Exhibit No.:	
Issue(s):	*System Energy Losses, Jurisdictional Allocation Factors for Demand and Energy, Loss Study -FAC, Voltage Adjustment Factors*
Witness:	*Alan J. Bax*
Sponsoring Party:	*MoPSC Staff*
Type of Exhibit:	*Direct Testimony*
Case No.:	*ER-2026-00143*
Date Testimony Prepared:	*June 30, 2026*

MISSOURI PUBLIC SERVICE COMMISSION

INDUSTRY ANALYSIS DIVISION

ENGINEERING ANALYSIS DEPARTMENT

DIRECT TESTIMONY
REVENUE REQUIREMENT

OF

ALAN J. BAX

EVERGY METRO, INC., d/b/a Evergy MISSOURI METRO

CASE NO. ER-2026-0143

Jefferson City, Missouri
June 2026

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DIRECT TESTIMONY OF

ALAN J. BAX

EVERGY METRO, INC., d/b/a EVERGY MISSOURI METRO

CASE NO. ER-2026-0143

DIRECT TESTIMONY

OF

ALAN J. BAX

EVERGY METRO, INC., d/b/a EVERGY MISSOURI METRO

CASE NO. ER-2026-0143

Q. Please state your name and business address.

A. Alan J. Bax, P.O. Box 360, Jefferson City, Missouri 65102.

Q. By whom are you employed and in what capacity?

A. I am employed by the Missouri Public Service Commission as an Associate Engineer in the Engineering Analysis Department of the Industry Analysis Division.

Q. Please describe your educational and work background.

A. My educational and work background is summarized in Schedule AJB-d1 .

Q. Are you a member of any professional organizations?

A. Yes, I am a member of the Institute of Electrical and Electronic Engineers ("IEEE").

Q. Have you previously filed testimony before the Commission?

A. Yes. My case participation history with the Commission is listed in Schedule AJB-d2.

EXECUTIVE SUMMARY

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to describe my calculation of the following inputs to Staff's direct case:

- System energy loss factor,
- Jurisdictional allocation factors for demand and energy, and
- Voltage Adjustment Factors ("VAF").

Q. Through this testimony, do you describe the development of any work product that you provided to another Staff witness for the development of an issue?

A. Yes. I provided a system energy loss factor to Staff witness Michael L. Stahlman for his development of hourly loads that are subsequently considered in Staff's fuel model. I provided jurisdictional demand and energy allocation factors to Staff witness Keith Majors for use in Staff's EMS run, which is utilized in allocating related demand and energy revenues and expenses to the Missouri retail jurisdiction. Finally, I provided the calculated VAFs to Staff witness Stacy L. Henderson, who utilized these VAFs in conjunction with the determination of Fuel Adjustment Rates ("FARs") that are reflected in Evergy Missouri Metro's ("EMM") Fuel Adjustment Clause ("FAC").

Q. Please summarize the results of your analyses.

A. A summary of the results of my calculations are included in Schedule AJB-d3.

SYSTEM ENERGY LOSS FACTOR

Q. What are system energy losses?

A. System energy losses are the unavoidable dissipation of input energy inherent in the production, transmission and distribution of electricity, largely occurring in the electrical equipment (e.g., transmission and distribution lines, transformers, etc.)

between a utility's generating sources and their respective customers' meters. For example, the losses associated with the heat produced in transmitting and distributing electricity along associated conductors. In addition, small fractional amounts of energy, either stolen (diversion) or not metered, are included in my calculation of system energy losses.

Q. How are system energy losses determined?

A. The basis for calculating system energy losses is that the Net System Input ("NSI") equals the sum of "Retail Sales", "Wholesale Sales", "Company Use," and "System Energy Losses." This can be expressed mathematically as:

NSI = Retail Sales + Wholesale Sales + Company Use + System Energy Losses.

NSI, Company Use, Retail Sales and Wholesale Sales are known quantities; therefore, system energy losses may be calculated as follows:

System Energy Losses = NSI - Retail Sales - Wholesale Sales - Company Use.

The system energy loss factor is the ratio of system energy losses to NSI:

System Energy Loss Factor = (System Energy Losses / NSI)

Q. How is NSI determined?

A. In addition to the relationship expressed in the equation above, NSI is also equal to the sum of net generation and the net interchange. Net generation is the total energy output of each generating station minus the energy consumed internally to enable its production of electricity at each plant. The output of each generation plant is continuously monitored and metered. Net interchange is the difference resulting from netting off-system purchases and off-system sales and is also similarly monitored.

