Exhibit No.:	
Issue(s):	Rate Design, Contract Term, Minimum Billing Demand, Capacity Reduction Charges, System Support Rider, Vintage Pricing
Witness:	Kevin C. Higgins
Type of Exhibit:	Rebuttal Testimony
Sponsoring Party:	Data Center Coalition
Case No.:	EO-2025-0154
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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. EO-2025-0154

REBUTTAL TESTIMONY OF KEVIN C. HIGGINS

ON BEHALF OF THE

DATA CENTER COALITION

PUBLIC VERSION

July 25, 2025

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SCHEDULES

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Kevin C. Higgins. My business address is 111 East Broadway, Suite 1200, Salt Lake City, Utah, 84111.

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

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by the Data Center Coalition ("DCC").

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward a Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics from 1981 to 1995. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was an economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you ever testified before the Missouri Public Service Commission ("Commission")?

A. Yes. I testified in the 2007 Aquila rate case, Case No. ER-2007-0004 and in the Ameren 2007 rate case, Case No. ER-2007-0004.

Q. Have you testified before utility regulatory commissions in other states?

A. Yes. I have testified in approximately 310 proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arizona, Arkansas, Colorado, Florida, Georgia, Idaho, Indiana, Illinois, Kansas, Kentucky, Michigan, Minnesota, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Utah, Virginia, Washington, West Virginia, and Wyoming. I have also filed affidavits in proceedings at the Federal Energy Regulatory Commission.

II. <u>OVERVIEW AND CONCLUSIONS</u>

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

A. My testimony responds to the proposal by Evergy Metro, Inc. d/b/a Evergy Missouri Metro and Evergy Missouri West, Inc. d/b/a Evergy Missouri West (collectively "Evergy" or the "Company") for approval of a new Large Load Power Service ("LLPS") rate plan.

Q. What are your primary conclusions and recommendations?

A. I offer the following conclusions and recommendations:

In response to the load-growth-related issues Evergy raises, it is reasonable for the Commission to adopt policies that accommodate load growth in a thoughtful and deliberate manner so as to avoid cost shifting if investments are made to serve new load that does not fully materialize. At the same time, the Commission should not impose unjust terms on important growing industries.

With regard to the specific proposals Evergy has made regarding the proposed LLPS rate plan:

- I recommend approval of the LLPS initial monthly pricing proposed by Evergy, with the exception of the System Support Rider.

- I recommend that the Commission approve a modification to Evergy's proposal for a 15-year contract term, including a 5-year load ramp, for LLPS customers. Instead, I recommend a contract term of 10 years at full contract demand *plus* a load ramp of up to five years.

- I recommend that the minimum billing demand for Schedule LLPS be set at 70% rather than 80% as proposed by Evergy.

- I recommend that LLPS customers be allowed a reduction in contract capacity up to 20% without penalty with three-years' notice (consistent with Evergy's proposed tariff, as distinct from the 10% allowance proposed by Evergy in its direct testimony). I also recommend that with three-years' notice, it should not be necessary for a customer to wait five years to effectuate the capacity reduction as Evergy proposes. Further, the period for measuring the capacity reduction fee minimum charges should be capped at no greater than five years following the three-year notice period for all minimum billing components.

- For the capacity reductions that are otherwise subject to penalty, I support the Company's proposal to use reasonable efforts to mitigate the capacity reduction fee amount owed by the customer by evaluating the opportunity to re-assign the reduced capacity. To the extent a customer pays the capacity reduction fee based on the Company's determination that it is unable to mitigate the fee, but the Company subsequently reassigns the capacity or otherwise mitigates the associated costs, I recommend that the customer should be eligible for a refund corresponding to the amount of costs Evergy is ultimately able to mitigate.

- I strongly recommend that the Commission reject the System Support Rider. I do not object to the goal of not allowing economic development rate discounts for Schedule LLPS customers, but it would be better to implement such a policy in a more straightforward manner, such as simple ban on such discounts, rather than through the rider proposed by Evergy.

- The acceleration component of the proposed System Support Rider is conceptually flawed in that the "acceleration" concept does not reasonably describe what happens with load growth. Putting aside the conceptual flaws with this approach, Evergy's calculation produces a one-sided result that cannot credibly be used to set rates. Just as costs are "accelerated" in Evergy's analysis, revenues from new LLPS load would be "accelerated" as well. Evergy's failure to recognize the incremental revenues that would come from the LLPS load is a fatal flaw in the structure of its System Support Rider calculation.

- As part of considering adoption of any vintage pricing regime, including the System Support Rider, the Commission should consider whether it would be more appropriate for LLPS customers to have the ability to procure their own generation resources to the extent permissible by state law, such as through a buy-through program.

III. <u>BACKGROUND ON THE DATA CENTER COALITION</u>

Q. Please describe DCC.

A. DCC is the national membership association for the data center industry, representing leading data center owners and operators who maintain data center infrastructure across the country and globe. DCC supports the data center community through public policy advocacy, thought leadership, stakeholder outreach, and community engagement. DCC also advocates for a highly skilled and diverse technology workforce, greater access to clean energy, and a competitive business environment to support the growth and success of this essential business sector. DCC has 38 members, including prospective customers of Evergy and companies with business interests in Evergy's service territories.

Q. What are data centers?

A. Data centers are facilities that house computing machines and related hardware. They provide the essential digital infrastructure that supports the applications, platforms and services people rely on every day.

In 2022, the U.S. digital economy accounted for $2.6 trillion of value added (10% of U.S. GDP), $1.3 trillion of compensation, and 8.9 million jobs. From 2017 to 2022, this segment of the economy grew at an annual rate of 7.1%, more than triple the rate of the rest of the economy.[1] Data centers are a critical component of the digital economy and an enabler of its growth and benefits.

Q. What is DCC's interest in this proceeding?

A. In this proceeding, Evergy has proposed the LLPS rate plan that potentially impacts data center customers. The proposed tariff includes terms and conditions that substantially depart from the Company's existing large power service tariff (Schedule LPS). If approved, the tariff changes could adversely impact planned data center development in the Company's service territory. DCC's members rely on reliable and affordable electric service and consequently have a substantial interest in ensuring service on just and reasonable terms to support their businesses over the short- and long-term.

IV. OVERVIEW OF EVERGY'S PROPOSED LLPS RATE PLAN

Q. Please describe Evergy's proposed Schedule LLPS rate plan.

A. Schedule LLPS will be available to customers expected to have a monthly demand equal to or above 100 MW, and which take service at a substation or transmission-level voltage. These customers would be required to take service for a term of 15 years, which may include a ramp period of no more than five years, with service remaining in effect thereafter until canceled or otherwise changed. Each LLPS customer would execute a Service Agreement that includes customer-specific provisions and details related to its electric service including, but not limited to, load ramp, applicable construction cost recovery terms, and the expected annual capacity requirements. The Company is also

[1] *See* Bureau of Economic Analysis, "U.S. Digital Economy: New and Revised Estimates 2017-2022" (Dec. 2023). Available at: SCB, U.S. Digital Economy: New and Revised Estimates, 2017–2022, December 2023.

proposing additional collateral requirements beyond the standard credit terms under the Company's rules and regulations for service under Schedule LLPS.

The LLPS rate plan includes a fixed customer charge, a grid charge based on the customer's highest monthly demand in the last 12 months, a generation demand charge, and an energy charge. The customer's grid charge is differentiated into substation and transmission level service. The demand charge has summer and winter seasonal rates with the winter seasonal rate being slightly lower than summer. As proposed, the summer and winter energy rates are identical.

Notably, Evergy proposes a minimum billing demand of 80% of the customer's annual Contract Capacity. LLPS customers would also be subject to a minimum monthly bill. Evergy proposes that the minimum monthly bill be the sum of the Customer Charge, Grid Charge, Demand Charge, and Reactive Demand Adjustment with the demand elements based on the Minimum Demand amounts and the customer capacity forecast detailed in the Service Agreement.

Evergy's proposal permits the customer to request to reduce its Contract Capacity after the first five years of the term by up to 10% by providing the Company with a 36-month written notice prior to the beginning of the year for which the reduction is sought. Evergy proposes a capacity reduction fee calculated as the nominal value of the remaining minimum charge for the terminated/reduced capacity in excess of the 10% reduction. Importantly, the Company states it will use reasonable efforts to mitigate the capacity reduction fee amount owed by the customer by evaluating the opportunity to re-assign the reduced capacity.

Evergy also proposes a termination fee if a customer chooses to terminate service under Schedule LLPS or "seeks service under another available rate schedule"[2] prior to the end of the 15-year term. According to the Company's proposal, a terminating customer must pay an exit fee equal to its minimum charges over the remaining term or 12 months, whichever is greater.

