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 Increase Its Revenues for Electric Service.	)))	File No. ER-2021-0240

UNANIMOUS STIPULATION AND AGREEMENT

COMES NOW Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "the Company"), the Staff of the Missouri Public Service Commission ("Staff"), the Office of the Public Counsel ("OPC"), Missouri Industrial Energy Consumers ("MIEC"), Midwest Energy Consumers Group ("MECG"), Consumers Council of Missouri ("CCM"), Natural Resources Defense Council, Renew Missouri Advocates, and Legal Services of Eastern Missouri (collectively "Signatories"), and present to the Missouri Public Service Commission ("Commission") for approval this Stipulation and Agreement ("*Stipulation*") commemorating an agreement between the Signatories resolving the issues in this case related to Ameren Missouri's revenue requirement and certain other issues enumerated herein.[1] In support of this *Stipulation*, the Signatories respectfully state as follows:

BACKGROUND

1. On March 31, 2021, Ameren Missouri filed tariff sheets designed to implement a general rate increase for its electric service territory, together with supporting testimony. The Commission issued a procedural schedule in its June 9, 2021 *Order Setting Procedural Schedule and Adopting Test Year*. This procedural schedule included a date for the provision of the preliminary true-up revenue requirement, including true-up accounting schedules with supporting

[1] There remain other issues that do not affect the revenue requirement not resolved by this Stipulation which will either be resolved by the Commission after an evidentiary hearing or which may be resolved, in whole or in part, by an additional stipulation among the parties.

workpapers, to all parties by November 5, 2021, and culminated in an evidentiary hearing set to begin November 29, 2021 and continue through December 10, 2021.

2. After the dissemination of the true-up information, the Signatories began negotiations in earnest to determine whether a resolution of issues could be mutually reached in advance of the evidentiary hearings. As a result of these discussions, the Signatories have agreed to a series of compromises to determine mutually acceptable resolutions to all issues relating to the revenue requirement and certain other issues as set forth in more detail below. The Signatories agree that resolution of these issues will shorten the forthcoming hearing, and only certain issues (i.e., rate design issues) may require a hearing. The Signatories agreed to the settled "black box" revenue requirement increase amount using their own assumptions.

SPECIFIC TERMS AND CONDITIONS

A. Revenue Requirement, Capital Structure, W.A.C.C., Billing Determinants, and Net Base Energy Costs

3. Revenue Requirement Increase. The Signatories agree that Ameren Missouri should be authorized to file tariffs designed to increase the Company's annual revenues by $220 million, exclusive of any applicable license, occupation, franchise, gross receipts taxes, or similar fees or taxes, to become effective February 28, 2022. If a customer's billing cycle covers days both before and after the effective date of the new rates, the new and old rates will be pro-rated on the customer's bill.

4. Capital Structure and W.A.C.C. For purposes of calculating Plant-in-Service Accounting ("PISA") deferrals, the Renewable Energy Standard Rate Adjustment Mechanism ("RESRAM") rates, and the Allowance for Funds Used During Construction ("AFUDC"), the Signatories agree that the Company's actual capital structure and capital costs as of September 30, 2021 will be used, and to a post-tax Weighted Average Cost of Capital ("W.A.C.C.") of 6.76%. The

Signatories also agree that AFUDC shall be calculated in accordance with the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts for Electric Utilities formula (short-term debt receives 100% weighting until Construction Work in Progress Balances exceed short-term debt balances).

5. Billing Determinants.

a. The Signatories agree that the billing determinants set forth in Exhibit A, which is incorporated herein by reference, shall be used to set the rates implemented from this case.

b. The Signatories agree that the level of cumulative kilowatt-hours ("kWh") to be rebased in the Missouri Energy Efficiency Investment Act ("MEEIA") Cycle 2 and MEEIA Cycle 3 Throughput Disincentive mechanisms are set forth in Exhibit B, attached hereto and incorporated herein.

6. Net Base Energy Costs ("NBEC"). The Signatories agree that the NBEC against which changes are tracked in the Company's FAC shall be set at $401,687,202, as shown on the attached Exhibit C, which is incorporated herein by reference.

B. Continuation of Existing Tracking Mechanisms

7. The Signatories agree that the Company's existing tracking mechanisms, on the terms approved by the Commission in the Company's prior general rate proceedings, shall continue as follows:

a. Uncertain Tax Positions (a/k/a Fin. 48 Tracker)
b. Pension Tracker, with its base level set at ($2,884,081)
c. Other Post-Employment Benefits (a/k/a OPEB) Tracker, with its base level set at ($8,193,873)
d. Renewable Energy Standard Compliance Cost Tracker, with its base level set at $7,573,102.
e. Excess Deferred Tax Tracker

C. Amortizations

8. Timing Amortizations. The Signatories agree that the Company's regulatory assets and liabilities shall be amortized starting on the effective date of new base rates set in this case in the amounts set forth in the attached Exhibit D, "Summary of Amortizations," which is incorporated herein by reference.

9. Meramec Retirement. Amortize asset (balance $60,918,097 per John Riley's rebuttal testimony) over 5 years starting on the effective date of new base rates set in this case, to reflect normal non-labor plant operating costs not including any post-closure costs. Carrying costs on the unamortized balance as of future rate cases, if any, will be addressed in those future rate cases.

10. Amortization Balances in Subsequent Rate Proceeding. The Signatories agree that in the Company's next electric general rate proceeding, the balance of each amortization relating to regulatory assets or liabilities that remain, after full recovery by Ameren Missouri (regulatory asset) or full credit to Ameren Missouri's customers (regulatory liability), shall be applied as offsets to other amortizations which do not expire before Ameren Missouri's new rates from that general rate proceeding take effect. If no other amortization expires before Ameren Missouri's new rates from that general rate proceeding take effect, then the remaining unamortized balance of any regulatory asset or liability that did not expire before new rates from that general rate proceeding take effect shall be a new regulatory liability or asset that is amortized over an appropriate period. Any over- or under-recovery of a regulatory asset or regulatory liability will be treated in the same manner as the underlying regulatory asset or regulatory liability.[2]

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[2] In other words, if the underlying regulatory asset or regulatory liability was included in rate base, the over- or under-recovery shall also be included in rate base; if the underlying regulatory asset or regulatory liability was not included in rate base, then the over- or under-recovery shall not be included in rate base.

D. Fuel Adjustment Clause ("FAC")

11. FAC Tariff/Reporting. The Signatories agree that the FAC tariff sheets attached as Exhibit E are incorporated herein by reference and should be approved and filed as compliance tariffs effective March 1, 2022. The Signatories further agree that the following information, in addition to information required by 20 CSR 4240-20.090(5), shall be included in Ameren Missouri's FAC Monthly Reports, starting with the Report covering March, 2022, unless otherwise contained in another monthly report or as otherwise noted below:

> the information provided in Attachment c to Schedule AMM-D1 to Andrew Meyer's direct testimony filed in this proceeding, which lists the major/minor accounts included and excluded within the FAC, and which includes detailed designations and descriptions for each account, updated with any changes to them between rate cases.

The Company shall also take the actions listed in the Staff Cost of Service Report filed in this docket on September 30, 2021, that are listed in said report at page 204, ll. 16-29, p. 205, ll. 1-31, p. 204, ll. 34-36, and p. 206, ll. 1-2. With respect to such actions, OPC shall have the same access to documents and receive the same notices as Staff.

E. RESRAM

12. The Signatories agree that the Company's RESRAM shall be rebased at $22,402,939 as of September 30, 2021.[3]

F. Rate Base and Depreciation

13. Rate Base. The Signatories agree that the rate base as of September 30, 2021 is $10,182,447,000.

[3] Appropriate consideration will be given to any interaction between the application of PISA and the RESRAM to Renewable Energy Standard investments.

