Sarah L.K. Lange

I received my J.D. from the University of Missouri, Columbia, in 2007, and am licensed to practice law in the State of Missouri. I received my B.S. in Historic Preservation from Southeast Missouri State University, and took courses in architecture and literature at Drury University. Since beginning my employment with the MoPSC I have taken courses in economics through Columbia College and courses in energy transmission through Bismarck State College, and have attended various trainings and seminars, indicated below.

I began my employment with the Commission in May 2006 as an intern in what was then known as the General Counsel's Office. I was hired as a Legal Counsel in September 2007, and was promoted to Associate Counsel in 2009, and Senior Counsel in 2011. During that time my duties consisted of leading major rate case litigation and settlement, and presenting Staff's position to the Commission, and providing legal advice and assistance primarily in the areas of depreciation, cost of service, class cost of service, rate design, tariff issues, resource planning, accounting authority orders, construction audits, rulemakings and workshops, fuel adjustment clauses, document management and retention, and customer complaints.

In July 2013 I was hired as a Regulatory Economist III in what is now known as the Tariff / Rate Design Department. In this position my duties include providing analysis and recommendations in the areas of RTO and ISO transmission, rate design, class cost of service, tariff compliance and design, and regulatory adjustment mechanisms and tariff design. I also continue to provide legal advice and assistance regarding generating station and environmental control construction audits and electric utility regulatory depreciation. I have also participated before the Commission under the name Sarah L. Kliethermes.

Presentations

Midwest Energy Policy Series – Impact of ToU Rates on Energy Efficiency (August 14, 2020)

Billing Determinants Lunch and Learn (March 27, 2019)

Support for Low Income and Income Eligible Customers, Cost-Reflective Tariff Training, in cooperation with U.S.A.I.D. and NARUC, Addis Ababa, Ethiopia (February 23-26, 2016)

Fundamentals of Ratemaking at the MoPSC (October 8, 2014)

Ratemaking Basics (Sept. 14, 2012)

Participant in Missouri's Comprehensive Statewide Energy Plan working group on Energy Pricing and Rate Setting Processes.

Relevant Trainings and Seminars

Regional Training on Integrated Distribution System Planning for Midwest/MISO Region (October 13-15, 2020)

"Fundamentals of Utility Law" Scott Hempling lecture series (January – April, 2019)

Today's U.S. Electric Power Industry, the Smart Grid, ISO Markets & Wholesale Power Transactions (July 29-30, 2014)

MISO Markets & Settlements training for OMS and ERSC Commissioners & Staff (January 27–28, 2014)

Validating Settlement Charges in New SPP Integrated Marketplace (July 22, 2013)

PSC Transmission Training (May 14 – 16, 2013)

Grid School (March 4–7, 2013)

Specialized Technical Training - Electric Transmission (April 18–19, 2012)

The New Energy Markets: Technologies, Differentials and Dependencies (June 16, 2011)

Mid-American Regulatory Conference Annual Meeting (June 5–8, 2011)

Renewable Energy Finance Forum (Sept. 29–Oct 3, 2010)

Utility Basics (Oct. 14–19, 2007)

Testimony and Staff Memoranda

Company	Case No.
Evergy Metro, Inc. d/b/a Evergy Missouri Metro Evergy Missouri West, Inc. d/b/a Evergy Missouri West In the Matter of the Joint Application of Evergy Metro, Inc. d/b/a Evergy Missouri Metro and Evergy Missouri West, Inc. d/b/a Evergy Missouri West for Approval of Tariff Revisions to TOU Program	ET-2024-0061
Evergy Metro, Inc. d/b/a Evergy Missouri Metro Evergy Missouri West, Inc. d/b/a Evergy Missouri West In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's Request to Revise Its Solar Subscription Rider	EO-2023-0423 EO-2023-0424
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust its Revenues for Electric Service	ER-2022-0337
NextEra Energy Transmission Southwest, LLC In the Matter of the Application of NextEra Energy Transmission Southwest, LLC for a Certificate of Public Convenience and Necessity to Construct, Install, Own, Operate, Maintain, and Otherwise Control and Manage a 345 kV Transmission Line and associated facilities in Barton and Jasper Counties, Missouri	EA-2022-0234
Spire Missouri, Inc. In the Matter of Spire Missouri Inc.'s d/b/a Spire Request for Authority to Implement a General Rate Increase for Natural Gas Service Provided in the Company's Missouri Service Areas	GR-2022-0179
Evergy Missouri West, Inc. dba Evergy Missouri West In the Matter of Evergy Missouri West, Inc. dba Evergy Missouri West for a Financing Order Authorizing the Financing of Extraordinary Storm Costs Through an Issuance of Securitized Utility Tariff Bonds	EF-2022-0155
Evergy Metro, Inc. dba Evergy Missouri Metro Evergy Missouri West, Inc. dba Evergy Missouri West In the Matter of Evergy Metro, Inc. dba Evergy Missouri Metro's Request for Authority to Implement a General Rate Increase for Electric Service. In the Matter of Evergy Missouri West, Inc. dba Evergy Missouri West's Request for Authority to Implement a General Rate Increase for Electric Service.	ER-2022-0129 ER-2022-0130
The Empire District Electric Company d/b/a Liberty In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financing Order that Authorizes the Issuance of Securitized Utility Tariff Bonds for Energy Transition Costs Related to the Asbury Plant	EO-2022-0193
The Empire District Electric Company d/b/a Liberty In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financing Order that Authorizes the Issuance of Securitized Utility Tariff Bonds for Qualified Extraordinary Costs	EO-2022-0040

Company	**Case No.**
Ameren Transmission Company of Illinois In the Matter of the Application of Ameren Transmission Company of Illinois for a Certificate of Convenience and Necessity Under Section 393.170 RSMo Relating to Transmission Investments in Southeast Missouri	EA-2022-0099
The Empire District Electric Company d/b/a Liberty In the Matter of the Request of The Empire District Electric Company d/b/a Liberty for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area	ER-2021-0312
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust its Revenues for Electric Service	ER-2021-0240
Ameren Transmission Company of Illinois In the Matter of the Application of Ameren Transmission Company of Illinois for a Certificate of Public Convenience and Necessity to Construct, Install, Own, Operate, Maintain, and Otherwise Control and Manage a 138 kV Transmission Line and associated facilities in Perry and Cape Girardeau Counties, Missouri	EA-2021-0087
Evergy Affiliates In the Matter of the Application of Evergy Metro, Inc. d/b/a Evergy Missouri Metro and Evergy Missouri West, Inc. d/b/a Evergy Missouri West for Approval of a Transportation Electrification Portfolio	ET-2021-0151
Spire Missouri, Inc. In the Matter of Spire Missouri Inc.'s d/b/a Spire Request for Authority to Implement a General Rate Increase for Natural Gas Service Provided in the Company's Missouri Service Areas	GR-2021-0108
Union Electric Company d/b/a Ameren Missouri In the Matter of the Request of Union Electric Company d/b/a Ameren for Approval of its Surge Protection Program	ET-2021-0082
Union Electric Company d/b/a Ameren Missouri In the Matter of the Request of Union Electric Company d/b/a Ameren Missouri to Implement the Delivery Charge Adjustment for the 1st Accumulation Period beginning September 1, 2019 and ending August 31, 2020	GT-2021-0055
The Empire District Electric Company In the Matter of The Empire District Electric Company's Tariffs Approval of a Transportation Electrification Portfolio for Electric Customers in its Missouri Service Area	ET-2020-0390
The Empire District Electric Company In the Matter of The Empire District Electric Company's Tariffs to Increase Its Revenues for Electric Service	ER-2019-0374
Union Electric Company d/b/a Ameren Missouri In the Matter of of Union Electric Company d/b/a Ameren Missouri's Tariffs to Decrease Its Revenues for Electric Service	ER-2019-0335

Company	**Case No.**
KCP&L Greater Missouri Operations Company In the Matter of KCP&L Greater Missouri Operations Company Request for Authority to Implement Rate Adjustments Required by 4 CSR 240-20.090(8) And the Company's Approved Fuel and Purchased Power Cost Recovery Mechanism	ER-2019-0413
Union Electric Company d/b/a Ameren Missouri In the Matter of of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Natural Gas Service	GR-2019-0077
Union Electric Company d/b/a Ameren Missouri In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri Revised Tariff Sheets	ET-2019-0149
The Empire District Electric Company In the Matter of The Empire District Electric Company's Revised Economic Development Rider Tariff Sheets	ET-2019-0029
The Empire District Electric Company In the Matter of a Proceeding Under Section 393.137 (SB 564) to Adjust the Electric Rates of The Empire District Electric Company	ER-2018-0366
Union Electric Company d/b/a Ameren Missouri In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Permission and Approval and a Certificate of Public Convenience and Necessity Authorizing it to Construct a Wind Generation Facility	EA-2018-0202
Kansas City Power & Light Company KCP&L Greater Missouri Operations Company In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	ER-2018-0145 ER-2018-0146
Union Electric Company d/b/a Ameren Missouri In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Approval of Efficient Electrification Program	ET-2018-0132
Union Electric Company d/b/a Ameren Missouri In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Approval of 2017 Green Tariff	ET-2018-0063
Laclede Gas Company Laclede Gas Company d/b/a Missouri Gas Energy In the Matter of Laclede Gas Company's Request to Increase Its Revenue for Gas Service, In the Matter of Laclede Gas Company d/b/a Missouri Gas Energy's Request to Increase Its Revenue for Gas Service.	GR-2017-0215 GR-2017-0216
Kansas City Power & Light Company In the Matter of Kansas City Power & Light Company's Demand Side Investment Rider Rate Adjustment And True-Up Required by 4 CSR 240-3.163(8)	ER-2017-0316
Kansas City Power & Light Company In the Matter of Kansas City Power & Light Company's Demand Side Investment Rider Rate Adjustment And True-Up Required by 4 CSR 240-3.163(8)	ER-2017-0167
KCP&L Great Missouri Operations Company In the Matter of KCP&L Greater Missouri Operations Company's Annual RESRAM Tariff Filing	ET-2017-0097

Company	**Case No.**
Grain Belt Express Clean Line, LLC In the Matter of the Application of Grain Belt Express Clean Line LLC for a Certificate of Convenience and Necessity Authorizing It to Construct, Own, Operate, Control, Manage, and Maintain a High Voltage, Direct Current Transmission Line and an Associated Converter Station Providing an Interconnection on the Maywood - Montgomery 345 kV Transmission Line	EA-2016-0358
Kansas City Power & Light Company In the Matter of Kansas City Power & Light Company's Demand Side Investment Rider Rate Adjustment And True-Up Required by 4 CSR 240-3.163(8)	ER-2016-0325
Kansas City Power & Light Company In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	ER-2016-0285
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri for Permission and Approval and a Certificate of Public Convenience and Necessity Authorizing it to Offer a Pilot Subscriber Solar Program and File Associated Tariff	EA-2016-0207
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service	ER-2016-0179
KCP&L Great Missouri Operations Company In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service	ER-2016-0156
Empire District Electric Company In the Matter of The Empire District Electric Company's Request for Authority to Implement a General Rate Increase for Electric Service	ER-2016-0023
Ameren Transmission Company of Illinois In the Matter of the Application of Ameren Transmission Company of Illinois for Other Relief or, in the Alternative, a Certificate of Public Convenience and Necessity Authorizing it to Construct, Install, Own, Operate, Maintain and Otherwise Control and Manage a 345,000-volt Electric Transmission Line from Palmyra, Missouri to the Iowa Border and an Associated Substation Near Kirksville, Missouri	EA-2015-0146
Ameren Transmission Company of Illinois In the Matter of the Application of Ameren Transmission Company of Illinois for Other Relief or, in the Alternative, a Certificate of Public Convenience and Necessity Authorizing it to Construct, Install, Own, Operate, Maintain and Otherwise Control and Manage a 345,000-volt Electric Transmission Line in Marion County, Missouri and an Associated Switching Station Near Palmyra, Missouri	EA-2015-0145
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri's 2nd Filing to Implement Regulatory Changes in Furtherance of Energy Efficiency as Allowed by MEEIA	EO-2015-0055
Kansas City Power & Light Company In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	ER-2014-0370

Company	Case No.
Empire District Electric Company In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area	ER-2014-0351
Union Electric Company d/b/a Ameren Missouri City of O'Fallon, Missouri, and City of Ballwin, Missouri, Complainants v. Union Electric Company d/b/a Ameren Missouri, Respondent	EC-2014-0316
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service	ER-2014-0258
Union Electric Company d/b/a Ameren Missouri Noranda Aluminum, Inc., et al., Complainants, v. Union Electric Company d/b/a Ameren Missouri, Respondent	EC-2014-0224
Grain Belt Express Clean Line, LLC In the Matter of the Application of Grain Belt Express Clean Line LLC for a Certificate of Convenience and Necessity Authorizing It to Construct, Own, Operate, Control, Manage, and Maintain a High Voltage, Direct Current Transmission Line and an Associated Converter Station Providing an Interconnection on the Maywood - Montgomery 345 kV Transmission Line	EA-2014-0207
KCP&L Great Missouri Operations Company In the Matter of KCP&L Greater Missouri Operations Company's Application for Authority to Establish a Renewable Energy Standard Rate Adjustment Mechanism	EO-2014-0151
Kansas City Power & Light Company In the Matter of Kansas City Power & Light Company's Filing for Approval of Demand-Side Programs and for Authority to Establish A Demand-Side Programs Investment Mechanism	EO-2014-0095
Veolia Energy Kansas City, Inc. In the Matter of Veolia Energy Kansas City, Inc. for Authority to File Tariffs to Increase Rates	HR-2014-0066

MPSC 0045

Separately, for each facility, as of July 10, 2023, what are the estimated total annual property taxes for the facility and interconnection? Please explain how these amounts are expected to vary or be held constant over the life of the facility. If these estimates are available as itemized, please provide in that form. If this information was included in direct testimony, please state the amount included in direct testimony, the location of the information in direct testimony, and the reason for the change in amount. Please update this DR for changes in amounts, if any, as of the first and fifteenth of each month. If any clarification is required concerning this data request, please contact Sarah Lange. Sarah Lange (sarah.lange@psc.mo.gov) RESPONSE Prepared By: Jordan Blackhurst; Lindsey Forsberg Title: Manager, Commercial Contracts; Renewable Energy Strategy Consultant Date: 07/17/2023 Subject to the Company's objection: The property taxes (or PILOT payment in lieu of property taxes) are included within the project model for each year of the project's expected life. Please see the following files provided as part of Matt Michels' direct testimony workpapers and refer to the tab titled, "Inputs": • Invenergy Split Rail ITC_Highly Confidential • Invenergy Split Rail PTC_Highly Confidential • Savion Cass County ITC_Highly Confidential • Savion Cass County PTC_Highly Confidential • Vandalia Solar ITC _Highly Confidential • Vandalia Solar PTC_Highly Confidential • Bowling Green Solar ITC_Highly Confidential • Bowing Green Solar PTC_Highly Confidential