Q. What riders will be applicable to Schedule LLPS?

A. All jurisdictional recovery riders would apply, such as the Fuel Adjustment Clause, Demand Side Investment Mechanism, Tax Adjustment, Renewable Energy Standard Rate Adjustment Mechanism, and any applicable Securitization Charge.

The Company is further proposing three unique riders to Schedule LLPS. The Customer Capacity Rider ("Schedule CCR") and the Demand Response Generation Rider ("Schedule DRLR") are proposed as optional riders. In addition, Evergy proposes a mandatory System Support Rider ("Schedule SR"), which would impose an acceleration charge on LLPS customers. I discuss the Schedule SR proposal in considerable detail later in my testimony.

V. RESPONSE TO EVERGY'S PROPOSED LLPS RATE PLAN

Q. What is your overall reaction to Evergy's proposed LLPS rate plan?

A. I acknowledge that Evergy is experiencing substantial load growth driven by large customer demand. In response to the high volume of large customer demand, it is reasonable for the Commission to adopt policies that accommodate load growth in a thoughtful and deliberate manner. I agree that it is appropriate to implement measures to

[2] Missouri Public Service Commission Case No. EO-2025-0154, *Direct Testimony of Bradley D. Lutz*, p. 18:20-21 (Feb. 14, 2025). On p. 19, lines 1-2, Mr. Lutz also provides seemingly contradictory testimony stating that the customer will not be required to pay an exit fee if "the customer switches to another rate schedule for which it qualifies."

protect against cost impacts that can occur if Evergy makes investments to serve new load that does not fully materialize. At the same time, it is important that the Commission not take actions that would depress the growth of important industries by imposing unreasonable terms.

At a high level, I agree with Evergy that a combination of long-term contracts with minimum demand charges is a reasonable framework for structuring the LLPS rate plan. The key is to strike the right balance. The optional CCR and DRLR riders proposed by the Company are steps in the right direction and I generally support their adoption, without necessarily endorsing every provision in the proposals. In particular, the CCR would allow the customer to manage its selection of generation to comply with its sustainability goals, while providing benefits to the utility in the form of capacity resources. I also support adoption of Evergy's proposed initial LLPS rate design. At the same time, certain details incorporated into the Company's proposal such as contract term, minimum billing demand, and contract reduction provisions, require modifications. Several of my recommended changes strive for modest improvements to these elements of the Company's proposal. Unfortunately, however, one feature of the Company's proposal, Schedule SR, is deeply flawed and should be rejected by the Commission. I will address each of these issues below.

A. The Commission Should Approve Evergy's Proposed LLPS Rate Design, With the Exception of the System Support Rider.

Q. Has Evergy proposed an initial rate design for Schedule LLPS?

A. Yes. Schedule LLPS was derived using the otherwise applicable Schedule LPS for both the Missouri Metro and Missouri West service territories as a baseline. The initial monthly pricing proposals for both the Missouri West and Missouri Metro Schedule LLPS rate plans are presented in Table 6 in the Direct Testimony of Evergy witness Lutz.[3] The proposed LLPS rate designs represent a simplification and improvement over the otherwise complex "hours use" rate designs currently used for Schedule LPS in both the Missouri Metro and Missouri West service territories. In the LLPS rate design, capacity-related costs are removed from the hours-use energy blocks and transferred to the production demand charge. Transmission and substation-related costs are recovered in a separately stated Grid charge. I support these changes and recommend approval of the Schedule LLPS initial monthly pricing proposed by Mr. Lutz, with the exception of the System Support Rider, which I will discuss later in my testimony.

B. The Commission Should Adopt a Ten-Year Contract Term, Plus the LLPS Customer's Load Ramp Period.

Q. What is your response to Evergy's proposed 15-year contract term?

A. I recommend that the Company's proposed contract term be modified somewhat. Evergy's proposed 15-year contract term includes a load ramp of up to five years. "Load ramp" refers to the phase-in of a customer's annual demand prior to reaching its full contract demand and is something that I expect to be negotiated between the customer, based on its operational needs, and the Company, based on its ability to deliver power. In response to Evergy's proposal, I recommend that the contract term applicable to LLPS customers be structured as 10 years *plus* the load ramp. That is, the LLPS customer would be required to contract for service for 10 years at its full contract demand level *plus* the specific number of years required for its load ramp. This approach is basically aligned with the Company's proposal in that a customer with a five-year load ramp would be required to be under contract for 15 years, just as proposed by Evergy. However, under

[3] *Id*. at 29.

my recommendation, a customer with just a two-year load ramp would require only a 12-year contract. This variation on the Company's proposal is reasonable because establishing a standard 10-year term at full contract demand places all customers on an equal footing, irrespective of load ramp duration. At the same time, it provides an equivalent contract term as Evergy's proposal for a customer with a five-year load ramp.

Q. Is Evergy's load ramp proposal reasonable?

A. Generally, yes. Data centers have diverse purposes – such as cloud computing, AI, or hybrid models – and require tailored ramping schedules prior to reaching their full contract demand. Part of this process involves an initial period of energization and commissioning of a customer's facility, as distinct from a sustained load ramp that occurs as a customer grows into its contract demand. Evergy's proposal for a load ramp of up to five years generally provides reasonable and needed flexibility, although I recommend that the contract terms should allow for an initial energization and commissioning "grace" period for up to six months, during which the minimum billing demand would not apply, in order to provide sufficient time for the initial energization and commissioning to be completed.

C. The Commission Should Implement a Minimum Billing Demand of 70% of Contract Capacity.

Q. By way of background, how does a minimum billing demand work?

A. A minimum billing demand requires that a customer pay a monthly charge for demand that is no less than a stated percentage of its <u>contract</u> capacity, irrespective of its actual <u>metered</u> demand in that month. So, for example, if an LLPS customer has a contract capacity of 100 MW, and Evergy's proposal to set minimum billing demand at 80% of contract capacity is adopted, the customer's minimum billing demand would be 80 MW. If, in a given month, the customer experiences a maximum metered demand of 90 MW, which exceeds its minimum billing demand, its billing demand would be that same 90 MW for that month. Alternatively, if the customer's maximum metered demand in a month was below its minimum billing demand, say 70 MW, the customer would nonetheless be subject to the minimum billing demand of 80 MW. The minimum demand charge provision therefore acts as a sort of "floor" for the amount of revenue (via demand charges) Evergy will recover from customers subject to the provision.

Q. What is your response to Evergy's proposal to set minimum billing demands for LLPS customers at 80% of contracted demand?

A. I agree that a minimum demand charge is appropriate; however, I believe the 80% minimum billing demand proposed by Evergy is too high. Load diversity allows utilities to plan for and procure generation capacity in an amount that is less than the sum of individual customer maximum demands. Moreover, generation assets are fungible in that they can be redeployed to serve other parts of a utility's system if a customer's contract demand amount does not fully materialize, or in the case of Evergy, sold into the Southwest Power Pool ("SPP") Integrated Marketplace, in which Evergy is a participant. My understanding is that Evergy bids all of its power plant output into the SPP day-ahead and real-time markets. My expectation is that would include new resources Evergy adds to meet growing load. Evergy's access to the larger SPP market supports a lower minimum billing demand than proposed by Evergy.

Recognizing the optionality of generation resources, Virginia Electric and Power Company ("Dominion") recently recommended a 60% minimum billing demand for generation service for its large load customers, which I believe is a more reasonable standard.[4] I acknowledge, though, that Dominion is a larger utility than Evergy and therefore may be better positioned to manage the risks associated with new large loads. For that reason, I suggest that a 70% minimum billing demand for Evergy represents a reasonable middle ground for adoption in this case. It is also in line with the 70% minimum billing demand proposed by Ameren in its recent filing before the Commission to address large loads.[5]

D. The Commission Should Modify Evergy's Proposed Capacity Reduction Charges to Allow for Greater Flexibility in Reduction of Contract Capacity and the Potential for Refunds of Fees that Were Ultimately Mitigated.

Q. What are your recommendations with regard to capacity reductions that are not subject to penalties?

A. I agree that it is reasonable to allow for a modest reduction in contract capacity without penalty after adequate notice. In his direct testimony, Mr. Lutz proposes that an LLPS customer could reduce its contract capacity up to 10% without penalty with three-years' notice.[6] However, the proposed tariff indicates this threshold would be 20%.[7] I agree that a reduction in contract capacity up to 20% without penalty with three-years' notice is reasonable and is consistent with the approaches proposed by other utilities.[8] These

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[4] *Application of Virginia Electric and Power Company for a 2025 Biennial Review of the Rates, Terms and Conditions for the Provision of Generation, Distribution and Transmission Services pursuant to § 56-585.1 A of the Code of Virginia,* Virginia State Corporation Commission, Case No. PUR-2025-00058, Direct Testimony of Stan Blackwell on behalf of Virginia Electric and Power Company at 17-18.