14. Depreciation Rates. The Signatories agree that the depreciation rates set forth on Exhibit F attached hereto and incorporated herein by this reference shall be implemented effective February 28, 2022.

G. FERC Return on Equity ("ROE") Cases

15. The Signatories agree that Ameren Missouri shall continue its regulatory liability for the first FERC ROE case refunds, except that amortization of the first FERC ROE case refunds regulatory liability will not begin until the conclusion of the Company's next electric rate case assuming all litigation that may impact the final first FERC ROE case refunds is completed. If said litigation is not completed, amortization will start after the conclusion of the first Company electric rate case concluding after those refunds are finalized. The Company will continue the treatment for refunds attributable to the second FERC ROE case that was agreed upon in File No. ER-2019-0335.

H. High Prairie Energy Center Reporting

16. Seasonal Reporting. The Signatories agree that until rates are reset in the Company's next electric general rate proceeding, the Company will provide Staff and OPC, by July 31, January 31, and April 30 (after the end of each of the Spring, Fall, and Winter Seasons) starting in 2022:

a. Copies of its summaries of mortality reporting to the United States Fish and Wildlife Service ("USFWS") (i.e., Seasonal Summaries);

b. Copies of its most recent Annual Mortality Monitoring Report submitted to USFWS;

c. A listing of adaptive management responses (i.e., changes in cut-in speed and date of occurrence by individual wind turbine);

d. In the event the Company curtails High Prairie for reasons other than endangered species that reduces what production would have been absent that curtailment by ten percent (10%) or more, Ameren Missouri will report such curtailment as an outage in the same manner it reports fossil fuel outages.

17. Annual Reporting. The Company will provide Staff, OPC, and MIEC concurrently with providing its budget as provided for by the FAC rules each year (starting in 2022):

a. Expenditures related to mitigation or monitoring of wildlife, separately by capital and expense, labor and non-labor by FERC account by month; and

b. A spreadsheet providing the information provided with the attachment to Staff DR No. 870 for the preceding calendar year.

I. Energy Delivery Investments.

18. Energy Delivery Projects

A. The Company shall meet at least three times with OPC, Staff, and other interested Signatories starting in the first quarter of 2022, and will in good faith consider meeting on additional occasions, to discuss the Company's energy delivery system projects, project justifications, and process for determining such projects. The Company agrees to consider the other interested Signatories' input on such issues. The Company shall provide updates made to its evaluation methodologies between each meeting.

The Company shall develop evaluation methodologies for major categories of energy delivery investments to be employed prior to investments in such categories (the categories outlined in Mark Birk's rebuttal testimony) no later than the 3rd quarter of 2022. Each evaluation methodology shall identify all costs and benefits that can be quantitatively evaluated and shall further identify how those costs and benefits are quantified for each category. For any cost or benefit that Company believes cannot be quantitatively evaluated, the Company shall state the reasons the cost or benefit cannot be quantitatively evaluated, and how the Company addresses such costs and benefits when reviewing and deciding on what projects to pursue. No evaluation methodology for a major category of energy delivery investment shall rely solely on costs and benefits that the Company believes cannot be quantitatively evaluated. Any quantification for a category that does not produce quantified benefits exceeding the costs will be accompanied by additional justification following the methodology(ies) adopted under this paragraph for addressing costs and benefits not quantitatively evaluated in support of the projects in each category.

The Signatories agree that different categories or projects within a category may have different methods and analysis of evaluation, and nothing in this paragraph shall be construed to suggest that all categories or projects can be evaluated under the same analysis or methodology.

B. By the end of the first quarter in 2022, the Company will submit in File No. EO-2019-0044, for those energy delivery projects falling within the above-referenced categories with an investment of $1 million or greater and which went into service the prior year (i.e., for the 2022 submission projects that went into service in 2021), the following information (as applicable, since not all the following items apply to all such projects):

a. Purchase orders;

b. Change orders;

c. Final project cost summaries;

d. Project Notifications/Project Charters;

e. Oversight Committee review materials; and

f. In-service dates.

Starting by June 30, 2022, the items listed above shall be submitted in the referenced docket for those energy delivery projects falling within the above-referenced categories with an investment of $1 million or greater and which went into service for the prior quarter (i.e., the June 30, 2022 submission will be for projects that went into service in the first quarter of 2022), and shall continue such submissions on a quarterly basis thereafter for subsequent quarters until submissions under subparagraph C commence.

C. Starting at the end of the first full quarter after the Company finalizes the evaluation methodologies under subparagraph A, and by the end of each year thereafter so long as the Company continues to utilize Plant-in-Service-Accounting, for energy delivery projects with an investment of $1 million or greater which went into service the prior quarter for projects initiated 90 days or more after the methodologies developed under subparagraph A have been finalized, Ameren Missouri will submit in File No. EO-2019-0044 items a-f as listed in subparagraph B, and will submit the evaluation results consistent with those methodologies for the categories in which those projects were completed.

With regard to outcome-based, objective metrics, they should include both baselines and targets (the values assumed when any associated benefit-cost analyses were developed).

To the extent comparable information on similar projects or categories of projects by other utilities is reasonably available, such information might be used to identify and quantify criteria.

J. Cost Measurement Savings Reporting.

19. The Company shall continue to provide the cost measurement savings (maintaining the same measurement threshold) reporting as outlined at p. 42, ll. 10-22 of Laura Moore’s rebuttal testimony in File No. ER-2019-0335, as it was implemented in response to Staff Data Request No. 345s1 in this case.

K. Low-Income Programs.[4]

20. Keeping Current and Keeping Cool. The Company shall increase (in 2022) the eligibility for its Keeping Current and Keeping Cool programs to 300% of the federal poverty level

[4] The Company's total low-income program related contributions are increasing by $1.5 million (over the following three programs) as compared to current Company contributions, with such sum not being included in the $220 million annual increase referenced above.

and will add the months of May and September to the Keeping Cool Program. The Company shall also inform customers who participate in Keeping Current or Keeping Cool about the availability of Missouri Energy Efficiency Investment Act ("MEEIA") programs, including PAYS® program home assessments. The combined funding for Keeping Current and Keeping Cool shall be $4 million annually, split equally between customers and the Company. The Company and the Company's low-income collaborative group (to which Legal Services of Eastern Missouri will be added) shall determine how to allocate any portion of an annual budget that is unspent in a given year to the Company's low-income energy assistance programs or to be used by the Energy Assistance Agencies to pay operating costs. The customer portion for Keeping Current and Keeping Cool funding shall be recovered through a proportional increase to each rate class's low-income pilot charge.

21. Critical Needs Program. Starting in the first quarter of 2022, the Signatories will work together and meet at least once per quarter to develop a program accomplishing the goals of the critical needs program generally described in OPC witness Marke's direct testimony. Costs of development, implementation, and operation will be split 50/50 between customers and the Company for $500,000 total annually. The customer portion for the Critical Needs Program shall be recovered through a proportional increase to each rate class's low-income pilot charge.

22. Rehousing Pilot Program. Starting in the first quarter of 2022, the Signatories will work together and meet at least once per quarter to develop a re-housing program accomplishing the goals of the re-housing and returning customer program generally described in OPC witness Marke's direct testimony. Costs of development, implementation, and operation will be split 50/50 between customers and the Company for $500,000 total annually. The customer portion for the Rehousing Pilot Program shall be recovered through a proportional increase to each rate class's low-income pilot charge.

L. Voltage Optimization Study.

23. Ameren Missouri will engage a third-party consultant to conduct a study of its distribution system designed to gauge the costs and benefits of a voltage optimization program in Ameren Missouri's service territory. The parameters of the study will be determined by Ameren Missouri in collaboration with the consultant, but prior to the determination of those parameters, Ameren Missouri will work with OPC and Staff and give them substantive input regarding the development of the specific methodology, inputs, outputs, and other features to be included in the study; provided, however, Ameren Missouri shall maintain its independence and control of the study, act as project manager with respect to the study, and will engage and direct the work of Ameren employees or consultants assigned or retained to perform it. Upon finalization of the settlement of this case, Ameren Missouri will seek an appropriate consultant and seek input from Staff and OPC as outlined above, with a target date for study completion and delivery of a report of December 31, 2022, it being understood that such date will depend on availability and workload of qualified consultants and on the methodology, inputs, outputs, and other features utilized.

