BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

NON-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 Department of Natural Resources - Division of Energy ("DE"), Missouri Industrial Energy Consumers ("MIEC"), Midwest Energy Consumers Group ("MECG"), Consumers Council of Missouri ("CCM"), Natural Resources Defense Council, and the Sierra Club (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, except as reserved herein, the issues in this case related to Ameren Missouri's revenue requirement and rate design. Renew Missouri Advocates has authorized the Signatories to indicate that it does not object to this Stipulation. In support of this *Stipulation*, the Signatories respectfully state as follows:

BACKGROUND

1. On July 3, 2019, Ameren Missouri filed tariff sheets designed to implement a general rate decrease for its electric service territory, together with supporting testimony. The Commission issued a procedural schedule in its August 15, 2019, *Order Setting Test Year and Adopting Procedural Schedule.* This procedural schedule included a date for the provision of preliminary true-up revenue requirement, including true-up accounting schedules with supporting

workpapers, to all parties by January 31, 2020, and culminated in an evidentiary hearing set to begin March 2, 2020, and continue through March 13, 2020.

2. After the dissemination of the true-up information and subsequent preliminary reconciliation of those numbers, the Signatories began negotiations in earnest to determine whether a resolution of issues could be mutually reached in advance of the submission of Surrebuttal Testimony. As a result of these discussions, the Signatories have agreed to a series of compromises to determine mutually acceptable resolutions to several issues relating to revenue requirement and rate design which are set forth in more detail below. The Signatories agree that resolution of these revenue requirement and rate design issues will shorten the forthcoming hearing, and only certain issues will require a hearing. Specifically, OPC's positions on the appropriate sharing percentage for Ameren Missouri's Fuel Adjustment Clause ("FAC") and on affiliate transactions. Each of the Signatories agreed to the settled "black box" revenue requirement decrease amount using their own assumptions.

SPECIFIC TERMS AND CONDITIONS

A. Revenue Requirement, Billing Determinants, and Net Base Energy Costs

3. Revenue Requirement Decrease. The Signatories agree that Ameren Missouri should be authorized to file tariffs designed to decrease the Company's revenues by $32 million, exclusive of any applicable license, occupation, franchise, gross receipts taxes, or similar fees or taxes, to become effective April 1, 2020, or as soon as possible thereafter. 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. After implementation of new base rates in this case, Ameren Missouri shall not file additional tariffs seeking to change its base electric rates before July 6, 2020.

4. 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 kWh to be rebased in the MEEIA Cycle 2 and MEEIA Cycle 3 TD mechanisms are set forth in Exhibit B, attached hereto and incorporated herein.

5. 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 $397,234,767, as shown on the attached Exhibit C, which is incorporated herein by reference.

B. Continuation of Existing Tracking Mechanisms

6. 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:

- Uncertain Tax Positions (a/k/a Fin. 48 Tracker)
- Pension Tracker, with its base level set at $(13,179,666)
- Other Post-Employment Benefits (a/k/a OPEB) Tracker, with its base level set at $(8,895,455)
- Renewable Energy Standard Compliance Cost Tracker, with its base level set at $8,194,423.

C. Amortizations

7. Timing Amortizations. The Signatories agree that the Company's regulatory assets and liabilities shall be amortized starting on the first day of the calendar month following the effective date of new rates in this case in the amounts set forth in the attached Exhibit D, except that if rates are approved to be effective on the first day of a month, then amortizations shall begin

on the effective date, "Summary of Amortizations," which is incorporated herein by reference. The Signatories further agree that the balances of such regulatory assets and liabilities, as of December 31, 2019, are set forth in the attached Exhibit E, which is incorporated herein by reference.

8. Amortization Balances in Subsequent Rate Proceeding. The Signatories agree that in the Company's next 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.[1]

D. Fuel Adjustment Clause ("FAC")

9. FAC Tariff. The Signatories agree that the FAC tariff sheets attached as Exhibit F and incorporated herein by reference should be approved and filed as compliance tariffs effective April 1, 2020. In the event the sharing percentage contained is altered by the Commission through an order issued in this case, Ameren Missouri shall submit substitute tariff sheets to replace any tariff sheets that are a part of Rider FAC as necessary to alter the sharing percentage.

[1] 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.

10. FAC Reporting. All Signatories shall have access to the following,[2] which shall be provided in Ameren Missouri's FAC Monthly Reports, unless otherwise contained in another monthly report or as otherwise noted below:

- Detailed account designations and descriptions, including changes to them between rate cases;[3]
- The additional information described at page 150, lines 9-14 of the *Staff Report – Cost of Service* filed with the Commission on December 4, 2019 ("*Staff Report*"), as modified by the description of additional information appearing in Marci Althoff's rebuttal testimony, starting at page. 4, line 19 through page 5, line 19;[4] and information related to the Renewable Choice Program as specified at page 150, lines. 15-17 of the Staff Report.

11. Documentation. Ameren Missouri will provide the follow documentation as part of its next request for a general review of its electric rates, in the form of workpapers:[5]

- For each thermal generation unit at the Labadie, Rush Island, and Sioux energy facility:
  - Hourly net generation;
  - Hourly energy offer quantities and prices;
  - Hourly energy revenues;
  - Hourly LMPs;
  - Hourly commitment status;
  - Hourly economic minimum level;

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[2] Information in FAC monthly reports could be marked as confidential and should be treated as such by those receiving it.

[3] Account designations and descriptions, as currently included in Tab 5L, pages 1-5, of the Company's FAC Monthly Report and changes as currently reported in Tab 5L, pages 6-7 (using the November 2019 Report as a reference).

[4] To the extent Ms. Althoff's modifications result in certain information not being included in the FAC monthly report, the information will be provided to all Signatories in the same manner and at the same time as it is provided to the Staff.

[5] This information need not be formally filed with the Commission through EFIS.

  - Hourly dispatch status;
  - Monthly fuel costs;
  - Monthly production costs;
  - All daily 10-day forward looking analyses documentation, as referenced in the rebuttal testimony of Andrew Meyer, used to inform unit commitment practices and generation offers; and
  - The proxy employed by the Company for variable operations and maintenance expense ("O&M");
- The 10-day forward looking analysis documentation referenced above shall:
  - Be provided for a period equal to the shorter of the time period when such documentation was maintained or for the prior three years; and
  - Show the costs and revenues accounted for in the analysis.

12. Transmission. The Signatories agree to meet prior to the next rate case to discuss FAC transmission issues related to making off-system sales or for purchases of power from outside the Midcontinent Independent Operator System, Inc. market.

E. Rate Base Adjustments

13. Intangible Plant. Undivided Joint-Interest software allocations will be treated in accordance with Staff's position as described at page 130 of the *Staff Report*.

14. Vehicles. The value of vehicles donated by Ameren Missouri, which still had an expected remaining life at the time of donation, will be represented with adjustments to increase vehicles' depreciation reserve accounts. Specifically the balances of FERC depreciation reserve account 392 shall be increased by $241,262 and FERC depreciation reserve account 396 shall be increased by $8,142.

15. Long-Term Incentive Compensation. The costs of the Performance Share Unit Plan and the Restricted Share Unit Plan shall not be recovered from Ameren Missouri's customers. No amount of capital or expense for long-term incentive compensation is included in the revenue requirement found in paragraph three above.

16. Eldon Facility. Ameren Missouri will accept Staff's position regarding the rate base value of the Eldon facility, as reflected in Exhibit G attached hereto and incorporated herein by reference.

17. BJC Healthcare. The solar facility installed at the BJC Healthcare site shall not be included in rates until in-service criteria contained in Exhibit H are shown in a future general rate proceeding to be satisfied.

18. Lambert Solar Facility. The solar facility installed near Lambert Airport shall be included in rate base.

F. Miscellaneous Expenses

19. Miscellaneous Expenses. Ameren Missouri further concedes that certain expenditures were included in its revenue requirement in error, as noted in the Rebuttal Testimony of David Loesch. The Company will examine and improve processes and provide training on those processes to address the mis-booking of expenditures. The Company will review the process changes and training with Staff and OPC for their input.

G. Rate of Return on Common Equity ("ROE")

20. The Signatories agree to an ROE range of 9.4% to 9.8%.[6]

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[6] The Signatories agree that after the effective date of new base rates as agreed herein, the Company will continue to utilize the same equity return for calculating its Allowance for Funds Used During Construction (AFUDC) as it is using as of the date of this Agreement.

H. Depreciation

21. The Signatories agree the Company shall use the depreciation rates set forth on Exhibit I hereto.

I. Integrated Resource Planning ("IRP")

22. Coal Plants. The Company will not oppose a request for an evidentiary hearing in its upcoming 2020 Triennial Resource Plan docket, and further agrees that discovery in accordance with the Commission's Chapter 2 rules shall apply in the IRP docket. All analyses required by the Commission's IRP rules and by the Commission's order on Special Contemporary Issues shall be submitted with the IRP. IRP materials shall be admissible in future rate case filings according to rules of evidence in Commission cases.