MPSC 0047

Separately, for each facility, as of July 10, 2023, What are the estimated annual operating expenses expected for year 1 of operation? Please explain how these amounts are expected to vary or be held constant over the life of the facility. If these estimates are available as itemized, please provide in that form. If this information was included in direct testimony, please state the amount included in direct testimony, the location of the information in direct testimony, and the reason for the change in amount. Please update this DR for changes in amounts, if any, as of the first and fifteenth of each month. If any clarification is required concerning this data request, please contact Sarah Lange. Sarah Lange (sarah.lange@psc.mo.gov) RESPONSE Prepared By: Lindsey Forsberg Title: Renewable Energy Strategy Consultant Date: 07/18/2023 Subject to the Company's objection: The information was included in the workpapers underlying Matt Michels' direct testimony. Specially, please refer to the 'Inputs' tab of each project model in the associated Matt Michels direct testimony workpapers provided to Staff on June 21, 2023 (filenames listed below), which show operating expense estimates by year. • Invenergy Split Rail ITC_Highly Confidential • Invenergy Split Rail PTC_Highly Confidential • Savion Cass County ITC_Highly Confidential • Savion Cass County PTC_Highly Confidential • Vandalia Solar ITC _Highly Confidential • Vandalia Solar PTC_Highly Confidential • Bowling Green Solar ITC_Highly Confidential • Bowing Green Solar PTC_Highly Confidential

MPSC 0049

Separately, for each facility, as of July 10, 2023, What are the estimated income tax benefits, for each income tax benefit available, for year 1 of operation? Please explain how these amounts are expected to vary or be held constant over the life of the facility. If these estimates are available as itemized, please provide in that form. If this information was included in direct testimony, please state the amount included in direct testimony, the location of the information in direct testimony, and the reason for the change in amount. Please update this DR for changes in amounts, if any, as of the first and fifteenth of each month. If any clarification is required concerning this data request, please contact Sarah Lange. Sarah Lange (sarah.lange@psc.mo.gov) RESPONSE Prepared By: Jordan Blackhurst Title: Manager, Commercial Transactions Date: 07/18/23 Please refer to the 'Results Summary' tab in the project model workpapers provided to Staff associated with Matt Michels' direct testimony, which show ITC or PTC value by year. • Invenergy Split Rail ITC_Highly Confidential • Invenergy Split Rail PTC_Highly Confidential • Savion Cass County ITC_Highly Confidential • Savion Cass County PTC_Highly Confidential • Vandalia Solar ITC _Highly Confidential • Vandalia Solar PTC_Highly Confidential • Bowling Green Solar ITC_Highly Confidential • Bowing Green Solar PTC_Highly Confidential

MPSC 0053S1

Separately, for each facility, as of July 10, 2023, What is the anticipated annual generation, year 1, at point of interconnection, in AC? Please explain how these amounts are expected to vary or be held constant over the life of the facility. If this information was included in direct testimony, please state the amount included in direct testimony, the location of the information in direct testimony, and the reason for the change in amount. Please update this DR for changes in amounts, if any, as of the first and fifteenth of each month. If any clarification is required concerning this data request, please contact Sarah Lange. Sarah Lange (sarah.lange@psc.mo.gov) RESPONSE Prepared By: Lindsey Forsberg Title: Strategy Consultant, Renewable Energy Development Date: July 31, 2023 The anticipated annual generation values for year 1, labeled "Annual MWh" in Schedule MM-D14, are at the point of interconnection and therefore can be considered AC. Please refer to tab "Data Entry" row 209 for ongoing annual AC generation estimates, labeled by year, with the impact of degradation included.

MPSC 0056

Separately, for each facility, based on the information available as of July 10, 2023, Will the facility be treated as generation or as offset to load for purposes of allocation of MISO expenses/tariffs? If this information was included in direct testimony, please state the expected treatment described in direct testimony, the location of the information in direct testimony, and the reason for the change in amount. Please update this DR for changes, if any, as of the first and fifteenth of each month. If any clarification is required concerning this data request, please contact Sarah Lange. Sarah Lange (sarah.lange@psc.mo.gov) RESPONSE Prepared By: Andrew Meyer Title: Sr. Director, Energy Management & Trading Date: 07/24/2023 Subject to the Company's objection, 1. Split Rail, through MISO's Generator Interconnection Process, will be registered with MISO's Network Model as a Generation Resource. Additionally, Split Rail will be registered as part of MISO's Commercial Model, capable of responding to dispatch instructions and receiving its own unique market settlements. Split Rail will also qualify as a Planning Resource, eligible to participate in MISO's Planning Resource Auction for Capacity (PRA.) 2. Cass County – (Similar to Split Rail above) 3. Bowling Green will be registered "Behind the Meter," as a Load Modifying Resource (LMR). LMRs are required to respond to

MISO deployment instructions under certain system conditions, but because it is a solar resource, its natural state will be to generate whenever there is irradiance. Bowling Green will not be specifically registered with MISO's Network and Commercial models, but rather act as an offset to the existing AMMO.UE CPNode representing Ameren Missouri retail load. LMRs do qualify as Planning Resources eligible to participate in MISO's PRA. Page 2 of 2 4. Vandalia – (Similar to Bowling Green above)

MPSC 0068

1. Separately, for each requested solar site, please describe a. Whether solar panels will be oriented to achieve maximum solar energy production, maximum solar energy value, maximum coincidence with Ameren Missouri load, maximum coincidence with MISO load, maximum coincidence with expected summer peak conditions used to develop capacity requirements, or some other orientation. Please fully explain the orientation selected. b. Whether the orientation of solar panels for the purposes described in part A of this question can be reconfigured in the future. If so, please explain the degree of intervention required to modify the orientation, and an estimate of the costs of reorientation, in 2023 dollars. If any clarification is required concerning this data request, please contact Sarah Lange. Sarah Lange (sarah.lange@psc.mo.gov). RESPONSE Prepared By: Brad Corder; Chuck Roberts Title: Sr. Project Manager; Project Manager Date: 07/19/23 a) The orientation and design for each of the four solar sites (Vandalia, Bowling Green, Cass County, and Split Rail) has been aimed at optimizing maximum yearly energy production. With single axis trackers, the most ideal orientation is North to South axis with tracking rotation from East to West. b) While the orientation of the solar panels could be reconfigured, this would likely result in significant cost increases. Given the unlikely scenario, cost estimates have not been assessed.

MPSC 0077

On page 35 of his direct testimony, Mr. Matt Michels states: The series of charts below, Figures 14-17, show energy needs and generation for the month of July. Analysis results are shown for (a) 2026, following the retirement of Rush Island, with and without the continued investments in renewable resources embodied in the Company's PRP; (b) 2031, following the retirement of Sioux; and (c) 2037, following the retirement of the first two units at Labadie. Resource additions likewise follow the PRP timeline shown in Figure 1. Figures 14 (without the Solar Projects) and 15 (with the Solar Projects) show that the Solar Projects are expected to help meet energy needs during the summer peak period in the relatively near term. This is not the only time solar resources generate electricity, but its value tends to be greatest during these times. It appears from the figures provided that the addition of renewables through 2026 is still not enough to meet Ameren's load for 2026. Did Ameren's IRP consider any plans with resource additions other than renewables in the near future, particularly dispatchable generation that would perform better in the winter season? Did any of the plans in the IRP provide a lower LOLE value than Ameren's preferred plan? If so, please identify. Cedric Cunigan (cedric.cunigan@psc.mo.gov) RESPONSE Prepared By: Matt Michels Title: Director, Corporate Analysis Date: July 23, 2023 The charts described in the cited portion of my direct testimony are intended to demonstrate the complementary nature of intermittent renewable resources and non-peaking dispatchable resources relative to load. The charts do not reflect the utilization of existing or new peaking dispatchable resources, which can be dispatched to meet load over a few hours during peak conditions. The Company continues to evaluate its need for dispatchable resources to integrate its planned renewable additions as part of the development of its 2023 IRP, which is to be filed with the MPSC no later than October 1, 2023, including near-term needs.

<u>MPSC 0085</u>

For Figures 5, 6, 7, 8, 9, 10, 11, 12, and 13 in Matt Michels' direct testimony, please clarify whether the figure is associated with a resource plan that was studied in the IRP. If a figure is associated with a resource plan that was studied in the IRP please identify the resource plan, state the NPVRR, and identify any changes between the values presented in Mr. Michaels' testimony and the values reflected in the IRP. J Luebbert (j.luebbert@psc.mo.gov) RESPONSE Prepared By: Matt Michels Title: Director, Corporate Analysis Date: August 4, 2023 Figures 7, 10 and 13 correspond to the Company's Preferred Resource Plan. The remaining figures do not correspond to a plan for which revenue requirements were estimated. The PVRR for the preferred plan was shown to be $79,024 million in the Company's June 2022 Notice of Change in Preferred Plan (see Schedule MM-D2 Part 2, page 27, Table 7, Line C). The Company has updated assumptions to reflect tax credits under the Inflation Reduction Act and project costs for wind and solar resources, as described in my direct testimony in this case on page 65. As a result, the PVRR for the preferred plan changed to $79,102 million as shown in Table 2 on page 55 of my direct testimony.

<u>MPSC 0088</u>

Fully explain Ameren Missouri's economic rationale for determining whether to move forward with acquisition of a supply-side resource. J Luebbert (j.luebbert@psc.mo.gov) RESPONSE Prepared By: Ajay Arora Title: Senior Vice President and Chief Renewable Development Officer Date: August 3, 2023 During the first Technical Conference, Staff posed the following question, which I believe also encompasses the question posed by this DR: "Please describe how the Company evaluates the proposed projects from an economic perspective in order to reasonably manage cost impacts to customers of the generation investments made by the Company to meet the needs of its retail customer base, including through the project selection process, and on an ongoing basis through the eventual construction or acquisition of the project" To answer the above-quoted broader question and the question posed in this DR, it is necessary to recognize that from the Company's perspective, the IRP is the foundation of the Company's Resource Acquisition Strategy. Under the IRP rules, the Resource Acquisition strategy should be designed to meet customers' needs using the primary criteria of minimization of the present worth of long-run utility costs. So, the driving "economic rationale" is to implement such a Strategy consistent with that primary criterion. The IRP filing itself fully documents the analysis, considerations, and risk assessments that lead to the selection of the Company's Preferred Resource Plan (PRP). A number of relevant sections of the Company's 2020 IRP and 2022 Notice of Change in Preferred Plan are attached to witness Michels' testimony in this case. The PRP is selected from a diverse group of candidate resource portfolios that are all designed to meet the anticipated needs of customers throughout the 20-year planning horizon using a variety of generation technologies and demand-side resource options, based off of generic (i.e., not project-specific) assumptions, which are informed by current market information, related to resource cost, capability, and performance associated with various candidate technologies.

The Page 2 of 3 PRP is selected by Company management based on a scorecard of metrics, which as noted includes as its primary (highest weighted) criteria the minimization of the net present value of revenue requirement (NPVRR) that will be incurred in providing service to customers. By virtue of using minimization of the NPVRR as the primary criterion in the plan selection, the Company ensures a process that focuses on the selection and addition of a portfolio of resources to meet customers' needs that are least cost to customers, subject to the Company's other planning objectives (customer satisfaction, portfolio diversity, economic development, and financial and regulatory risks) and any identified constraints to minimizing NPVRR. In the case of the Company's current PRP as filed in the 2022 Notification of Change in PRP, the PRP has the lowest NPVRR of all candidate resource portfolios and is $632 million lower on an NPVRR basis than another alternative – the Renewables for Capacity Need plan - that represents what may be considered an alternative approach to meeting customers' needs. Using updated information that will underlie the 2023 triennial IRP, the Company estimates that its 2023 PRP, which will continue to reflect the addition of significant renewable generation capacity (such as the projects proposed in this docket) will reflect an NPVRR that is $1.2 billion lower than such a reference case. As a result of that comparison, the Company's PRP reflects a cost-effective plan to acquire the resources needed to meet customer needs, including the addition of the solar generation facilities that are the subject of this case. The Resource Acquisition Strategy in the IRP also includes a 3-year implementation plan that identifies steps that need to be taken within the immediately ensuing years to execute on the PRP. Based on resource types reflected in the Company's PRP, and the timing of the need for those resources, the Company evaluates what actions need to be taken to execute its plan, while maintaining flexibility to update the PRP to adjust to changes in energy markets, environmental laws and regulations, and technology advancements. The steps taken within the planning window must inherently recognize the long lead time needed to bring new large-scale generation resources online. For generation needs identified within the next ten years, the Company may engage in site evaluation, project definition and scoping, and market assessment activities. As the generation needs gets closer (within five years), more direct project development and acquisition efforts must begin to meet the timelines reflected in the IRP, including issuing requests for proposals (RFPs), completing project due diligence and contract negotiation, and submitting applications for Certificates of Convenience and Necessity (CCNs). As the IRP moves from a generic assessment of resource technologies to the assessment of specific projects needed to execute the Company's implementation plan, the RFP process is the next key customer protection to ensure the Company's actions will reasonably manage costs while meeting customer needs. The Company solicits competitive bids from across the marketplace of qualified and reputable developers of projects, and/or providers of components and engineering/construction services, to provide robust and reliable market information related to the costs of projects, components, and services. The Company's assessment of bids – as further described in the testimony of witness Scott Wibbenmeyer – is based on a scorecard of metrics created with the goal of identifying valuable projects, and utilizes critical project metrics such as project pricing, maturity, performance, and technology. Such evaluation necessarily and appropriately frames any costs that may fall outside of the range of generic assumptions used in the IRP in the context of the relative magnitude of the difference in NPVRR between the PRP Page 3 of 3 and other candidate portfolios. For example, if the PRP is at worst $500 million better than an alternate plan that could be selected, and costs of a project that makes up a significant portion of the execution of the PRP increase by say $10 million, there is essentially no chance that selecting said project would change the PRP and cause a change in selected generation technologies or timing of their implementation. In this scenario, the only relevant assessment of the $10 million increase that would impact the potential to implement the project may be to determine whether the cost increase is project-specific – and therefore warrants reevaluation of the project's selection over other available projects – or whether the cost increase is reflective of changes in the market that would similarly impact other alternative projects. In the case of the latter, it is reasonable to continue to pursue the project at the higher cost level. Projects selected from the RFP process are subjected to due diligence prior to final selection and contracting. Company personnel continue to assess the market by maintaining relationships with a variety of developers, refreshing RFPs to get updated bids and pricing, and carefully monitoring industry news and trends related to topics such as supply chain issues, tariffs, and law and regulation changes. Contracts that the Company enters into must themselves maintain flexibility to accommodate the CCN process, recognizing that the Company cannot fully commit to constructing a project until CCN approval has been granted by the PSC. During the pendency of CCN applications and up until the Company issues what is generally referred to as a notice to proceed or Firm Date, market conditions are such that certain costs generally cannot be "locked in". Ameren Missouri's practice has generally been to sign contracts that are subject to final competitive, market-based pricing that include cost caps that give the Company the ability to terminate a project if final pricing exceeds some contractual benchmark. This does not mean that the Company must cancel the project if the final pricing exceeds that value, but it gives the Company the ability and opportunity to reassess the relative project costs in the context of the current market environment prior to proceeding with a project above the contractual price cap.