M. Community Solar.

24. The permanent Community Solar Program as proposed by the Company should be approved, but with the following modifications to the Company's proposal: (1) Language will be added to the proposed tariff allowing transfer of the Community Solar pilot program resource to the extent pilot participants desire to participate under the permanent program terms; (2) permanent program resource construction cannot begin until 70% of a resource for the permanent program is subscribed; (3) shareholders to bear the risk for any undersubscribed portion of the permanent Community Solar program to a 50% undersubscribed threshold, provided, that if the subscription rate falls below 50%, non-participant ratepayers would shoulder the costs; and (4) Market costs and revenues for any

undersubscribed portion of a permanent program resource will be allocated to shareholders and not flow through the FAC.

N. Miscellaneous Agreements.

25. Green Button. Customers served with an Advanced Metering Infrastructure ("AMI") meter will have online access to data from their AMI meter by the end of 2023, with the Company having a goal to provide such access by the end of 2022.

26. Convenience Charges. Customer-facing convenience charges associated with bill payments will be eliminated for all payment channels.

27. Combination Bill Formatting. The Company will start the process of redesigning its bills in 2022. This work is expected to be completed in 2023. The Company will ensure that the revisions include the formatting of its combination bills (where a customer receives both natural gas and electric service from the Company) as described by OPC witness Mantle in her direct testimony, so that all gas charges are separated from electric charges. The Company agrees to take comments from Staff and OPC on this bill redesign before it is final.

28. Customer Charges. No change to the residential customer charge for any residential rate plan shall be made as a result of this case. Remaining rate increase after the customer charge increase allocated to each rate element of the residential rate plans on an equal percentage basis, except as noted otherwise. The Evening/Morning Savers peak adder will remain at the current level. The peak period for Smart Savers rate option for the summer period will be modified to be 3-7 p.m., and the method used to adjust the different TOU energy prices in the Company's direct testimony work papers will be followed to establish the charges prior to applying the percentage increase.

29. Late Fees. The late fee assessed on customer payments made after the bill due date shall be reduced from its current 1.5% per month to 1% per month.

30. Data Collection. A. For each voltage at which service is provided to large primary service (Rate Schedule 11M) customers, or at which three or more customers which are not large primary service customers are served, the Company shall identify (1) the retirement units and quantities associated with providing one span of overhead (and the equivalent distance of underground) infrastructure including devices, and (2) the typical meter(s) and related installations. If these items vary with usage characteristics of customers, Company shall provide items (1) and (2) for a minimum of high, medium, and low infrastructure customers.

B. For each voltage and phase at which the distribution system operates Company shall provide (1) an example typical retirement unit and quantity list for one span or underground equivalent, and (2) an estimate of the number of miles operating at that voltage and phase.

C. Company agrees to undertake reasonable data collection to facilitate allocation or assignment of labor and non-labor distribution expenses in future cases on a more detailed basis than application of the plant allocators, in good faith collaboration with Staff.

31. Document Availability. Between rate cases, Staff will be afforded continuous access to Board and Board committee, ELT, ALT, and SLT documents. Company will continuously maintain the above documentation for Staff access within 2 weeks of notice given to Company for review.

32. Advertising materials for the test year to be provided to Staff and OPC within one month after filing a general rate proceeding.

33. Rate Schedule 12(M) will remain in effect.

34. Standby Service Rider rates to be updated consistent with the underlying class rate changes.

35. Ameren Missouri will work with Renew Missouri, Consumers Council, and other interested parties to this case to provide access to Residential customer usage and billing data aggregated by zip code for use in an analysis of energy burdens across Ameren Missouri territory.

GENERAL PROVISIONS

36. This *Stipulation* is being entered into solely for the purpose of settling the issues specifically set forth above, and unless otherwise specifically set forth herein represents a settlement on a mutually-agreeable outcome without resolution of specific issues of law or fact. This *Stipulation* is intended to relate *only* to the specific matters referred to herein; no Signatory waives any claim or right which it may otherwise have with respect to any matter not expressly provided for herein. No Signatory will be deemed to have approved, accepted, agreed, consented, or acquiesced to any substantive or procedural principle, treatment, calculation, or other determinative issue underlying the provisions of this *Stipulation* except as otherwise specifically set forth herein. Except as specifically provided herein, no Signatory shall be prejudiced or bound in any manner by the terms of this *Stipulation* in any other proceeding, regardless of whether this *Stipulation* is approved.

37. This *Stipulation* has resulted from extensive negotiations among the Signatories and the terms hereof are interdependent. In the event the Commission does not approve this *Stipulation,* or approves it with modifications or conditions to which a Signatory objects, then this *Stipulation* shall be null and void, and no Signatory shall be bound by any of its provisions.

38. If the Commission does not approve this *Stipulation* unconditionally and without modification, and notwithstanding its provision that it shall become void, neither this *Stipulation*, nor any matters associated with its consideration by the Commission, shall be considered or argued to be a waiver of the rights that any Signatory has for a decision in accordance with Section 536.090, RSMo 2016 or Article V, Section 18 of the Missouri Constitution, and the Signatories shall retain all

procedural and due process rights as fully as though this *Stipulation* had not been presented for approval, and any suggestions or memoranda, testimony or exhibits that have been offered or received in support of this *Stipulation* shall become privileged as reflecting the substantive content of settlement discussions and shall be stricken from and not be considered as part of the administrative or evidentiary record before the Commission for any further purpose whatsoever.

39. If the Commission unconditionally accepts the specific terms of this *Stipulation* without modification, the Signatories waive, with respect only to the issues resolved herein: their respective rights (1) to call, examine and cross-examine witnesses pursuant to Section 536.070(2), RSMo 2016; (2) their respective rights to present oral argument and/or written briefs pursuant to Section 536.080.1, RSMo 2016; (3) their respective rights to the reading of the transcript by the Commission pursuant to Section 536.080.2, RSMo 2016; (4) their respective rights to seek rehearing pursuant to Section 386.500, RSMo 2016; and (5) their respective rights to judicial review pursuant to Section 386.510, RSMo Supp. 2020. These waivers apply only to a Commission order respecting this *Stipulation* issued in this above-captioned proceeding, and do not apply to any matters raised in any prior or subsequent Commission proceeding, or any matters not explicitly addressed by this *Stipulation*.

40. The Signatories shall also have the right to provide, at any agenda meeting at which this *Stipulation* is noticed to be considered by the Commission, whatever oral explanation the Commission requests, provided that each Signatory shall, to the extent reasonably practicable, provide the other parties with advance notice of the agenda meeting for which the response is requested. Signatory's oral explanations shall be subject to public disclosure, except to the extent they refer to matters that are privileged or protected from disclosure pursuant to the Commission’s rules on confidential information.

41. This *Stipulation* contains the entire agreement of the Signatories concerning the issues addressed herein.

42. This *Stipulation* does not constitute a contract with the Commission and is not intended to impinge upon any Commission claim, right, or argument by virtue of the *Stipulation*'s approval. Acceptance of this *Stipulation* by the Commission shall not be deemed as constituting an agreement on the part of the Commission to forego the use of any discovery, investigative or other power which the Commission presently has or as an acquiescence of any underlying issue. Thus, nothing in this *Stipulation* is intended to impinge or restrict in any manner the exercise by the Commission of any statutory right, including the right to access information, or any statutory obligation.