[5] Missouri Public Service Commission Case No. ET-2025-0184, *Direct Testimony of Steven M. Wills*, pp. 11, 13 (May 14, 2025).

[6] Lutz Direct at 20.

[7] *See* Lutz Direct at Schedule BDL-1, p. 89.

[8] *See, e.g.*, *In re Verified Petition of Indiana Michigan Power Company for Approval of Modifications to its Industrial Power Tariff – Tariff I.P.*, Indiana Utility Regulatory Commission, Cause No. 46097, Stipulation and Settlement Agreement (Nov. 22, 2024) (permitting large load customers to reduce contract capacity up to 20% without any penalty). *See also*, *Application of Virginia Electric and Power Company for a 2025 Biennial Review of the Rates, Terms and Conditions for the Provision of Generation, Distribution and Transmission Services pursuant to § 56-585.1 A of the Code of Virginia,* Virginia State Corporation Commission, Case No. PUR-2025-00058, Direct Testimony of Stan Blackwell on behalf of Virginia Electric and Power Company at 20. *See also In re the Application of Consumers Energy for Ex Parte Approval of Certain Amendments to Rate GPD*, Michigan Public Service

proposals rightly recognize that it is reasonable that large load customers may not know their exact load requirements 10 to 20 years into the future, and that factors outside of their control may impact their plans and capacity requirements. Allowing customers the flexibility to make limited changes to their Contract Capacity without penalty—with adequate notice that allows the utility to plan around that change—permits a measure of flexibility that acknowledges this reality.

I also recommend that with three-years' notice, it should not be necessary for a customer to wait five years to effectuate the capacity reduction. If a customer learns early during the term of its contract that its contract demand needs to be reduced, it is preferable to allow that change to go forward sooner rather than later, so that the resources can be freed up to serve other system needs.

Q. What are your recommendations with regard to capacity reductions that are subject to penalties?

A. For the capacity reductions that are otherwise subject to penalty, I support the Company's proposal to use reasonable efforts to mitigate the capacity reduction fee amount owed by the customer by evaluating the opportunity to re-assign the reduced capacity. This provision demonstrates needed flexibility. To the extent a customer pays the capacity reduction fee based on the Company's determination that it is unable to mitigate the fee, but the Company subsequently reassigns the capacity or otherwise mitigates the associated costs, I recommend that the customer should be eligible for a refund corresponding to the amount of costs Evergy is ultimately able to mitigate. I also recommend that the period

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Commission, Case No. U-21859, Direct Testimony of Laura M. Connolly on behalf of Consumers Energy Company at 7.

for measuring the capacity reduction fee minimum charges should be capped at no greater than five years following the three-year notice period for all minimum billing components.

Q. Should there be any other considerations in determining a customer's capacity reduction charge?

A. Yes. For any month in which a customer had paid demand charges in *excess* of its minimum billing demand, it would be appropriate to credit that excess against the remaining revenue obligation in calculating the capacity reduction charge. The capacity reduction charge appropriately focuses on recovering revenues associated with the minimum demand charge. If the customer had previously made payments in excess of this amount, it would be reasonable to credit the excess portion of such prior payments against the capacity reduction charge owing. In addition, the tariff should permit customers to negotiate mutually agreeable capacity reduction or exit terms with the Company, which would allow both parties to take into account factors and considerations not foreseen at this time.

E. The Commission Should Reject Evergy's Proposed System Support Rider.

Q. Please describe Evergy's System Support Rider proposal.

A. Evergy proposes the System Support Rider to be a new mandatory tariffed charge to customers receiving service under Schedule LLPS. While the Company's description of how this rider is intended to work is somewhat convoluted, it has two basic functions: (1) to eliminate any discount a Schedule LLPS customer might otherwise receive as a result of an economic development incentive ("cost recovery component"), and (2) to add an additional demand charge to Schedule LLPS rates to account for a presumed "acceleration" of costs that would be incurred to serve new LLPS customers ("acceleration component").

Q. Are you opposed to the *intent* of the cost recovery component?

A. No. In the interest of avoiding inter-class rate subsidization, I do not object to the goal of not allowing economic development rate discounts for Schedule LLPS customers. However, the System Support Rider strikes me as an awkward means to accomplish this objective. Moreover, it is not clear whether the confusing tariff phrasing that describes the cost recovery component would have unintended consequences besides preventing rate discounts.[9] It would be preferable to effectuate such a policy in a more straightforward manner, such as a simple ban on such discounts.

Q. Please describe the acceleration component of the proposed System Support Rider.

A. The acceleration component is purported to represent the cost to non-LLPS customers of "accelerating" the construction of a power plant from a later time when it would otherwise be constructed to serve "normal" load growth to an earlier time period, in order to serve LLPS load growth. Although Evergy presents an actual Rider SR charge of $9.59 per kW-month in tariff format for Missouri Metro and $9.64 per kW-month for Missouri West,[10] it is my understanding that **[redacted]

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[9] The proposed tariff language states: "The Cost Recovery Component shall be calculated based on comparing the Schedule LLPS Customer's estimated rate revenue and estimated revenue prior to applying Schedule CCR, Schedule DRLR, or Schedule CEC. Should the Schedule LLPS Customer's estimated revenue fall below the Customer's estimated rate revenue, an amount, expressed in a dollar per kW ($/kw) charge, will be added to the customer billing through this Rider charge." This language is a very confusing and roundabout way to eliminate the effects of an economic development discount.

[10] *See* Lutz Direct at Schedule BDL-1, pp. 43, 95.

[11] *See also* Schedule KCH-3: Evergy Response to DCC DR 11.

[redacted]** when there may not be adequate opportunity for interested parties to comment or protest.

Q. How does Evergy calculate the acceleration component charge?

A. Evergy derives its illustrative Rider SR charges using a confidential workpaper.[12] In discussing this calculation, I will avoid revealing information that I understand to be confidential, **[redacted]**[13]

As explained by Mr. Lutz, the Company calculated the annual revenue requirements for a 700 MW CCGT for two different time periods that are 10 years apart. Evergy calculated a 40-year stream of annual revenue requirements for each time period. The Company's analysis measures the difference in annual revenue requirements for each year of the analysis. For each of the first 10 years of the analysis, customers experience an increase in costs due to the accelerated plant coming online 10 years sooner. However, in Year 11 of the analysis, customers start to experience a net *reduction* in annual costs because, by that time, the accelerated plant has experienced ten years of accumulated depreciation. As a result, in Year 11, the annual revenue requirement of the accelerated plant is lower than the first-year revenue requirement of the (same) plant, had it first come into service in Year 11, *i.e.*, if it had not been accelerated.

[12] Lutz Workpaper "CONF System Support Rider Model_CCGT_01.27.25."
[13] Schedule KCH-3: Evergy Response to DCC DR 11.

Evergy's analysis calculates the net present value of the difference in these two revenue streams to arrive at a total cost impact from the acceleration. Evergy then assigns around 83%[14] of the cost impact to non-LLPS customers based on their assumed share of total load after the addition of the LLPS load (that is assumed to have caused the ten-year acceleration of the plant). Evergy then calculates the per-kW charge that, if paid by the LLPS load to the non-LLPS load over 30 years, would offset the rate impact on the non-LLPS load due to the acceleration. This per-kW charge is the illustrative Rider SR charge.

Q. What is your assessment of the acceleration component calculation?

A. The acceleration component calculation is deeply flawed, both conceptually and analytically, and I strongly recommend that the Commission reject it. I also note that it is a form of vintage pricing, which I discuss later in my testimony.

1. Evergy's Proposed Acceleration Component is Novel and Conceptually Flawed.

Q. What are your conceptual objections to the acceleration component?

A. As a threshold matter, characterizing the revenue requirement impacts of load growth in terms of "acceleration" does not comport well with what actually occurs with load growth. Unless a utility has excess capacity or allows customers to acquire generation supplies from third-party providers, substantial load growth will *change* a utility's resource portfolio. As such, we would expect a growing utility to acquire *additional* resources, as distinct from simply *accelerating* resources. The acquisition of additional resources would result in a change in revenue requirements, but any net change in *rates* would result from the interplay of the increase in revenue requirements and the increase in billing determinants associated with the new load. Incremental load results in incremental

[14] The precise percentages are slightly different between Evergy Metro and Evergy West.

resources; it does not really result in accelerated resources. Conceptually, the "acceleration" concept does not reasonably describe what happens with load growth.