MPSC 0090

How does Ameren Missouri account for changes to locational marginal prices on existing Ameren Missouri owned generation assets based upon proposed additions within the context of Ameren's integrated resource planning? J Luebbert (j.luebbert@psc.mo.gov) RESPONSE Prepared By: Matt Michels Title: Director, Corporate Analysis Date: August 4, 2023 See response to MPSC 0091.

MPSC 0091

How does Ameren Missouri account for changes to locational marginal prices on existing Ameren Missouri owned generation assets based upon proposed additions within the context of Ameren's analysis provided in support of this case? J Luebbert (j.luebber@psc.mo.gov) RESPONSE Prepared By: Matt Michels Title: Director, Corporate Analysis Date: August 4, 2023 The Company does not explicitly account for changes in LMPs for existing resources resulting from specific proposed additions. The Company's market price scenarios do account for price impacts resulting from the broad transition of the resource mix within MISO and the Eastern Interconnect, including the addition of wind and solar resources.

MPSC 0094.4

The CRA Report at page 20, states “Overall, renewable entry directly affects the total amount of fossil-fuel capacity in the system since low variable cost resources drive traditional fossil fuel resources up the merit order making them uneconomic more frequently.” (1) Please state whether Ameren Missouri disputes this CRA statement. (2) Please confirm that Ameren Missouri’s fuel model dispatch to market price to show meeting of “energy need” with the additions of solar resources neither (a) reflects a dynamic market price to reflect a relative increase in total fossilfuel generation in a given year when modeled with fewer renewables, nor (b) reflects a relative reduction in the total level of fossil-fuel generation in a given year when modeled with more renewables. Please confirm that in the modeling underlying Mr. Michels’ Figure 5, Figure 6, and Figure 7 neither (a) reflects dynamic market pricing to reflect a relative increase output of a given fossil-fuel generator in a given year when modeled with fewer renewables, nor (b) reflects a relative reduction in the total generation modeled by a given fossil-fuel generator in a given year when modeled with more renewables. Sarah Lange (sarah.lange@psc.mo.gov) RESPONSE Prepared By: Matt Michels Title: Director, Corporate Analysis Date: August 28, 2023 1. The Company does not dispute the statement from CRA. 2. Ameren Missouri's dispatch model simulates its own portfolio's dispatch in the MISO market based on a range of market power price assumptions, which were in turn based on scenarios that reflect combinations of carbon price and natural gas price assumptions. The market power price scenario results were developed based on simulation of resource portfolio changes and dispatch for the entire Eastern Interconnect and MISO. Each modeled scenario reflects different levels and mixes of new resource deployment based on the scenario variables (carbon price and natural gas price). This modeling does not determine specific ownership of new resources (e.g., specific new resources deployed in each scenario may or may not be owned by Ameren Missouri), only the mix of resources Page 2 of 2 that would be operating during the planning horizon. The energy positions presented in Figures 5, 6 and 7 of my direct testimony reflect probability weighted average results of dispatch modeling for all price scenarios. Neither power prices used by the dispatch model nor generator output produced by the model are further adjusted to reflect Ameren Missouri's ownership of specific renewable resources

MPSC 0096

If MISO is unable to provide energy to meet the needs of Ameren Missouri load, please explain how Ameren Missouri owned generation assets will be able to alternatively meet said load outside of the frameworks of MISO markets. Does Ameren Missouri intend to exit MISO prior to 2030? Does Ameren Missouri plan to dispatch its generation against MISO instructions, and if so, under what circumstances. J Luebbert (j.luebbert@psc.mo.gov) RESPONSE Prepared By: Ajay Arora Title: Senior Vice President and Chief Renewable Development Officer Date: August 2, 2023 Ameren Missouri's plan is to add summer and winter energy and capacity resources in a sustained manner to ensure it has an energy buffer in each hour of the year. Ameren Missouri anticipates continuing to be a part of MISO for the foreseeable future, and dispatching its generation consistent with MISO instructions. While Ameren Missouri's load can still be subject to impacts of shortages across MISO, ensuring that Ameren Missouri is contributing resources to the market sufficient to meet the load that it must serve from the market including a buffer of excess energy in the summer and also across all seasons reflects prudent planning. Ameren Missouri is optimistic that other states – and market mechanisms in states that with competitive generation supply - will do the same to mitigate MISO summer energy and capacity shortages. The risk that other states or competitive regions do not cover their load with resources clearly points to the fact that Ameren Missouri needs to be maintain an energy surplus to best protect its customers. In the event that other states in the MISO region do not develop resources to meet their load needs and load impacts are experienced in Ameren Missouri's service territory but Ameren Missouri is able to execute on its plan, the load impacts to the Company's customers will necessarily be less than they otherwise would have been if the Company had not developed an energy buffer, and revenues from the resources the Company has developed will be more likely to be in the higher end of the range of energy and capacity market prices reflected in the Company's IRP and project-specific economic analyses due to the supply side issues that would impact the market in such a scenario.

MPSC 0115

Refer to Matt Michels' direct testimony at page 34, stating "8 Q. Has the Company evaluated energy needs and the role of solar resources in 9 fulfilling those needs on a more granular basis? 10 A. Yes. Ameren Missouri has analyzed hourly energy needs and expected generation, 11 which highlights the value of the Solar Projects and the Company's longer-term renewable 12 additions in meeting customer energy needs. This was done by taking the Company's new 2023 13 IRP load forecasts and showing an explicit build-up of energy resources compared to the load. 14 Specific time periods were evaluated, including summer and winter peak conditions, for several 15 key timeframes during the 20-year planning horizon." 1. Please clarify whether or not Ameren Missouri has done iterative production modeling in any context under which it has added the solar resource, developed new LMPs that recognize the resource, and then done production modeling with the new LMPs? If Ameren Missouri has done such modeling, please provide such modeling and all results and inputs in native format. 2. For all years for which data is available, (a) by resource, please identify the annual MWh from existing Ameren Missouri resources that Ameren Missouri has modeled to be dispatched by MISO or self-committed in the absence of the four proposed solar projects or other additions to the Ameren Missouri generation fleet, and (b) by resource, please identify the annual MWh from existing Ameren Missouri resources that Ameren Missouri has modeled to be dispatched by MISO or self-committed with the addition of the four proposed solar projects or other additions to the Ameren Missouri generation fleet. 3. Please provide any and all analysis that Ameren Missouri has performed to prove that the proposed additional solar resources will reasonably be expected to materially increase the amount of generation that Ameren Missouri is called by MISO to dispatch or that Ameren Missouri self-commits. 4. Please provide any and all analysis that Ameren Missouri has performed to quantify the impact that the proposed additional solar resources can reasonably be expected to cause on (a) Ameren Missouri's costs to generate electricity, (b) Ameren Missouri's revenues from the generation of electricity, and (c) Ameren Missouri's costs to obtain energy to serve its load. Sarah Lange (sarah.lange@psc.mo.gov) RESPONSE Prepared By: Matt Michels Title: Director, Corporate Analysis Date: August 7, 2023 1. The requested analysis has not been performed. Please see response to MPSC 0091. Page 2 of 2 2. Please see attached file "MPSC 0115 Attach – Emissions Generation 05-27-22.xlsx." This shows the production cost model results used for both the Company's 2022 Notice of Change in Preferred Plan and the analysis presented in my direct testimony in this case. The pivot table shows generation by coal energy center and by fuel type for all other generation. The pivot table as provided shows results for the current preferred resource plan

(PRP), which is labeled "Renewable Transition" in the file, for price scenario 5 (base gas price, low carbon price). Other plans and scenarios can be selected to see the corresponding results. Plan names can be found in the "Probabilities" tab. 3. A quantitative proof has not been prepared. However, given that dispatchable units in MISO are dispatched by the model to price, changes in generation from dispatchable resources would not be expected to result from the inclusion of solar resources. Note from subpart 1 above and the response to DR 0091 that it references that the prices used for dispatch do include recognition of additional renewable resources being added to the market as a result of the transition taking place in the industry, of which the generation additions that are the subject of this case are a subset. 4. For purposes of subpart c of this part of this response, it is assumed that the costs referenced refer to the LMP prices for load. a. Please see workpapers containing the individual project models for each solar project. b. Please see workpapers containing the individual project models for each solar project. c. Please see response to MPSC 0091.
[attachment omitted]

MPSC 0117

Please identify all market participants in MISO Zone 5 that are load serving entities. 2. Please identify all market participants in MISO Zone 5 that own or operate generation located in Zone 5 or pseudo-tied into Zone 5. 3. Please provide Ameren Missouri's forecasts of the capacity positions of all market participants in MISO Zone 5. 4. Please fully explain the extent to which capacity physically located in MISO Zone 5 may be used for load obligations located outside of Zone 5, including discussion as applicable of costs and processes required to satisfy MISO and NERC requirements. Sarah Lange (sarah.lange@psc.mo.gov) RESPONSE Prepared By: Mark J. Peters Title: Manager Date: August 9, 2023 1. In addition to itself, Ameren Missouri is aware of the following loadzone CpNodes in the AMMO and CWLD (City of Columbia) LBAs (which are the only two LBAs in Zone 5). The Company knows the identities of the market participants in the AMMO CpNodes but does not know the market participants for CWLD CpNodes. The nodes for both LBAs are as follows: AMMO.AEM.MO AMMO.CALI AMMO.CENT AMMO.HANN.LD AMMO.KAHO_NEM AMMO.KIRK AMMO.MARC_NEM AMMO.NEWMADRID AMMO.PERR AMMO.WVPA AMMO.WVPA.CZHI AMMO.WVPA.CZML Page 2 of 4 AMMO.WVPA.CZPG CWLD.CWLD CWLD.FULT CWLD.UMC Please note that under MISO's tariff, while the list of nodes is not confidential the identity of the market participants is confidential (please note that the name for the Node does not necessarily mean that such name is the identity of the market participant(s) settling at that Node). Under the MISO tariff, Ameren Missouri cannot release the market participant identities unless and until it gives notice to the market participants and gives them the opportunity to object to the disclosure. Ameren Missouri does not yet have the requisite contact information to provide those notices as this is information in the possession of MISO. Ameren Missouri believes, however, that the MISO tariff provides a means for the Staff to obtain this information directly from MISO as an Authorized Requestor – see Module A – Common Tariff Provisions – at the following URL: https://docs.misoenergy.org/legalcontent/Module_A_-_Common_Tariff_Provisions.pdf 2. In addition to itself, Ameren Missouri is aware of the following generation CpNodes in the AMMO and CWLD local balancing authorities. The Company is also aware that there are other behind the meter generators located in the AMMO LBA which do not have generator CpNodes, such as the QF facilities whose electric output is purchased by Ameren Missouri under Rider

QF and those owned by the Cities of Kahoka and Marceline. The Company knows the identities of the market participants for the AMMO CpNodes, but does not know the market participants for CWLD CpNodes. Ameren Missouri does not know whether non-Ameren Missouri owned behind the meter generation resources are or are not registered by their owners as BTMG with MISO, in both AMMO and CWLD, absent any with a CpNode listed below. The generation nodes are as follows: AMMO.TRIGCTG1 CWLD.BLRG CWLD.CEC2CTG1 CWLD.CEC2CTG2 CWLD.CEC2CTG3 CWLD.CEC2CTG4 CWLD.PLANTD6 CWLD.PLANTD8 See the answer to part 1 about the confidentiality restrictions in MISO's tariff and the provisions Ameren Missouri believes allow Staff to obtain information from MISO. Page 3 of 4 3. The requested forecast does not exist. 4. Module E-1 of the MISO Tariff and the accompanying Business Practice Manual 11 provide the requested detail. https://docs.misoenergy.org/legalcontent/Module_E-1_-_Resource_Adequacy.pdf
https://www.misoenergy.org/legal/business-practice-manuals/#5576Collapse8 As noted in Module E-1 of the MISO tariff (69A RAR Process 36.0.0) LSEs will meet their PRMR by: (i) submitting a Fixed Resource Adequacy Plan; (ii) Self-Scheduling ZRCs; (iii) purchasing ZRCs through the Planning Resource Auction process; and/or (iv) paying the Capacity Deficiency Charge. With the exception of a resource which has been included in a Fixed Resource Adequacy Plan (FRAP), or a resource which is only deliverable to a single LRZ, specific ZRCs are not "mapped" source to sink. Ameren Missouri historically utilizes self-scheduling, and its LRZ 5 PRMR exceeds owned ZRCs in LRZ 5. When self-scheduling is used, an LSE with ownership or contractual rights to capacity resources offers them into the PRA up to the megawatt ("MW") amount needed to meet its PRMR, at a price of $0.00. This ensures that at least that amount of its resources will clear (i.e., be sold) in the capacity auction, regardless of which LRZ the resource is located in. When the clearing price is the same in the load and the resource LRZ, the revenues from the sale of capacity from the resources offset the cost of acquiring the capacity for load. If the clearing price in the resource zone is higher than that for the load zone, the Company receives a benefit – revenue is greater than cost (for that specific volume of capacity resources). If the price of capacity in the load zone is higher than the price of capacity in the resource zone, then the Company's costs will exceed the revenue (for that specific volume of capacity resources). Generally, capacity in MISO takes the form of Zonal Resource Credits (ZRCs). Accredited values are established for each capacity resource, and this amount is converted to a ZRC. For resources determined to be universally deliverable, that ZRC may be cleared by MISO and used to meet the overall PRMR in MISO. Capacity import and export limits in given zones will affect how much capacity in a given LRZ will clear. As noted previously, specific ZRCs are not "mapped" source to sink. For illustration, following is the Summer 2023 PRA Results by zone (slide 17 in the MISO 2023-2024 Planning Resource Auction Results presentation)
Page 4 of 4

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	System
PRMR	18,234.4	13,371.2	10,491.9	9,559.5	8,115.3	18,107.7	21,232.8	7,915.8	21,234.3	4,628.3	N/A	132,891.2
Offer Submitted (Including FRAP)	21,293.8	14,191.9	11,323.8	8,482.5	7,392.0	15,473.9	21,730.0	11,083.2	21,198.7	4,755.5	2,448.6	139,373.9
FRAP	14,042.9	11,237.4	4,245.7	537.4	0.0	949.7	1,457.5	535.2	166.2	1,315.6	309.1	34,796.7
Self Scheduled (SS)	5,302.9	2,431.7	6,557.7	5,673.2	7,372.0	9,940.7	19,918.7	9,777.1	19,359.6	3,071.6	1,569.6	90,974.8
Non-SS Offer Cleared	168.9	443.5	517.4	1,312.0	20.0	3,423.1	4.4	449.4	331.5	321.7	127.8	7,119.7
Committed (Offer Cleared + FRAP)	19,514.7	14,112.6	11,320.8	7,522.6	7,392.0	14,313.5	21,380.6	10,761.7	19,857.3	4,708.9	2,006.5	132,891.2
LCR	15,076.1	10,552.0	6,806.3	2,935.0	6,529.5	11,567.6	18,785.5	7,134.5	18,931.4	3,690.0	-	N/A
CIL	5,301	3,477	6,108	7,884	3,576	8,492	5,087	4,139	5,268	3,064	-	N/A
ZIA	5,299	3,477	6,043	6,992	3,576	8,092	5,087	4,091	4,456	3,064	-	N/A
Import	0.0	0.0	0.0	2,036.9	723.3	3,794.2	0.0	0.0	1,377.0	0.0	-	7,931.4
CEL	3,959	2,550	4,310	NLF*	NLF*	2,703	3,953	5,503	1,574	1,794	-	N/A
Export	1,280.3	741.4	828.9	0.0	0.0	0.0	147.8	2,845.9	0.0	80.6	2,006.5	7,931.4
ACP ($/MW-Day)	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	N/A

Values displayed in MW UCAP **NLF = No Limit Found: Tier 1 & 2 source capacity is less than the study transfer limit*

17

MISO

https://cdn.misoenergy.org/2023%20Planning%20Resource%20Auction%20(PRA)%20Results6 28925.pdf To the extent that question is seeking information regarding the process for using capacity resources physically located in MISO LRZ 5 to meet capacity obligations outside of the MISO, the Company is generally aware that this would require securing adequate transmission service from the source to the ultimate sink on all affected transmission systems. Please reference the tariffs of adjoining transmission service providers for detail.