J. No RESRAM Rebase in this Case

23. For this case only, there are no Renewable Energy Standard Rate Adjustment Mechanism ("RESRAM") costs in revenue requirement and no rebase of RESRAM is necessary.

K. Revenue Allocation

24. The revenue requirement decrease described in paragraph 3 above will be applied across all classes as shown in attached spreadsheet, Exhibit J.

L. Rate Design

25. Seasonal Rates. The seasonal rate application will be prorated such that summer rates apply to all customers from June 1 through September 30 beginning in 2021. Staff and Company will collaborate on tariff language and billing units to implement this change. Ameren Missouri shall meet with Staff and OPC regarding billing cycle start dates prior to its next rate case.

26. Residential Customer Charge. The $9.00 residential customer charge will remain unchanged.

27. Residential Rate Designs.

a. Residential Default Rate with Advanced Metering Infrastructure ("AMI") Phase in:

i.

Approximate Standard and Daytime/Overnight rates are provided below, for residential customers, pending refinement and finalization:

Summer Daytime	$ 0.11960
Summer Overnight	$ 0.11460
NonSummer Daytime	$ 0.00250
NonSummer Block 1	$ 0.07850
NonSummer Block 2	$ 0.05270

ii. Within six billing months after a customer receives an AMI meter, Ameren Missouri shall communicate with the customer to educate the customer on what their bill would have been in prior billing periods under available rate options, and shall shift the customer to being billed on the Daytime/Overnight rate going forward, unless the customer opts for another available rate option.

iii. As of January 1, 2021, new customers or new accounts with AMI shall be placed directly on the Daytime/Overnight rate, but will be informed of and have the option to request all other eligible rate options.

iv. Residential AMI Deployment Communications.

1) Ameren Missouri shall provide customers a notice of intent to install AMI meters at least thirty (30) days prior to installation, and will provide an opportunity to opt-out of installation.

2) A customer will receive information regarding rate options no later than the date their AMI meter is installed.

3) Ameren Missouri shall develop an on-line neutral rate comparison tool to show a customer their bill under each available rate option based on historical usage information, and will communicate to

residential customers via their preferred communication method how to access the rate comparison tool. The timing of this communication will be addressed at the meeting in March 2020 described in point 4) below.

4) Ameren Missouri shall meet with Staff, DE, and OPC in March, April, May, and June 2020 to discuss plans to roll out customer engagement for customers receiving AMI meters.

    a) A status report shall be submitted on the progress of these meetings in the pending AMI waiver docket (File No. EE-2019-0382).

    b) Nothing precludes any Signatory from raising concerns to the Commission regarding the roll out of customer engagement.

v. The Signatories acknowledge that Ameren Missouri represents that substantial IT programming work is needed to be conducted to meet the timelines of paragraph ii, iii, and iv above. Such changes were not able to be fully scoped during the negotiation of this agreement; however, Ameren Missouri represents that it intends to meet these timelines and will make all best efforts to do so. If the fully defined scope results in barriers to meeting these timelines, Ameren Missouri shall communicate with the parties, and shall file any appropriate pleadings to request to adjust rate implementation timeframes accordingly. Signatories agree not to oppose a reasonable request to adjust the timeframes.

b. <u>EV Savers and Smart Savers Optional Rates</u>. Rate options described in Company witness Steven Wills' direct testimony as "EV Savers" and "Smart Savers" TOU rate options will be implemented as non-pilot rate options for customers with AMI metering installed. “EV Savers” will be renamed within the tariff.

    i. The EV Savers rate option will be available to non-AMI (AMR) customers for a $1.50 monthly incremental fee.

ii. The EV Savers rate option will also be made available to separately metered residential EV charging in lieu of being assigned to schedule 2(M), Small General Service ("SGS").

iii. The EV Savers and Smart Savers options may be renamed or rebranded by the Company for marketing purposes, but EV Savers shall not be marketed as limited to only electric vehicle charging customers. Tariff language will explain that the EV Savers option will be available for the whole house whether or not that household participates in electric vehicle charging. Ameren Missouri will provide its proposed rebranding terminology to parties prior to beginning active marketing.

iv. The peak to off-peak ratio for the Smart Savers option will be reduced from 6:1 ratio to 5:1.

v. The Smart Savers option's peak period will be extended to incorporate the 2 o’clock p.m. hour.

vi. Ameren Missouri will meet with Sierra Club and any other interested stakeholders no later than March 1, 2021 regarding steps needed to make sub-metering available to EV customers.

c. The Company's current flat summer and declining block non-summer residential rate will also be another option for customers to choose, but the winter rate differential shall be flattened, pending refinement and finalization as follows:

Customer Charge	$	9.00
Summer Energy Charge	$	0.11780
Non-Summer Block 1	$	0.08010
Non-Summer Block 2	$	0.05379

d. The three-part rate with demand charge and TOU energy charges as described in the direct testimony of Steven Wills will be implemented as an optional rate rather than as a pilot program. The implementation of this rate may be delayed pending completion of IT programming changes necessary to offer it on a non-pilot basis.

i. Ameren Missouri agrees that it will not propose a residential or SGS demand charge rate on any basis other than opt-in until after August 29, 2025.

ii. Report. Within six (6) months after Ameren Missouri has 500 customers (with interval data from at least one (1) year prior to, and one (1) year after, being on the three-part rate) participating on its three (3)-part rate with demand charges, the Company will provide a report to stakeholders, including Renew Missouri, detailing the following information:

1) Energy savings, if any, realized by participating customers compared to prior year;
2) Demand reduction during coincident peak ("CP") peak hours, if any, realized compared to the prior year;
3) Annual bill impact compared to what it would have been under each of the following:
   a) Daytime/Overnight rate;
   b) Company's Smart savers TOU;
   c) Company's EV savers rate;
   d) Standard non-AMI rates;
4) Billing analysis of 365 net-metered solar Ameren Missouri customers comparing what would have been the bill impact if that customer was billed using:
   a) Three (3)-part rate with demand charge;
   b) Daytime/Overnight rate;
   c) Company's Smart savers rate;
   d) Company's EV savers rate; and
   e) Standard non-AMI rates.

e. Customers who have elected to participate in the Company's current TOU rate pilot will be permitted to remain on the rate until they receive an AMI meter, at which time they will transfer to the Smart Savers optional TOU rate schedule and be given the option of selecting any other eligible rate.

28. Non-residential Rate Design.

a. The Company will propose a TOU rate option for SGS customers having AMI meters consistent with EV Savers residential rate principles in its next electric general rate case.

M. Tariffs

29. Consistency. Consistency across classes (such as Rider B, SPS and LPS customer charge, reactive charge, and TOD customer charge) shall be maintained.

30. Rider I. Rider I is changed to make application automatic for all AMI customers taking service under tariff schedule 3(M). Staff and Company will collaborate on tariff language to implement this change.

31. Schedule 2(M). Customers on tariff schedule 2(M) with AMI meters shall be reclassified to 3(M) when demand exceeds 100 kW. Prior to reclassification, the Company will notify the customer of planned reclassification with an explanation of the reason for reclassification and how the newly applied rate works. A customer shall not be reclassified in the middle of a billing cycle.

32. Remote Meter Reading Opt-Out. The language below will be used for remote meter opt out changes in tariff Sheet No. 129

> REMOTE METER READING OPT-OUT
> Customers receiving Residential Service have the option of refusing the installation of remotely read metering or requesting the removal of previously installed remotely read metering. In such instances, non-standard metering equipment will be installed that requires a manual meter read. Customers requesting non-standard metering service after April 1, 2017 will be charged a one-time setup charge and a monthly recurring Non-Standard Meter Charge. Charges are listed on Sheet No. 63, Miscellaneous Charges. Charges shall not be applicable to customers who have not been offered remote metering equipment by the Company due to geographic or similar considerations.
>
> To the extent that a customer denies access to property through verbal denial or threats of violence, or fails to establish a suitable time for access or allow access,

customer will be notified, in writing, that failure to provide access to install remotely read metering equipment will result in customer being considered an opt-out customer not sooner than 30 days after Company's notice. Company's notification will include the charges that will be added to the customer's bill as listed on Sheet No. 63, miscellaneous charges and provide information for the customer to understand the financial impact of opt-out status. Prior to deeming a residential customer to have accepted opt-out status, Company shall follow the notice procedures found in 20 CSR 4240-13.035(1)(C), with the exception of 20 CSR 4240-13.035(1)(C)2.B.

33. Miscellaneous Charges. Changes to the Miscellaneous Charges tariff sheet proposed in the direct testimony of Company witness Michael Harding will be implemented.

34. Riders SP and M. Riders SP and M will be eliminated in the Company's compliance tariff filing resulting from this case.

35. Voltage Adjustment Factors. The Company shall break out voltage adjustment factors for FAC primary level voltages in its next electric general rate case.