43. The Signatories agree that this *Stipulation*, except as specifically noted herein, resolves all issues related to these topics, and that the agreement and its exhibits should be received into the record without the necessity of any witness taking the stand for examination. Further, contingent upon Commission approval of this *Stipulation* without modification, the Signatories hereby stipulate to the admission into the evidentiary record of the pre-filed written testimony of their witnesses except for those witnesses testifying on the remaining issues set for evidentiary hearing.

WHEREFORE, the Signatories respectfully request that the Commission approve this *Stipulation*, so that Ameren Missouri may move forward on these provisions, and grant any other and further relief as it deems just and equitable.

Respectfully submitted,

(*Signature block on following pages*)

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CERTIFICATE OF SERVICE

I do hereby certify that a true and correct copy of the foregoing document has been hand-delivered, transmitted by e-mail or mailed, First Class, postage prepaid, this 24th day of November, 2021, to counsel for all parties on the Commission's service list in this case.

/s/Wendy K. Tatro_______________
Wendy K. Tatro

Residential - Basic	Billing Units	Current Rates	Current Revenue
Customer Charge			
Total Bills	12,918,156	9.00	116,263,404
Low Income Charge	12,918,156	0.06	775,089
Energy Charge			
Summer kWh	4,816,507,323	0.1181	568,829,515
Winter kWh			
First 750 kWh	4,843,130,015	0.0804	389,387,653
Over 750 kWh	3,724,848,375	0.0538	200,396,843
Total kWh	13,384,485,712		
Total R-Basic Revenue			1,275,652,504

Residential - Basic TOD	Billing Units	Current Rates	Current Revenue
Customer Charge			
Total Bills	1,044	9.00	9,396
Low Income Charge	1,044	0.06	63
Energy Charge			
Summer kWh			
Off Peak	445,792	0.0716	31,919
On Peak	77,397	0.305	23,606
Winter kWh			
First 750 kWh	460,828	0.0804	37,051
Over 750 kWh	541,531	0.0538	29,134
Total kWh	1,525,549		
Total R-Basic TOD Revenue			131,168

Residential - TOU2	Billing Units	Current Rates	Current Revenue
Customer Charge			
Total Bills	108	9.00	972
Low Income Charge	108	0.06	6
Energy Charge			
Summer kWh			
Off Peak	20,558	0.0554	1,139
On Peak	23,342	0.139	3,244
Winter kWh			
Off Peak	19,154	0.0478	916
On Peak	30,140	0.0782	2,357
First 750 kWh	17,591	0.0804	1,414
Over 750 kWh	19,014	0.0538	1,023
Total kWh	129,798		
Total R-TOU2 Revenue			11,072

Residential - Smart Savers	Billing Units	Current Rates	Current Revenue
Customer Charge			
Total Bills	180	9.00	1,620
Low Income Charge	180	0.06	11
Energy Charge			
Summer kWh			
Off Peak	20,329	0.0563	1,145
Intermediate Peak	31,892	0.0873	2,784
On Peak	2,673	0.2821	754
Winter kWh			
Off Peak	12,970	0.0479	621
Intermediate Peak	16,787	0.0588	987
On Peak	3,322	0.1639	544
First 750 kWh	34,853	0.0804	2,802
Over 750 kWh	23,586	0.0538	1,269
Total kWh	146,413		
Total R-SmartSavers Revenue			12,538

Community Solar Revenue	94,056
Total Residential Revenue	1,275,901,338

Small General Service Class			
	Billing Units	Current Rates	Current Revenue
Customer Charge			
One-phase	1,141,084	10.42	11,890,099
Three-phase	465,359	19.92	9,269,956
Limited Unmetered Service	84,530	5.52	466,605
TOD Bills			
One-phase	13,956	19.96	278,561
Three-phase	1,716	38.98	66,889
Low Income Charge	1,706,645	0.07	119,465
Total Bills	1,706,645		
Energy Charge			
Summer kWh	1,050,914,666	0.1043	109,610,400
Off Peak	24,622,427	0.0632	1,556,137
On Peak	13,962,457	0.1550	2,164,181
Winter kWh			
Base	1,390,456,307	0.0779	108,316,546
Seasonal	533,241,232	0.0449	23,942,531
Off Peak	47,341,064	0.0469	2,220,296
On Peak	25,858,629	0.1021	2,640,166
kWh Lighting Rate	2,342,264	0.0441	103,294
Total kWh	3,088,739,046		
Total Revenue			272,645,127

Large General Service			
	Billing Units	Current Rates	Current Revenue
Customer Charge			
Standard Bills	128,077	94.51	12,104,557
TOD Bills	528	21.08	11,130
Low Income Charge	128,077	0.78	99,900
Demand Charge (kW)			
Summer	7,726,199	5.4	41,721,475
Winter	14,603,347	2.00	29,206,695
Energy Charge			
Summer kWh			
First 150HU	1,018,876,259	0.0969	98,729,109
Next 200HU	1,091,843,327	0.0729	79,595,379
Over 350HU	473,640,872	0.0491	23,255,767
Off Peak	10,827,201	-0.0065	-70,377
On Peak	5,627,985	0.0114	64,159
Winter kWh			
Base Energy Charge			
First 150HU	1,583,214,700	0.0609	96,417,775
Next 200HU	1,687,799,846	0.0452	76,288,553
Over 350HU	742,766,130	0.0356	26,442,474
Seasonal Energy	549,745,273	0.0356	19,570,932
Off Peak	20,246,375	-0.0019	-38,468
On Peak	9,939,331	0.0035	34,788
Total kWh	7,194,527,298		
Total EDI Discount			-198,864
Total Revenue			503,234,984

Small Primary Service			
	Billing Units	Current Rates	Current Revenue
Customer Charge			
Standard Bills	7,982	323.83	2,584,811
TOD Bills	215	21.08	4,532
Low Income Charge	7,982	0.78	6,226
Demand Charge (kW)			
Summer	2,733,277	4.65	12,709,739
Winter	4,961,006	1.69	8,384,100
Energy Charge			
Summer kWh			
First 150HU	402,475,406	0.0941	37,872,936
Next 200HU	487,524,514	0.0708	34,516,736
Over 350HU	380,680,706	0.0475	18,082,334
Off Peak	28,592,705	-0.0048	-137,245
On Peak	12,930,202	0.0084	108,614
Winter kWh			
Base Energy Charge			
First 150HU	642,090,913	0.0592	38,011,782
Next 200HU	780,047,618	0.044	34,322,095
Over 350HU	620,014,733	0.0344	21,328,507
Seasonal Energy	231,621,330	0.0344	7,967,774
Off Peak	47,494,524	-0.0018	-85,490
On Peak	22,657,540	0.0031	70,238
Reactive Power (kvar)	1,292,368	0.35	452,329
Rider B 34.5/69 kV Discount	823,731	-1.14	-939,054
Rider B 138 kV Discount	6,446	-1.35	-8,701
Total kWh	3,656,130,190		
Total EDI Discount			-109,583
Total Revenue			215,142,678

Large Primary Service			
	Billing Units	Current Rates	Current Revenue
Customer Charge			
Standard Bills	768	323.82	248,694
TOD	60	21.08	1,265
Low Income Charge	768	84.83	65,149
Demand Charge (kW)			
Summer	2,364,063	19.27	45,555,498
Winter	4,288,418	8.58	36,794,627
Energy Charge			
Summer kWh			
Energy	1,320,885,154	0.0328	43,325,033
Off Peak	78,453,446	-0.0035	-274,587
On Peak	39,850,345	0.0064	255,042
Winter kWh			
Energy	2,350,778,675	0.03	70,523,360
Off Peak	145,312,966	-0.0018	-261,563
On Peak	71,942,984	0.0029	208,635
Reactive Power (kvar)	341,894	0.35	119,663
Rider B 34.5/69 kV Discount	1,779,850	-1.14	-2,029,029
Rider B 138 kV Discount	628,570	-1.35	-848,570
Total kWh	3,671,663,829		
Total Revenue			193,683,217