Q. What are Retail Sales, Wholesale Sales and Company Use and how are these values determined?

A. For each utility it regulates, the Commission sets cost of service based rates for the utility's Missouri retail customers. However, not all sales are necessarily associated with a utility's provision of service to its Missouri retail customers. EMM has retail customers in both Missouri and Kansas as well as wholesale customers in Missouri. Retail sales in Missouri, retail sales in Kansas, and wholesale sales (under the jurisdiction of the Federal Energy Regulatory Commission ("FERC") are described as sales occurring in three separate jurisdictions. Retail Sales and Wholesale Sales represent the jurisdictional energy metered within EMM's system. In this case, EMM has three applicable jurisdictions: a wholesale jurisdiction and retail jurisdictions in the states of Missouri and Kansas. Company Use is the electricity consumed at each of the non-generation facilities, such as the corporate office building.

Q. What is the resultant system energy loss factor for EMM?

A. As shown on Schedule AJB-d3, I have calculated the following system energy loss factor, as a percentage of NSI:

EMM - 0.0584

Q. Which Staff witness used your calculated system energy loss factor?

A. I provided my calculated system energy loss factor to Staff witness Michael L. Stahlman.

JURISDICTIONAL ALLOCATIONS

Q. Please describe the jurisdictions applicable to this case.

A. EMM has retail customers in both Missouri and Kansas and wholesale customers in Missouri. Retail sales in Missouri, retail sales in Kansas and wholesale sales (under the jurisdiction of the FERC) are described as sales occurring in three separate jurisdictions.

Q. Please define the phrase "jurisdictional allocation".

A. Some costs incurred in serving customers in a particular jurisdiction may be directly assigned to that jurisdiction. The costs that are not directly assigned to a particular jurisdiction are allocated among the various applicable jurisdictions. Jurisdictional allocation refers to the process by which demand-related and energy-related costs are allocated to the applicable jurisdictions of the respective utility. Costs that do not vary significantly over the course of a year, or that do not vary with the amount of energy generated or consumed, such as the capital costs associated with generation and transmission plant, are typically allocated on the basis of demand (i.e. "demand related"). Variable costs, such as fuel and purchased power, are typically allocated on the basis of energy consumption (i.e. "energy related"). Demand-related and energy-related costs are divided between applicable retail and wholesale operations in EMM. The application of a particular allocation factor is dependent upon the types of costs being allocated among the associated jurisdictions.

DEMAND ALLOCATION FACTORS

Q. What is the definition of demand?

A. Demand refers to the rate of electric energy that is delivered to a system to meet the requirements of its customers, generally expressed in kilowatts or megawatts, either at an instant in time or averaged over any designated interval of time.

Q. What is the system peak demand?

A. System peak demand is the largest electric requirement that occurs on a utility's system within a specified period of time (e.g. hour, day, month, season, or year). In my analyses, I used hourly demands.

Q. Please explain the term coincident peak as used in your testimony.

A. A coincident peak is the hourly contribution of each of EMM's three jurisdictions (Missouri Retail, Kansas Retail and Wholesale Operations) that occurs at the same time as the system peak demand, i.e., each individual jurisdiction contributing demand at the time of the corresponding system peak.

Q. What types of costs are allocated on the basis of demand?

A. Capital costs associated with generation and transmission plant, as well as certain operational and maintenance expenses, are typically allocated on this basis. This is appropriate because generation and transmission are planned, designed and constructed to meet a utility's anticipated demand.

Q. Why use peak demand as the basis for allocations?

A. Peak demand is the largest electric requirement occurring within a specified period of time (e.g., day, month, season, year) on a utility's system. In addition, for planning purposes, an amount must be included for meeting required contingency reserves. Since generation units and transmission lines are planned, designed, and

constructed to meet a utility's anticipated system peak demands plus required reserves, the contribution of each individual jurisdiction to these peak demands is the appropriate basis on which to allocate the costs of these facilities.