<u>MPSC 0118</u>

1. Provide specific citations for each federal rule or law that requires Ameren Missouri to generate energy in excess of the Ameren Missouri load. 2. Provide specific citations for each Missouri rule or law that requires Ameren Missouri to generate energy in excess of the Ameren Missouri load. 3. Provide specific citations for each MISO tariff requirement that requires Ameren Missouri to generate energy in excess of the Ameren Missouri load. J Luebbert (j.luebbert@psc.mo.gov) RESPONSE Prepared By: Matt Michels Title: Director, Corporate Analysis Date: August 7, 2023 The Company is not aware of any federal or state law, rule or regulation or MISO rule or regulation that requires Ameren Missouri to generate energy in excess of the Ameren Missouri load. The Company seeks to ensure sufficient capacity and energy to serve its customers in light of numerous risks, as explained in the Company's testimony in this and prior CCN cases.

<u>MPSC 0129</u>

Please provide the following information for any solar projects that will be in service by the end of 2026 that was modeled in Ameren's latest triennial IRP filing (EO-2021-0021) and in

Ameren' updated preferred resource plan changed in EO-2022-0362. Please provide/direct Staff to which workpapers this information is in and precisely which cell's the information can be located? 1. Expected Capital Cost of facility including land, site prep, panels, converter, and fencing. 2. Expected Capital Cost of interconnection. 3. Estimated annual property tax of facility and interconnection 4. Offsetting tax estimates for property tax, year 1, and over life of the facility. 5. Estimated annual operating expense, year 1, and over the life of the facility. 6. Type of tax benefits expected. 7. Estimated tax benefits year 1, and over life of the facility. 8. Any other considerations impacting revenue requirement 9. Expected life of facility for depreciation purposes 10. Anticipated net salvage value. 11. Anticipated capacity value for MISO purposes, in AC. 12. Anticipated annual generation, year 1, at point of interconnection, in AC, specify voltage of interconnection. 13. Anticipated energy value, by location, and as granular as possible 14. Variability in generation and capacity accreditation for solar resources 15. Anticipated degradation factor. 16. Will the facility be treated as generation or as offset to load for purposes of MISO dispatch? (or does the model include differentiation?) 17. Will the facility be treated as generation, or as offset to load for purposes of allocation of MISO expenses/tariffs (is there differentiation)? Data Request submitted by Mark Kiesling (mark.kiesling@psc.mo.gov) RESPONSE Prepared By: Matt Michels Title: Director, Corporate Analysis Date: August 11, 2023 For specific project assumptions and modeling, please refer to the project model workpapers provided in this case, and the project modeling provided in the Boomtown Solar (EA-2022-0245) and Huck Finn Solar (EA-2022-0244) cases. The IRP model uses generic resource assumptions and does not model specific projects. The responses below provide guidance on where to find inputs and assumptions used in the generic solar IRP modeling completed for EO-2021-0021 and EO-2022-0362: 1. Expected capital cost assumptions for solar utilized in EO-2021-0021 – including items such as land, site prep, panels, converter, and fencing – can be found in workpaper "RR Page 2 of 3 Model" provided in that case, tab RESCapex starting in cell L58. Comparable capital cost assumptions utilized in EO-2022-0362 can be found in attached workpaper "MPSC 0129 - RR Model 2022" tab RESCapex starting in cell L58. 2. Expected capital cost of interconnection is included in the capital cost estimates referenced in part 1. No separate assumption was made. 3. In case EO-2021-0021 no annual property tax was assumed for solar resources given the lack of solar property taxation in Missouri. The workpaper and tab reference in part 1 (""RR Model" tab RESCapex) indicates solar property tax as "Included" in column T, which means no additional amount was added for solar property taxes. In case EO-2022- 0362, solar property tax was included to reflect the likelihood that some solar projects pursued by the Company may be located outside the state of Missouri. Workpaper "MPSC 0129 - RR Model 2022," attached, indicates property tax as "Not included" in column T tab RESCapex, indicating additional property tax is added in the model. The assumed solar property tax rate can be seen in attached workpaper "MPSC 0129 - RES Compliance" which was also recently provided in response to MPSC 0119 (tab Assumptions, cell E10). 4. NA 5. Solar projects modeled in both EO-2021-0021 and EO-2022-0362 assume annual O&M of $4/kW annually in 2019 dollars, escalated at 2% annual inflation. Please refer to workpaper "RR Model" provided in case EO-2021-0021 and "MPSC 0129 - RR Model 2022" attached for case EO-2022-0362. In both models, the O&M assumption for solar can be seen on tab Uncertainty cell N12 and flows through to populate solar O&M cost estimates on tab FOM. 6. Solar projects modeled in both EO-2021-0021 and EO-2022-0362 assume the ITC will be utilized, normalized over the life of the facility. Please refer to workpaper "RR Model" provided for EO-2021-0021 and attached workpaper "MPSC 0129 - RR Model 2022" for EO-

2022-0362 tab RESCapex column U for assumed ITC rates by year. 7. As discussed in response to MPSC 0119, the best place to see how solar tax benefits are calculated by year in EO-2021-0021 and EO-2022-0362 is to view workpapers titled "RES Compliance" (provided in the case for EO-2021-0021 and attached for EO-2022- 0362). Reviewing the formulas on any numbered tab will illustrate how ITC benefits are normalized over the life of the facility. 8. NA 9. EO-2021-0021 assumed a twenty-five year life for solar for depreciation purposes. In EO-2022-0362 the assumption was updated to a thirty year life for depreciation purposes. Please see workpaper "RR Model" for EO-2021-0021 and attached workpaper "MPSC 0129 - RR Model 2022" for EO-2022-0362 tab RESCapex, column Q. 10. $0 was assumed for net salvage value in both EO-2021-0021 and EO-2022-0362. 11. Solar projects modeled in EO-2021-0021 assumed a 50% capacity credit for solar. Please refer to workpaper 22.060 Integrated Resource Plan-Risk\3-Risk\Capacity Position.xlsx, Cell O71 on each tab. Solar projects modeled in EO-2022-0362 assumed a 50% capacity accreditation value from MISO in the summer and 11% in the winter. Please refer to workpapers Capacity Position-Summer.xlsx, Cell O71 and Capacity Position-Winter, Cell O71. 12. For assumed capacity factors for solar, please view EO-2021-0021 Chapter 6, Appendix A Table 6A.2RT. These capacity factor assumptions were unchanged in EO-2022-0362. Page 3 of 3 Annual generation estimates for all solar projects combined can be seen by year in workpaper "RT Sim 26 CoalPrice2" provided for EO-2021-0021 (row 18, any tab) and in attached workpaper "MPSC 0129 –Powersimm 8 CoalPrice2" for EO-2022-0362 (row 18, any tab). 13. For generic resources modeled in the IRP there is no differentiation by location. All modeled solar projects receive estimate annual energy revenues based on the nine price scenarios modeled. For hourly price assumptions please see numerous workpapers provided in folder HC_22.060 Integrated Resource Plan Risk→Scenarios→Power Prices →Final Feb 2020→Hourly in case EO-2021-0021. The same power prices were used in EO-2022-0362. 14. The IRP model reflects generic solar additions. Therefore, variability in generation and capacity accreditation is not reflected. 15. Solar projects modeled in EO-2021-0021 and EO-2022-0362 assumed a 0.5% annual degradation factor. For EO-2021-0021, this value can only be easily seen within the RTSim model, and therefore no workpaper is readily available to provide. For EO-2022- 0362 please see workpaper "MPSC 0129 –Renewables 2022" (tab MWh cell G1). 16. Generation. 17. Generation.

[Attachments omitted]

MPSC 0130

For each year 2017-2023, please provide the following: 1. (a) Please identify the MISO tariff provisions that are assessed to Ameren Missouri based on Ameren Missouri's load in isolation. (b) Please state for each tariff provision if the charge is assessed based on daily load, monthly load, quarterly load, annual load, etc. (c) For each, please state the charge assessed, and the relevant load. (For example, if a charge is assessed based on monthly load, the response should state "Charge X is assessed on monthly load," and provide a table showing the charge and the load for each month for each year.) 2. (a) Please identify the MISO tariff provisions that are assessed to Ameren Missouri based on Ameren Missouri's load as a share of MISO load. (b) Please state for each tariff provision if the charge is assessed based on daily load-ratio-share, monthly load-ratio-share, quarterly load-ratio-share, annual load-ratio-share, etc. (c) For each, please state the charge assessed, and the relevant load for Ameren Missouri and for MISO. (For example, if a charge is assessed based on monthly load-ratio-share, the response should state "Charge X is assessed on monthly load-ratio-share," and provide a table showing the charge, the Ameren Missouri load, and the relevant MISO load for each month for each year.) 3. (a) Please identify the MISO tariff provisions that are assessed to Ameren Missouri based on Ameren Missouri's load at MISO Peak. (b) Please state for each tariff provision if the charge is assessed based on daily load at peak, monthly load at peak, quarterly load at peak, annual load at peak, etc. (c) For each, please state the charge assessed, and the relevant load. (For example, if a charge is assessed based on monthly load at peak, the response should state "Charge X is assessed on monthly load," and provide a table showing the charge and the load for each month for each year, as well as an indication of the hour.) 4. For purposes of this data request, do not include DA and RT energy market participation. Data Reques submitted by Sarah Lange (sarah.lange@psc.mo.gov). RESPONSE Prepared By: Greg Gudeman Title: Director – Transmission Financial & Regulatory Services Date: 8/11/23 Based on clarification from Staff, rather than specifically addressing each individual question above, the MISO transmission charge Schedules that Ameren Missouri pays are listed below with a detailed description on those schedules for which Ameren Missouri pays charges related Page 2 of 3 to its Native Load NITS reservation (" NL NITS") in the AMMO Pricing Zone that could be impacted by generation on the distribution system that is not reported to MISO. Below is a list of MISO transmission related charges for which Ameren Missouri is invoiced. Several charges are not billed for the Ameren Missouri NL NITS and therefore appear to not be relevant to the ultimate goal of the questions above. Therefore, the requested information is being provided for the highlighted Schedules below (Schedules 26, 26A, 9, 10E, 10D and 10F). Note that Schedules 26C, D and E are allocated to the load in the AMMO pricing zone based on monthly load ratio. However, these totaled less than $17,000 for all of 2022, with any potential cost shift

MISO BILLED 565 EXPENSES:		
MISO Schedule	**Description**	
1	Scheduling, System Control, and Dispatch	UEC does not pay for native load NITS
2	Reactive Supply and Voltage Control	UEC does not pay for native load NITS
7 & 8	Basic Transmission Revenue	Only charged to UEC PTP
26	Network Upgrade Charge From MTEP	Charged to all AMUE reservations
26A	ARR Pass-Through Rev Related to MVPs	Pass Thru
26A	MVP Charges 9/	Total UEC energy market settlements
26C	TMEP Constructed by MISO TOs	Load Ratio Share in Pricing Zone
26D	TMEP Constructed by PJM TOs	Load Ratio Share in Pricing Zone
26E	IMEP Constructed by MISO TOs	Load Ratio Share in Pricing Zone
33	Blackstart Service	Only charged to UEC PTP
	Entergy Related Charges for UEC Load in EAI Pricing Zone	
1	Scheduling, System Control, and Dispatch	Charged to UEC NITS in EAI PZ
2	Reactive Supply and Voltage Control	Charged to UEC NITS in EAI PZ
9	Schedule 9	Charged to UEC NITS in EAI PZ
11	Wholesale Distribution Charges	Charged to UEC NITS in EAI PZ
41	Storm Securitization Charge	Charged to UEC NITS in EAI PZ
42A	Accrued and Paid Interest	Charged to UEC NITS in EAI PZ
42B	Credit Associated with AFUDC	Charged to UEC NITS in EAI PZ
47	MISO Transition Cost Recovery	Charged to UEC NITS in EAI PZ
	Total Entergy Charges	
565 Schedule 9 paid to other TOs in AMMO PZ		Charged to UEC NITS in AMMO PZ
MISO NON-565 EXPENSES:		
10D & 10E	MISO Admin Fee (Demand and Energy Charge)	Charged to all AMUE reservations
10F	FERC Annual Charges	Charged to all AMUE reservations