36. Facilities Charge. The facilities charge on tariff Sheet No. 158 shall be updated as described by Company witness Michael Harding in his direct testimony.

37. MEEIA Margin Rates. The MEEIA margin rates on tariff Sheet Nos. 91.7, 91.19, and 91.20 shall be updated.

38. Pure Power. Ameren Missouri may request extension of its Pure Power Program beyond the current June 30, 2020 expiration date until the Company implements a future Community Solar program of sufficient size to transition existing Pure Power Customers to that program. The transition of customers from Pure Power to Community Solar may occur in phases. Further, the existing Pure Program tariff is frozen and no new customers may enroll in that program as of the effective date of compliance tariffs approved by the Commission in this rate case.

N. Miscellaneous

39. Federal Energy Regulatory Commission ("FERC") ROE. 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-2016-0179.

40. Cost Measurement Savings. The Company will provide the cost measurement savings reporting to Staff and OPC and other Signatories that request it as outlined at p. 42, ll. 10-22 of Laura Moore's rebuttal testimony, except the threshold will be $500,000 and reporting will commence by July 1, 2020.

41. AMI Data Tracking.

a. Ameren Missouri shall retain a minimum of rolling 12 months interval data for customers with AMI meters so that customers may compare TOU options. Data shall be maintained in such a manner that it is accessible for load research purposes, which will require at least 16 months of data. Upon request by Staff, the Company shall make available determinants associated with the potential creation of a coincident peak demand charge for all classes, which may be based on either fifteen (15) minute or one (1) hour readings. Data shall be made available in the form of hourly usage per customer and aggregate hourly usage by rate schedule with and without applicable metering or voltage adjustments.

b. Ameren Missouri shall meet with Staff, OPC, and other interested Stakeholders in April 2020 to discuss data collection and retention policies around voltage level data, including but not limited to the following:

1. Cost of 600 V network elements;
2. Cost of network between 600 V and 34 kV;
3. Cost of 34 kV network;
4. Cost of 69 kV network;
5. Cost of 115 kV network;
6. New customer-prepaid investments by voltage and rate schedule of customer;
7. New meter investment by rate schedule;
8. Service drop investment by rate schedule and by voltage;
9. Transformer investment by rate schedule; and
10. Customer load data by geographic area as may be useful in creation of cost-based DSM programs.

c. Ameren Missouri shall follow up with Staff, OPC, and other interested Stakeholders by the end of June 2020 regarding any outstanding questions on data collection and retention policies.

42. NARUC Resolution. Interested Signatories agree to meet at a mutually agreeable time to discuss the National Association of Regulatory Utility Commissioners ("NARUC") resolution on cloud computing and the merits of rate-making solutions for the concerns raised therein.

43. Energy Statements. The Company agrees to alter customer bill presentations (also known as "energy statements") as soon as possible, but no later than September 1, 2020, so that the energy charge is broken out by rate block and season, as applicable. In addition, the Company agrees to alter non-residential customers' energy statements to show the applicable demand charges as soon as possible, but not later than September 1, 2020.

44. Pre-Pay. Ameren Missouri agrees to not propose a non-MEEIA prepay option for its customers for five years following conclusion of this rate case.

45. Keeping Current. The total budget for Keeping Current shall be increased from $1.3 million to $2 million, with a 50/50 ratepayer/shareholder funding sharing mechanism for the entire budget. The Company shall undertake a third-party study of the program consistent with the recommendation contained in the Direct Testimony of Geoff Marke. The study shall be paid for with a portion of the $2 million budget, and will have a deadline of October 31, 2020, for completion.

46. Income-Eligible Weatherization Assistance Program ("IEWAP"). Ameren Missouri shall assume administration of the IEWAP from DE, and will work with DE to smoothly transition administration of the IEWAP to the Company. The current budget of $1.2 million shall continue to be used for the weatherization subprogram and shall allow for a rollover of unspent funds to subsequent years. Since the administrative functions and the funding for IEWAP are not federally sourced, the Signatories agree the agencies need not adhere to the same guidelines for spending these funds as necessary for spending federally administered or sourced funds; therefore, assistance agencies will not have to adhere to the US DOE guidelines for weatherization. The assistance agencies, at their discretion, can use funds to weatherize properties that have historically been passed over due to eligibility related to date-last-weatherized or reasonable health and hazard conditions. Participating assistance agencies are required to document use of discretionary funds and number of properties completed annually with invitations extended to assistance agencies to participate once a year (by phone or in person) in one of the two bi-annual collaborative energy efficiency meetings. During the collaborative energy efficiency meetings, stakeholders shall discuss any guidelines that may be necessary for the assistance agencies to implement. The

Company will provide regular updates to the MEEAC Low-income Workgroup regarding funds spent and measures installed through the weatherization subprogram.

47. Paperless Bill Credit. The Signatories agree that Ameren Missouri may implement its paperless bill credit proposal as outlined in the Direct Testimony of Mark Birk. The Company shall exclude bill credits from revenues used to determine the revenue requirement in its next rate case. Ameren Missouri shall not seek recovery for any incentives or other costs directly associated with paperless billing.

48. Dues and Donations. The Signatories agree that Staff's position on dues and donations, as contained in the *Staff Report*, may be adopted for the purposes of this settlement for the following groups and associations: UARG, USWAG, UWAG, MOG, RegForm, IERG and other environmental group dues.

49. Unregulated Competition Waiver. At this time, the Company will withdraw, without prejudice, the changes it requested to its Tariff Sheet No. 161 necessary to expand its unregulated competition activities.

O. Issues Reserved for Litigation at Hearing

50. FAC Sharing Ratio. The Signatories agree that the issue of whether the FAC sharing ratio should be 95/5 or 85/15 remains unresolved and is reserved for hearing.

51. Affiliate Transactions. The Signatories agree that the affiliate transaction rules issues raised by the OPC remain unresolved and are reserved for hearing. The Signatories agree that if OPC were to obtain a cost disallowance after hearing, the sum would be deferred to a regulatory liability for recovery over a period of time, beginning with the effective date of rates in the next electric rate case.

GENERAL PROVISIONS

52. 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.

53. 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.

54. 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 2000 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.

55. 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 2000; (2) their respective rights to present oral argument and/or written briefs pursuant to Section 536.080.1, RSMo 2000; (3) their respective rights to the reading of the transcript by the Commission pursuant to Section 386.080.2, RSMo 2000; (4) their respective rights to seek rehearing pursuant to Section 386.500, RSMo 2000; and (5) their respective rights to judicial review pursuant to Section 386.510, RSMo Supp. 2011. 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*.

56. 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.

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

58. 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.

59. 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,

/s/ Wendy Tatro
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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 28th day of February, 2020, to counsel for all parties on the Commission's service list in this case.

/s/ Wendy Tatro

Weather Normalized-12 months ending June 2019
December 2019 Actuals

Residential Class

	Billing Units	Present Rates	Present Revenue
Customer Charge			
Summer Bills	4,273,116	$9.00	$38,458,044
Winter Bills	8,546,232	$9.00	$76,916,088
TOD Bills	1,440	$9.00	$12,960
Low Income Charge	12,820,788	$0.04	$512,832
Total Bills	12,820,788		
Energy Charge			
Summer kWh	4,684,150,566	$0.1258	$589,266,141
On-peak	103,415	$0.3150	$32,576
Off-peak	599,997	$0.0787	$47,220
Energy Eff kwh	4,684,544,568	$0.0003	$1,405,363
Tax Credit	4,684,853,978	-$0.0062	-$29,092,943
Winter kWh			
First 750 kWh	4,798,417,126	$0.0876	$420,341,340
Over 750 kWh	3,618,247,401	$0.0600	$217,094,844
On-peak			
Off-peak			
Energy Eff Charge	8,414,975,385	$0.0002	$1,682,995
Tax Credit	8,416,664,527	-$0.0062	-$52,267,487
Total kWh	13,101,518,505		
		Total	**$1,264,409,973**

Weather Normalized-12 months ending June 2019
December 2019 Actuals

Small General Service Class

	Billing Units	Present Rates	Present Revenue
Customer Charge			
Summer Bills			
One-phase	375,068	$11.19	$4,197,011
Three-phase	154,464	$21.38	$3,302,440
Winter Bills			
One-phase	750,136	$11.19	$8,394,022
Three-phase	308,928	$21.38	$6,604,881
TOD Bills			
Limited Unmetered Service	82,092	$5.92	$485,985
One-phase	13,872	$21.43	$297,277
Three-phase	1,656	$41.84	$69,287
6M		$6.71	$0
Low Income Charge	1,686,216	$0.05	$84,311
Total Bills	1,686,216		
Energy Charge			
Summer kWh	1,118,027,013	$0.1120	$125,219,025
On-peak	13,938,343	$0.1664	$2,319,340
Off-peak	24,411,083	$0.0678	$1,655,071
Energy Eff Charge	1,153,704,474	$0.0001	$115,370
Summer kWh to Lighting Rate	713,461	$0.0472	$33,675
Tax Credit	1,157,089,900	-$0.0058	-$6,722,692
Winter kWh			
Base	1,605,429,446	$0.0836	$134,213,902
Seasonal	430,016,096	$0.0482	$20,726,776
On-peak	24,005,098	$0.1096	$2,630,959
Off-peak	43,603,039	$0.0503	$2,193,233
Energy Eff Charge	2,092,612,575	$0.0001	$209,261
Winter kWh to Lighting Rate	1,484,934	$0.0472	$70,089
Tax Credit	2,104,538,613	-$0.0058	-$12,227,369
Total kWh	3,261,628,513	Total	**$293,871,854**