Q. What methodology did you use to determine the demand allocators?

A. I used what is known as the Four Coincident Peak ("4 CP") methodology. A 4 CP method is appropriate for a utility that experiences dominant seasonal demands in the four summer months (June to September) relative to the demands in the other eight months of a calendar year. A utility that experiences similar hourly peaks in both winter and summer months might consider using a 12 CP method. Comparatively, a utility that does not experience similar peaks in both winter and summer months, but instead experiences a peak demand in one particular month within a calendar year may consider utilizing a 1 CP. The monthly demands reported for the months in calendar year 2025, which includes a portion of the test year and the update period for the current case, are consistent with the monthly demands in the reporting periods associated with the last several rate cases involving EMM.

Q. What additional information did you consider in recommending using a 4 CP?

A. In various cases, the FERC has utilized particular tests in its determination of a methodology to employ. The results of these tests are compared to specific ranges identified from prior decisions made by the FERC that have persuaded the FERC in deciding which methodology is more appropriate. The FERC has used these tests to support its adoption of a 4 CP methodology in a number of cases.

Q. Please describe the FERC tests you used in your selection of a CP methodology.

A. A description of the FERC tests used are as follows:

Test 1 - Computes the difference between the following two percentages:

a) The average of the summer monthly system peaks during the reported peak period as a percentage of the annual peak, (Summer Average / Annual Peak) and

b) The average of the system peaks during the remainder of the analyzed period as a percentage of the annual peak. (Winter Average / Annual Peak)

For calculated differences that fell between 18% and 19%, FERC typically adopted a 12 CP methodology. For differences that fell between 26% and 31%, FERC typically adopted a 4 CP methodology.

Test 2 - The average of the twelve monthly peaks in the reporting period as a percentage of the annual peak, (12-Month Average/ Annual Peak).

When the resulting percentage fell between 81% and 88%, the FERC typically adopted a 12 CP methodology. When the resulting percentage fell between 78% and 81%, the FERC typically adopted a 4 CP methodology.

Test 3 - The lowest monthly peak as a percentage of the annual peak (Minimum Monthly Peak /Maximum Monthly Peak).

When the resulting percentage fell between 66% and 81%, the FERC typically adopted a 12 CP methodology. When the resulting percentage fell between 55% and 60%, the FERC typically adopted a 4 CP methodology.

Q. What were the results of the tests you conducted?

A. I applied these tests on the reported monthly demands for EMM in calendar year 2025, a period of time included within the update period of this case. The result of each test, along with its significance, is as follows:

Test 1 – Summer Month Average / Annual Peak – 0.9392

Winter Month Average / Annual Peak – 0.7026

The difference between these two ratios is 23.66%. While this is below the range typically identified in cases for utilizing a 4 CP, it is nonetheless well above the range of 18%-19% noted in utilizing a 12 CP and is closer to the 4 CP range.

Test 2 - 12-Month Average / Annual Peak = 0.7814

The result of the second test, 78.14%, is a strong indicator in utilizing a 4 CP as it lies at the low end of the range of 78-81% noted by the FERC in cases the FERC adopted a 4 CP methodology.

Test 3 – Minimum Monthly Peak / Maximum Monthly Peak - .5404

The result of the third test, 54.04%, is the strongest indicator of utilizing a 4 CP methodology as it falls below the range of 55-60% noted by FERC in cases utilizing a 4 CP, but far outside the much higher range FERC typically uses for a 12 CP (66-81%). Overall, the results of these three tests highly suggest that a 4 CP methodology is most appropriate for EMM.

Q. What have EMM's consultants acknowledged in historical cases regarding this issue?

A. In every rate case since 2006, the consultant for EMM, or its predecessor Kansas City Power and Light Company ("KCPL") has concluded that this utility is a "seasonal utility", or has "dominant peaks in the summer months" etc.

Q. Please describe the procedure for calculating the jurisdictional demand allocation factors using the 4 CP methodology.

A. The allocation factor for each applicable jurisdiction for EMM's operating system was determined using the following process:

a. Identify the peak hourly load on EMM's operating system in each month for the four-month period of June 2025 through September 2025 and sum these hourly peak loads.

b. Identify the corresponding load in each of the applicable jurisdictions identified earlier on EMM's system that contributed to the overall system monthly peaks identified in "a" above and sum these loads for each particular jurisdiction.

c. Divide b. above by a. above.

The resultant ratios are the allocation factors for each applicable jurisdiction for the EMM electric system as follows:

EMM:

Missouri Retail Jurisdiction:	0.5320
Kansas Retail Jurisdiction:	0.4666
Wholesale Jurisdiction:	0.0014
Total:	1.0000

Q. Which Staff witness used your jurisdictional demand allocation factors?

A. I provided these jurisdictional demand allocation factors to Staff witness Keith Majors who will use these factors in Staff's EMS run.