See the attached excel file for monthly billing determinants, MISO rates and Ameren Missouri charges for its NL NITS reservation for 2017-2023 for Schedules 26, 26A, 9, 10E, 10D and 10F. Please note that the calculations will not match the general ledger as the charges are based on MISO's initial invoices each month, and therefore, exclude any pass thru adjustments. The exception is Schedule 26-A where the MNAEW MWHs are based on final TS4 settlements to the extent they are available. Schedule 26 – Collects the revenue requirement for certain regional cost-shared projects. MISO allocates the appropriate revenue requirement to the AMMO pricing zone and divides by the zonal divisor (prior year's load) to determine the rate. All NITS reservations in the AMMO Page 3 of 3 pricing zone pay the monthly rate based on its load at time of system peak. This charge is similar to a load ratio share charge as less zonal load the prior year will increase the price to be paid by the load in the current year. Schedule 26A – Collects the revenue requirement for certain regional cost-shared projects – the Multi-Value Projects. MISO allocates the total revenue requirement to each month of the year based on the prior year's energy usage pattern. For example, if 8.0% of MISO total energy in 2022 occurred in January, then it would allocate 8% of the 2023 annual revenue requirement to January 2023. Following the end of each month, MISO will divide the monthly revenue requirement by the total MISO energy (Monthly Net Actual Monthly Energy Withdrawals - "MNAEW") in the month to determine the rate for that month. MISO then charges that rate to each market participants MNAEW. This calculation is performed in MISO energy market settlement system and transferred to transmission billing. Therefore, since the invoice does not break down the Schedule 26-A charge by individual transmission reservation, the amounts in the spreadsheet reflect the total paid by AMUE for all MISO transmission reservations. Schedule 9 – MISO does not directly charge Schedule 9 to AMUE's NL NITS reservation. Rather, AMUE pays this charge to other Transmission Owners in the AMMO pricing zone through the Joint Pricing Zone Revenue Allocation Agreement. Therefore, the rate shown in the spreadsheet is the AMMO rate for the other MISO TOs in the AMMO pricing zone (i.e., excludes AMUE revenue requirement). Therefore, the calculated amount shown represents the amount paid by AMUE to other MISO Transmission Owners in the AMMO pricing zone. Note that this charge is similar to a load ratio share charge as less zonal load the prior year will increase the price to be paid by the load in the current year. Schedule 10D&E – These charges collect MISO Admin Fees related to its transmission activities. MISO sets the rates based on its costs and the total system load. MISO collects these fees based on combination of demand and energy charges. For NITS reservations, these charges are based on the monthly peak demand at time of system peak. The demand charge is multiplied by the peak demand times the number of hours in the month to obtain the Schedule 10D charge. The energy charge is based on the same billing determinant but multiplies by the prior year load factor for that month to obtain the Schedule 10E charge. Schedule 10F– This charge collects the FERC annual fee and is based on the same billing determinants as Schedule 10D

MPSC 0165.1

1. Please describe the additional actions that must be taken to convert UCAP Energy Resource Interconnection Service (ERIS) into Zonal Resource Credits (ZRC). 2. Please provide a narrative description of the transactions and transaction costs associated with the additional actions identified in Response to Part 1 of this data request. 3. Please provide a quantification and itemization of the transaction costs or any other costs associated with these additional actions for all UCAP ERIS converted into ZRC in each year Ameren Missouri has undertaken

such additional actions. Sarah Lange (sarah.lange@psc.mo.gov) RESPONSE Prepared By: Jeff Holmes Title: Manager Trading Date: September 6, 2023 1. Conversion of ERIS UCAP to ZRCs is accomplished by identifying and/or securing sufficient firm transmission service to ensure the deliverability of the ERIS portion of the resource's UCAP. In Ameren Missouri's case, this is accomplished through the use of its Network Integrated Transmission Service. This requires Ameren Missouri personnel to access the Module E Capacity Tracking tool in the MISO Portal, reference Ameren Missouri NITS contract, and hit submit. This is then reviewed by MISO and the Company is notified of the amounts which have been accepted. 2. As Ameren Missouri does not incur additional costs for the use of its NITS, it has not incurred transaction costs in converting ERIS to ZRCs. There are no associated "transactions". 3. See answer to #2. Ameren Missouri Staff uses existing personnel and systems to enter the necessary information into the MISO portal.

MPSC 0165.3

1. Does Ameren Missouri intend to offer the solar resources that are the subject of this CCN for bilateral capacity transactions? If so, at what prices for which resources for each applicable year/seasons of the facility's life? 2. Will the capacity values of Bowling Green and Vandalia solar projects be available for offer into a capacity market or as part of a bilateral transaction, or will the output of these projects be simply treated as an offset to load which would reduce the amount of capacity Ameren Missouri is otherwise obligated to procure? 3. If in a given capacity auction the market clearing price is less than Ameren Missouri's offer price for a given solar resource, please confirm that Ameren Missouri will be unable to monetize the capacity value of that resource (absent an existing bilateral transaction). 4. Please confirm that it is possible that in a given year/season Ameren Missouri may be unable to monetize the capacity value of a given solar resource if demand does not exist for that capacity. Sarah Lange (sarah.lange@psc.mo.gov) RESPONSE Prepared By: Jeff Holmes Title: Manager Trading Date: September 5, 2023 1. No. While the Company's participation strategy for all future PRAs through the life of these solar facilities is not yet determined, it is not our intention to bilaterally sell ZRCs associated with these solar facilities. Rather, Ameren Missouri anticipates utilizing the ZRCs associated with these solar resources to satisfy its PRMR capacity obligation in MISO's Planning Resource Auction, either in the form of a Self-Schedule (Offer at $0/MWDay) or include these solar resources as part of a Fixed Resource Adequacy Plan (FRAP). 2. Under MISO's resource adequacy construct, BTMG, including Bowling Green and Vandalia once in service, receive their own ZRCs in the capacity auction, rather than being treated as an offset to load. (For energy settlement, the output Page 2 of 2 of these two facilities will reduce the amount of load settled with MISO at the AMMO.UE CpNode in the MISO Energy and Ancillary Services Market). ZRCs associated with Bowling Green and Vandalia are available for both offer into the MISO PRA and bilateral transactions. However, as noted above, Ameren Missouri does not intend to offer these ZRCs for bilateral transactions. 3. It is true that resources that are offered at a price above the auction clearing price for a given zone would not clear in that given auction. This scenario does not apply to resources offered via self-schedule or FRAP. A Self-Scheduled PRA offer of $0/MW-Day is guaranteed to clear the auction at the auction clearing price. While a FRAP does not have a specified clearing price, it serves as a direct offset to the Company's PRMR obligation. As such, it has the same financial impact as receiving the MISO PRA clearing price for the zone in which the resource is located (and the load paying the applicable zonal price for a like amount). Additionally, MISO's recent PRA rule changes require

replacement capacity for units unable to meet performance requirements. So, resources that do not clear the PRA may still be utilized, and therefore monetized, throughout the Planning Year as replacement capacity, thus ensuring the capacity revenue for ZRC sales in the PRA. 4. As noted above, Ameren Missouri anticipates offering the ZRCs of these solar resources via a Self-Schedule or FRAP. As such, these resources will be monetized at the auction clearing price, either directly (Self-Schedule), or virtually (FRAP), as described in part 3 above.
[Attachment]