Q. Are there other conceptual concerns with using an acceleration component as a ratemaking tool?

A. Yes. It is not at all clear how such a ratemaking device would be equitably applied in practice. Mr. Lutz admits that "Schedule SR is not a cost recovery rider. There is no total amount that needs to be recovered."[15] Thus, revenues would be collected from LLPS customers, but with no specific costs to be recovered. From a ratemaking perspective, such a premise is problematic at the outset.

As drafted, Rider SR calls for the acceleration component to be calculated each rate proceeding based on accelerating the construction of a combined-cycle gas turbine by 10 years. The underlying premise of 10 years of "acceleration" of a single resource type and the application of the calculation to every tranche of new LLPS load is highly arbitrary. In actuality, the arrival of new large load customers will result in a change in the Company's resource portfolio. New resources will be acquired, which will be utilized by the entire system. There will be additional billing units over which costs can be spread. The natural venue to work out the allocation of cost responsibilities after a change in the Company's resource portfolio is a general rate case, not an abstract acceleration charge that is unrelated to actual costs and actual retail load.

[15] Lutz Direct at 33.

Q. Are you aware of any other utilities that have proposed an "acceleration charge" as part of addressing concerns associated with new large loads?

A. No. I have been involved in several proceedings involving tariff changes proposed by utilities to address large loads, and I am not aware of *any* other utility that has proposed a mechanism like the acceleration charge, including Ameren, which has filed its own application with the Commission to address large load issues.[16] I believe the reason other utilities have not advocated for this approach is straightforward: it is not a sound analytical construct.

2. Evergy's Calculation of the Acceleration Component Suffers from Material Flaws.

Q. Putting aside your conceptual objections to the acceleration charge, do you have concerns about how it is actually calculated by Evergy?

A. Yes, I have two serious concerns about the calculation. The first concern involves the assumption the Company makes in comparing the two revenue requirements streams. In making this comparison, Evergy fails to consider that the capital and operating costs of a facility that comes into service 10 years in the future will very likely be more expensive than the same plant built today. Instead, in its calculation of the Rider SR charge that the Company presented in its Application in this case, Evergy assumed that a plant constructed 10 years in the future would cost the same as the same plant built 10 years prior. This unreasonable assumption results in an upward bias in the Rider SR charge presented by Evergy. While that faulty assumption can be easily remedied, there is a second, more fundamental flaw in the structure of the acceleration calculation.

[16] *See* Missouri Public Service Commission Case No. ET-2025-0184.

Q. What is the more fundamental flaw in the structure of the acceleration charge calculation?

A. Evergy's calculation fails to consider the revenues that would be provided by the new LLPS load, which would provide a benefit to non-LLPS customers by helping to pay for *existing* production costs. As I stated above, Evergy's analysis (initially) assigns around 83% of the responsibility for the "accelerated" cost to non-LLPS customers. This means that 17% of the cost responsibility (prior to the Rider SR charge) is allocated to the LLPS load. The important implication here is that, within Evergy's analysis, the revenues generated by the LLPS load are not going exclusively to pay for the new (*i.e.*, accelerated) plant, even though it is assumed to have been built because of the need to serve the incremental LLPS load. Indeed, 83% of the costs are (initially) allocated to non-LLPS load. This raises the question: if the revenue from LLPS load is only paying for 17% of the cost of the accelerated plant (which is supposedly sized to serve the LLPS load) where is the rest of the revenue recovered from this new load going?

The answer, of course, is that the <u>revenues recovered from new LLPS load will also be making a pro rata contribution to existing fixed production costs</u>. That is, the new LLPS load will also contribute to recovering the base revenue requirement that pays for the Company's current fleet, aside from the accelerated plant. Any "acceleration" analysis that assigns 83% of the acceleration cost to non-LLPS customers must also recognize that, in this example, the new LLPS load will pick up 17% of the costs of the current generation fleet – offsetting part of the costs that otherwise would have been borne entirely by non-LLPS customers. Yet this critical part of the equation is completely missing from Evergy's analysis. Like the accelerated costs Evergy's proposal attempts to isolate, these accelerated contributions to existing fixed production costs *would not have occurred* absent the new load. Thus, they are the essential "other side of the coin."

Just as *costs* are "accelerated" in Evergy's SR analysis, *revenues* from new LLPS load would be "accelerated" as well. The accelerated costs and accelerated revenues would occur in tandem. Yet the accelerated revenues are completely absent from Evergy's acceleration calculation. Evergy's failure to recognize the incremental revenues that would come from the LLPS load is a fatal flaw in the structure of its Rider SR calculation.

Q. But could it not be argued that the incremental revenues from the LLPS load would be considered as part of future rate cases?

A. Of course, the incremental revenues from the LLPS load would be considered in future rate cases, but that fact is distinct from Evergy's effort to isolate the cost implications for non-LLPS customers due to "acceleration." Acceleration would bring costs and revenues. Evergy tallies up the costs, but ignores the revenues that would by definition accompany those costs. In doing so, the Company generates a one-sided calculation that cannot credibly be used to set rates.

Q. Notwithstanding the fact that you recommend that the acceleration calculation be rejected on conceptual grounds, have you analyzed the results of the calculation if the incremental revenues from LLPS load were recognized?

A. Yes. I have prepared analyses for both Missouri West and Missouri Metro that begin with the acceleration framework proposed by Evergy and make two modifications to account for the omissions I identified above:

(1) Instead of Evergy's assumption of no cost escalation over 10 years for the power plant, I assume a modest annual cost escalation of 2.5%; and

(2) I account for the revenue contributed to the recovery of current fixed costs from 665 MW of new LLPS load by allocating to these customers a pro rata share of the production-related revenue requirement that Evergy requested in its most recent Missouri West and Missouri Metro rate cases.

Q. Why did you select 665 MW to be the amount of LLPS load in your analysis?

A. As I discussed above, the acceleration analysis presented by Evergy in this case assumes the accelerated plant has a nameplate capacity of around 700 MW. Evergy's own analysis assumes the incremental LLPS load is 665 MW in the Missouri Metro service territory, so I selected 665 MW of LLPS load to be consistent with Evergy's assumption. I note, though, that Evergy's analysis inexplicably assumes only 425 MW of incremental LLPS load in its Missouri West analysis, despite assuming a 700 MW plant is constructed to accommodate the new load. As this mismatch does not make any sense, I assumed 665 MW of incremental LLPS load in my Missouri West analysis as well.

Q. What does your analysis show?

A. My analysis is presented in confidential Schedule KCH-1 for Missouri West and confidential Schedule KCH-2 for Evergy Metro.[17]

Starting with Missouri West, page 1, column (c) of Schedule KCH-1 shows that 665 MW of new LLPS load would make a $108.5 million annual contribution to the recovery of $437.9 million in production-related revenue requirement (shown in column (b)) based on the LLPS load ratio share of the retail revenue requirement.[18] Column (d) shows the share of the accelerated cost of the new resource allocated to non-LLPS

[17] Schedules KCH-1 and KCH-2 are confidential because Evergy considers the underlying cost information concerning the assumed 700 MW power plant to be confidential.

[18] For the purpose of determining load ratio share, I used a 1 CP allocator to match the assumptions in Evergy's acceleration analysis. The actual allocation factor used in a rate case may differ.

customers and column (e) shows the benefit to non-LLPS customers of avoiding the revenue requirement of the "non-accelerated" version of the plant starting in Year 11 (as described earlier in my testimony).

Q. Does page 1 of Schedule KCH-1 show the Missouri West Rider SR payments as calculated by Evergy?

A. Yes. Column (f) shows the transfer from LLPS load to non-LLPS customers of $76.9 million per year in Rider SR payments based on Evergy's illustrative Rider SR charge of $9.64 per kW.[19]

Q. Does page 1 of Schedule KCH-1 also show the net revenue requirement impact on non-LLPS customers from the 10-year plant acceleration?

A. Yes. Column (g) shows the non-LLPS production revenue requirement inclusive of current plant costs, accelerated plant costs, avoidance of the revenue requirement of the "non-accelerated" version of the plant starting in Year 11, and receipt of the Rider SR payments. And finally, column (h) shows the net impact on non-LLPS customers by taking the difference between the resulting revenue requirement after acceleration (column g) and the revenue requirement prior to acceleration (*i.e.* prior to the assumed arrival of the LLPS load) (column b).