ENERGY ALLOCATION FACTORS

Q. What types of costs were allocated on the basis of energy?

A. Variable expenses, such as fuel and purchased power, along with certain operational and maintenance ("O&M") expenses, are allocated to the applicable EMM jurisdictions based on energy consumption.

Q. How did you calculate the energy allocation factor?

A. The energy allocation factor for an individual jurisdiction in EMM is the ratio of the normalized annual kilowatt-hour ("kWh") usage in the particular jurisdiction, during the period of January 2025 – December 2025, to the respective EMM total system kWh usage. Staff also applied adjustments to these normalized kWhs accounting for losses, anticipated growth, and certain customer annualizations. Normalized weather adjustments were provided by Staff witness Michael L. Stahlman. The adjustments for growth and certain annualizations were provided by Staff witness Kim Cox.

Q. What are the energy allocation factors you determined in this case?

A. Staff has calculated the following energy allocation factors for the aforementioned jurisdictions of EMM based on kWh usage data in calendar year 2025, which is included in the update period of this case, including the aforementioned adjustments:

EMM:

Missouri Retail Jurisdiction:	0.5693
Kansas Retail Jurisdiction:	0.4293
Wholesale Jurisdiction:	0.0014
Total:	1.0000

These jurisdictional energy allocation factors were provided to Staff witness Keith Majors to allocate related costs to the respective applicable jurisdictions for EMM in Staff's EMS run.

LOSS STUDY AS IT APPLIES TO THE FUEL ADJUSTMENT CLAUSE

Q. Did EMM provide a System Energy Loss Study on which you relied, in whole or in part, in developing Staff's loss factors for Staff's direct case?

A. Yes, a document entitled "Evergy 2025 System Loss Study ("Loss Study"), was provided in EMM's Response to Staff Data Request No. 0297 as well as a portion being attached to the Direct Testimony of Evergy witness Linda J. Nunn.

Q. Please provide a brief description of this document.

A. The Loss Study includes information pertaining to EMM's operating system. The Loss Study is indicated to include an analysis of data pertaining to the operation of EMM, in both Missouri and Kansas, collected during calendar year 2024, with the associated Report indicating a preparation date of November 7, 2025.

Q. Why was this Loss Study provided?

A. EMM has a Fuel Adjustment Clause ("FAC"). In order to remain in compliance with Commission regulation 20 CSR 4240-20.090(13), it was necessary for

EMM to submit a current loss study in conjunction with their request to continue a Rate Adjustment Mechanism, i.e. their FAC in the current case.

Q. What information are you evaluating in the Loss Study?

A. The derived loss factor for each of the corresponding operating voltage levels (transmission, substation primary and secondary) in which EMM serves its customers.

VOLTAGE ADJUSTMENT FACTORS

Q. What are the VAFs for each operating level for EMM's system?

A. VAFs are determined to account for the energy losses experienced in the delivery of electricity from the generation level to the customer. VAFs applicable to the transmission, substation, primary and secondary operating voltage levels for EMM are illustrated in Schedule AJB-d3 utilizing information concerning losses and energy sold at each specific voltage level contained in the Loss Study EMM provided in its direct filing in this case:

EMM:

$VAF_{Transmission}$ - 1.00879

$VAF_{Substation}$ - 1.00982

$VAF_{Primary}$ - 1.024

$VAF_{Secondary}$ - 1.04902

Q. What Staff members used these VAFs?

A. These VAFs were provided to Staff witness Stacy Henderson for utilization in calculating associated FARs for use in EMM's FAC tariff. These FARs will be applied to

the individual voltage service classification of a particular customer in EMM's FAC tariffs should the Commission authorize EMM to continue utilization of their FAC and associated tariff.