Company Owned Lighting 5M			
Description	Billing Units	Current Rates	Current Revenue
100000 MH Direct	464	68.36	380,628
11000 MV Open Btm	86	9.72	10,031
140000 HPS Direct	4	68.93	3,309
20000 MV Direct	194	21.02	48,935
20000 MV Enclosed	1,866	16.01	358,496
25500 HPS Direct	2,576	21.86	675,736
25500 HPS Enclosed	5,394	16.85	1,090,667
27500 HP Enclosed	267	16.85	53,987
3300 MV Open Btm	1,295	9.7	150,738
3300 MV Post Top	92	21.53	23,769
34000 MH Direct	736	21.05	185,914
34200 HPS Direct	5	21.86	1,312
36000 MH Direct	2,431	21.05	614,071
47000 HPS Direct	91	34.59	37,772
50000 HPS Direct	2,380	34.59	987,890
50000 HPS Enclosed	1,283	30.41	468,192
54000 MV Direct	22	31.2	8,237
54000 MV Enclosed	49	27.02	15,888
5800 HPS Open Btm	52	10.02	6,252
6800 MV Enclosed	3,817	11.69	535,449
6800 MV Open Btm	6,664	10.21	816,473
6800 MV Post Top	7,790	22.37	2,091,148
9500 HPS Enclosed	5,675	12.18	829,458
9500 HPS Open Btm	16,474	10.7	2,115,262
9500 HPS Post Top	40,078	22.87	10,999,006
LED 100 W EQ Bracket	70,504	9.83	8,316,652
LED 250 W EQ Bracket	10,630	15.86	2,023,102
LED 400 W EQ Bracket	1,813	29.15	634,187
LED Direct-Large	434	66.02	343,832
LED Direct-Medium	2,784	33.12	1,106,473
LED Direct-Small	2,298	20.66	569,720
LED Post Top - All	6,316	21.83	1,654,539
Municipal Discount		-0.0387	-1,439,642
Total Revenue			35,717,484

Customer Owned Lighting 6M			
Description	Billing Units	Current Rates	Current Revenue
100W LED Energy Only	48	1.49	858
11000 MV Energy Only	24	4.2	1,210
11000 MV Enrg&Maint	26	6.38	1,991
12900 MH Enrg&Maint	53	6.35	4,039
162W LED Energy Only	8	2.4138	232
180W LED Energy Only	4	2.682	129
196W LED Energy Only	28	2.9204	981
20000 MV Energy Only	84	6.48	6,532
20000 MV Enrg&Maint	38	8.39	3,826
25500 HPS Enrg&Maint	681	6.29	51,402
25500 HPS Enrgy Only	26	4.38	1,367
25W LED Energy Only	2	0.3725	9
26W LED Energy Only	12	0.3874	56
27W LED Energy Only	10	0.4023	48
3300 MV Enrg&Maint	2	3.67	88
3300 MV Enrgy Only	84	1.82	1,835
36W LED Energy Only	43	0.5364	277
40W LED Energy Only	25	0.596	179
44W LED Energy Only	1	0.6556	8
45W LED Energy Only	47	0.6705	378
50000 HPS Enrg&Maint	66	9.03	7,152
50000 HPS Enrgy Only	1	6.88	83
54000 MV Energy Only	11	15.44	2,038
54000 MV Enrg&Maint	4	17.8	854
54W LED Energy Only	33	0.8046	319
5500 MH Enrg&Maint	169	5.36	10,870
57W LED Energy Only	7	0.8493	71
60W LED Energy Only	4	0.894	43
6800 MV Enrg&Maint	1626	4.72	92,097
6800 MV Enrgy Only	121	2.95	4,283
6M Ltd LED 100 W EQ	8329	2.76	275,856
6M Ltd LED 250 W EQ	98	3.58	4,210
6M Ltd LED 400 W EQ	8	6.32	607
70W LED Energy Only	13	1.043	163
72W LED Energy Only	26	1.0728	335
75W LED Energy Only	182	1.1175	2,441
85W LED Energy Only	50	1.2665	760
9500 HPS Enrg&Maint	9477	3.67	417,367
9500 HPS Enrgy Only	116	1.71	2,380
Municipal Discount		-0.0387	-34,768
Total Revenue			862,602

Customer Owned Lighting 6M Metered			
	Billing Units	Current Rates	Current Revenue
Bills	18,355	6.97	127,934
Energy	42,213,409	0.0441	1,861,611
Municipal Discount		-0.0632	-125,713
Total Revenue			1,863,833

Total Lighting Revenue	38,443,918

MSD Horsepower Service			
	Billing Units	Current Rates	Current Revenue
	36,900	0.1693	74,966

Rebasing Summary (kWh)

Actual savings through April 2021

	MEEIA 2 Long Lead Non-Low-Income	MEEIA 3 PY2019 Non-Low-Income	MEEIA 3 PY2020 Non-Low-Income	MEEIA 3 PY2021 Non-Low-Income	MEEIA 2 Long Lead Low-Income	MEEIA 3 PY2019 Low-Income	MEEIA 3 PY2020 Low-Income	MEEIA 3 PY2021 Low-Income
1M kWh *								
Building Shell	-	15,240,737.23	36,050,719.06	11,881,902.24	-	103,535.60	235,060.16	37,882.70
Cooling	-	23,471,158.56	26,999,395.60	8,468,677.16	-	600,449.54	1,682,528.73	142,649.57
Freezer	-	288,814.71	103,977.72	44,594.92	-	-	-	-
Heating		13,176,855.28	16,952,237.68	3,986,464.98		1,493,962.41	1,981,814.91	577,188.73
HVAC	-	7,168,208.25	1,914,732.65	457,864.20	-	55,914.95	332,328.67	162,109.18
Lighting	-	101,050,959.90	117,297,129.14	24,189,439.03	-	663,753.43	6,516,904.73	569,920.87
Miscellaneous	-	9,117.36	215,394.89	44,463.60	-	27,230.04	190,835.99	5,521.00
Pool Spa	-	1,503,219.89	1,435,475.86	108,801.05	-	-	-	-
Refrigeration	-	1,425,027.84	633,220.73	267,096.16	-	37,267.56	80,220.04	-
Water Heating	-	3,303,560.82	3,223,021.22	677,047.68	-	160,524.86	583,163.71	322,895.96
Motors(uses bus. load shape)	-				-			
Total	**-**	**166,637,659.84**	**204,825,304.56**	**50,126,351.02**	**-**	**3,142,638.39**	**11,602,856.94**	**1,818,168.01**
2M kWh								
Air Comp	-	-	19,432.41	415,991.00	-	-	-	-
Building Shell	-	2,592.88	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-
Cooling	52,396.92	61,192.76	389,205.88	138,575.00	-	2,542.11	-	-
Ext Lighting	37,060.94	51,833.06	-	-	-	40,081.20	-	31,689.30
Heating	-	2,621.13	-	-	-	-	-	-
HVAC	7,396.49	385,749.91	4,559,978.17	2,730,713.00	-	-	-	-
Lighting	1,218,971.03	23,830,701.16	27,401,251.27	6,346,917.00	-	659,756.25	534,528.06	302,311.98
Miscellaneous	-	-	58,078.98	-	-	-	-	-
Motors	-	167,578.04	-	-	-	-	-	2,620.50
Process	-	-	-	-	-	-	-	-
Refrigeration	-	33,812.13	16,833.98	5,265.00	-	-	-	-
Water Heating	3,586.71	17,097.54	58,136.69	-	-	-	-	-
Total	**1,319,412.09**	**24,553,178.60**	**32,502,917.39**	**9,637,461.00**	**-**	**702,379.56**	**534,528.06**	**336,621.78**
3M kWh								
Air Comp	355,865.22	1,869,764.04	2,356,502.95	1,506,799.00	-	-	-	-
Building Shell	304,461.29	119,807.18	72,044.62	-	-	-	-	-
Cooking	-	16,817.13	8,130.42	-	-	-	-	-
Cooling	1,699,889.08	2,034,891.54	7,172,951.83	919,547.00	-	-	-	-
Ext Lighting	877,077.90	148,788.69	-	8,949.00	-	-	-	-
Heating	11,187.78	-	-	-	-	-	-	-
HVAC	2,728,027.72	5,821,593.18	13,045,743.47	986,420.00	-	-	-	-
Lighting	5,355,536.08	42,634,912.96	57,447,583.14	6,967,629.00	-	536,516.72	330,259.81	-
Miscellaneous	-	303,927.09	-	-	-	-	-	-
Motors	-	764,703.83	2,073,827.90	61,960.00	-	-	-	-
Process	-	-	-	-	-	-	-	-
Refrigeration	103,179.93	910,262.86	2,057,337.70	-	-	-	-	-
Water Heating	-	38,737.35	218,023.59	-	-	-	-	-
Total	**11,435,225.00**	**54,664,205.84**	**84,452,145.60**	**10,451,304.00**	**-**	**536,516.72**	**330,259.81**	**-**
4M kWh								
Air Comp	-	67,137.51	2,398,416.02	-	-	-	-	-
Building Shell	-	-	8,969.05	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-
Cooling	1,363,845.95	2,260,296.09	2,992,104.84	692,604.00	-	-	-	-
Ext Lighting	78,843.60	-	-	-	-	-	-	-
Heating	-	-	44,326.09	-	-	-	-	-