Weather Normalized-12 months ending June 2019
December 2019 Actuals

Large General Service

	Billing Units	Present Rates	Present Revenue
Customer Charge			
Summer Bills	42,548	$94.51	$4,021,211
Winter Bills	85,096	$94.51	$8,042,423
TOD Bills	444	$115.59	$51,322
Low Income Charge	128,088	$0.56	$71,729
Demand Charge (kW)			
Summer	8,273,089	$5.40	$44,674,680
Winter	15,518,045	$2.00	$31,036,090
Energy Charge			
Summer kWh			
First 150HU	1,085,493,087	$0.1058	$114,845,169
Next 200HU	1,208,921,574	$0.0796	$96,230,157
Over 350HU	521,393,649	$0.0535	$27,894,560
On-peak	5,456,949	$0.0125	$68,212
Off-peak	10,871,547	-$0.0071	-$77,188
Energy Eff Charge	2,708,685,886	$0.0003	$812,606
Tax Credit	2,815,808,310	-$0.0046	-$13,009,034
Winter kWh			
Base Energy Charge			
First 150HU	1,792,732,766	$0.0665	$119,216,729
Next 200HU	1,949,165,137	$0.0494	$96,288,758
Over 350HU	815,697,139	$0.0389	$31,730,619
Seasonal Energy	372,719,692	$0.0389	$14,498,796
On-peak	8,611,362	$0.0038	$32,723
Off-peak	17,860,411	-$0.0021	-$37,507
Energy Eff Charge	4,728,712,157	$0.0002	$945,742
Tax Credit	4,930,314,734	-$0.0046	-$22,778,054
Total kWh	7,746,123,044		**$554,559,744**

Weather Normalized-12 months ending June 2019
December 2019 Actuals

Small Primary Service

	Billing Units	Present Rates	Present Revenue
Customer Charge			
Summer Bills	2,571	$323.82	$832,541
Winter Bills	5,191	$323.82	$1,680,950
TOD Bills	216	$344.90	$74,498
Low Income Charge	7,978	$0.56	$4,468
Demand Charge (kW)			
Summer	2,891,919.29	$4.66	$13,476,344
Winter	5,325,745.14	$1.69	$9,000,509
Energy Charge			
Summer kWh			
First 150HU	415,881,916	$0.1023	$42,544,720
Next 200HU	509,749,137	$0.0770	$39,250,684
Over 350HU	381,029,001	$0.0516	$19,661,096
On-peak	14,445,544	$0.0091	$131,454
Off-peak	30,463,144	-$0.0051	-$155,362
Energy Eff Charge	1,173,234,774	$0.0003	$351,970
Tax Credit	1,306,660,054	-$0.0040	-$5,278,907
Winter kWh			
First 150HU	699,721,280	$0.0644	$45,062,050
Next 200HU	862,936,780	$0.0478	$41,248,378
Over 350HU	641,375,537	$0.0374	$23,987,445
Seasonal Energy	183,211,164	$0.0374	$6,852,098
On-peak	28,598,592	$0.0034	$97,235
Off-peak	54,590,952	-$0.0018	-$98,264
Energy Eff Charge	2,037,593,701	$0.0002	$407,519
Tax Credit	2,387,244,761	-$0.0040	-$9,644,469
Total kWh	3,693,904,815		
Reactive Charge	1,319,827	$0.38	$501,534
Rider b			
115 kV	4,547.07	-$1.46	-$6,639
69 kV	884,519.34	-$1.23	-$1,087,959
			$228,893,896

Weather Normalized-12 months ending June 2019
December 2019 Actuals

Large Primary Service

	Billing Units	Present Rates	Present Revenue
Customer Charge			
Bills	708	$323.82	$229,265
TOD	60	$344.90	$20,694
Low Income Charge	768	61.1	$46,925
Demand Charge (kW)			
Summer	2,432,878.50	$21.16	$51,479,709
Winter	4,366,541.60	$9.61	$41,962,465
Energy Charge			
Summer kWh			
Energy	1,354,048,178	$0.0354	$47,933,305
On Peak	42,663,576	$0.0069	$294,379
Off-Peak	88,342,211	-$0.0038	-$335,700
Energy Eff Charge	689,408,376	$0.0001	$68,941
Tax Credit	1,354,048,178	-$0.0035	-$4,712,088
Winter kWh			
Energy	2,379,902,001	$0.0314	$74,728,923
On Peak	74,334,194	$0.0031	$230,436
Off-Peak	149,600,127	-$0.0018	-$269,280
Energy Eff Charge	1,219,609,454	$0.0001	$121,961
Tax Credit	2,379,902,001	-$0.0035	-$8,282,059
Total kWh	3,733,950,179		
Reactive Charge	376,667	$0.38	$143,133
Rider b			
115 kV	619,835.90	-$1.46	-$904,960
69 kV	1,843,786.90	-$1.23	-$2,267,858
			$200,488,190

Weather Normalized-12 months ending June 2019
December 2019 Actuals

Company Owned Lighting 5M

Description CSS Code	Count	Present Rates	Present Revenue
LED 100 W EQ Bracket	51,618	$10.31	$6,386,179
LED 250 W EQ Bracket	7,549	$16.70	$1,512,820
LED 400 W EQ Bracket	1,414	$30.89	$524,142
9500 HPS Enclosed	8,797	$12.89	$1,360,720
25500 HPS Enclosed	8,345	$18.63	$1,865,608
50000 HPS Enclosed	1,708	$33.21	$680,672
6800 MV Enclosed	4,818	$12.89	$745,248
20000 MV Enclosed	2,280	$18.63	$509,717
54000 MV Enclosed	58	$33.21	$23,114
LED Direct-Small	1,214	$21.61	$314,814
LED Direct-Medium	1,630	$34.69	$678,536
LED Direct-Large	264	$69.13	$219,004
LED Post Top - All	3,507	$22.59	$950,678
5800 HPS Open Btm	86	$10.44	$10,774
9500 HPS Open Btm	28,276	$11.41	$3,871,550
3300 MV Open Btm	1,679	$10.44	$210,345
6800 MV Open Btm	9,048	$11.41	$1,238,852
9500 HPS Post Top	42,104	$23.65	$11,949,115
3300 MV Post Top	95	$22.35	$25,479
6800 MV Post Top	8,154	$23.65	$2,314,105
25500 HPS Direct	2,997	$23.65	$850,549
50000 HPS Direct	3,052	$37.40	$1,369,738
34000 MH Direct	4,273	$23.65	$1,212,677
100000 MH Direct	671	$74.76	$601,968
20000 MV Direct	236	$23.65	$66,977
54000 MV Direct	26	$37.40	$11,669
11000 MV Open Btm	101	$11.41	$13,829
140000 HPS Direct	9	$74.76	$8,074
			$39,526,952
		Tax Credit	-$1,907,139
		Realized Municpal Discount	0.03942
			$36,136,709

Weather Normalized-12 months ending June 2019
December 2019 Actuals

Customer Owned Lighting 6M

Description CSS Code	Count	Present Rates	Present Revenue
Metered service (cust charge	1,608	$6.97	$134,493
Energy charge (per kWh)	51,913,763	$0.0472	$2,450,330
9500 HPS Enrg&Maint	11,468	$3.8000	$522,941
25500 HPS Enrg&Maint	701	$6.6100	$55,603
50000 HPS Enrg&Maint	71	$9.5400	$8,128
5500 MH Enrg&Maint	169	$5.4900	$11,134
12900 MH Enrg&Maint	53	$6.5700	$4,179
3300 MV Enrg&Maint	5	$3.8000	$228
6800 MV Enrg&Maint	2,024	$4.9400	$119,983
11000 MV Enrg&Maint	26	$6.6900	$2,087
20000 MV Enrg&Maint	38	$8.8700	$4,045
54000 MV Enrg&Maint	4	$18.9300	$909
9500 HPS Enrgy Only	178	$1.8400	$3,930
25500 HPS Enrgy Only	44	$4.7000	$2,482
50000 HPS Enrgy Only	1	$7.3900	$89
3300 MV Enrgy Only	84	$1.9500	$1,966
6800 MV Enrgy Only	122	$3.1700	$4,641
11000 MV Energy Only	24	$4.5100	$1,299
20000 MV Energy Only	88	$6.9600	$7,350
54000 MV Energy Only	11	$16.5700	$2,187
100W LED Energy Only	36	$1.5900	$687
180W LED Energy Only	2	$2.8600	$69
25W LED Energy Only	2	$0.4000	$10
26W LED Energy Only	17	$0.4100	$84
36W LED Energy Only	42	$0.5700	$287
40W LED Energy Only	25	$0.6400	$192
45W LED Energy Only	33	$0.7200	$285
57W LED Energy Only	7	$0.9100	$76
60W LED Energy Only	4	$0.9500	$46
70W LED Energy Only	13	$1.1100	$173
72W LED Energy Only	2	$1.1400	$27
75W LED Energy Only	182	$1.1900	$2,599
85W LED Energy Only	51	$1.3500	$826
6M Ltd LED 100 W EQ	5,930	$3.5200	$250,483
6M Ltd LED 250 W EQ	103	$4.9800	$6,155
6M Ltd LED 400 W EQ	5	$9.4200	$565
			$3,600,566
		Tax Credit	-$195,772
		Realized Municpal Discount	0.0538452
			$3,221,462