Q. Does this conclude your direct testimony?

A. Yes it does.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2026-0143

AFFIDAVIT OF ALAN J. BAX

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

COMES NOW ALAN J. BAX and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Direct Testimony-Revenue Requirement*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

ALAN J. BAX

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 23rd day of June 2026.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: April 04, 2029
Commission Number: 12412070

Notary Public

ALAN J. BAX

I graduated from the University of Missouri - Columbia with a Bachelor of Science degree in Electrical Engineering in December 1995. Concurrent with my studies, I was employed as an Engineering Assistant in the Energy Management Department of the University of Missouri – Columbia from the Fall of 1992 through the Fall of 1995. Prior to this, I completed a tour of duty in the United States Navy, completing a course of study at the Navy Nuclear Power School and a Navy Nuclear Propulsion Plant. Following my graduation from the University of Missouri - Columbia, I was employed by The Empire District Electric Company as a Staff Engineer until August 1999, at which time I began my employment with the Staff of the Missouri Public Service Commission. My current position is an Engineer in the Engineering Analysis Department, within the Industry Analysis Division. I presented in a Peer Review of Power Quality Regulations in the National Association of Regulatory Utility Commissioners (NARUC) outreach program with the Public Utilities Commission of Sri Lanka (PUCSL), supported by the Bureau of Energy Resources (ENR) at the United States Department of State. I am a member of the Institute of Electrical/Electronic Engineers (IEEE).

TESTIMONY AND REPORTS
BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION

BY ALAN J. BAX

COMPANY	CASE NUMBER
Aquila Networks – MPS	ER-2004-0034
Union Electric Company d/b/a AmerenUE	EO-2004-0108
Empire District Electric Company	ER-2002-0424
Kansas City Power and Light Company	EA-2003-0135
Union Electric Company d/b/a AmerenUE	EO-2003-0271
Aquila Networks – MPS	EO-2004-0603
Union Electric Company d/b/a AmerenUE	EC-2002-0117
Three Rivers and Gascosage Electric Coops	EO-2005-0122
Union Electric Company d/b/a AmerenUE	EC-2002-1
Aquila Networks – MPS	EO-2001-0384
Empire District Electric Company	ER-2001-299
Aquila Networks – MPS	EA-2003-0370
Union Electric Company d/b/a AmerenUE	EW-2004-0583
Union Electric Company d/b/a AmerenUE	EO-2005-0369
Trigen Kansas City	HA-2006-0294
Union Electric Company d/b/a AmerenUE	EC-2005-0352
Missouri Public Service	ER-2001-672
Aquila Networks – MPS	EO-2003-0543
Kansas City Power and Light Company	ER-2006-0314
Macon Electric Coop	EO-2005-0076
Aquila Networks – MPS	EO-2006-0244
Union Electric Company d/b/a AmerenUE	EC-2004-0556
Union Electric Company d/b/a AmerenUE	EC-2004-0598
Empire District Electric Company	ER-2004-0570
Union Electric Company d/b/a AmerenUE	EC-2005-0110
Union Electric Company d/b/a AmerenUE	EC-2005-0177
Union Electric Company d/b/a AmerenUE	EC-2005-0313
Empire District Electric Company	EO-2005-0275
Aquila Networks – MPS	EO-2005-0270

COMPANY	CASE NUMBER
Union Electric Company d/b/a AmerenUE	EO-2006-0145
Empire District Electric Company	ER-2006-0315
Aquila Networks – MPS	ER-2005-0436
Union Electric Company d/b/a AmerenUE	EO-2006-0096
West Central Electric Cooperative	EO-2006-0339
Kansas City Power and Light Company	ER-2006-0314
Union Electric Company d/b/a AmerenUE	EO-2008-0031
Union Electric Company d/b/a AmerenUE	EC-2009-0193
Empire District Electric Company	ER-2008-0093
Missouri Rural Electric Cooperative	EO-2008-0332
Grundy Electric Cooperative	EO-2008-0414
Osage Valley Electric Cooperative	EO-2009-0315
Union Electric Company d/b/a AmerenUE	EO-2009-0400
Union Electric Company d/b/a AmerenUE	EO-2008-0310
Aquila Networks – MPS	EA-2008-0279
West Central Electric Cooperative	EO-2008-0339
Empire District Electric Company	EO-2009-0233
Union Electric Company d/b/a/ AmerenUE	EO-2009-0272
Empire District Electric Company	EO-2009-0181
Union Electric Company d/b/a AmerenUE	ER-2008-0318
Kansas City Power and Light Company	ER-2009-0089
Kansas City Power and Light – GMO	ER-2009-0090
Union Electric Company d/b/a AmerenUE	ER-2010-0036
Empire District Electric Company	ER-2010-0130
Laclede Electric Cooperative	EO-2010-0125
Union Electric Company d/b/a AmerenUE	EC-2010-0364
Union Electric Company d/b/a AmerenUE	EO-2011-0052
Kansas City Power and Light Company	ER-2010-0355
Union Electric Company d/b/a AmerenUE	EO-2010-0263
Kansas City Power and Light – GMO	EO-2011-0137
Kansas City Power and Light – GMO	ER-2010-0356
Union Electric Company d/b/a AmerenUE	ER-2011-0028
Kansas City Power and Light – GMO	EO-2012-0119
Kansas City Power and Light Company	EO-2011-0137