Q. What do the results of your analysis show for Missouri West?

A. Viewed over the 30-year time horizon of Evergy's acceleration analysis, the net present value rate impact to non-LLPS Missouri West customers is a *benefit* of $1.2974 billion,

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[19] While Evergy does not explicitly propose a mechanism to transfer the Rider SR payments directly to non-LLPS customers, for purposes of this discussion I assume they are deferred into a regulatory liability account for later recognition in rates, rather than simply accrue to Evergy's bottom line. If, despite my recommendation to reject Rider SR, it is approved by the Commission, then it would be essential to defer the revenues recovered in this manner to prevent a windfall recovery of them by the Company.

inclusive of $700 million in Rider SR payments made from Years 1 through 15. This benefit accrues from the combination of avoiding the cost of the "non-accelerated" plant starting in Year 11, the contribution to current cost recovery from the LLPS load, and the Rider SR payments. The results also demonstrate that if the Rider SR payments were eliminated, there would still be a net present value benefit to non-LLPS customers of $597.4 million[20] over the 30-year time horizon.

Q. Part of the benefit to non-LLPS customers comes from avoiding the cost of the non-accelerated plant. Are these costs truly avoided?

A. In reality, these costs may not actually be avoided because, as I stated previously, I do not believe plants are actually *accelerated* as a result of load growth. Rather, load growth will cause *additional* plants to be built. However, within the framework of the acceleration analysis, the costs of the non-accelerated plant <u>are</u> avoided. In fact, the presumed avoidance of these costs is foundational to Evergy's Rider SR rate calculation.

Q. What is shown on page 2 of Schedule KCH-1?

A. Page 2 calculates a theoretical "break-even" Rider SR rate that would result in a zero net impact for non-LLPS customers. Since the 30-year analysis shows a net benefit to non-LLPS customers, the Rider SR rate would be a credit to the LLPS customers, not a charge. Of course, I am not proposing that such a credit be adopted, as I do not support the adoption of the acceleration component in the first place.

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[20] $1.297 billion - $700 million.

Q. Are the results for your analysis for Missouri Metro similar to the results for Missouri West?

A. Yes. The Missouri Metro results are shown in Schedule KCH-2. Over the 30-year time horizon, the net present value benefits to non-LLPS customers are somewhat lower than in Missouri West: $1.0958 billion, inclusive of $708 million of Rider SR payments at Evergy's calculated Rider SR rate of $9.59 per kW. But the net benefits to non-LLPS customers still exceed the costs even if the Rider SR rate is set to zero.

Q. Did you analyze the rate impacts using a shorter time horizon than 30 years?

A. Yes. As the time horizon is reduced, the net benefits to non-LLPS customers is reduced, primarily because there are fewer years of avoided costs associated with the non-accelerated plant. Page 3 of both Schedule KCH-1 and Schedule KCH-2 replicates the analysis presented on page 1 of those schedules, except the time horizon is limited to 15 years rather than 30 years. The results show that over a 15-year period, there is a net present value benefit to Missouri West customers of $708.6 million, consisting almost entirely of $700 million in Rider SR payments from LLPS load. In other words, if the Rider SR payment were eliminated, the non-LLPS customers would be essentially in a break-even position over 15 years.

For Missouri Metro, the 15-year analysis shows a net present value benefit to non-LLPS customers of $489 million, inclusive of $708 million in Rider SR payments, demonstrating that the $9.59 per kW charge calculated by Evergy is much greater than what would be needed to produce a net zero impact on non-LLPS customers. Page 4 of Schedule KCH-2 shows that the Rider SR charge that would be needed to produce a net zero impact on non-LLPS customers over 15 years is $2.97 per kW.

Q. What does page 5 of Schedules KCH-1 and KCH-2 show?

A. Page 5 of Schedules KCH-1 and KCH-2 shows the allocation to LLPS customers of the production revenue requirement for current plant as used in my analysis. As I stated above, this information is based on the production cost recovery Evergy requested in its most recent Missouri West and Missouri Metro rate cases.

Q. Please summarize your assessment of Evergy's System Support Rider proposal.

A. I strongly recommend that the Commission reject the System Support Rider.

With respect to the "cost recovery component" of the System Support Rider, I do not object to the goal of not allowing economic development rate discounts for Schedule LLPS customers, but it would be better to implement such a policy in a more straightforward manner, such as simple ban on such discounts, rather than through Rider SR.

The acceleration component of Rider SR is of much greater concern. The proposal is conceptually flawed in that the "acceleration" concept does not reasonably describe what happens with load growth. Putting aside the conceptual flaws with this approach, Evergy's calculation produces a one-sided result that cannot credibly be used to set rates. Just as costs are "accelerated" in Evergy's SR analysis, revenues from new LLPS load would be "accelerated" as well. Evergy's failure to recognize the incremental revenues that would come from the LLPS load is a fatal flaw in the structure of its Rider SR calculation.

My analysis of Evergy's acceleration calculation demonstrates that properly recognizing the incremental revenues from LLPS load (without including any System Support Rider revenues) would result in no net increase in revenue requirement to non-

LLPS customers within the acceleration framework over the 30-year time horizon of the analysis. If the timeframe of the analysis is truncated to 15 years, there is still no net increase in revenue requirement to non-LLPS customers in the Missouri West service territory, while there is an increase in the Missouri Metro territory that would be eliminated by an SR charge that is less than one-third of what Evergy has calculated.

A summary of these results is presented in Table KCH-1 below.

Table KCH-1

Net Present Value of Revenue Impacts to Non-LLPS Customers After Correction of Omissions to Evergy's Acceleration Calculation[21]

	Net Present Value Revenue Impact to non-LLPS – 30 Years		Net Present Value Revenue Impact to non-LLPS – 15 Years	
	w/ SR (millions)	w/o SR (millions)	w/ SR (millions)	w/o SR (millions)
Missouri West	($1,297.4)	($597.4)	($708.6)	($8.6)
Missouri Metro	($1,095.8)	($387.8)	($489.0)	$219.0

VI. SHOULD THE COMMISSION WISH TO CONSIDER VINTAGE PRICING, IT SHOULD DO SO THROUGH COMPREHENSIVE ANALYSIS IN A RATE CASE PROCEEDING.

Q. What is vintage pricing?

A. Vintage pricing refers to the regulatory practice of setting higher prices for newer service, *i.e.*, allowing price discrimination based on vintage of service. The term was coined in the 1960s to refer to the decision by Federal regulatory authorities to allow higher prices for natural gas contracts, which were regulated at the time, entered after a certain date.

[21] Sources: Schedule KCH-1, pp. 1, 3, Schedule KCH-2, pp. 1, 3.

Q. In your experience, is vintage pricing common in the United States for regulated electric service?

A. Generally, no. Typically, new customers are not charged higher rates than similarly situated customers that had been taking service for a longer period.

Q. Is the acceleration component of the proposed System Support Rider a form of vintage pricing?

A. Yes, in that it would levy a vintage-based surcharge on new large customers.

Q. If the Commission wishes to consider adopting vintage pricing in the Evergy service territories, is there a more appropriate venue than this proceeding?

A. Yes. Adoption of vintage pricing would be a major policy change. If the Commission were to consider implementing vintage pricing, it would be better to conduct such an evaluation as part of a general rate case in which the costs of actual resources would be considered along with the actual LLPS loads that materialize.

Q. Are there other considerations that should be borne in mind when considering vintage pricing?

A. Yes, at least two important considerations come to mind, although there are undoubtedly more.

First, as part of considering adoption of any vintage pricing regime, including Rider SR, the Commission should consider whether it would be more appropriate for LLPS customers to have the ability to procure their own generation resources to the extent permissible by state law, such as through a buy-through program. Under a buy-through program, a customer can arrange for a third-party generation service provider to sell wholesale power to the Company on the customer’s behalf. The Company would provide this power to the LLPS customer and bill it according to the terms of a buy-through contract instead of the otherwise applicable generation charges on the customer's bill. Evergy would continue to provide transmission and delivery service in accordance with the applicable LLPS rate. If a discriminatory pricing scheme based on vintage is considered, then I recommend that a buy-through program be given equal consideration.

Second, to the extent that Evergy remains the monopoly provider of generation service to LLPS loads, I would have every expectation that there would be an essential interdependence between resources developed in response to new load growth and the provision of service to Evergy's current customers, both from a planning and operational perspective. Any vintage pricing regime would have to fairly assess the system benefits that would be provided by the acquisition of new resources.