Weather Normalized-12 months ending June 2019
December 2019 Actuals

MSD Horsepower Service

Connected Horsepower	Current Rate	Amount of Bill at .1735 per Horsepower Per Month	Annual
36,900.0	0.1735	$6,402	**$76,826**

Cumulative Deemed Gross kWh Savings through December 2019

	Residential: Non Low-Income				Residential: Low-Income	
End Use	MEEIA 2	MEEIA 2 Long Lead	MEEIA 3	End Use	MEEIA 2	MEEIA 3
Building Shell	28,987,950	0	11,016,425	Building Shell	0	0
Cooling	82,504,705	0	16,103,847	Cooling	136,785	575,036
Freezer	0	0	316,240	Freezer	0	0
Heating		0	10,718,216	Heating		1,105,731
HVAC	109,002,041	0	9,706,549	HVAC	4,320,808	50,903
Lighting	78,836,547	0	50,406,495	Lighting	1,549,657	176,431
Miscellaneous	0	0	0	Miscellaneous	0	26,244
Pool Spa	5,301,091	0	1,437,025	Pool Spa	0	0
Refrigeration	0	0	1,026,251	Refrigeration	1,787,539	22,586
Water Heating	6,626,065	0	2,598,848	Water Heating	1,263,575	145,310
Motors(uses bus. load shape)	476,446	0	0	Motors(uses bus. load shape)	0	0
Total	311,734,844	0	103,329,897	Total	9,058,364	2,102,242

NOTES: 1) MEEIA 3 energy savings were adjusted to 1) exclude Low Income building shell, 2) use different lighting savings for Nov. and Dec. 2019, 3) additional adjustment to reflect the inadvertant inclusion of losses in the rate case annualization adjustment'

	2M - Small General Service				2M - Small General Service Low-income	
End Use	MEEIA 2	MEEIA 2 Long Lead	MEEIA 3	End Use	MEEIA 2	MEEIA 3
Air Comp BUS	979,848	0	0	Air Comp BUS	0	0
Building Shell BUS	59,252	0	2,295	Building Shell BUS	0	0
Cooking BUS	0	0	0	Cooking BUS	0	0
Cooling BUS	928,850	2,135	41,184	Cooling BUS	2,994	2,464
Ext Lighting BUS	13,259,868	40,611	0	Ext Lighting BUS	509,166	0
Heating BUS	13,592	0	0	Heating BUS	0	0
HVAC BUS	1,031,114	0	336,986	HVAC BUS	296,368	0
Lighting BUS	112,915,401	960,952	18,349,922	Lighting BUS	5,368,832	427,500
Miscellaneous BUS	1,139,299	0	0	Miscellaneous BUS	0	0
Motors BUS	394,979	0	169,521	Motors BUS	0	0
Process BUS	404,477	0	0	Process BUS	0	0
Refrigeration BUS	225,555	0	26,245	Refrigeration BUS	25,964	0
Water Heating BUS	211,560	3,804	10,700	Water Heating BUS	25,303	0
Total	131,563,795	1,007,502	18,936,853	Total	6,228,627	429,964

3M - Large General Service

End Use	MEEIA 2	MEEIA 2 Long Lead	MEEIA 3
Air Comp BUS	4,002,689	0	1,545,304
Building Shell BUS	291,822	0	139,580
Cooking BUS	33,120	0	18,369
Cooling BUS	15,373,436	1,275,633	1,002,448
Ext Lighting BUS	20,186,298	873,816	0
Heating BUS	1,238,062	10,989	0
HVAC BUS	15,368,325	1,282,183	3,981,895
Lighting BUS	253,653,443	3,772,656	34,983,335
Miscellaneous BUS	12,176,630	0	67,040
Motors BUS	1,897,032	0	366,737
Process BUS	1,076,145	0	0
Refrigeration BUS	1,804,521	111,385	1,490,010
Water Heating BUS	1,810	0	41,830
Total	327,103,333	7,326,662	43,636,547

3M - Large General Service Low-income

End Use	MEEIA 2	MEEIA 3
Air Comp BUS	0	0
Building Shell BUS	0	0
Cooking BUS	0	0
Cooling BUS	185,786	0
Ext Lighting BUS	30,126	0
Heating BUS	0	0
HVAC BUS	65,908	0
Lighting BUS	3,118,172	520,032
Miscellaneous BUS	30,869	0
Motors BUS	0	0
Process BUS	0	0
Refrigeration BUS	17,964	0
Water Heating BUS	52,919	0
Total	3,501,744	520,032

4M - Small Primary Service

End Use	MEEIA 2	MEEIA 2 Long Lead	MEEIA 3
Air Comp BUS	6,481,530	0	21,083
Building Shell BUS	97,256	0	0
Cooking BUS	0	0	0
Cooling BUS	15,195,549	427,722	924,197
Ext Lighting BUS	1,815,850	86,396	0
Heating BUS	67,382	0	0
HVAC BUS	6,232,115	0	34,800
Lighting BUS	75,511,951	1,430,374	5,528,324
Miscellaneous BUS	1,988,893	0	0
Motors BUS	13,636,876	137,000	411,896
Process BUS	5,779,417	0	0
Refrigeration BUS	2,844,277	0	0
Water Heating BUS	0	0	0
Total	129,651,096	2,081,492	6,920,299

4M - Small Primary Service Low-income

End Use	MEEIA 2	MEEIA 3
Air Comp BUS	0	0
Building Shell BUS	0	0
Cooking BUS	0	0
Cooling BUS	320,857	0
Ext Lighting BUS	10,302	0
Heating BUS	0	0
HVAC BUS	0	0
Lighting BUS	531,301	0
Miscellaneous BUS	0	0
Motors BUS	0	0
Process BUS	0	0
Refrigeration BUS	16,872	0
Water Heating BUS	0	0
Total	879,331	0

11M - Large Primary Service			
End Use	MEEIA 2	MEEIA 2 Long Lead	MEEIA 3
Air Comp BUS	4,851,064	0	275,865
Building Shell BUS	37,045	0	0
Cooking BUS	0	0	0
Cooling BUS	8,661,269	0	329,836
Ext Lighting BUS	428,429	0	0
Heating BUS	0	0	0
HVAC BUS	4,660,888	0	0
Lighting BUS	14,996,551	151,462	561,876
Miscellaneous BUS	794,921	0	83,115
Motors BUS	96,758	0	0
Process BUS	1,080,758	0	0
Refrigeration BUS	0	0	0
Water Heating BUS	0	0	0
Total	35,607,683	151,462	1,250,693

11M - Large Primary Service Low-income		
End Use	MEEIA 2	MEEIA 3
Air Comp BUS	0	0
Building Shell BUS	0	0
Cooking BUS	0	0
Cooling BUS	0	0
Ext Lighting BUS	0	0
Heating BUS	0	0
HVAC BUS	0	0
Lighting BUS	0	0
Miscellaneous BUS	0	0
Motors BUS	0	0
Process BUS	0	0
Refrigeration BUS	0	0
Water Heating BUS	0	0
Total	0	0