HVAC	923,788.18	120,290.91	5,334,099.64	-	-	-	-	-
Lighting	4,436,609.80	11,300,099.98	9,329,202.63	3,041,911.00	-	-	92,578.16	-
Miscellaneous	-	93,454.18	-	-	-	-	-	-
Motors	139,547.80	539,602.23	1,287,886.36	-	-	-	-	-
Process	-	-	1,839,476.57	-	-	-	-	-
Refrigeration	-	-	-	-	-	-	-	-
Water Heating	-	-	-	-	-	-	-	-
Total	**6,942,635.32**	**14,380,880.90**	**23,234,481.20**	**3,734,515.00**	**-**	**-**	**92,578.16**	**-**

11M kWh								
Air Comp	-	759,344.04	295,665.37	274,837.00	-	-	-	-
Building Shell	-	-	-	-	-	-	-	-
Cooking	-	-	-	-	-	-	-	-
Cooling	-	2,311,315.89	829,843.85	-	-	-	-	-
Ext Lighting	-	-	-	-	-	-	-	-
Heating	-	-	-	-	-	-	-	-
HVAC	-	462,078.80	64,044.94	75,176.00	-	-	-	-
Lighting	127,404.63	978,114.24	2,456,576.82	139,284.00	-	-	-	-
Miscellaneous	-	82,043.55	-	-	-	-	-	-
Motors	-	-	689,548.84	-	-	-	-	-
Process	-	-	-	-	-	-	-	-
Refrigeration	-	-	-	-	-	-	-	-
Water Heating	-	-	-	-	-	-	-	-
Total	**127,404.63**	**4,592,896.52**	**4,335,679.82**	**489,297.00**	**-**	**-**	**-**	**-**

*** Home Energy Report is fully rebased and no more TD will be collected.**

Ameren Missouri - Pro Forma Revenue Requirement
Net Base Energy Cost (NBEC)
12 Months Ended December 31, 2020 With True-Up Through September 30, 2021

		Total	Summer	Winter	Summer %	Winter %
A	**Fuel & Purchased Power Costs**					
	Base Load					
	Fuel Acct 501	304,125,000	101,781,000	202,344,000	33.47%	66.53%
	Fuel Acct 518	68,927,000	17,989,000	50,938,000	26.10%	73.90%
	Fuel Acct 547	1,217,000	50,000	1,167,000	4.11%	95.89%
	Fly Ash Acct. 501 (1)	(2,442,085)	(817,291)	(1,624,794)	33.47%	66.53%
	Fuel Additives Acct. 502 (2)	4,977,482	1,669,438	3,308,044	33.54%	66.46%
	Fixed Gas Supply Costs Acct. 547 (2)	6,538,503	2,193,002	4,345,501	33.54%	66.46%
	Purchased Power Act. 555	20,733,000	8,635,000	12,098,000	41.65%	58.35%
	Total Fuel and Purchased Power	404,075,900	131,500,149	272,575,751		
	OSS					
	Fuel For OSS Acct 501	205,679,000	68,834,000	136,845,000	33.47%	66.53%
	Fuel For OSS Acct 518	-	-	-	26.10%	73.90%
	Fuel For OSS Acct 547	13,483,000	555,000	12,928,000	4.11%	95.89%
	Fly Ash Acct. 501 (1)	(1,430,020)	(478,584)	(951,436)	33.47%	66.53%
	Fuel Additives Acct. 502 (2)	2,914,681	977,579	1,937,102	33.54%	66.46%
	Fixed Gas Supply Costs for OSS Acct. 547 (2)	3,828,774	1,284,164	2,544,610	33.54%	66.46%
	Purchased Power for OSS Acct. 555	-	-	-	41.65%	58.35%
	Total Fuel and Purchased Power for OSS	224,475,435	71,172,159	153,303,276		
	Total Fuel and Purchased Power	**628,551,335**	**202,672,308**	**425,879,027**		
B	**Transmission Costs**					
	Transmission by Others (Acct 565) (at 1.84%) (2)	1,495,525	501,599	993,926	33.54%	66.46%
	Transmission Revenues (Acct 456.1) (2)	(534,354)	(179,222)	(355,132)	33.54%	66.46%
	Total Transmission	**961,170**	**322,377**	**638,793**		
C	**Other Costs**					
	MISO Day 2 Account 555 (2)	33,725,703	11,311,541	22,414,162	33.54%	66.46%
	Common Boundary	198,077	66,435	131,642	33.54%	66.46%
	Capacity Expense (2)	11,829,415	3,967,565	7,861,850	33.54%	66.46%
	Ancillary Services Account 555(2)	3,701,564	1,241,505	2,460,059	33.54%	66.46%
	PJM Account 555 expense (2)	-	-	-	33.54%	66.46%
	Replacement Power Insurance (Acct. 925) (2)	653,138	219,062	434,076	33.54%	66.46%
	Total Other Expenses	**50,107,897**	**16,806,108**	**33,301,789**		
	Total Fuel, Purchased Power & Other Expenses	**679,620,402**	**219,800,793**	**459,819,609**		
D	**Sales**					
	Off-System Energy Sales (Acct. 447)	241,529,364	63,441,000	178,088,364	26.27%	73.73%
	Make Whole Payments Margins (Acct 447) (2)	3,246,722	1,088,945	2,157,777	33.54%	66.46%
	Capacity Sales(Acct. 447) (2)	18,026,213	6,045,960	11,980,253	33.54%	66.46%
	Bilateral Energy Sales Margins (447)	32,506	10,902	21,604	33.54%	66.46%
	Financial Swaps (Acct. 447) (2)	3,839,423	1,287,736	2,551,687	33.54%	66.46%
	Ancillary Services Revenue (Acct. 447) (2)	5,244,900	1,759,130	3,485,770	33.54%	66.46%
	Total Sales	**271,919,128**	**73,633,673**	**198,285,455**		
E	**Other Adjustments**					
	Real-Time Load and Generation Deviation (2)	6,014,073	2,017,109	3,996,964	33.54%	66.46%
	Total Other Adjustments	**6,014,073**	**2,017,109**	**3,996,964**		
	Total Sales and Other Adjustments	**277,933,200**	**75,650,782**	**202,282,418**		
A + B + C - D -	**Net Base Energy Costs**	**401,687,202**	**144,150,011**	**257,537,191**		
	Load at MISO CP Node AMMO.UE (KWH)	32,496,511,680	10,899,000,000	21,597,511,680	33.54%	66.46%
	Base Factor (BF) ($ per MWH)	**12.36**	**13.23**	**11.92**		
	Base Factor (BF) (cents per KWH)	**1.236**	**1.323**	**1.192**		