COMPANY	CASE NUMBER
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Union Electric Company d/b/a/ Ameren Missouri	EX-2012-0332
Empire District Electric Company	EO-2011-0085
Empire District Electric Company	EO-2012-0192
Empire District Electric Company	EO-2013-0313
Union Electric Company d/b/a AmerenUE	ER-2012-0180
Union Electric Company d/b/a AmerenUE	EO-2013-0418
City Utilities of Springfield	EO-2012-0441
Kansas City Power and Light – GMO	EO-2012-0367
Empire District Electric Company	ER-2011-0004
Union Electric Company d/b/a/ Ameren Missouri	ER-2012-0166
Kansas City Power and Light Company	ER-2012-0174
Union Electric Company d/b/a/ Ameren Missouri	ER-2013-0044
Kansas City Power and Light – GMO	ER-2012-0175
Central Missouri Electric Cooperative	EO-2015-0137
Empire District Electric Company	ER-2012-0345
Kansas City Power and Light Company	EO-2012-0367
Boone Electric Cooperative	EO-2015-0012
Transource Missouri, LLC	EA-2013-0098
Black River Electric Cooperative	EO-2015-0096
Union Electric Company d/b/a/ Ameren Missouri	EW-2012-0369
Empire District Electric Company	ER-2014-0351
Union Electric Company d/b/a/ Ameren Missouri	EO-2014-0044
Union Electric Company d/b/a/ Ameren Missouri	EO-2013-0418
Union Electric Company d/b/a/ Ameren Missouri	EE-2013-0511
Union Electric Company d/b/a/ Ameren Missouri	EO-2015-0017
Union Electric Company d/b/a/ Ameren Missouri	EO-2016-0087
Union Electric Company d/b/a/ Ameren Missouri	EO-2014-0009
Kansas City Power and Light Company	EO-2014-0128
Union Electric Company d/b/a/ Ameren Missouri	EO-2017-0358
Empire District Electric Company	EO-2016-0192
Empire District Electric Company	EO-2017-0217
Union Electric Company d/b/a/ Ameren Missouri	EO-2014-0296
Union Electric Company d/b/a/ Ameren Missouri	EO-2015-0328

COMPANY	CASE NUMBER
Union Electric Company d/b/a/ Ameren Missouri	ER-2014-0258
Union Electric Company d/b/a/ Ameren Missouri	EX-2017-0153
Union Electric Company d/b/a/ Ameren Missouri	EO-2019-0391
Empire District Electric Company	EO-2018-0118
Empire District Electric Company	ER-2016-0023
Ozark Electric Cooperative Inc.	EO-2020-0163
Union Electric Company d/b/a/ Ameren Missouri	EC-2016-0235
Union Electric Company d/b/a/ Ameren Missouri	EO-2018-0058
Union Electric Company d/b/a/ Ameren Missouri	EE-2019-0395
Kansas City Power and Light – GMO	ER-2016-0156
Kansas City Power and Light – GMO	EO-2019-0061
Kansas City Power and Light Company	ER-2014-0370
Union Electric Company d/b/a/ Ameren Missouri	EO-2017-0044
Kansas City Power and Light Company	ER-2016-0285
Empire District Electric Company	EO-2019-0381
Union Electric Company d/b/a/ Ameren Missouri	EE-2019-0395
Union Electric Company d/b/a/ Ameren Missouri	ER-2016-0179
Union Electric Company d/b/a/ Ameren Missouri	EO-2018-0278
Union Electric Company d/b/a/ Ameren Missouri	EO-2020-0315
Union Electric Company d/b/a/ Ameren Missouri	EO-2017-0127
Kansas City Power and Light Company	ER-2018-0145
Kansas City Power and Light Company – GMO	ER-2018-0146
Evergy Missouri West LLC	EO-2021-0388
Gridliance High Plains, LLC	EM-2022-0156
Union Electric Company d/b/a/ Ameren Missouri	EO-2021-0305
Union Electric Company d/b/a/ Ameren Missouri	EM-2021-0309
Union Electric Company d/b/a/ Ameren Missouri	ER-2019-0335
Union Electric Company d/b/a/ Ameren Missouri	EE-2019-0383
Osage Valley Electric Cooperative, LLC	EO-2022-0073
Osage Valley Electric Cooperative, LLC	EO-2023-0126
Ozark Border Electric Cooperative, LLC	EO-2022-0264
Evergy Missouri West LLC	EO-2021-0339
Union Electric Company d/b/a/ Ameren Missouri	EE-2021-0086
Union Electric Company d/b/a/ Ameren Missouri	EM-2022-0292
Liberty Utilities-Empire	EO-2021-0389