Ameren Missouri Native Load Reservation Transmission Charges
2017 - 2023

			AMUE Schedule 26A			AMUE Schedule 10D, 10E & 10F									AMUE Schedule 26			AMUE Schedule 9		
			Based on all AMUE Reservations			*AMUE Native Load Reservation in AMMO*									*AMUE Native Load Reservation in AMMO*			*AMUE Native Load Reservation in AMMO*		
Month	Year		Final MNAEW	Final MUR Rate per MWH	AMUE Charge	Days in Month	Network Load	Load Factor	Schedule 10E Rate	Schedule 10D Rate	Schedule 10F Rate	Schedule 10E Charge	Schedule 10D Charge	Schedule 10F Charge	Network Load	Monthly Schedule 26 Rate	Schedule 26 Charge	Network Load	Annual Schedule 9 Rate 1/	Schedule 9 Charge
Jan	2017		3,039,255	$1.2450	$3,783,968	31	6,016	0.7308	0.0820	0.0616	0.0586	$268,230	$275,724	$262,296	6,016	190.1081	$1,143,726	6,016	$0.0000	$0
Feb	2017		2,380,998	$1.3372	$3,183,973	28	5,291	0.7195	0.0939	0.0722	0.0586	$240,203	$256,696	$208,343	5,291	190.1081	$1,005,803	5,291	$0.0000	$0
Mar	2017		2,544,046	$1.1710	$2,979,023	31	5,367	0.6753	0.1106	0.0858	0.0586	$298,242	$342,614	$234,000	5,367	190.1081	$1,020,340	5,367	$0.0000	$0
Apr	2017		2,264,737	$1.2444	$2,818,299	30	4,704	0.7010	0.1000	0.0725	0.0586	$237,423	$245,552	$198,474	4,704	190.1081	$894,280	4,704	$0.0000	$0
May	2017		2,541,113	$1.2313	$3,128,973	31	5,713	0.6342	0.0949	0.0663	0.0586	$255,802	$281,789	$249,063	5,713	190.1081	$1,086,023	5,713	$0.0000	$0
June	2017		3,029,726	$1.2804	$3,879,242	30	6,670	0.6346	0.0981	0.0686	0.0586	$298,953	$329,426	$281,405	6,670	238.6442	$1,591,667	6,670	$0.0000	$0
Jul	2017		3,604,757	$1.2619	$4,548,972	31	7,466	0.6407	0.0820	0.0573	0.0586	$291,837	$318,293	$325,514	7,466	238.6442	$1,781,764	7,466	$0.0000	$0
Aug	2017		3,059,773	$1.4016	$4,288,493	31	6,397	0.6420	0.0851	0.0591	0.0570	$260,038	$281,294	$271,299	6,397	238.6442	$1,526,689	6,397	$0.0000	$0
Sep	2017		2,750,844	$1.2779	$3,515,283	30	6,563	0.5945	0.0956	0.0637	0.0570	$268,549	$300,991	$269,332	6,563	238.6442	$1,566,144	6,563	$0.0000	$0
Oct	2017		2,481,777	$1.2385	$3,073,742	31	4,923	0.6107	0.1088	0.0799	0.0570	$243,369	$292,655	$208,777	4,923	238.6442	$1,174,861	4,923	$0.0000	$0
Nov	2017		2,478,741	$1.1988	$2,971,460	30	4,571	0.7542	0.1041	0.0810	0.0570	$258,413	$266,601	$187,608	4,571	238.6442	$1,090,926	4,571	$0.0000	$0
Dec	2017		3,033,583	$1.0060	$3,051,701	31	5,909	0.6722	0.0945	0.0709	0.0570	$279,289	$311,724	$250,610	5,909	238.6442	$1,410,267	5,909	$0.0000	$0
Jan	2018		3,365,973	$1.2387	$4,169,493	31	6,580	0.6895	0.0993	0.0730	0.0570	$335,182	$357,372	$279,044	6,580	240.3099	$1,581,233	6,580	$0.0000	$0
Feb	2018		2,713,513	$1.2252	$3,324,680	28	5,834	0.6754	0.1008	0.0755	0.0570	$266,925	$296,016	$223,482	5,834	240.3099	$1,402,073	5,834	$0.0000	$0
Mar	2018		2,683,989	$1.2874	$3,455,431	31	4,815	0.6445	0.1168	0.0870	0.0570	$269,676	$311,671	$204,198	4,815	240.3099	$1,157,112	4,815	$0.0000	$0
Apr	2018		2,430,851	$1.2295	$2,988,633	30	4,680	0.6828	0.1101	0.0824	0.0570	$253,294	$277,633	$192,052	4,680	240.3099	$1,124,562	4,680	$0.0000	$0
May	2018		2,893,835	$1.2037	$3,483,235	31	6,163	0.6112	0.0887	0.0607	0.0570	$248,576	$278,317	$261,352	6,163	240.3099	$1,480,985	6,163	$0.0000	$0
June	2018		3,295,994	$1.2753	$4,203,359	30	7,035	0.6326	0.0818	0.0560	0.0570	$262,120	$283,665	$288,730	7,035	228.8567	$1,610,083	7,035	$0.0000	$0
Jul	2018		3,450,113	$1.3147	$4,535,782	31	7,052	0.6550	0.0840	0.0585	0.0570	$288,660	$306,918	$299,048	7,052	228.8567	$1,613,826	7,052	$0.0000	$0
Aug	2018		3,319,304	$1.2071	$4,006,587	31	7,025	0.6441	0.0784	0.0541	0.0560	$263,935	$282,764	$292,695	7,025	228.8567	$1,607,748	7,025	$0.0000	$0
Sep	2018		2,892,792	$1.3064	$3,779,042	30	6,590	0.5778	0.0954	0.0624	0.0560	$261,555	$296,089	$265,721	6,590	228.8567	$1,508,232	6,590	$0.0000	$0
Oct	2018		2,536,833	$1.3209	$3,350,905	31	5,831	0.6696	0.0993	0.0737	0.0560	$288,475	$319,751	$242,959	5,831	228.8567	$1,334,550	5,831	$0.0000	$0
Nov	2018		2,754,236	$1.2946	$3,565,712	30	5,328	0.7552	0.0791	0.0623	0.0560	$229,143	$238,977	$214,810	5,328	228.8567	$1,219,266	5,328	$0.0000	$0
Dec	2018		2,923,224	$1.0490	$3,066,316	31	5,345	0.6903	0.0909	0.0716	0.0560	$249,509	$284,707	$222,676	5,345	228.8567	$1,223,137	5,345	$0.0000	$0
Jan	2019		3,242,361	$1.4859	$4,817,810	31	6,494	0.6936	0.1104	0.0787	0.0560	$369,962	$380,236	$270,562	6,494	227.5491	$1,477,683	6,494	$0.0000	$0
Feb	2019		2,805,810	$1.4192	$3,982,132	28	5,757	0.6879	0.0863	0.0656	0.0560	$229,668	$253,786	$216,647	5,757	227.5491	$1,309,997	5,757	$0.0000	$0
Mar	2019		2,738,182	$1.4389	$3,940,093	31	6,023	0.7296	0.1030	0.0800	0.0560	$336,737	$358,475	$250,932	6,023	227.5491	$1,370,474	6,023	$0.0000	$0
Apr	2019		2,240,358	$1.5264	$3,419,615	30	4,449	0.7084	0.1131	0.0872	0.0560	$256,669	$279,350	$179,399	4,449	227.5491	$1,012,452	4,449	$0.0000	$0
May	2019		2,535,435	$1.6013	$4,060,109	31	5,778	0.6294	0.1098	0.0749	0.0560	$297,095	$321,994	$240,743	5,778	227.5491	$1,314,826	5,778	$0.0000	$0
June	2019		2,736,270	$1.6038	$4,388,517	30	6,174	0.6505	0.0924	0.0682	0.0560	$267,196	$303,176	$248,942	6,174	206.2318	$1,273,308	6,174	$721.9257	$366,352
Jul	2019		3,385,013	$1.4266	$4,829,010	31	6,947	0.6489	0.0621	0.0427	0.0560	$208,278	$220,700	$289,442	6,947	206.2318	$1,432,703	6,947	$721.9257	$425,953
Aug	2019		3,175,587	$1.5413	$4,894,561	31	6,802	0.6406	0.0791	0.0543	0.0530	$256,431	$274,794	$268,215	6,802	206.2318	$1,402,783	6,802	$721.9257	$417,058
Sep	2019		2,973,735	$1.4763	$4,390,064	30	6,521	0.6041	0.1043	0.0681	0.0530	$295,821	$319,730	$248,835	6,521	206.2318	$1,344,806	6,521	$721.9257	$386,923
Oct	2019		2,393,769	$1.4762	$3,533,674	31	6,276	0.5843	0.1094	0.0811	0.0530	$298,498	$378,712	$247,494	6,276	206.2318	$1,294,408	6,276	$721.9257	$384,837
Nov	2019		2,646,607	$1.4190	$3,755,613	30	5,536	0.7227	0.0886	0.0664	0.0530	$255,209	$264,650	$211,242	5,536	206.2318	$1,141,634	5,536	$721.9257	$328,467
Dec	2019		2,857,044	$1.5198	$4,342,014	31	5,220	0.7360	0.0983	0.0725	0.0530	$280,986	$281,573	$205,840	5,220	206.2318	$1,076,554	5,220	$721.9257	$320,067
Jan	2020		3,026,387	$1.6808	$5,086,811	31	5,467	0.6733	0.0764	0.0568	0.0530	$209,232	$231,033	$215,577	5,467	197.8761	$1,081,799	5,467	$718.5123	$333,623
Feb	2020		2,778,686	$1.6126	$4,480,794	29	6,023	0.7193	0.1220	0.0886	0.0530	$367,887	$371,431	$222,188	6,023	197.8761	$1,191,870	6,023	$718.5123	$343,855
Mar	2020		2,459,418	$1.7230	$4,237,686	31	4,281	0.6198	0.0842	0.0675	0.0530	$166,235	$215,012	$168,824	4,281	197.8761	$847,185	4,281	$718.5123	$261,269
Apr	2020		2,119,344	$1.7506	$3,710,141	30	4,365	0.7089	0.1466	0.1163	0.0530	$326,600	$365,491	$166,561	4,365	197.8761	$863,689	4,365	$718.5123	$257,767
May	2020		2,256,217	$1.7469	$3,941,367	31	4,866	0.6094	0.1274	0.0867	0.0530	$281,066	$313,874	$191,872	4,866	197.8761	$962,845	4,866	$718.5123	$296,938
June	2020		2,941,663	$1.5349	$4,515,253	30	6,198	0.6123	0.0883	0.0550	0.0530	$241,256	$245,423	$236,499	6,198	185.8415	$1,151,763	6,198	$985.2890	$501,895
Jul	2020		3,429,310	$1.5875	$5,444,191	31	6,566	0.6655	0.0804	0.0547	0.0530	$261,380	$267,211	$258,907	6,566	185.8415	$1,220,218	6,566	$985.2890	$549,449
Aug	2020		3,054,587	$1.5831	$4,835,705	31	6,576	0.6397	0.0936	0.0649	0.0620	$292,923	$317,502	$303,315	6,576	185.8415	$1,222,001	6,576	$985.2890	$550,252
Sep	2020		2,482,543	$1.7469	$4,336,636	30	5,783	0.6459	0.0972	0.0641	0.0620	$261,413	$266,904	$258,160	5,783	185.8415	$1,074,748	5,783	$985.2890	$468,334
Oct	2020		2,358,893	$1.6819	$3,967,410	31	4,253	0.5264	0.1064	0.0742	0.0620	$177,226	$234,787	$196,183	4,253	185.8415	$790,387	4,253	$985.2890	$355,901
Nov	2020		2,358,390	$1.7521	$4,132,212	30	4,734	0.6839	0.1144	0.0866	0.0620	$266,692	$295,195	$211,341	4,734	185.8415	$879,835	4,734	$985.2890	$383,399
Dec	2020		2,915,541	$1.6124	$4,700,907	31	5,156	0.7578	0.1284	0.0951	0.0620	$373,266	$364,821	$237,843	5,156	185.8415	$958,227	5,156	$985.2890	$431,478
Jan	2021		3,073,099	$1.6855	$5,179,720	31	5,199	0.7667	0.1053	0.0796	0.0620	$312,253	$307,869	$239,797	5,199	189.2294	$983,712	5,199	$1,509.8923	$666,644
Feb	2021		3,132,178	$1.6270	$5,096,011	28	6,845	0.6756	0.0966	0.0738	0.0620	$300,197	$339,465	$285,188	6,845	189.2294	$1,295,264	6,845	$1,509.8923	$792,831
Mar	2021		2,399,995	$1.6888	$4,053,227	31	4,460	0.7905	0.1258	0.0935	0.0620	$329,945	$310,221	$205,708	4,460	189.2294	$843,869	4,460	$1,509.8923	$571,875
Apr	2021		2,205,478	$1.5654	$3,452,431	30	4,198	0.6911	0.1252	0.0966	0.0620	$261,514	$291,963	$187,388	4,198	189.2294	$794,340	4,198	$1,509.8923	$520,946
May	2021		2,345,543	$1.5426	$3,618,236	31	5,258	0.6411	0.1135	0.0795	0.0620	$284,648	$310,995	$242,537	5,258	189.2294	$994,952	5,258	$1,509.8923	$674,261
June	2021		2,991,912	$1.5812	$4,730,769	30	6,772	0.6702	0.1077	0.0734	0.0620	$351,915	$357,861	$302,280	6,772	201.5956	$1,365,106	6,772	$1,705.6770	$949,316
Jul	2021		3,244,204	$1.7579	$5,703,064	31	6,834	0.7092	0.0750	0.0515	0.0620	$270,453	$261,860	$315,249	6,834	201.5956	$1,377,748	6,834	$1,705.6770	$990,044
Aug	2021		3,314,958	$1.5831	$5,247,904	31	6,924	0.6274	0.0934	0.0654	0.0730	$301,862	$336,895	$376,045	6,924	201.5956	$1,395,807	6,924	$1,705.6770	$1,003,021
Sep	2021		2,686,940	$1.5800	$4,245,251	30	5,927	0.6079	0.1130	0.0763	0.0730	$293,157	$325,622	$311,539	5,927	201.5956	$1,194,919	5,927	$1,705.6770	$830,964
Oct	2021		2,346,087	$1.6770	$3,934,485	31	4,824	0.7519	0.1246	0.0864	0.0730	$336,278	$310,123	$262,025	4,824	201.5956	$972,587	4,824	$1,705.6770	$698,897
Nov	2021		2,413,095	$1.7383	$4,194,761	30	4,542	0.7004	0.1029	0.0772	0.0730	$235,700	$252,473	$238,738	4,542	201.5956	$915,686	4,542	$1,705.6770	$636,782
Dec	2021		2,587,826	$1.7052	$4,412,771	31	4,870	0.7717	0.1341	0.0991	0.0730	$374,969	$359,081	$264,510	4,870	201.5956	$981,808	4,870	$1,705.6770	$705,523
Jan	2022		3,276,517	$1.4651	$4,800,526	31	6,214	0.7987	0.1045	0.0780	0.0730	$385,847	$360,587	$337,472	6,214	207.9417	$1,292,064	6,214	$1,923.0672	$1,014,859
Feb	2022		2,786,832	$1.6133	$4,495,933	28	5,485	0.6894	0.0857	0.0654	0.0730	$217,763	$241,052	$269,064	5,485	207.9417	$1,140,524	5,485	$1,923.0672	$809,138
Mar	2022		2,507,113	$1.5227	$3,817,554	31	5,008	0.7372	0.1338	0.1048	0.0730	$367,491	$390,451	$271,975	5,008	207.9417	$1,041,297	5,008	$1,923.0672	$817,892
Apr	2022		2,247,861	$1.5240	$3,425,833	30	4,329	0.7471	0.1394	0.1066	0.0730	$324,643	$332,293	$227,556	4,329	207.9417	$900,272	4,329	$1,923.0672	$684,313
May	2022		2,540,105	$1.5201	$3,861,090	31	6,210	0.6088	0.1212	0.0810	0.0730	$340,912	$374,240	$337,278	6,210	207.9417	$1,291,320	6,210	$1,923.0672	$1,014,275
June	2022		3,071,474	$1.6328	$5,015,178	30	6,955	0.6176	0.1034	0.0703	0.0730	$319,805	$352,057	$365,578	6,955	198.9479	$1,383,771	6,955	$1,729.0812	$988,482
Jul	2022		3,430,414	$1.5747	$5,401,710	31	7,160	0.6381	0.0877	0.0656	0.0730	$298,127	$349,475	$388,897	7,160	198.9479	$1,424,553	7,160	$1,729.0812	$1,051,535
Aug	2022		3,187,182	$1.6695	$5,321,033	31	6,830	0.6497	0.1034	0.0713	0.0640	$341,394	$362,337	$325,239	6,830	198.9479	$1,358,906	6,830	$1,729.0812	$1,003,077
Sep	2022		2,539,822	$1.6100	$4,088,994	30	6,512	0.6384	0.0599	0.0401	0.0640	$179,289	$188,009	$300,064	6,512	198.9479	$1,295,511	6,512	$1,729.0812	$925,434
Oct	2022		2,223,334	$1.6508	$3,670,228	31	4,268	0.6663	0.1015	0.0719	0.0640	$214,750	$228,311	$203,225	4,268	198.9479	$849,110	4,268	$1,729.0812	$626,771
Nov	2022		2,509,588	$1.5515	$3,893,692	30	4,889	0.7535	0.1018	0.0760	0.0640	$270,037	$267,550	$225,306	4,889	198.9479	$972,745	4,889	$1,729.0812	$694,870
Dec	2022		3,064,705	$1.5178	$4,651,738	31	6,871	0.7282	0.0903	0.0678	0.0640	$336,139	$346,585	$327,160	6,871	198.9479	$1,366,931	6,871	$1,729.0812	$1,009,001
Jan	2023	*TS4*	2,886,285	$1.7461	$5,039,656	31	5,699	0.7236	0.0693	0.0531	0.0640	$212,617	$225,144	$271,361	5,699	199.3192	$1,135,907	5,699	$1,923.0672	$930,801
Feb	2023	*TS4*	2,426,606	$1.7341	$4,207,900	28	5,572	0.7734	0.0776	0.0582	0.0640	$224,731	$217,932	$239,650	5,572	199.3192	$1,110,651	5,572	$1,923.0672	$822,031
Mar	2023	*TS4*	2,578,162	$1.6024	$4,131,267	31	4,880	0.6826	0.1137	0.0866	0.0640	$281,778	$314,411	$232,359	4,880	199.3192	$972,648	4,880	$1,923.0672	$797,021
Apr	2023	*TS1*	2,172,196	$1.6581	$3,601,645	30	4,117	0.7332	0.1318	0.1012	0.0640	$286,474	$300,004	$189,726	4,117	199.3192	$820,660	4,117	$1,923.0672	$650,784
May	2023	*TS1*	2,477,254	$1.6581	$4,107,537	31	5,414	0.5563	0.0916	0.0600	0.0640	$205,254	$241,678	$257,790	5,414	199.3192	$1,079,102	5,414	$1,923.0672	$884,254
June	2023	*TS1*	2,896,325	$1.6633	$4,817,488	30	6,878	0.6219	0.0929	0.0642	0.0640	$286,125	$317,947	$316,956	6,878	177.8965	$1,223,643	6,878	$1,719.0076	$971,837
	2017		33,209,350		$41,223,130							$3,200,348	$3,503,358	$2,946,721	69,591		$15,292,491	69,591		$0
	2018		35,260,657		$43,929,175							$3,217,050	$3,533,878	$2,986,767	72,278		$16,862,808	72,278		$0
	2019		33,730,172		$50,353,213							$3,352,550	$3,637,177	$2,878,294	71,978		$15,451,628	71,978		$2,629,658
	2020		32,180,978		$53,389,113							$3,225,176	$3,488,684	$2,667,268	64,268		$12,244,569	64,268		$4,734,159
	2021		32,741,316		$53,868,630							$3,652,891	$3,764,428	$3,231,004	66,652		$13,115,798	66,652		$9,041,104
	2022		33,384,945		$52,443,509							$3,596,198	$3,792,947	$3,578,814	70,732		$14,317,004	70,732		$10,639,646
	2023		15,436,828		$25,905,493							$1,496,978	$1,617,116	$1,507,842	32,561		$6,342,611	32,561		$5,056,728

1/ - AMUE does not get billed Schedule 9 for it native load reservation. Rather AMUE pays Schedule 9 through the Joint Pricing Zone Revenue Allocation Agreement. Therefore, the rate shown here is the AMMO rate for the other MISO TOs in the AMMO pricing zone (i.e., excludes AMUE revenue requirement)

Wabash became a TO in the AMMO pricing zone in June 2019, ATXI in Jan 2021 and MJMEUC in Jan 2023

MPSC 0167

1. a. Has Ameren Missouri attempted to quantify or estimate the change in the cost to serve load as a MISO Load Serving Entity with and without the installation of approximately 400 MW of solar generation within the Ameren Missouri service footprint? This question specifically refers to estimates or analysis of changes in Load Locational Marginal Price, not the valuation of distribution-sited solar as an offset to load. b. If so, please provide such quantifications or estimates. c. If not, please explain why Ameren Missouri did not do any such analysis. 2. a. Has Ameren Missouri attempted to quantify or estimate the change in the Locational Marginal Prices for load in the area surrounding the proposed Cass County solar installation, or the changes in the cost to serve load for any MISO Load Serving Entities in the state of Illinois, with and without the installation of the Cass County solar installation? b. If so, please provide such quantifications or estimates. c. If not, please explain why Ameren Missouri did not do any such analysis. 3. a. Has any Ameren entity, affiliate, contractor, or other entity known to Ameren attempted to quantify or estimate the change in the cost to serve load as a MISO Load Serving Entity with and without the installation of approximately 400 MW of solar generation within the Ameren Missouri service footprint? This question specifically refers to estimates or analysis of changes in Load Locational Marginal Price, not the valuation of distribution-sited solar as an offset to load. b. If so, please provide such quantifications or estimates. c. If not, please explain why any such analysis has not been performed. 4. a. Has any Ameren entity, affiliate, contractor, or other entity known to Ameren attempted to quantify or estimate the change in the Locational Marginal Prices for load in the area surrounding the proposed Cass County solar installation, or the changes in the cost to serve load for any MISO Load Serving Entities in the state of Illinois, with and without the installation of the Cass County solar installation? b. If so, please provide such quantifications or estimates. c. If not, please explain why any such analysis has not been performed. 5. a. Has Ameren Missouri attempted to quantify or estimate the change in the dispatch and margin of existing Ameren Missouri generation with and without the installation of approximately 400 MW of solar generation within the Ameren Missouri service footprint, relying on a model that acknowledges through either load requirements or model pricing the addition or absence of the approximate 400 MW of solar generation? b. If so, please provide such quantifications or estimates. c. If not, please explain why Ameren Missouri did not do any such analysis. 6. a. Has any Ameren entity, affiliate, contractor, or other entity known to Ameren attempted to quantify or estimate the change in the dispatch and margin of existing Ameren Missouri generation with and without the installation of approximately 400 MW of solar generation within the Ameren Missouri service footprint, relying on a model that acknowledges through either load requirements or model pricing the addition or absence of the approximate 400 MW of solar generation? b. If so, please provide such quantifications or estimates. c. If not, Page 2 of 3 please explain why any such analysis has not been performed. Sarah Lange (sarah.lange@psc.mo.gov) RESPONSE Prepared By: Matt Michels Title: Director, Corporate Analysis Date: August 28, 2023 1. Ameren Missouri analysis of change in cost to serve load - 400 MW solar in Ameren Missouri territory a. No. b. N/A c. Based on Ameren Missouri's development of its range of power prices for IRP analysis and the uncertainty with respect to the development and/or ownership of the solar projects in this case or any other generation projects, the Company does not expect the development of these projects and/or ownership of these projects by Ameren Missouri to have a material impact on the cost to serve load relative to the variation in power prices used for its