Ameren Missouri
Case No. ER-2019-0335
Net Base Energy Costs
Base Factors

Acct. No.	Description	Total	Summer	Winter	Summer %	Winter %	Total
	Fuel and Purchased Power Costs						
501	Fuel for Baseload	383,869,528	135,301,082	248,568,446	35.25%	64.75%	100.00%
518	Fuel for Baseload (Nuclear)	80,726,617	29,442,194	51,284,423	36.47%	63.53%	100.00%
547	Other Power for Baseload (i.e. natural gas and oil)	15,075,556	7,739,429	7,336,126	51.34%	48.66%	100.00%
501	Fly Ash Expense	2,728,953	961,864	1,767,089	35.25%	64.75%	100.00%
501	Fly Ash Revenue	(3,451,299)	(1,216,467)	(2,234,832)	35.25%	64.75%	100.00%
502	Fuel Additives	5,665,444	2,056,394	3,609,051	36.30%	63.70%	100.00%
547	Fixed Gas Supply Costs for Baseload	6,251,880	2,269,253	3,982,627	36.30%	63.70%	100.00%
555	Purchased Power for Baseload	13,917,481	3,105,140	10,812,341	22.31%	77.69%	100.00%
	Total Fuel and PP for Baseload	504,784,160	179,658,889	325,125,271			
501	Fuel for Off-System Sales	140,364,185	49,473,648	90,890,537	35.25%	64.75%	100.00%
518	Fuel for Baseload (Nuclear)	-	-	-	36.47%	63.53%	100.00%
547	Other Power for OSS (i.e. natural gas and oil)	5,513,840	2,830,674	2,683,167	51.34%	48.66%	100.00%
501	Fly Ash Expense	998,106	351,799	646,308	35.25%	64.75%	100.00%
501	Fly Ash Revenue	(1,262,302)	(444,919)	(817,383)	35.25%	64.75%	100.00%
502	Fuel Additives	2,072,120	752,120	1,320,000	36.30%	63.70%	100.00%
547	Fixed Gas Supply Costs for OSS	2,286,037	829,766	1,456,271	36.30%	63.70%	100.00%
555	Purchased Power for OSS	5,090,278	1,135,696	3,954,582	22.31%	77.69%	100.00%
	Total Fuel and PP for Interchange (OSS)	155,062,264	54,928,784	100,133,480			
	Total Fuel and Purchased Power Costs	659,846,424	234,587,673	425,258,751			
	Other Costs						
555	MISO Day 2 Expense	21,767,387	7,900,937	13,866,450	36.30%	63.70%	100.00%
555	Common Boundary Purchases	83,518	30,315	53,203	36.30%	63.70%	100.00%
555	Capacity Expenses	8,208,207	2,979,344	5,228,863	36.30%	63.70%	100.00%
555	Ancillary Services	2,728,925	990,521	1,738,404	36.30%	63.70%	100.00%
555	PJM Expense	2,264,803	822,058	1,442,745	36.30%	63.70%	100.00%
565	Transmission by Others	1,089,545	395,474	694,071	36.30%	63.70%	100.00%
456	Transmission Revenue (offset)	(406,498)	(147,547)	(258,951)	36.30%	63.70%	100.00%
	Total Other Costs	35,735,887	12,971,101	22,764,786			
	Total Fuel, PP, and Other Costs	695,582,311	247,558,774	448,023,537			
	Sales						
447	Off-System Energy Sales	259,827,205	82,342,720	177,484,485	31.69%	68.31%	100.00%
447	MISO Day 2 Revenues - Make Whole Payments	3,341,561	1,212,891	2,128,670	36.30%	63.70%	100.00%
447	MISO Day 2 Revenues - Inadvertent	-	-	-	36.30%	63.70%	100.00%
447	Capacity Revenues	17,633,058	6,400,294	11,232,764	36.30%	63.70%	100.00%
447	Ancillary Services Revenue	6,216,782	2,256,513	3,960,269	36.30%	63.70%	100.00%
447	Bilateral Energy Sales Margins	1,309,855	475,440	834,415	36.30%	63.70%	100.00%
447	Financial Swaps	1,674,837	607,918	1,066,919	36.30%	63.70%	100.00%
447	Load and Generation Forecasting Deviation	8,344,246	3,028,722	5,315,524	36.30%	63.70%	100.00%
	Total Sales	298,347,544	96,324,498	202,023,046			
	Net Base Energy Costs	397,234,767	151,234,276	246,000,491			
	Load Forecast at Generation Level	33,095,994,000	12,012,896,000	21,083,098,000	36.30%	63.70%	100.00%
	Net Base Fuel Costs ($/MWh)	$ 12.00	$ 12.59	$ 11.67			
	Net Base Fuel Costs (cents/kWh)	1.200	1.259	1.167			

Exhibit D

File No. ER-2019-0335
Summary of Amortizations

Callaway Post Op Amortization	3,687,466
PISA Amortization	2,575,376
Pension Tracker Amortization	(13,355,744)
OPEB Tracker Amortization	(2,289,697)
Storm Tracker Amortization (2014)	0
Storm Tracker Amortization (2016)	(566,668)
Sioux Scrubber Construction Accounting	2,040,689
FIN 48 Tracker (2016)	0
Solar Rebate (2019)	136,999
Fukushima Study Costs	92,656
RES Regulatory Liability (2019)	(3,623,483)
Expired & Expiring Amortizations – Non Rate Base	(3,569,798)
Expired & Expiring Amortizations – Rate Base	(1,006,570)
Callaway Life Extension	103,877
Excess Deferred Tax Tracker	(368,768)
Federal Income Tax Rate Change – Stub Period	(19,912,622)
Federal Excess Deferred Tax Amortization	(55,912,669)
State Excess Deferred Tax Amortization	(21,122,762)

Exhibit E

File No. ER-2019-0335

Summary of Balances of Amortizations

	Balances At 12/31/2019
Callaway Post Op Amortization	17,822,736
PISA Regulatory Asset	51,507,518
Pension Tracker Amortization	(56,710,948)
OPEB Tracker Amortization	(10,963,435)
Storm Tracker Amortization (2014)	(534,562)
Storm Tracker (2016)	(1,275,004)
Sioux Scrubber Construction Accounting	28,059,479
FIN 48 Tracker (2016)	570,296
Solar Rebate (2019)	410,996
Fukushima Study Costs	501,889
RES Regulatory Liability (2019)	(10,870,449)
Expired & Expiring Amortizations – Non Rate Base	(5,797,506)
Expired & Expiring Amortizations – Rate Base	(537,066)
Callaway Life Extension	2,572,611
Excess Deferred Tax Tracker	(1,106,304)
Federal Income Tax Rate Change – Stub Period	(59,737,866)
Federal Excess Deferred Tax [1]	(939,546,408)
State Excess Deferred Tax[1]	(105,613,810)

[1] These amounts are not grossed up for taxes.

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.

* 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.

*Indicates Change.

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;

   **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.

*Indicates Change. **Indicates Addition.

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, (b) all charges under Midcontinent Independent System Operator, Inc. ("MISO") Schedules 10, 16, 17 and 24 (or any successor to those MISO Schedules), and excluding generation capacity charges for contracts with terms in excess of one (1) year. 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);

*Indicates Change.

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.)

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 44/100 percent (1.44%) of transmission service costs reflected in FERC Account 565 and one and 44/100 percent (1.44%) 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 and (b) costs or revenues under MISO Schedule 10, or any successor to that MISO Schedule). Such transmission service costs and revenues included in Factor PP include:

*Indicates Addition. **Indicates Change.

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.

* Indicates Change

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.)

*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, (b) amounts associated with generation assets dedicated, as of the date BF was determined, to specific customers under the Renewable Choice Program tariff and (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 when it began commercial operation) 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.

* Indicates Change.

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 $0.01259 per kWh. The BF applicable to October through May calendar months (BF_{WINTER}) is $0.01167 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), 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).

*Indicates Change.

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.)

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) 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).

*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 $FAR_{(RP-1)}$

*Indicates Change. **Indicates Addition.

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.)

**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 1.0476%.

*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})	1.0570
Primary Voltage Service (VAF_{PRI})	1.0224

** 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} = Fuel Adjustment Rate applicable to customers taking service under Service Classification No. 11(M), Large Primary Service, which is calculated as the minimum of the Initial Rate Component for the FAR applicable to Primary Voltage Service and RAC_{LPS}

*Indicates Change. **Indicates Addition.

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 Initial Rate Component for Primary Customers 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 =
(((Initial Rate Component For Primary Customers– 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 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)

The FAR applicable to the individual Service Classifications, including the calculations on Lines 16 through 21 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.

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.

*Indicates Addition. **Indicates Change.

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.)

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 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;

* Indicates Change.

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;

*Indicates Change.

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 Regulation Deployment Adjustment;
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;

*Indicates Addition.

