery Adder;

RT Market Administration Amount;
RT Schedule 24 Allocation Amount;
RT Schedule 24 Distribution Amount;
Schedule 10 - FERC - Annual Charges Recovery;

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

FAC CHARGE TYPE TABLE (Cont'd.)

PJM Market Settlement Charge Types

Auction Revenue Rights;
Balancing Operating Reserve;
Balancing Operating Reserve for Load Response;
Balancing Spot Market Energy;
Balancing Transmission Congestion;
Balancing Transmission Losses;
Capacity Resource Deficiency;
Capacity Transfer Rights;
Day-ahead Economic Load Response;
Day-Ahead Load Response Charge Allocation;
Day-ahead Operating Reserve;
Day-ahead Operating Reserve for Load Response;
Day-ahead Spot Market Energy;
Day-ahead Transmission Congestion;
Day-ahead Transmission Losses;
Demand Resource and ILR Compliance Penalty;
Emergency Energy;
Emergency Load Response;
Energy Imbalance Service;
Financial Transmission Rights Auction;
Generation Deactivation;
Generation Resource Rating Test Failure;
Inadvertent Interchange;
Incremental Capacity Transfer Rights;
Interruptible Load for Reliability;
Load Reconciliation for Inadvertent Interchange;
Load Reconciliation for Operating Reserve Charge;
Load Reconciliation for Regulation and Frequency Response Service;
Load Reconciliation for Spot Market Energy;
Load Reconciliation for Synchronized Reserve;
Load Reconciliation for Synchronous Condensing;
Load Reconciliation for Transmission Congestion;
Load Reconciliation for Transmission Losses;
Locational Reliability;
Miscellaneous Bilateral;
Non-Unit Specific Capacity Transaction;
Peak Season Maintenance Compliance Penalty;
Peak-Hour Period Availability;
PJM Customer Payment Default;
Planning Period Congestion Uplift;
Planning Period Excess Congestion;
Ramapo Phase Angle Regulators;
Real-time Economic Load Response;
Real-Time Load Response Charge Allocation;
Regulation and Frequency Response Service;
RPM Auction;
Station Power;
Synchronized Reserve;
Synchronous Condensing;
Transmission Congestion;
Transmission Losses;

PJM Transmission Service Charge Types

Black Start Service;
Day-ahead Scheduling Reserve;
Direct Assignment Facilities;
Expansion Cost Recovery;
Firm Point-to-Point Transmission Service;
Internal Firm Point-to-Point Transmission Service;
Internal Non-Firm Point-to-Point Transmission Service;
Load Reconciliation for PJM Scheduling, System Control and Dispatch Service;
Load Reconciliation for PJM Scheduling, System Control and Dispatch Service Refund;
Load Reconciliation for Reactive Services;
Load Reconciliation for Transmission Owner Scheduling, System Control and Dispatch Service;
Network Integration Transmission Service;
Network Integration Transmission Service (exempt);
Network Integration Transmission Service Offset;
Non-Firm Point-to-Point Transmission Service;
Non-Zone Network Integration Transmission Service;
Other Supporting Facilities;
PJM Scheduling, System Control and Dispatch Service Refunds;
PJM Scheduling, System Control and Dispatch Services;
Qualifying Transmission Upgrade Compliance Penalty;
Reactive Supply and Voltage Control from Generation and Other Sources Service;
Transmission Enhancement;
Transmission Owner Scheduling, System Control and Dispatch Service;
Unscheduled Transmission Service;
Reactive Services;

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

FAC CHARGE TYPE TABLE (Cont'd.)