COMPANY	CASE NUMBER
Laclede Electric Cooperative	EO-2022-0143
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Union Electric Company d/b/a/ Ameren Missouri	ET-2021-0082
Union Electric Company d/b/a/ Ameren Missouri	ER-2021-0240
Union Electric Company d/b/a/ Ameren Missouri	EO-2022-0226
Union Electric Company d/b/a/ Ameren Missouri	EO-2022-0190
Union Electric Company d/b/a/ Ameren Missouri	EO-2022-0332
Union Electric Company d/b/a/ Ameren Missouri	EO-2023-0256
NextEra Energy Transmission Southwest, LLC	EA-2022-0234
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Missouri Joint Municipal Utility Electric Commission	EM-2022-0156
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Union Electric Company d/b/a/ Ameren Missouri	EM-2022-0094
Union Electric Company d/b/a/ Ameren Missouri	EO-2022-0102
Union Electric Company d/b/a/ Ameren Missouri	ER-2022-0337
Liberty Utilities-Empire	EO-2022-0132
Liberty Utilities-Empire	ER-2021-0312
Union Electric Company d/b/a/ Ameren Missouri	EO-2024-0116
Liberty Utilities-Empire	EO-2024-0098
Union Electric Company d/b/a/ Ameren Missouri	EO-2024-0144
Evergy Missouri West LLC	EC-2024-0015
Osage Valley Electric Cooperative, LLC	EO-2023-0439
Howard Electric Cooperative	EO-2024-0247
Union Electric Company d/b/a/ Ameren Missouri	EO-2024-0208
Union Electric Company d/b/a/ Ameren Missouri	EX-2023-0254
Liberty Utilities-Empire	EO-2023-0266
Liberty Utilities-Empire	EO-2024-0165
Liberty Utilities-Empire	ER-2024-0261
Grain Belt Express LLC	EA-2023-0017
Liberty Utilities-Empire	EO-2023-0108
Liberty Utilities-Empire	EO-2024-0194

COMPANY	CASE NUMBER
Invenergy	EC-2025-0136
Evergy Missouri West LLC	EC-2024-0168
Osage Valley Electric Cooperative, LLC	EO-2025-0031
Union Electric Company d/b/a/ Ameren Missouri	EO-2025-0092
Union Electric Company d/b/a/ Ameren Missouri	EC-2026-0095
Liberty Utilities-Empire	EO-2025-0253
Liberty Utilities-Empire	EO-2025-0228
Evergy Missouri West LLC	ER-2024-0189
Evergy Missouri Metro	EC-2025-0143
Union Electric Company d/b/a/ Ameren Missouri	EM-2025-0243
Union Electric Company d/b/a/ Ameren Missouri	ER-2024-0319
Union Electric Company d/b/a/ Ameren Missouri	EO-2026-0208

SCHEDULE AJB-d2

SUMMARY

RESULTS OF CALCULATIONS

SYSTEM ENERGY LINE LOSS FACTORS

Evergy Metro	0.0584

DEMAND ALLOCATION FACTORS

Evergy Metro

Missouri Retail	0.5320
Kansas Retail	0.4666
Wholesale	0.0014

ENERGY ALLOCATION FACTORS

Evergy Metro

Missouri Retail	0.5693
Kansas Retail	0.4293
Wholesale	0.0014

VOLTAGE ADJUSTMENT FACTORS

Evergy Metro

$VAF_{Transmission}$	1.00879
$VAF_{Substation}$	1.00982
$VAF_{Primary}$	1.0240
$VAF_{Secondary}$	1.0492