(1) Allocation Between Summer, Winter of Fly Ash

Fuel Acct 501	33.47%	66.53%

(2) Allocation Between Summer, Winter

Load Summer/Winter	33.54%	66.46%

File No. ER-2021-0240
Summary of Amortizations

Callaway Post Op Amortization	3,687,468
PISA Amortization (2019)	2,573,051
PISA Amortization (2021)	9,950,377
Pension Tracker Amortization	(5,078,090)
OPEB Tracker Amortization	(1,385,498)
Sioux Scrubber Construction Accounting	3,459,217
Fukushima Study Costs	92,656
RES Tracker Amortization	(363,620)
Expired & Expiring Amortizations – Non Rate Base	(2,734,186)
Expired & Expiring Amortizations – Rate Base	74,369
Callaway Life Extension	103,877
COVID Cost Amortization	1,747,232
PAYS Amortization	16,187
Charge Ahead Corridor Amortization	615,671
Equity Issuance Costs	255,447
Excess Deferred Tax Tracker	(3,362,196)
Federal Income Tax Rate Change – Stub Period	(17,257,609)
Federal and State Excess Deferred Tax Amortization	(78,324,777)
Meramec Retirement	$12,183,619

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 event has occurred that results in an increase to actual net energy costs in an accumulation period, for good cause shown, subject to Commission approval after an opportunity for any party to be heard, the Company shall defer recovery beyond eight months over a period determined by the Commission upon a finding that the magnitude of the increase 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.

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.

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.)

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;

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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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 30, or its successor);

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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.)

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 84/100 percent (1.84%) of transmission service costs reflected in FERC Account 565 and one and 84/100 percent (1.84%) 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:

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.)

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.

Notwithstanding anything to the contrary contained in the tariff sheets for Rider FAC, factors PP and OSSR shall not include costs and revenues for any undersubscribed portion of a permanent Community Solar Program resource allocated to shareholders under the approved stipulation in File No. ER-2021-0240.

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.)

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 $0.01323 per kWh. The BF applicable to October through May calendar months (BF_{WINTER}) is $0.01192 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).

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

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;

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	DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	NET SALVAGE PERCENT	DEPRECIATION RATE
	STEAM PRODUCTION PLANT				
	MERAMEC STEAM PRODUCTION PLANT				
311	STRUCTURES AND IMPROVEMENTS	12-2022	95-R1.5	0	8.73
312	BOILER PLANT EQUIPMENT	12-2022	55-R0.5	0	8.64
314	TURBOGENERATOR UNITS	12-2022	60-S0.5	0	6.19
315	ACCESSORY ELECTRIC EQUIPMENT	12-2022	75-S0	0	10.97
316	MISCELLANEOUS POWER PLANT EQUIPMENT	12-2022	40-L0	0	21.81
316.21	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE FURNITURE		20-SQ	0	5.00
316.22	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE EQUIPMENT		15-SQ	0	6.67
316.23	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTERS		5-SQ	0	20.00
	SIOUX STEAM PRODUCTION PLANT				
311.00	STRUCTURES AND IMPROVEMENTS	09-2033	95-R1.5	0	3.98
312.00	BOILER PLANT EQUIPMENT	12-2028	55-R0.5	(2)	7.92
314.00	TURBOGENERATOR UNITS	12-2028	60-S0.5	0	7.23
315.00	ACCESSORY ELECTRIC EQUIPMENT	12-2028	75-S0	0	8.21
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	12-2028	40-L0	0	9.76
316.21	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE FURNITURE		20-SQ		5.00
316.22	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE EQUIPMENT		15-SQ		6.67
316.23	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTERS		5-SQ		20.00
	LABADIE STEAM PRODUCTION PLANT				
311.00	STRUCTURES AND IMPROVEMENTS	12-2042	95-R1.5	(2)	3.17
312.00	BOILER PLANT EQUIPMENT	12-2042	55-R0.5	(6)	3.88
312.03	BOILER PLANT EQUIPMENT - ALUMINUM COAL CARS	12-2042	30-R2	25	0.31
314.00	TURBOGENERATOR UNITS	12-2042	60-S0.5	(2)	2.94
315.00	ACCESSORY ELECTRIC EQUIPMENT	12-2042	75-S0	(2)	2.96
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	12-2042	40-L0	0	3.96
316.21	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE FURNITURE		20-SQ		5.00
316.22	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE EQUIPMENT		15-SQ		6.67
316.23	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTERS		5-SQ		20.00
	RUSH ISLAND STEAM PRODUCTION PLANT				
311.00	STRUCTURES AND IMPROVEMENTS	12-2039	95-R1.5	(1)	3.44
312.00	BOILER PLANT EQUIPMENT	12-2039	55-R0.5	(5)	4.11
314.00	TURBOGENERATOR UNITS	12-2039	60-S0.5	(2)	3.38
315.00	ACCESSORY ELECTRIC EQUIPMENT	12-2039	75-S0	(1)	3.39
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	12-2039	40-L0	0	5.05
316.21	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE FURNITURE		20-SQ		5.00
316.22	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE EQUIPMENT		15-SQ		6.67
316.23	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTERS		5-SQ		20.00
	COMMON - ALL STEAM PLANTS				
311.00	STRUCTURES AND IMPROVEMENTS	12-2028	95-R1.5	0	6.81
312.00	BOILER PLANT EQUIPMENT	12-2028	55-R0.5	(2)	6.12
315.00	ACCESSORY ELECTRIC EQUIPMENT	12-2028	75-S0	0	6.70
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	12-2028	40-L0	0	7.75
	NUCLEAR PRODUCTION PLANT				
	CALLAWAY NUCLEAR PRODUCTION PLANT				
321.00	STRUCTURES AND IMPROVEMENTS	10-2044	100-R1.5	(1)	1.37
322.00	REACTOR PLANT EQUIPMENT	10-2044	55-R0.5	(6)	2.51
323.00	TURBOGENERATOR UNITS	10-2044	50-S1	(3)	2.45
324.00	ACCESSORY ELECTRIC EQUIPMENT	10-2044	80-R2	(1)	1.57
325.00	MISCELLANEOUS POWER PLANT EQUIPMENT	10-2044	35-L0	0	5.32
325.21	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE FURNITURE		20-SQ		5.00
325.22	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE EQUIPMENT		15-SQ		6.67
325.23	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTERS		5-SQ		20.00
	HYDRAULIC PRODUCTION PLANT				
	OSAGE HYDRAULIC PRODUCTION PLANT				
331.00	STRUCTURES AND IMPROVEMENTS	06-2047	125-R1	(2)	3.38
332.00	RESERVOIRS, DAMS, AND WATERWAYS	06-2047	150-R2.5	(1)	2.89
333.00	WATER WHEELS, TURBINES, AND GENERATORS	06-2047	105-L0	(7)	2.88
334.00	ACCESSORY ELECTRIC EQUIPMENT	06-2047	65-R1	(1)	3.06
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2047	50-R0.5	0	4.51
335.21	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE FURNITURE		20-SQ		5.00
335.22	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE EQUIPMENT		15-SQ		6.67
335.23	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTERS		5-SQ		20.00
336.00	ROADS, RAILROADS, AND BRIDGES	06-2047	60-O1	0	-