PJM Charge Types Which Appear On The Settlement Statements Represent Administrative Charges Are Specifically Excluded From The FAC

Annual PJM Building Rent;
Annual PJM Cell Tower;
FERC Annual Charge Recovery;
Load Reconciliation for FERC Annual Charge Recovery;
Load Reconciliation for North American Electric Reliability Corporation (NERC);
Load Reconciliation for Organization of PJM States, Inc. (OPSI) Funding;
Load Reconciliation for Reliability First Corporation (RFC);
Market Monitoring Unit (MMU) Funding;
Michigan - Ontario Interface Phase Angle Regulators;
North American Electric Reliability Corporation (NERC);
Organization of PJM States, Inc. (OPSI) Funding;
PJM Annual Membership Fee;
PJM Settlement, Inc.;
Reliability First Corporation (RFC);
RTO Start-up Cost Recovery;
Virginia Retail Administrative Fee;

SPP Market Settlement Charge Types

DA Asset Energy Amount;
DA Non-Asset Energy Amount;
DA Make-Whole Payment Distribution;
DA Make-Whole Payment;;
DA Virtual Energy;
DA Virtual Energy Transaction Fee;
DA Demand Reduction Amount;
DA Demand Reduction Distribution Amount;
DA GFA Carve-Out Daily Amount;
DA GFA Carve-Out Monthly Amount;
DA GFA Carve-Out Yearly Amount;
GFA Carve Out Distribution Daily Amount;
GFA Carve Out Distribution Monthly Amount;
GFA Carve Out Distribution Yearly Amount;
RT Asset Energy Amount
RT Over Collected Losse;s Distribution;
RT Miscellaneous Amount;
RT Non-Asset Energy;
RT Revenue Neutrality Uplift;
RT Joint Operating Agreement;
RUC Make Whole Payment Distribution;
RUC Make Whole Payment;
RT Virtual Energy Amount;
RT Demand Reduction Amount;
RT Demand Reduction Distribution Amount;
Transmission Congestion Rights Daily Uplift;
Transmission Congestion Rights Monthly Payback;
Transmission Congestion Rights Auction Transaction;
Transmission Congestion Rights Annual Payback;
Transmission Congestion Rights Funding;
Auction Revenue Rights Annual Closeout;
Auction Revenue Rights Funding;
Transmission Congestion Rights Annual Closeout
Auction Revenue Rights Uplift
Auction Revenue Rights Monthly Payback
Auction Revenue Rights Annual Payback
DA Regulation Up
DA Regulation Down
DA Regulation Up Distribution
DA Regulation Down Distribution
DA Spinning Reserve
DA Spinning Reserve Distribution
DA Supplemental Reserve
DA Supplemental Reserve Distribution
RT Regulation Up
RT Regulation Up Distribution
RT Regulation Down
RT Regulation Down Distribution
RT Regulation Out of Merit
RT Spinning Reserve Amount
RT Supplemental Reserve Amount
RT Spinning Reserve Cost Distribution Amount
RT Supplemental Reserve Distribution Amount
RT Regulation Non-Performance
RT Regulation Non-Performance Distribution
RT Regulation Deployment Adjustment;
RT Contingency Reserve Deployment Failure
RT Contingency Reserve Deployment Failure Distribution;
RT Reserve Sharing Group;
RT Reserve Sharing Group Distribution;
RT Pseudo-Tie Congestion Amount;
RT Pseudo-Tie Losses Amount;
RT Unused Regulation -Up Mileage Make Whole Payment;
RT Unused Regulation -Down Mileage Make Whole Payment;

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

FAC CHARGE TYPE TABLE (Cont'd.)

SPP Transmission Service Charge Types

Schedule 1 – Scheduling, System Control & Dispatch Service;
Schedule 2 – Reactive Voltage;
Schedule 7 – Zonal Firm Point-to-Point;
Schedule 8 – Zonal Non-Firm Point-to-Point;
Schedule 11 – Base Plan Zonal and Regional;

SPP charge types representing administrative charges specifically excluded from the FAC

Schedule 1A – Tariff Administrative Fee;
Schedule 1A2 – Transmission Congestionk Rights Administratoin
Schedule 1A3 – Integrated Marketplace Clearing Administration
Schedule 1A4 – Integrated Marketplace Facilitation Administration
Schedule 12 – FERC Assessment;

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-2021-0240

AFFIDAVIT OF ANDREW MEYER

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

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

My name is Andrew Meyer, and on his oath declare that he is of sound mind and lawful age; that he has prepared the foregoing *Surrebuttal 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 3rd day of November, 2021.