Q. Does this conclude your testimony?

A. Yes, it does.

DCC Illustrative Impact of New LLPS Customer Load on Non-LLPS Evergy MO West Customers' Production Revenue Requirement With Evergy's Proposed SR Charge

Line No.	Year	Non-LLPS Customer Production Function Revenue Req't Before Impact from New LLPS Customers ($M)[1]	Non-LLPS Production Function Revenue Req't Impact from New LLPS Customers ($M)[1]	**Non-LLPS Customer Share of "Accelerated" New Production Resource ($M)[2]**	**Non-LLPS Customer Share of "Avoided" Future Production Resource ($M)[3]**	Non-LLPS Customer Benefit of Evergy Proposed $9.64 SR Charge ($M)[4]	Non-LLPS Customer Production Function Revenue Req't After Impact from New LLPS Customers ($M)	Non-LLPS Customer Production Function Net Cost/ (Benefit) from New LLPS Customers ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Yr 1	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$438.8	$0.9
2	Yr 2	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$431.5	($6.4)
3	Yr 3	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$426.7	($11.2)
4	Yr 4	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$422.1	($15.8)
5	Yr 5	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$417.8	($20.1)
6	Yr 6	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$413.7	($24.2)
7	Yr 7	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$409.7	($28.1)
8	Yr 8	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$405.8	($32.1)
9	Yr 9	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$401.9	($36.0)
10	Yr 10	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$398.0	($39.9)
11	Yr 11	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$155.3	($282.6)
12	Yr 12	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$159.6	($278.3)
13	Yr 13	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$162.6	($275.3)
14	Yr 14	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$163.5	($274.4)
15	Yr 15	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$164.8	($273.1)
16	Yr 16	$437.9	($108.5)	[redacted]	[redacted]	$0.0	$243.3	($194.5)
17	Yr 17	$437.9	($108.5)	[redacted]	[redacted]	$0.0	$245.6	($192.3)
18	Yr 18	$437.9	($108.5)	[redacted]	[redacted]	$0.0	$248.3	($189.6)
19	Yr 19	$437.9	($108.5)	[redacted]	[redacted]	$0.0	$251.0	($186.9)
20	Yr 20	$437.9	($108.5)	[redacted]	[redacted]	$0.0	$253.7	($184.2)
21	Yr 21	$437.9	($108.5)	[redacted]	[redacted]	$0.0	$256.9	($181.0)
22	Yr 22	$437.9	($108.5)	[redacted]	[redacted]	$0.0	$261.0	($176.8)
23	Yr 23	$437.9	($108.5)	[redacted]	[redacted]	$0.0	$262.9	($175.0)
24	Yr 24	$437.9	($108.5)	[redacted]	[redacted]	$0.0	$267.0	($170.9)
25	Yr 25	$437.9	($108.5)	[redacted]	[redacted]	$0.0	$270.2	($167.7)
26	Yr 26	$437.9	($108.5)	[redacted]	[redacted]	$0.0	$272.7	($165.2)
27	Yr 27	$437.9	($108.5)	[redacted]	[redacted]	$0.0	$274.1	($163.8)
28	Yr 28	$437.9	($108.5)	[redacted]	[redacted]	$0.0	$274.9	($163.0)
29	Yr 29	$437.9	($108.5)	[redacted]	[redacted]	$0.0	$275.7	($162.2)
30	Yr 30	$437.9	($108.5)	[redacted]	[redacted]	$0.0	$276.5	($161.4)
31	NPV @ 7.01%	$5,425.7	($1,343.8)	[redacted]	[redacted]	($700.0)	$4,128.2	($1,297.4)

Data Sources:

1. See Sch. KCH-1, p. 5, herein.
2. Evergy "CONF System Support Rider Model_CCGT_01.27.25" Workpaper, "Summary MO" Worksheet. Allocated amount adjusted to reflect new LLPS load appropriately synched-up with new resource size.
3. Evergy "CONF System Support Rider Model_CCGT_01.27.25" Workpaper, "Summary MO" Worksheet. Resource cost adjusted to account for 10-year cost difference in timing of new resource. Allocated amount adjusted to reflect new LLPS load appropriately synched-up with new resource size.
4. Evergy's proposed SR Charge times DCC adjusted projected annualized LLPS peak load. See Evergy "CONF System Support Rider Model_CCGT_01.27.25" Workpaper, "Summary MO" Worksheet.

DCC Illustrative Impact of New LLPS Customer Load on Non-LLPS Evergy MO West Customers' Production Revenue Requirement With the SR Charge Set at Break-even Amount

Line No.	Year	Non-LLPS Customer Production Function Revenue Req't Before Impact from New LLPS Customers ($M)[1]	Non-LLPS Production Function Revenue Req't Impact from New LLPS Customers ($M)[1]	**Non-LLPS Customer Share of "Accelerated" New Production Resource ($M)[2]**	**Non-LLPS Customer Share of "Avoided" Future Production Resource ($M)[3]**	Non-LLPS Customer Benefit of Calculated Break-even $-8.23 SR Charge ($M)[4]	Non-LLPS Customer Production Function Revenue Req't After Impact from New LLPS Customers ($M)	Non-LLPS Customer Production Function Net Cost/ (Benefit) from New LLPS Customers ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Yr 1	$437.9	($108.5)	[redacted]		$65.7	$581.3	$143.4
2	Yr 2	$437.9	($108.5)	[redacted]		$65.7	$574.1	$136.2
3	Yr 3	$437.9	($108.5)	[redacted]		$65.7	$569.3	$131.4
4	Yr 4	$437.9	($108.5)	[redacted]		$65.7	$564.7	$126.8
5	Yr 5	$437.9	($108.5)	[redacted]		$65.7	$560.4	$122.5
6	Yr 6	$437.9	($108.5)	[redacted]		$65.7	$556.3	$118.4
7	Yr 7	$437.9	($108.5)	[redacted]		$65.7	$552.3	$114.4
8	Yr 8	$437.9	($108.5)	[redacted]		$65.7	$548.4	$110.5
9	Yr 9	$437.9	($108.5)	[redacted]		$65.7	$544.5	$106.6
10	Yr 10	$437.9	($108.5)	[redacted]		$65.7	$540.6	$102.7
11	Yr 11	$437.9	($108.5)	[redacted]		$65.7	$297.9	($140.0)
12	Yr 12	$437.9	($108.5)	[redacted]		$65.7	$302.2	($135.7)
13	Yr 13	$437.9	($108.5)	[redacted]		$65.7	$305.2	($132.7)
14	Yr 14	$437.9	($108.5)	[redacted]		$65.7	$306.1	($131.8)
15	Yr 15	$437.9	($108.5)	[redacted]		$65.7	$307.4	($130.5)
16	Yr 16	$437.9	($108.5)	[redacted]		$0.0	$243.3	($194.5)
17	Yr 17	$437.9	($108.5)	[redacted]		$0.0	$245.6	($192.3)
18	Yr 18	$437.9	($108.5)	[redacted]		$0.0	$248.3	($189.6)
19	Yr 19	$437.9	($108.5)	[redacted]		$0.0	$251.0	($186.9)
20	Yr 20	$437.9	($108.5)	[redacted]		$0.0	$253.7	($184.2)
21	Yr 21	$437.9	($108.5)	[redacted]		$0.0	$256.9	($181.0)
22	Yr 22	$437.9	($108.5)	[redacted]		$0.0	$261.0	($176.8)
23	Yr 23	$437.9	($108.5)	[redacted]		$0.0	$262.9	($175.0)
24	Yr 24	$437.9	($108.5)	[redacted]		$0.0	$267.0	($170.9)
25	Yr 25	$437.9	($108.5)	[redacted]		$0.0	$270.2	($167.7)
26	Yr 26	$437.9	($108.5)	[redacted]		$0.0	$272.7	($165.2)
27	Yr 27	$437.9	($108.5)	[redacted]		$0.0	$274.1	($163.8)
28	Yr 28	$437.9	($108.5)	[redacted]		$0.0	$274.9	($163.0)
29	Yr 29	$437.9	($108.5)	[redacted]		$0.0	$275.7	($162.2)
30	Yr 30	$437.9	($108.5)	[redacted]		$0.0	$276.5	($161.4)
31	NPV @ 7.01%	$5,425.7	($1,343.8)	[redacted]		$597.5	$5,425.7	$0.0

Data Sources:

1. See Sch. KCH-1, p. 5, herein.
2. Evergy "CONF System Support Rider Model_CCGT_01.27.25" Workpaper, "Summary MO" Worksheet. Allocated amount adjusted to reflect new LLPS load appropriately synched-up with new resource size.
3. Evergy "CONF System Support Rider Model_CCGT_01.27.25" Workpaper, "Summary MO" Worksheet. Resource cost adjusted to account for 10-year cost difference in timing of new resource. Allocated amount adjusted to reflect new LLPS load appropriately synched-up with new resource size.
4. Break-even SR Charge times DCC adjusted projected annualized LLPS peak load.