analysis. Please see response to MPSC 0094.4 for additional detail on the Company's development of power price scenarios. 2. Ameren Missouri analysis of change in cost to serve load – Cass County solar a. No. b. N/A c. Based on Ameren Missouri's development of its range of power prices for IRP analysis and the uncertainty with respect to the development and/or ownership of the solar projects in this case or any other generation projects, the Company does not expect the development of these projects and/or ownership of these projects by Ameren Missouri to have a material impact on the cost to serve load relative to the variation in power prices used for its analysis. As a result, Ameren Missouri did not request that another entity perform this analysis. Please see response to MPSC 0094.4 for additional detail on the Company's development of power price scenarios. 3. Other party analysis of change in cost to serve load – 400 MW solar in Ameren Missouri territory a. No. b. N/A c. Based on Ameren Missouri's development of its range of power prices for IRP analysis and the uncertainty with respect to the development and/or ownership of the solar projects in this case or any other generation projects, the Company does not expect the development of these projects and/or ownership of these projects by Ameren Missouri to have a material impact on the cost to serve load relative to the variation in power prices used for its analysis. Please see response to MPSC Page 3 of 3 0094.4 for additional detail on the Company's development of power price scenarios. 4. Other party analysis of change in cost to serve load – Cass County solar a. No. b. N/A c. Based on Ameren Missouri's development of its range of power prices for IRP analysis and the uncertainty with respect to the development and/or ownership of the solar projects in this case or any other generation projects, the Company does not expect the development of these projects and/or ownership of these projects by Ameren Missouri to have a material impact on the cost to serve load relative to the variation in power prices used for its analysis. As a result, Ameren Missouri did not request that another entity perform this analysis. Please see response to MPSC 0094.4 for additional detail on the Company's development of power price scenarios. 5. Ameren Missouri analysis of change in dispatch and margin of existing Ameren Missouri generation – 400 MW solar in Ameren Missouri territory a. No. b. N/A c. Please see response to MPSC 0094.4 for additional detail on the Company's development of power price scenarios. 6. Other party analysis of change in dispatch and margin of existing Ameren Missouri generation – 400 MW solar in Ameren Missouri territory a. No. b. N/A c. Ameren Missouri did not request that another entity perform this analysis. Please see response to MPSC 0094.4 for additional detail on the Company's development of power price scenarios

MPSC 0168

Please confirm that the Astrape representative on the 8/22/2023 call with Astrape, Ameren Missouri, and members of Staff and OPC indicated the following: 1. Astrape modeled Ameren Missouri’s generation (or potential future generation) meeting Ameren Missouri’s load, with potential for up to 2,200 MW of market interaction. 2. Astrape did not represent municipal load or generation that is located within MISO Zone 5 in the modeling. 3. As modeled, Ameren Missouri’s units were required to provide regulating and ramping ancillary services as needed. 4. For scenarios in which Astrape modeled 350 MW of additional solar generation, that capacity was assumed to be distributed evenly among five sites, as depicted on slide 22 of the provided slides, generally situated (1) north of Milan, Mo., (2) in Illinois across from Hannibal, Mo., (3) west of St. Louis, (4) in Illinois across from Perryville, Mo., and (5) In extreme eastern Missouri or extreme western Kentucky near Caruthersville, Mo. 5. The Astrape representative made a statement to the effect that any capacity addition will decrease LOLE, but it is a matter of the degree to which LOLE is decreased. 6. The Astrape representative made a statement that solar resources have a worse ELCC on winter mornings than other times of the year. 7. The Astrape representative made a statement that solar resource additions improve LOLE less on winter mornings than other times of the year. Sarah Lange (sarah.lange@psc.mo.gov) RESPONSE Prepared By: Michael Flanagan Title: Manager, Program & Project Support Date: August 24, 2023 As the 8/22/2023 call with Astrape, Ameren Missouri, and members of Staff and OPC was not recorded, exact statements made during the meeting cannot be verified. However, responses below address the questions above, and are consistent with the information attempted to be conveyed during said call. 1. Astrape used Ameren Missouri's load forecast to develop (43) synthetic load curves based on historical weather patterns, with the potential for up to 2,150 MW of market support. The model dispatches generation to meet load. The 2,200 MW shown in the summary table in testimony was a slight misrepresentation of the 2,150 MW included in the model and does not impact relative results or conclusions from the modeling. Page 2 of 2 2. Confirmed. 3. Confirmed. Ancillary service assumptions are input into SERVM. SERVM commits resources to meet energy needs plus ancillary service requirements. These ancillary services are generally needed for uncertain movement in net load or sudden loss of generators. Within SERVM, these include regulation up and down, spinning reserves, load following reserves, and quick start reserves. Spinning reserves and load following up reserves are interchangeable products and represent the sum of the 10-minute ramping capability of each unit on the system. An increase in 10-minute spinning reserves requirement would mean that resources are either dispatched down from maximum, or more resources are committed allowing the fleet to have more ramping capability. All of these products are met with Ameren Missouri resources in the model. In the current modeling performed for Ameren Missouri, market support units are not allowed to serve ancillary services but can bring in more energy to allow Ameren resources to back down to serve these ancillary service products. From an LOLE perspective, which has been the primary use of SERVM for Ameren Missouri, all of these products can be depleted except for the regulation requirement. SERVM, as setup for Ameren Missouri, is defining a load shed event in an hour when load plus regulating reserves cannot be met. 4. Confirmed. 5. Confirmed. 6. While the statement may have been different than that stated in the question, this response addresses the question posed. Solar resources produce less in winter than summer due to shorter days and lower sun angle. Also, a solar resource has a comparatively lower (worse) ELCC in the winter than in the summer due to the potential for higher morning loads without sufficient coincident generation capability from the solar resource. 7. While the statement may have been different than that stated in the question, this response addresses the question posed. See response to 6. above. LOLE is driven by instances when load exceeds available capacity.

MPSC 0173

(1) Please describe the status of project cost certainty for each project. (2) Please provide an updated timeline for dates when capital costs for each project are likely to become more certain. (3) Please confirm that in the 8/25/2023 technical conference, Ameren Missouri represented that price certainty for the Split Rail, Bowling Green, and Vandalia projects was likely to improve in December of 2023. Sarah Lange (sarah.lange@psc.mo.gov) RESPONSE Prepared By: Brad Corder; Chuck Roberts Title: Sr. Project Manager; Project Manager Date: 09/01/2023 1. Status of project cost certainty for each project: a. Split Rail i. The Total Base Cost given in MSPC#0042 is target price based on the developer's knowledge and experience, market

intelligence and past projects. Price certainty will continue to advance as the design advances and the project progresses toward firm date which requires CCN approval. The Firm date ("FNTP") for Split Rail is in Q2 2024. b. Cass County i. The project cost given in response to MSPC#0042 has high cost certainty. The largest project cost components are known, e.g., EPC and purchased equipment, purchase agreement, and modules. These costs, along with other smaller known costs such as transmission related costs, make up approximately 90% of the total project estimate (not including risk adjusted contingency). The remaining project costs are Ameren Missouri internal and financing costs which have a modest variability (order of magnitude of 10%). The project cost certainty will continue to advance as the project progress and becomes more certain upon a timely CCN approval. Page 2 of 3 c. Vandalia: i. The EPC contract for Vandalia has a target price. The target price becomes firm (not-to-exceed) at FNTP. FNTP is expected roughly 60 days after CCN approval. The EPC contract price is the largest variable of project cost at this time. d. Bowling Green: i. The EPC contract for Bowling Green has a target price. The target price becomes firm (not-to-exceed) at FNTP. FNTP is expected roughly 60 days after CCN approval. The EPC contract price is the largest variable of project cost at this time. 2. Updated timeline when capital costs will become more certain: a. Split Rail i. The Total Base Cost of the project is a target cost. Cost certainty will be further confirmed in the 4th quarter of 2024 as the developer obtains market pricing per the terms of the BTA and will continue to improve as the project approaches the firm date estimated in the 2nd quarter of 2024. b. Cass County i. The project has a high cost certainty. After a CCN is approved, cost certainty will improve (by a small amount) because some variable cost estimate components are subject to assumptions with regard to timing of the execution of Closing. c. Vandalia: i. The EPC contract for Vandalia has a target price. The target price becomes firm (not-to-exceed) at full notice to proceed (FNTP). FNTP is expected roughly 60 days after CCN approval. Equipment costs can continue to vary by limited amounts (likely tied to material indices) until final delivery. The majority of materials are expected to be delivered by 2nd quarter of 2025. More cost certainty will be known after all material is delivered and the majority of equipment is installed (expected Q3 2025). d. Bowling Green: i. The EPC contract for Bowling Green has a target price. The target price becomes firm (not-to-exceed) at full notice to proceed (FNTP). FNTP is expected roughly 60 days after CCN approval. Equipment costs can continue to vary by limited amounts (likely tied to material indices) until final delivery. The majority of materials are expected to be delivered by 2nd quarter of 2025. More cost certainty will be known after all material is delivered and the majority of equipment is installed (expected Q4 2025). 3. Confirmed for Split Rail. We don't expect the price certainty for Cass County to change materially this year as the certainty is already high, as discussed above. In general, we expect price certainty to continue to grow for the other projects as well as they progress toward firm date and ultimately completion but as to Vandalia and Bowling Green, there is no particular event that would cause price certainty to increase materially this year. Page 3 of 3 Increasing price certainty as we move through time for all projects depends on them maintaining their schedules including maintaining the CCN schedule.

MPSC 0116S - CONFIDENTIAL

** [redacted]

[redacted]

**

MPSC 0127 – CONFIDENTIAL

** [redacted] **

MPSC 0128 – CONFIDENTIAL

** [redacted]

[redacted]

[redacted] **

SCHEDULE SLKL-r3
SCHEDULE SLKL-r4
and
SCHEDULE SLKL-r5

HAVE BEEN DEEMED

CONFIDENTIAL

IN THEIR ENTIRETY

Exhibit No.:	
Issues:	DSIM
Witness:	Sarah L. Kliethermes
Sponsoring Party:	MO PSC Staff
Type of Exhibit:	Supplemental Direct Testimony
Case No.:	EO-2015-0055
Date Testimony Prepared:	July 9, 2015

MISSOURI PUBLIC SERVICE COMMISSION

REGULATORY REVIEW DIVISION

SUPPLEMENTAL DIRECT TESTIMONY

OF

SARAH L. KLIETHERMES

UNION ELECTRIC COMPANY d/b/a AMEREN MISSOURI

CASE NO. EO-2015-0055

Jefferson City, Missouri
July 2015

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's 2nd Filing to Implement Regulatory Changes in Furtherance of Energy Efficiency as allowed by MEEIA	)))))	Case No. EO-2015-0055

AFFIDAVIT OF SARAH L. KLIETHERMES

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Comes now, Sarah Kliethermes on her oath declares that she is of sound mind and lawful age; that she contributed to the attached Supplemental Direct Testimony; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Sarah L. Kliet

Sarah L. Kliethermes

Subscribed and sworn to before me this 9th day of July, 2015.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 28, 2018
Commission Number: 14942086

Susan L Sundermeyer

Notary Public

Table of Contents

SUPPLEMENTAL DIRECT TESTIMONY

OF

SARAH L. KLIETHERMES

UNION ELECTRIC COMPANY d/b/a AMEREN MISSOURI

CASE NO. EO-2015-0055

SUPPLEMENTAL DIRECT TESTIMONY

OF

SARAH L. KLIETHERMES

UNION ELECTRIC COMPANY d/b/a AMEREN MISSOURI

CASE NO. EO-2015-0055

Q. Are you the same Sarah L. Kliethermes who filed rebuttal testimony in this case?

A. Yes.

Executive Summary

Q. What is the subject of your supplemental direct testimony?

A. I will generally describe the Non-Unanimous Stipulation and Agreement ("Non-Utility Stipulation") filed on July 7, 2015, and as amended on July 8, 2015, concerning Union Electric Company's d/b/a Ameren Missouri ("Ameren Missouri" or "Company") application for approval of its second cycle of MEEIA programs., and provide support for the throughput disincentive mechanism and the demand-related performance incentive mechanism of the Non-Utility Stipulation. I recommend the Commission authorize the Net Throughput Disincentive ("NTD") and the Performance Incentive ("PI") mechanisms that form the alternative DSIM. The terms of the Non-Utility Stipulation remove the financial disincentive to Ameren Missouri's promotion of DSM programs and incent Ameren Missouri's promotion of DSM programs, respectively.

Overview of Non-Utility Stipulation

Q. Does the Non-Utility Stipulation result in the MEEIA statutory policy objective "to value demand-side investments equal to traditional investments in supply and delivery infrastructure and allow recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs?" *See 393.1075.3.*

A. Yes, the Non-Utility Stipulation sets up an interrelated framework of programs, disincentive removal, and incentive creation that supports the statutory policy. Specifically, in exchange for Ameren Missouri's development and promotion of a suite of programs to promote cost-effective measureable and verifiable efficiency savings, the Non-Utility Stipulation would provide Ameren Missouri with:

1. Contemporaneous program cost recovery on:
    a. A base level of programs that provide some level of benefit to all customers over the planning horizon,
    b. Targeted low-income programs that may not be cost effective, and
    c. Analysis and implementation of additional programs which provide some level of benefit to all customers over the planning horizon.
2. A mechanism to remove Ameren Missouri's throughput disincentive in a manner that makes Ameren Missouri financially indifferent to whether or not it promotes DSM programs.
3. A mechanism to incent Ameren Missouri to promote DSM programs through:
    a. A base level of benefit associated with annual energy savings targets, if approved by the Commission,
    b. An incentive targeted to improve participation among multi-family low income customers, and
    c. An incentive to meaningfully reduce future capacity requirements.

<u>Support for limited waiver of Chapter 20</u>

Q. In your pre-filed rebuttal testimony, you recommend the lost revenues mechanism described in Chapter 20 of the Commission's rules. Does the Non-Utility Stipulation contemplate the lost revenues mechanism?

A. No. The NTD mechanism recommended in the Non-Utility Stipulation is more generous to Ameren Missouri than the mechanism provided in the rules and recommended in my rebuttal testimony. The rules require a utility to show reduction in sales prior to the utility receiving an opportunity to collect revenues associated with the throughput disincentive. In contrast the Non-Utility Stipulation provides Ameren Missouri throughput disincentive recovery regardless of whether its overall utility sales are up or down.