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**

Transmission Schedule 1A – Tariff Administrative Fee;
Transmission Schedule 12 – FERC Assessment;

** Indicates Addition.

RIDER FAC

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

(Applicable To services provided on XXXXXX through XXXXX)

*Calculation of Current Fuel Adjustment Rate (FAR):

	Accumulation Period Ending:		
* 1.	Actual Net Energy Cost = (ANEC) (FC+PP+E+R -OSSR)		$
2.	(B) = (BF x S_{AP})	-	$
2.1	Base Factor (BF)		$/kWh
2.2	Accumulation Period Sales (S_{AP})		kWh
3.	Total Company Fuel and Purchased Power Difference	=	$
3.1	Customer Responsibility	x	95%
4.	Fuel and Purchased Power Amount to be Recovered	=	$
4.1	Interest (I)	-	$
*4.2	True-Up Amount (TUP)	+	$
4.3	Prudence Adjustment Amount (P)	±	$
5.	Fuel and Purchased Power Adjustment (FPA)	=	$
6.	Estimated Recovery Period Sales (S_{RP})	÷	kWh
7.	Current Period Fuel Adjustment Rate (FAR_{RP})	=	$0.00000/kWh
8.	Prior Period Fuel Adjustment Rate (FAR_{RP-1})	+	$0.00000/kWh
** 9.	Preliminary Fuel Adjustment Rate (PFAR)	=	$0.00000/kWh
**10.	Rate Adjustment Cap (RAC)	=	$0.00000/kWh
*11.	Fuel Adjustment Rate (FAR, lesser of PFAR and RAC)	=	$0.00000/kWh

**Initial Rate Component for the Individual Service Classifications

*12.	Secondary Voltage Adjustment Factor (VAF_{SEC})		1.0570
13.	Initial Rate Component for Secondary Customers		$0.00000/kWh
*14.	Primary Voltage Adjustment Factor (VAF_{PRI})		1.0224
15.	Initial Rate Component for Primary Customers		$0.00000/kWh

**FAR Applicable to the Individual Service Classifications

16.	RAC_{LPS}	=	$0.00000/kWh
17.	FAR for Large Primary Service (FAR_{LPS},Final, lesser of 15 and 16)	=	$0.00000/kWh
18.	Difference (Line 15 – Line 17) if applicable	=	$0.00000/kWh
19.	Estimated Recovery Period Metered Sales for LPS (SLPS)		kWh
20.	FAR Shortfall Adder (Line 18 x Line 19)		$
21.	Per kWh FAR Shortfall Adder (Line 20 / (Line 6 – SRP-LPS))	=	$0.00000/kWh
22.	FAR for Secondary Customers (FARSEC) (Line 13 + (Line 21 x Line 12))	=	$0.00000/kWh
23.	FAR for Primary Customers (FARPRI) (Line 15 + (Line 21 x Line 14))	=	$0.00000/kWh

The Applicable FARs, which became effective with the June 2020 billing month, will apply to all customer usage through September 30, 2020.

*Indicates Change. **Indicates Addition.

Exhibit G

Eldon Rate Base

Account			Joint		Electric (89.98%)	
389	Land - NBV @ 12/31/19	$	251,709	$	226,488	
	Staff Adjustments from direct					
	Remove Repurchase	$	(216,438)	$	(194,751)	1)
	Plus Orginal Cost	$	9,851	$	8,864	2)
	Adj. NBV	$	45,122	$	40,601	

Account						
390	Building - NBV @ 12/31/19	$	1,325,269	$	1,192,477	
	Staff Adjustments from direct					
	Plus Orginal Cost	$	130,611	$	117,524	3)
	Plus Orginal Reserve updated through 12/31/19	$	(101,818)	$	(91,616)	4)
	Adj. NBV	$	1,354,062	$	1,218,385	

Staff's four adjustments from its direct filing

1) 389 Plant: $8,864 - restore original cost of the land at the time of donation
2) 389 Plant: ($194,751) - remove repurchase price of the land
3) 390 Plant: $117,524 - restore original cost at the time of donation
4) 390 Reserve: $91,616 - restore reserve of the at the time of the doantion and update through December 31, 2019

EXHIBIT H

Solar Electrical Generator
In-Service Test Criteria

1. All major construction work is complete.
2. All preoperational tests have been successfully completed.
3. Facility successfully meets contract operational guarantees that are necessary for satisfactory completion of all other items in this list.
4. Upon observation of the facility for 72 consecutive hours the facility will have demonstrated that when sunlight was shining on it during that period it produced power in a standard operating mode.
5. Facility shall meet at least 95% of the guaranteed capacity (in MW AC) based on the Capacity Test in Attachment 1. The Capacity Test shall determine the facility's Corrected Capacity at the Design Point Conditions.
6. Sufficient transmission/distribution interconnection facilities shall exist for the total plant design net electrical capacity at the time the facility is declared fully operational and used for service.
7. Sufficient transmission/distribution facilities shall exist for the total plant design net electrical capacity into the utility service territory at the time the facility is declared fully operational and used for service.

EXHIBIT H

Attachment 1

Definitions:

"Corrected Capacity" means the most recent actual tested Capacity, in MW, corrected to Design Point Conditions (DPC) as described herein.

"Design Point Conditions" (DPC) means a set of ambient reference conditions, which include a solar irradiance of 1050 watts per meter square, module cell temperature of forty-five degrees (45°) Celsius, atmospheric air mass of 1.5 or less and wind speed of one (1) meter per second.

"POA" means plan of array irradiance.

The Capacity Test shall determine the Corrected Capacity at the Design Point Conditions. Capacity Test will be based on the relevant environmental conditions in the field at the time of such test, including field irradiance and temperature. The measured Capacity shall then be "corrected" to the Design Point Conditions and the resulting Corrected Capacity shall be compared to the Guaranteed Capacity as set forth herein.

The Capacity Test data shall consist of a minimum of 50, 15-minute blocks of average Plane of Array Irradiance (POA) solar irradiance data; where POA is at least 500 W/m2.

a. **Calculations Procedures:**

(1) $T_{cell} = T_{module} + 1.5$

(2) $W_{COR} = W_{meas} * (IRR_{DPC}/IRR) * (1/(1+TCOEFF\ (T_{cell}-T_{DPC})))$

(3) $W_{guar} = \dfrac{W_{COR}}{W_{GUAR}}$

Where …

- W_{MEAS} = Measured AC capacity in [MW]
- W_{COR} = Corrected AC capacity at Design Point Condition (DPC) in [MW]
- IRR_{DPC} = Direct normal irradiance at DPC (1050 W/M2) in [W/m2]
- IRR = Measured irradiance in [W/m2]
- TCOEFF = Temperature at coefficient of maximum power of installed panel (-0.0036/°C) [/°C]
- T_{module} = Measured module temperature in [°C]
- T_{cell} = Measured cell temperature in [°C]
- T_{DPC} = Temperature at DPC (45°C in [°C]
- W_{GUAR} = Guaranteed AC capacity of the system (1.45 MW-AC) in [MW]

EXHIBIT H

Note: Cell temperature is calculated based on the module temperature readings taken from a T-type thermocouple placed on the underside and center of the DUT. A correction factor of 1.5°C is assumed for backsheet to cell temperature as per the standard practice of glass and backsheet constructed c-Si modules.

AMEREN MISSOURI

ELECTRIC DIVISION

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, AND ANNUAL DEPRECIATION RATES

	DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	NET SALVAGE PERCENT	DEPRECIATION RATE
	STEAM PRODUCTION PLANT				
	MERAMEC STEAM PRODUCTION PLANT				
311	STRUCTURES AND IMPROVEMENTS	09-2022	90-R1.5	0	6.09
312	BOILER PLANT EQUIPMENT	09-2022	55-R0.5	(1)	8.43
314	TURBOGENERATOR UNITS	09-2022	60-S0.5	0	6.44
315	ACCESSORY ELECTRIC EQUIPMENT	09-2022	75-S0	0	8.57
316	MISCELLANEOUS POWER PLANT EQUIPMENT	09-2022	40-L0	0	16.85
316.21	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE FURNITURE		20-SQ	0	5.63
316.22	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE EQUIPMENT		15-SQ	0	8.26
316.23	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTERS		5-SQ	0	40.23
	SIOUX STEAM PRODUCTION PLANT				
311.00	STRUCTURES AND IMPROVEMENTS	09-2033	100-R1.5	(1)	3.37
312.00	BOILER PLANT EQUIPMENT	09-2033	55-R0.5	(5)	4.49
314.00	TURBOGENERATOR UNITS	09-2033	60-S0	(2)	3.57
315.00	ACCESSORY ELECTRIC EQUIPMENT	09-2033	70-S0	(1)	3.70
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	09-2033	40-L0	0	6.14
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	09-2042	100-R1.5	(1)	1.56
312.00	BOILER PLANT EQUIPMENT	09-2042	55-R0.5	(5)	2.18
312.03	BOILER PLANT EQUIPMENT - ALUMINUM COAL CARS	09-2042	25-R25	25	0.69
314.00	TURBOGENERATOR UNITS	09-2042	60-S0	(2)	2.61
315.00	ACCESSORY ELECTRIC EQUIPMENT	09-2042	70-S0	(1)	2.20
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	09-2042	40-L0	0	3.83
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

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SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, AND ANNUAL DEPRECIATION RATES

	DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	NET SALVAGE PERCENT	DEPRECIATION RATE
	RUSH ISLAND STEAM PRODUCTION PLANT				
311.00	STRUCTURES AND IMPROVEMENTS	09-2045	100-R1.5	(1)	1.59
312.00	BOILER PLANT EQUIPMENT	09-2045	55-R0.5	(5)	2.09
314.00	TURBOGENERATOR UNITS	09-2045	60-S0	(2)	2.57
315.00	ACCESSORY ELECTRIC EQUIPMENT	09-2045	70-S0	(1)	2.11
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	09-2045	40-L0	0	3.69
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	09-2042	100-R1.5	(1)	2.66
312.00	BOILER PLANT EQUIPMENT	09-2042	55-R0.5	(5)	2.82
315.00	ACCESSORY ELECTRIC EQUIPMENT	09-2042	70-S0	(1)	2.78
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	09-2042	40-L0	0	3.88
	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	130-R1	(3)	2.73
332.00	RESERVOIRS, DAMS, AND WATERWAYS	06-2047	150-R2.5	(1)	1.59

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ELECTRIC DIVISION

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, AND ANNUAL DEPRECIATION RATES

	DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	NET SALVAGE PERCENT	DEPRECIATION RATE
333.00	WATER WHEELS, TURBINES, AND GENERATORS	06-2047	95-S0.5	(14)	2.93
334.00	ACCESSORY ELECTRIC EQUIPMENT	06-2047	65-R0.5	(2)	3.43
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2047	55-O1	(2)	3.39
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	50-R0.5		2.30
	KEOKUK HYDRAULIC PRODUCTION PLANT				
331.00	STRUCTURES AND IMPROVEMENTS	06-2055	130-R1	(1)	1.86
332.00	RESERVOIRS, DAMS, AND WATERWAYS	06-2055	150-R2.5	(6)	1.36
333.00	WATER WHEELS, TURBINES, AND GENERATORS	06-2055	95-S0.5	(3)	2.53
334.00	ACCESSORY ELECTRIC EQUIPMENT	06-2055	65-R0.5	(1)	2.50
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2055	55-O1	0	2.90
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	50-R0.5		1.16
	TAUM SAUK HYDRAULIC PRODUCTION PLANT				
331.00	STRUCTURES AND IMPROVEMENTS	06-2089	130-R1	(1)	1.37
332.00	RESERVOIRS, DAMS, AND WATERWAYS	06-2089	150-R2.5	(6)	2.39
333.00	WATER WHEELS, TURBINES, AND GENERATORS	06-2089	95-S0.5	(3)	1.52
334.00	ACCESSORY ELECTRIC EQUIPMENT	06-2089	65-R0.5	(1)	1.83
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2089	55-O1	0	2.28
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	50-R0.5		1.47
	OTHER PRODUCTION PLANT				
341.00	STRUCTURES AND IMPROVEMENTS		40-R2.5	(5)	2.48

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SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, AND ANNUAL DEPRECIATION RATES

	DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	NET SALVAGE PERCENT	DEPRECIATION RATE
342.00	FUEL HOLDERS, PRODUCERS, AND ACCESSORIES		40-R3	(5)	2.60
344.00	GENERATORS				
	OTHER CTS		40-R4	(5)	1.93
	MARYLAND HEIGHTS LANDFILL CTG		6-S2	40	10.66
	SOLAR		20-S2.5	0	4.19
345.00	ACCESSORY ELECTRIC EQUIPMENT		35-R2.5	(5)	3.23
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT		20-L2.5	(5)	7.88
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		60-R2.5	(5)	1.86
353.00	STATION EQUIPMENT		60-R2.5	(5)	1.67
354.00	TOWERS AND FIXTURES		70-R4	(30)	1.94
355.00	POLES AND FIXTURES		58-R4	(100)	3.78
356.00	OVERHEAD CONDUCTORS AND DEVICES		58-R4	(25)	2.54
359.00	ROADS AND TRAILS		70-R4	0	1.09
	DISTRIBUTION PLANT				
361.00	STRUCTURES AND IMPROVEMENTS		60-R2.5	(5)	1.79
362.00	STATION EQUIPMENT		60-R2.5	(5)	1.69
364.00	POLES AND FIXTURES		47-R2.5	(150)	5.03
365.00	OVERHEAD CONDUCTORS AND DEVICES		50-R1	(50)	3.00
366.00	UNDERGROUND CONDUIT		70-R3	(50)	2.13
367.00	UNDERGROUND CONDUCTORS AND DEVICES		56-R2	(25)	2.19
368.00	LINE TRANSFORMERS		41-R2.5	5	2.36
369.01	OVERHEAD SERVICES		43-R2.5	(150)	4.05
369.02	UNDERGROUND SERVICES		55-R3	(90)	3.21

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SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, AND ANNUAL DEPRECIATION RATES

	DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	NET SALVAGE PERCENT	DEPRECIATION RATE
370.00	METERS		26-S0.5	0	3.97
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES		25-O1	0	0.03
373.00	STREET LIGHTING AND SIGNAL SYSTEMS		36-S0	(40)	3.33
	GENERAL PLANT				
390.00	STRUCTURES AND IMPROVEMENTS				
	MISCELLANEOUS STRUCTURES - OLD		55-R1.5	(5)	1.91
	LARGE STRUCTURES		48-R1.5	(10)	2.30
390.05	STRUCTURES AND IMPROVEMENTS - TRAINING ASSETS		5-SQ	0	20.00
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-R1.5	10	8.00
392.05	TRANSPORTATION EQUIPMENT - TRAINING ASSETS		5-SQ	0	20.00
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	20.00
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	20.00
398.00	MISCELLANEOUS EQUIPMENT		20-SQ	0	5.00

NOTE: NEW ADDITIONS FOR UTILITY SCALE WIND GENERATION AND SOLAR GENERATION EQUIPMENT WILL HAVE THE FOLLOWING LIFE AND NET SALVAGE PAR/
SERVICE, WIND ASSETS WILL ALSO HAVE A 30-YEAR LIFE SPAN:

ACCOUNT	DESCRIPTION	INTERIM SURVIVOR CURVE	NET SALVAGE PERCENT	ACCRUAL RATE

AMEREN MISSOURI

ELECTRIC DIVISION

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, AND ANNUAL DEPRECIATION RATES

	DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	NET SALVAGE PERCENT	DEPRECIATION RATE
341	STRUCTURES AND IMPROVEMENTS - WIND	70-R2.5	(5)	3.53	
344	GENERATORS - WIND	45-R2	(5)	3.71	
345	ACCESSORY ELECTRIC EQUIPMENT - WIND	40-R2.5	(5)	3.70	
346	MISCELLANEOUS POWER PLANT EQUIPMENT - WIND	35-S2.5	(5)	3.70	
341	STRUCTURES AND IMPROVEMENTS - SOLAR	20-R4	0	5.00	
345	ACCESSORY ELECTRIC EQUIPMENT - SOLAR	20-S2.5	0	5.00	

Exhibit J

Mo Electric
12 Months Ending June 2018 with Actual Dec 2019

	Normalized Revenue w/ Tax Reduction	Low Income	EE Program Charge	Total Test Year Revenues	Revenue Requirement Decrease	Low Income Increase	Net Revenue Requirement Decrease	Total Revenue Requirement
Residential	$1,260,808,783	$512,832	$3,088,358	$1,264,409,973	-$14,699,173	$199,173	-$14,500,000	$1,249,909,973
Small General Service	$293,462,911	$84,311	$324,632	$293,871,854	-$2,732,745	$32,745	-$2,700,000	$291,171,854
Large General Service	$552,729,666	$71,729	$1,758,348	$554,559,744	-$8,199,260	$27,858	-$8,171,402	$546,388,342
Small Primary Service	$228,129,939	$4,468	$759,489	$228,893,896	-$3,376,462	$1,735	-$3,374,727	$225,519,169
Large Primary Service	$200,250,363	$46,925	$190,902	$200,488,190	-$2,972,096	$18,225	-$2,953,871	$197,534,319
Lighting Company Owned	$36,136,709		$0	$36,136,709	-$300,000	$0	-$300,000	$35,836,709
Lighting Customer Owned	$3,221,462		$0	$3,221,462	$0	$0	$0	$3,221,462
MSD	$74,966		$0	$74,966	$0	$0	$0	$74,966
Total Revenue	$2,574,814,800	$720,264	$6,121,729	$2,581,656,794	-$32,279,736	$279,736	-$32,000,000	$2,549,656,794

	% Change	Rate Design Changes to Tariffed Rates
Residential	-1.15%	Per the Stip
Small General Service	-0.92%	Equal % to all rate elements
Large General Service	-1.47%	Equal % to all Energy charges with a floor of 3.1 cents
Small Primary Service	-1.47%	Equal % to all Energy charges with a floor of 3.1 cents
Large Primary Service	-1.47%	Equal % to Energy and Demand charges with a floor of 3.0 cents
Lighting Company Owned	-0.83%	Company Proposal
Lighting Customer Owned	0.00%	Received the tax decrease only
MSD	0.00%	Received the tax decrease only
Total Revenue	-1.24%	