DCC Illustrative Impact of New LLPS Customer Load on Non-LLPS Evergy MO West Customers' Production Revenue Requirement With Evergy's Proposed SR Charge

Line No.	Year	Non-LLPS Customer Production Function Revenue Req't Before Impact from New LLPS Customers ($M)[1]	Non-LLPS Production Function Revenue Req't Impact from New LLPS Customers ($M)[1]	**Non-LLPS Customer Share of "Accelerated" New Production Resource ($M)[2]**	**Non-LLPS Customer Share of "Avoided" Future Production Resource ($M)[3]**	Non-LLPS Customer Benefit of Evergy Proposed $9.64 SR Charge ($M)[4]	Non-LLPS Customer Production Function Revenue Req't After Impact from New LLPS Customers ($M)	Non-LLPS Customer Production Function Net Cost/ (Benefit) from New LLPS Customers ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Yr 1	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$438.8	$0.9
2	Yr 2	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$431.5	($6.4)
3	Yr 3	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$426.7	($11.2)
4	Yr 4	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$422.1	($15.8)
5	Yr 5	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$417.8	($20.1)
6	Yr 6	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$413.7	($24.2)
7	Yr 7	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$409.7	($28.1)
8	Yr 8	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$405.8	($32.1)
9	Yr 9	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$401.9	($36.0)
10	Yr 10	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$398.0	($39.9)
11	Yr 11	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$155.3	($282.6)
12	Yr 12	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$159.6	($278.3)
13	Yr 13	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$162.6	($275.3)
14	Yr 14	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$163.5	($274.4)
15	Yr 15	$437.9	($108.5)	[redacted]	[redacted]	($76.9)	$164.8	($273.1)
16	NPV @ 7.01%	$3,984.5	($986.9)	[redacted]	[redacted]	($700.0)	$3,275.9	($708.6)

Data Sources:

1. See Sch. KCH-1, p. 5, herein.
2. Evergy "CONF System Support Rider Model_CCGT_01.27.25" Workpaper, "Summary MO" Worksheet. Allocated amount adjusted to reflect new LLPS load appropriately synched-up with new resource size.
3. Evergy "CONF System Support Rider Model_CCGT_01.27.25" Workpaper, "Summary MO" Worksheet. Resource cost adjusted to account for 10-year cost difference in timing of new resource. Allocated amount adjusted to reflect new LLPS load appropriately synched-up with new resource size.
4. Evergy's proposed SR Charge times DCC adjusted projected annualized LLPS peak load. See Evergy "CONF System Support Rider Model_CCGT_01.27.25" Workpaper, "Summary MO" Worksheet.

DCC Illustrative Impact of New LLPS Customer Load on Non-LLPS Evergy MO West Customers' Production Revenue Requirement With the SR Charge Set at Break-even Amount

Line No.	Year	Non-LLPS Customer Production Function Revenue Req't Before Impact from New LLPS Customers ($M)[1]	Non-LLPS Production Function Revenue Req't Impact from New LLPS Customers ($M)[1]	**Non-LLPS Customer Share of "Accelerated" New Production Resource ($M)[2]**	**Non-LLPS Customer Share of "Avoided" Future Production Resource ($M)[3]**	Non-LLPS Customer Benefit of Calculated Break-even $-0.12 SR Charge ($M)[4]	Non-LLPS Customer Production Function Revenue Req't After Impact from New LLPS Customers ($M)	Non-LLPS Customer Production Function Net Cost/ (Benefit) from New LLPS Customers ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Yr 1	$437.9	($108.5)	[redacted]	[redacted]	$0.9	$516.6	$78.7
2	Yr 2	$437.9	($108.5)	[redacted]	[redacted]	$0.9	$509.4	$71.5
3	Yr 3	$437.9	($108.5)	[redacted]	[redacted]	$0.9	$504.6	$66.7
4	Yr 4	$437.9	($108.5)	[redacted]	[redacted]	$0.9	$500.0	$62.1
5	Yr 5	$437.9	($108.5)	[redacted]	[redacted]	$0.9	$495.7	$57.8
6	Yr 6	$437.9	($108.5)	[redacted]	[redacted]	$0.9	$491.6	$53.7
7	Yr 7	$437.9	($108.5)	[redacted]	[redacted]	$0.9	$487.6	$49.7
8	Yr 8	$437.9	($108.5)	[redacted]	[redacted]	$0.9	$483.7	$45.8
9	Yr 9	$437.9	($108.5)	[redacted]	[redacted]	$0.9	$479.8	$41.9
10	Yr 10	$437.9	($108.5)	[redacted]	[redacted]	$0.9	$475.9	$38.0
11	Yr 11	$437.9	($108.5)	[redacted]	[redacted]	$0.9	$233.2	($204.7)
12	Yr 12	$437.9	($108.5)	[redacted]	[redacted]	$0.9	$237.5	($200.4)
13	Yr 13	$437.9	($108.5)	[redacted]	[redacted]	$0.9	$240.5	($197.4)
14	Yr 14	$437.9	($108.5)	[redacted]	[redacted]	$0.9	$241.3	($196.6)
15	Yr 15	$437.9	($108.5)	[redacted]	[redacted]	$0.9	$242.7	($195.2)
16	NPV @ 7.01%	$3,984.5	($986.9)	[redacted]	[redacted]	$8.6	$3,984.5	($0.0)

Data Sources:
1. See Sch. KCH-1, p. 5, herein.
2. Evergy "CONF System Support Rider Model_CCGT_01.27.25" Workpaper, "Summary MO" Worksheet. Allocated amount adjusted to reflect new LLPS load appropriately synched-up with new resource size.
3. Evergy "CONF System Support Rider Model_CCGT_01.27.25" Workpaper, "Summary MO" Worksheet. Resource cost adjusted to account for 10-year cost difference in timing of new resource. Allocated amount adjusted to reflect new LLPS load appropriately synched-up with new resource size.
4. Break-even SR Charge times DCC adjusted projected annualized LLPS peak load.

Illustrative Non-LLPS & LLPS Share of Existing Production Revenue Requirement (Excluding Fuel)
Using Evergy MO West Utility's 2024 General Rate Case Information

Line No.	Description			
1	**Evergy MO West Existing Production Revenue Requirement**			
		Amount[1]		
2	Production Energy ($M)	$ 255.5		
3	Production Demand ($M)	$ 182.4		
4	Total Production ($M)	$ 437.9		
5	**Customer Revenue Requirement Before LLPS Customers Take Service**			
6	*Load Ratio Share Before LLPS Customers Take Service*			
7	Non-LLPS Customer Share		100.00%	
8	New LLPS Share		NA	
9	Total		100.00%	
10	*Annual Revenue Requirement*		Amount	Derivation
11	Non-LLPS Customer Revenue Req't ($M)		$ 437.9	= Ln. 4 x Ln. 7
12	New LLPS Revenue Req't ($M)		NA	
13	Total Existing Production ($M)		$ 437.9	
14	**Customer Revenue Requirement After LLPS Customers Take Service**			
15	*Load Ratio Share After LLPS Customers Take Service* [2]			
16	Non-LLPS Customer Share		75.23%	
17	New LLPS Share		24.77%	
18	Total		100.00%	
19	*Annual Revenue Requirement*		Amount	Derivation
20	Non-LLPS Customer Revenue Req't ($M)		$ 329.4	= Ln. 4 x Ln. 16
21	New LLPS Revenue Req't ($M)		$ 108.5	= Ln. 4 x Ln. 17
22	Total Non-LLPS Production ($M)		$ 437.9	
23	Non-LLPS Customer Benefit from New LLPS Customers		$ (108.5)	= Ln. 20 - Ln. 11

Data Sources:

1. **Evergy Response to DCC Data Request No. 16 - "QDCC-16_CONF_Evergy MO West 2024 CCOS Model - Direct" Workpaper, "Unbundled RR" Worksheet.**
2. **Evergy "CONF System Support Rider Model_CCGT_01.27.25" Workpaper, "Summary MO" Worksheet. New LLPS Load adjusted to more appropriately synch-up with new resource size.**

DCC Illustrative Impact of New LLPS Customer Load
on Non-LLPS Evergy MO Metro Customers' Production Revenue Requirement
With Evergy's Proposed SR Charge