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	DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	NET SALVAGE PERCENT	DEPRECIATION RATE
	KEOKUK HYDRAULIC PRODUCTION PLANT				
331.00	STRUCTURES AND IMPROVEMENTS	06-2055	125-R1	(2)	2.41
332.00	RESERVOIRS, DAMS, AND WATERWAYS	06-2055	150-R2.5	(2)	1.75
333.00	WATER WHEELS, TURBINES, AND GENERATORS	06-2055	105-L0	(10)	2.68
334.00	ACCESSORY ELECTRIC EQUIPMENT	06-2055	65-R1	(1)	2.63
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2055	55-R0.5	0	3.02
335.21	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE FURNITURE		20-SQ		5.00
335.22	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE EQUIPMENT		15-SQ		6.67
335.23	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTERS		5-SQ		20.00
336.00	ROADS, RAILROADS, AND BRIDGES	06-2055	60-O1	0	1.06
	TAUM SAUK HYDRAULIC PRODUCTION PLANT				
331.00	STRUCTURES AND IMPROVEMENTS	06-2089	125-R1	(5)	1.34
332.00	RESERVOIRS, DAMS, AND WATERWAYS	06-2089	150-R2.5	(3)	2.40
333.00	WATER WHEELS, TURBINES, AND GENERATORS	06-2089	105-L0	(23)	2.02
334.00	ACCESSORY ELECTRIC EQUIPMENT	06-2089	65-R1	(3)	1.80
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2089	50-R0.5	0	2.34
335.21	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE FURNITURE		20-SQ		5.00
335.22	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE EQUIPMENT		15-SQ		6.67
335.23	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTERS		5-SQ		20.00
336.00	ROADS, RAILROADS, AND BRIDGES	06-2089	60-O1	0	1.21
	WIND PRODUCTION PLANT				
	HIGH PRAIRIE WIND PRODUCTION PLANT				
341.40	STRUCTURES AND IMPROVEMENTS	06-2050	35-S2.5	0	2.90
344.40	GENERATORS - WIND	06-2050	45-R2	(1)	3.67
345.40	ACCESSORY ELECTRIC EQUIPMENT - WIND	06-2050	40-R2.5	(1)	3.66
346.40	MISCELLANEOUS POWER PLANT EQUIPMENT - WIND	06-2050	35-S2.5	0	2.89
346.21	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE FURNITURE		20-SQ		5.00
346.22	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE EQUIPMENT		15-SQ		6.67
346.23	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTERS		5-SQ		20.00
	ATCHISON WIND PRODUCTION PLANT				
341.40	STRUCTURES AND IMPROVEMENTS	06-2050	35-S2.5	0	2.90
344.40	GENERATORS - WIND	06-2050	45-R2	(1)	3.67
345.40	ACCESSORY ELECTRIC EQUIPMENT - WIND	06-2050	40-R2.5	(1)	3.66
346.40	MISCELLANEOUS POWER PLANT EQUIPMENT - WIND	06-2050	35-S2.5	0	2.89
346.21	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE FURNITURE		20-SQ		5.00
346.22	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE EQUIPMENT		15-SQ		6.67
346.23	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTERS		5-SQ		20.00
	SOLAR PRODUCTION PLANT				
341.20	STRUCTURES AND IMPROVEMENTS - SOLAR		20-R4	0	5.17
344.20	GENERATORS - SOLAR		20-S2.5	0	6.71
345.20	ACCESSORY ELECTRIC EQUIPMENT - SOLAR		25-S2.5	0	4.13
	OTHER PRODUCTION PLANT				
341.00	STRUCTURES AND IMPROVEMENTS		40-L2.5	(5)	2.40
342.00	FUEL HOLDERS, PRODUCERS, AND ACCESSORIES		45-R2.5	(5)	2.04
	GENERATORS				
344.00	OTHER CTS		45-R5	(5)	1.65
344.10	MARYLAND HEIGHTS LANDFILL CTG		10-S2.5	40	1.28
345.00	ACCESSORY ELECTRIC EQUIPMENT		40-R2.5	(5)	2.05
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT		25-L2.5	0	2.11
346.21	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE FURNITURE		20-SQ		5.00
346.22	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE EQUIPMENT		15-SQ		6.67
346.23	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTERS		5-SQ		20.00
	TRANSMISSION PLANT				
352.00	STRUCTURES AND IMPROVEMENTS		70-R2.5	(5)	1.61
353.00	STATION EQUIPMENT		65-S0	(5)	1.52
354.00	TOWERS AND FIXTURES		70-R4	(40)	2.47
355.00	POLES AND FIXTURES		64-L2.5	(100)	3.12
356.00	OVERHEAD CONDUCTORS AND DEVICES		75-R3	(30)	1.63
359.00	ROADS AND TRAILS		70-R4	0	-

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	DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	NET SALVAGE PERCENT	DEPRECIATION RATE
	DISTRIBUTION PLANT				
361.00	STRUCTURES AND IMPROVEMENTS		60-R2.5	(5)	1.84
362.00	STATION EQUIPMENT		60-R2.5	(10)	1.87
364.00	POLES AND FIXTURES		58-L2.5	(150)	3.76
365.00	OVERHEAD CONDUCTORS AND DEVICES		65-O1	(50)	1.97
366.00	UNDERGROUND CONDUIT		70-R3	(50)	2.33
367.00	UNDERGROUND CONDUCTORS AND DEVICES		57-R2	(40)	2.57
368.00	LINE TRANSFORMERS		42-R2.5	0	2.43
369.01	OVERHEAD SERVICES		48-R2.5	(170)	3.99
369.02	UNDERGROUND SERVICES		60-R3	(90)	2.76
370.00	METERS	12-2024	28-S0.5	(5)	15.58
370.01	AMI METERS		20-S2.5	(5)	5.33
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES		30-O1	0	1.18
373.00	STREET LIGHTING AND SIGNAL SYSTEMS		40-O1	(30)	2.42
	GENERAL PLANT				
390.00	STRUCTURES AND IMPROVEMENTS				
	MISCELLANEOUS STRUCTURES - OLD		45-S0	(10)	1.67
	LARGE STRUCTURES		55-R1	(10)	1.93
390.05	STRUCTURES AND IMPROVEMENTS - TRAINING ASSETS		5-SQ	0	-
391.00	OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20-SQ	0	5.00
391.10	MAINFRAME COMPUTERS		5-SQ	0	-
391.20	OFFICE FURNITURE AND EQUIPMENT - PERSONAL COMPUTERS		5-SQ	0	20.00
391.30	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		15-SQ	0	6.67
392.00	TRANSPORTATION EQUIPMENT		11-R2	15	6.30
392.05	TRANSPORTATION EQUIPMENT - TRAINING ASSETS		5-SQ	0	-
393.00	STORES EQUIPMENT		20-SQ	0	5.00
394.00	TOOLS, SHOP, AND GARAGE EQUIPMENT		20-SQ	0	5.00
394.05	TOOLS, SHOP, AND GARAGE EQUIPMENT - TRAINING ASSETS		5-SQ	0	-
395.00	LABORATORY EQUIPMENT		20-SQ	0	5.00
396.00	POWER OPERATED EQUIPMENT		15-L2	15	6.15
397.00	COMMUNICATION EQUIPMENT		15-SQ	0	6.67
397.05	COMMUNICATION EQUIPMENT - TRAINING ASSETS		5-SQ	0	-
398.00	MISCELLANEOUS EQUIPMENT		20-SQ	0	5.00

NOTES: **NEW WIND FARM FACILITIES WILL HAVE THE FOLLOWING RATES:**

ACCOUNT	DESCRIPTION	ACCRUAL RATE
341.40	STRUCTURES AND IMPROVEMENTS	3.53
344.40	GENERATORS	3.71
345.40	ACCESSORY ELECTRIC EQUIPMENT	3.70
346.40	MISCELLANEOUS POWER PLANT EQUIPMENT	3.70