Q. Does Staff support the Non-Utility Stipulation NTD mechanism and the associated waiver of the applicable Chapter 20 rules for Ameren Missouri MEEIA Cycle 2?

A. Yes, Staff supports a waiver of a portion of 4 CSR 240-20.093(1)(Y). The Non-Utility Stipulation NTD mechanism is part of an interrelated resolution derived in the spirit of compromise and with the support of several parties with diverse interests. To achieve the result of a MEEIA Cycle 2 as is described in the Non-Utility Stipulation, there is good cause to waive 4 CSR 240-20.093(1)(Y) which states "Lost revenue means the net reduction in utility retail revenue, taking into account all changes in costs and all changes in any revenues relevant to the Missouri jurisdictional revenue requirement, that occurs when utility demand-side programs approved by the commission in accordance with 4 CSR 240-20.094 cause a drop in net system retail kWh delivered to jurisdictional customers below the level used to set the electricity rates. Lost revenues are only those net revenues lost due to energy and demand savings from utility demand-side programs approved by the commission in accordance with 4 CSR 240-20.094 Demand-Side Programs and measured and verified through EM&V[.]"

Q. To what extent does Staff recommend a waiver of 4 CSR 240-20.093(1)(Y) in support of the Non-Utility Stipulation?

A. Staff recommends only waiver of the requirement that a utility prove that "utility demand-side programs approved by the commission in accordance with

4 CSR 240-20.094 cause a drop in net system retail kWh delivered to jurisdictional customers below the level used to set the electricity rates."

Q. Is Staff's recommendation to waive certain requirements of 4 CSR 240-20.093(1)(Y) similar to Ameren Missouri's request to waive the requirements of Chapter 20 for its throughput-disincentive net-shared benefit mechanism as contained in the Non-Unanimous Stipulation and Agreement filed June 30, 2015?

A. No. Ameren Missouri's proposed throughput disincentive mechanism is not modeled on the lost revenue concept found in Chapter 20. Rather it is modeled as an additional performance incentive mechanism. As such, Ameren Missouri requested a much broader waiver of the Chapter 20 rules than is reasonable.

Q. Why is the limited waiver of 4 CSR 240-20.093(1)(Y) recommended by Staff reasonable when Staff has testified that Ameren Missouri's requested waivers of Chapter 20 are unreasonable?

A. Staff recommends the Commission adopt the Non-Utility Stipulation of NTD, which requires measurement and verification of the magnitude and causation of realized kWh savings, but still relies on a quantification of the net reduction in utility retail revenue. In contrast, Ameren Missouri requested that the Commission authorize its throughput disincentive mechanism as an additional performance incentive mechanism, and it relied on accelerating the recovery of pre-deemed projections of program effectiveness.

<u>Net Throughput Disincentive</u>

Q. What is the goal of the NTD mechanism provided in the Non-Utility Stipulation?

A. The Non-Utility Stipulation NTD mechanism provides Ameren Missouri with revenue as a result of energy efficiency programs it offers and promotes in lieu of revenue it did not earn because of sales of energy it did not make. This recovery of the net throughput disincentive results in Ameren Missouri being financially indifferent to whether or not it promotes DSM programs, all else being equal. The Non-Utility Stipulation NTD mechanism removes any disincentive associated with Ameren Missouri's promotion of energy efficiency.

Q. Is the Non-Utility Stipulation NTD structured as an incentive or as a share of future net benefits that may or may not materialize?

A. No, the Non-Utility Stipulation does not rely on an estimate of the future benefits of the programs, and it preserves the distinction between removing disincentives and creating positive incentives that is contained in the MEEIA statute.

Q. How does the Non-Utility Stipulation NTD work?

A. The Non-Utility Stipulation allows Ameren Missouri to bill and retain the unrealized revenue caused by its promotion of the DSM programs in MEEIA Cycle 2. Each month, Ameren Missouri will book revenues associated with the unbilled kWh for that month. The dollar values booked will later be trued-up after it is determined how many unbilled kWh actually occurred that month.

Q. What is an unbilled kWh and what is unrealized revenue?

A. DSM programs, by design, reduce the number of kWh a utility sells. An unbilled kWh is a kWh that an Ameren Missouri customer did not buy from Ameren Missouri, because that customer participated in an Ameren Missouri MEEIA Cycle 2 program to reduce his or her energy usage. The unrealized revenue is the revenue that Ameren Missouri did not receive from the sales of energy it did not sell because of MEEIA Cycle 2, minus the costs that Ameren Missouri avoided incurring because it did not have to procure that energy.

Q. How much revenue does Ameren Missouri lose on each unbilled kWh?

A. It depends. The rate Ameren Missouri would charge for that kWh will vary by customer class, season, the level of energy that customer otherwise consumes that month, and whether or not a rate case has occurred to change applicable rates.

Q. Does Ameren Missouri avoid incurring costs when it does not sell a given kWh of energy?

A. Yes. Ameren Missouri avoids incurring the cost of obtaining that energy for its customer through the MISO integrated energy market, as well as the cost of transmission and ancillary services associated with that energy. Reductions in customer load also translate to reduction in Ameren Missouri's share of MISO administrative charges, capacity requirements, and transmission build-out expense.

Q. Is the FAC Base Factor an accurate measure of the specific costs Ameren Missouri avoids when it avoids selling a specific kWh of energy?

A. No. Not only are some of the elements of the transmission costs excluded from the FAC Base Factor, the FAC Base Factor is netted against revenues from Off-System Sales. Additionally, while the market value of energy varies greatly during the hours of the year, the FAC Base Factor is adjusted only twice annually.

Q. Will net revenues from Off-System Sales go up or down, all else being equal, if Ameren Missouri avoids selling energy to its customers because of a program under MEEIA Cycle 2?

A. All else being equal, net revenues from Off-System Sales will go up if Ameren Missouri avoids selling a given kWh of energy to its customers, because Ameren Missouri will not have to buy that energy through the MISO integrated marketplace.

Q. Although it is not an accurate measure of the specific costs and revenues Ameren Missouri avoids when it avoids selling a specific kWh of energy, is it reasonable to use the FAC Base Factor for determining marginal avoided cost under the Non-Utility Stipulation NTD?

A. While it is not 100% accurate, it is reasonable to use the FAC Base Factor as a measure of net avoided costs and off-system sales revenues because the Non-Utility Stipulation provides that unbilled revenues are recorded real-time, and are not subject to significant present-valuing. Additionally, by relying on the existing FAC mechanism, shareholders will retain 5% of the net avoided costs and off-system sales revenues.

Q. Why has Staff not developed a number that represents this 5% shareholder retention?

A. To develop that number Staff needs hourly savings estimates for each measure. Ameren Missouri has stated in its response to Staff Data Request 0013 that it will not provide Staff with those numbers on an hourly basis.

Q. Under the Non-Utility Stipulation NTD, is it necessary to make assumptions about rate case timing?

A. No. Because unbilled revenues are tracked on a monthly basis, there is no need to create a projection of rate case intervals years into the future to determine the NTD.

Q. Under the Non-Utility Stipulation NTD, is it necessary to make assumptions about what level of revenue will be collected through the fixed customer charge in the outcome of a future rate case?

A. No. Because unbilled revenues are tracked on a monthly basis, there is no need to project out future rate case outcomes to determine the NTD.

Q. Under the Non-Utility Stipulation NTD, is it necessary to make assumptions about what future fuel and transportation expense, purchased power expense, transmission expense, and off-system sales revenue levels will be in the outcome of a future rate case?

A. No. By eliminating the present valuing of the throughput disincentive, the Non-Utility Stipulation NTD is able to avoid the need to make many of the critical and controversial assumptions that would be necessary for a present-value throughput disincentive.

Q. Is the Non-Utility Stipulation NTD designed to be trued-up for the actual effectiveness of the measures that have been installed?

A. Yes. An important characteristic of the Non-Utility Stipulation NTD is that by requiring true-up based on the results of Evaluation, Measurement, and Verification ("EM&V") and Net to Gross ("NTG") adjustments, the mechanism is designed to make the utility truly indifferent to not only whether programs are delivered pursuant to MEEIA Cycle 2, but more importantly, the utility is made indifferent as to which programs are delivered and whether or not that delivery is effective.

Q. Is the utility protected against the chance that the programs have not reduced energy consumption?

A. Yes. Unlike lost revenue recovery pursuant to 4 CSR 240-20.093(1), the Non-Utility Stipulation does not require a showing that sales have decreased. Under the Non-Utility Stipulation NTD, overall energy consumption could be up, but Ameren Missouri will still recover NTD associated with the realized kWh savings determined through EM&V and NTG analysis.

Q. Is there a floor and a cap associated with the Non-Utility Stipulation NTD?

A. Yes. Staff witness Mark Oligschlaeger is providing supplemental direct testimony related to the floor and cap, as well as the alternative 100% booking mechanism described in the Non-Utility Stipulation.

Demand-related Performance Incentive

Q. What is the goal of the Non-Utility Stipulation demand-related PI mechanism?

A. The Non-Utility Stipulation demand-related PI mechanism results in Ameren Missouri shareholders receiving a performance incentive equal to the present value of the earnings opportunity on capacity-related investments that they would receive if Ameren Missouri did not promote DSM programs, all else being equal. This creates an incentive for Ameren Missouri to promote energy efficiency.

Q. What is the basis for the dollar values and the kW values in the Non-Utility Stipulation's demand-related PI?

A. The first tier of the demand-related PI is the approximate value to shareholders of the change in retirement date of the Meramec plant pursuant to the modeling of DSM in Ameren Missouri's Chapter 22 filing. The second tier of the demand-related PI is the approximate value to shareholders of the deferred investment in a combined cycle plant pursuant to the modeling of DSM in Ameren Missouri's Chapter 22 filing.

Q. How were the Meramec numbers derived?

A. The rate base value of the Meramec generating units is approximately $685 million, and the current depreciation reserve is approximately $345 million, leaving a net rate base value of approximately $340 million. Ameren Missouri's shareholders earn a return on this net investment. Every year, the net investment in the plant decreases, all else being equal, because ratepayers contribute depreciation expense which increases the depreciation reserve. Because Ameren Missouri's generating units receive "life span" depreciation treatment, an acceleration of the projected retirement date of a generating unit increases the level of depreciation expense the ratepayers will contribute, which decreases the net rate base on which shareholders earn a return (assuming rate cases occur to adjust the depreciation expense and to recognize the decrease in net rate base). Assuming a 2030 retirement date, shareholders will receive an earnings stream of approximately $145 million from now until plant retirement. This earnings stream has a present-value of approximately $140 million. But, assuming a 2026 retirement date, the shareholders' earnings stream is valued at approximately $110 million, which has a present value of approximately $108 million. Moving the Meramec projected retirement date from 2030 to 2026 therefore reduces the estimated present-value earnings stream by approximately $31 million, all else being equal.

Q. What is the total capacity of the Meramec generating units?

A. The total capacity at Meramec is approximately 834,000 kW. This means, that if the projected date of all of the Meramec generating units is moved from 2030 to 2026, shareholders will forego an earnings opportunity of approximately $37/kW.

Q. If sufficient kW savings are not generated to move the projected retirement date of all of the units at Meramec from 2030 to 2026, will shareholders forego that same earnings opportunity?

A. No. The $37/kW value assumes that all units will be retired in 2026 for depreciation purposes. Foregone shareholder earnings would be less if all units are not retired in 2026, all else being equal.

Q. How were the combined cycle numbers derived?

A. In its 2014 Chapter 22 filing, at Table 9.9 on page 23, Ameren Missouri provided an estimated capital cost of $1,297/kW for a 600,000 kW combined cycle plant, including associated transmission upgrades, in 2013 dollars. On an annual basis, that investment represents an earnings opportunity of approximately $65/kW. Three years of that earnings stream therefore yields an earnings opportunity of approximately $250/kW. To generously incent Ameren Missouri to achieve meaningful demand-related savings, Staff did not compare the difference in earnings streams associated with simply moving the date of constructing a combined cycle unit, which would substantially reduce the value of the earnings stream for which shareholders are compensated under the demand-related PI.

Q. What is contemplated under the MEEIA statute for the performance incentive?

A. The MEEIA statute relies on certain assumptions:

1. Utility opportunities for profits come from investment of shareholder dollars, including investment in generation facilities.
2. Rates can ultimately be cheaper for all ratepayers to reduce the amount of generation facilities needed in the future.
3. Absent MEEIA, the utility's incentive to invest in generation facilities serves as a disincentive for that utility to facilitate programs to reduce future capacity requirements.

In light of these assumptions, the MEEIA statute provides utilities with timely earnings opportunities associated with cost-effective measurable and verifiable efficiency savings.

Q. Does the Non-Utility Stipulation demand-related PI provide Ameren Missouri with timely earnings opportunities associated with cost-effective measurable and verifiable efficiency savings?

A. Yes. In fact, the mechanism is more generous than would otherwise be reasonable in that it:

1. Does not require Ameren Missouri to reach the total demand savings that are associated with moving the retirement date of the Meramec units before being compensated on a per-kWh basis for the change in retirement date of those units; and
2. Does not require Ameren Missouri to reach the 600 MW demand savings associated with deferral of the construction of a combined cycle unit in order to receive payout of the Non-Utility Stipulation demand-related PI Tier 2.

Q. Will shareholders lose earnings opportunities if the retirement date of the Meramec generating units is not shifted, all else being equal?

A. No. Unless the retirement date for depreciation purposes shifts, the earnings opportunity remains constant. In this sense, the Non-Utility Stipulation demand-related PI is very generous to Ameren Missouri's shareholders.

Q. Is it fair to ratepayers to design a performance incentive that compensates Ameren Missouri shareholders for a lost earnings opportunity that may not be lost?

A. In Staff's opinion, it is a reasonable compromise for ratepayers to accept the risk of compensating Ameren Missouri's shareholders for lost earnings opportunities associated with early Meramec retirement (and potential deferral of the construction of a combined cycle unit) in that it encourages Ameren Missouri to promote meaningful cost-effective energy efficiency programs, while maintaining the statutory requirement for measured and verified results of those programs.

Q. Are there other aspects of the Non-Utility Stipulation demand-related PI that are more advantageous to Ameren Missouri shareholders?

A. Yes. Please see the supplemental direct testimony of Staff witness Mark Oligschlaeger.

Q. Is another witness filing testimony in support of the participation-related component of the PI mechanism?

A. Yes. I understand that Geoffrey Marke will be filing testimony on this component on behalf of the Office of the Public Counsel, in support of the Non-Utility Stipulation.

Q. Does the Non-Utility Stipulation provide for the creation of an additional incentive mechanism related to meeting energy savings targets?

A. Yes.

Q. Does this conclude your supplemental direct testimony?

A. Yes.