Line No.	Year	Non-LLPS Customer Production Function Revenue Req't Before Impact from New LLPS Customers ($M)[1]	Non-LLPS Production Function Revenue Req't Impact from New LLPS Customers ($M)[1]	**Non-LLPS Customer Share of "Accelerated" New Production Resource ($M)[2]**	**Non-LLPS Customer Share of "Avoided" Future Production Resource ($M)[3]**	Non-LLPS Customer Benefit of Evergy Proposed $9.59 SR Charge ($M)[4]	Non-LLPS Customer Production Function Revenue Req't After Impact from New LLPS Customers ($M)	Non-LLPS Customer Production Function Net Cost/ (Benefit) from New LLPS Customers ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Yr 1	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$653.1	$36.6
2	Yr 2	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$645.0	$28.5
3	Yr 3	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$639.6	$23.0
4	Yr 4	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$634.5	$17.9
5	Yr 5	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$629.6	$13.1
6	Yr 6	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$625.0	$8.5
7	Yr 7	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$620.6	$4.0
8	Yr 8	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$616.2	($0.4)
9	Yr 9	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$611.8	($4.8)
10	Yr 10	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$607.4	($9.2)
11	Yr 11	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$335.0	($281.5)
12	Yr 12	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$339.8	($276.7)
13	Yr 13	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$343.2	($273.4)
14	Yr 14	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$344.1	($272.4)
15	Yr 15	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$345.7	($270.9)
16	Yr 16	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$424.0	($192.6)
17	Yr 17	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$426.5	($190.0)
18	Yr 18	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$429.5	($187.0)
19	Yr 19	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$432.6	($184.0)
20	Yr 20	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$435.7	($180.9)
21	Yr 21	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$439.2	($177.3)
22	Yr 22	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$443.9	($172.7)
23	Yr 23	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$445.9	($170.6)
24	Yr 24	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$450.6	($166.0)
25	Yr 25	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$454.1	($162.5)
26	Yr 26	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$456.9	($159.6)
27	Yr 27	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$458.5	($158.0)
28	Yr 28	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$459.4	($157.1)
29	Yr 29	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$460.3	($156.2)
30	Yr 30	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$461.2	($155.4)
31	NPV @ 6.76%	$7,842.5	($1,220.2)	[redacted]	[redacted]	($708.0)	$6,746.7	($1,095.8)

Data Sources:
1. See Sch. KCH-2, p. 5, herein.
2. Evergy "CONF System Support Rider Model_CCGT_01.27.25" Workpaper, "Summary MO" Worksheet.
3. Evergy "CONF System Support Rider Model_CCGT_01.27.25" Workpaper, "Summary MO" Worksheet. Resource cost adjusted to account for 10-year cost difference in timing of new resource.
4. Evergy's proposed SR Charge times Evergy's projected annualized LLPS peak load. See Evergy "CONF System Support Rider Model_CCGT_01.27.25" Workpaper, "Summary MO" Worksheet.

DCC Illustrative Impact of New LLPS Customer Load on Non-LLPS Evergy MO Metro Customers' Production Revenue Requirement With the SR Charge Set at Break-even Amount

Line No.	Year	Non-LLPS Customer Production Function Revenue Req't Before Impact from New LLPS Customers ($M)[1]	Non-LLPS Production Function Revenue Req't Impact from New LLPS Customers ($M)[1]	**Non-LLPS Customer Share of "Accelerated" New Production Resource ($M)[2]**	**Non-LLPS Customer Share of "Avoided" Future Production Resource ($M)[3]**	Non-LLPS Customer Benefit of Calculated Break-even $-5.25 SR Charge ($M)[4]	Non-LLPS Customer Production Function Revenue Req't After Impact from New LLPS Customers ($M)	Non-LLPS Customer Production Function Net Cost/ (Benefit) from New LLPS Customers ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Yr 1	$616.6	($95.9)	[redacted]	[redacted]	$41.9	$771.6	$155.0
2	Yr 2	$616.6	($95.9)	[redacted]	[redacted]	$41.9	$763.5	$146.9
3	Yr 3	$616.6	($95.9)	[redacted]	[redacted]	$41.9	$758.1	$141.5
4	Yr 4	$616.6	($95.9)	[redacted]	[redacted]	$41.9	$752.9	$136.4
5	Yr 5	$616.6	($95.9)	[redacted]	[redacted]	$41.9	$748.1	$131.5
6	Yr 6	$616.6	($95.9)	[redacted]	[redacted]	$41.9	$743.5	$126.9
7	Yr 7	$616.6	($95.9)	[redacted]	[redacted]	$41.9	$739.0	$122.5
8	Yr 8	$616.6	($95.9)	[redacted]	[redacted]	$41.9	$734.6	$118.1
9	Yr 9	$616.6	($95.9)	[redacted]	[redacted]	$41.9	$730.2	$113.7
10	Yr 10	$616.6	($95.9)	[redacted]	[redacted]	$41.9	$725.8	$109.3
11	Yr 11	$616.6	($95.9)	[redacted]	[redacted]	$41.9	$453.5	($163.1)
12	Yr 12	$616.6	($95.9)	[redacted]	[redacted]	$41.9	$458.3	($158.3)
13	Yr 13	$616.6	($95.9)	[redacted]	[redacted]	$41.9	$461.6	($154.9)
14	Yr 14	$616.6	($95.9)	[redacted]	[redacted]	$41.9	$462.6	($154.0)
15	Yr 15	$616.6	($95.9)	[redacted]	[redacted]	$41.9	$464.1	($152.4)
16	Yr 16	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$424.0	($192.6)
17	Yr 17	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$426.5	($190.0)
18	Yr 18	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$429.5	($187.0)
19	Yr 19	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$432.6	($184.0)
20	Yr 20	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$435.7	($180.9)
21	Yr 21	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$439.2	($177.3)
22	Yr 22	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$443.9	($172.7)
23	Yr 23	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$445.9	($170.6)
24	Yr 24	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$450.6	($166.0)
25	Yr 25	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$454.1	($162.5)
26	Yr 26	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$456.9	($159.6)
27	Yr 27	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$458.5	($158.0)
28	Yr 28	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$459.4	($157.1)
29	Yr 29	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$460.3	($156.2)
30	Yr 30	$616.6	($95.9)	[redacted]	[redacted]	$0.0	$461.2	($155.4)
31	NPV @ 6.76%	$7,842.5	($1,220.2)	[redacted]	[redacted]	$387.8	$7,842.5	($0.0)

Data Sources:

1. See Sch. KCH-2, p. 5, herein.
2. Evergy "CONF System Support Rider Model_CCGT_01.27.25" Workpaper, "Summary MO" Worksheet.
3. Evergy "CONF System Support Rider Model_CCGT_01.27.25" Workpaper, "Summary MO" Worksheet. Resource cost adjusted to account for 10-year cost difference in timing of new resource.
4. Break-even SR Charge times Evergy's projected annualized LLPS peak load.

DCC Illustrative Impact of New LLPS Customer Load on Non-LLPS Evergy MO Metro Customers' Production Revenue Requirement With Evergy's Proposed SR Charge

Line No.	Year	Non-LLPS Customer Production Function Revenue Req't Before Impact from New LLPS Customers ($M)[1]	Non-LLPS Production Function Revenue Req't Impact from New LLPS Customers ($M)[1]	**Non-LLPS Customer Share of "Accelerated" New Production Resource ($M)[2]**	**Non-LLPS Customer Share of "Avoided" Future Production Resource ($M)[3]**	Non-LLPS Customer Benefit of Evergy Proposed $9.59 SR Charge ($M)[4]	Non-LLPS Customer Production Function Revenue Req't After Impact from New LLPS Customers ($M)	Non-LLPS Customer Production Function Net Cost/ (Benefit) from New LLPS Customers ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Yr 1	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$653.1	$36.6
2	Yr 2	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$645.0	$28.5
3	Yr 3	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$639.6	$23.0
4	Yr 4	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$634.5	$17.9
5	Yr 5	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$629.6	$13.1
6	Yr 6	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$625.0	$8.5
7	Yr 7	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$620.6	$4.0
8	Yr 8	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$616.2	($0.4)
9	Yr 9	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$611.8	($4.8)
10	Yr 10	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$607.4	($9.2)
11	Yr 11	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$335.0	($281.5)
12	Yr 12	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$339.8	($276.7)
13	Yr 13	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$343.2	($273.4)
14	Yr 14	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$344.1	($272.4)
15	Yr 15	$616.6	($95.9)	[redacted]	[redacted]	($76.5)	$345.7	($270.9)
16	NPV @ 6.76%	$5,703.2	($887.4)	[redacted]	[redacted]	($708.0)	$5,214.2	($489.0)

Data Sources:

1. See Sch. KCH-2, p. 5, herein.
2. Evergy "CONF System Support Rider Model_CCGT_01.27.25" Workpaper, "Summary MO" Worksheet.
3. Evergy "CONF System Support Rider Model_CCGT_01.27.25" Workpaper, "Summary MO" Worksheet. Resource cost adjusted to account for 10-year cost difference in timing of new resource.
4. Evergy's proposed SR Charge times Evergy's projected annualized LLPS peak load. See Evergy "CONF System Support Rider Model_CCGT_01.27.25" Workpaper, "Summary MO" Worksheet.

DCC Illustrative Impact of New LLPS Customer Load on Non-LLPS Evergy MO Metro Customers' Production Revenue Requirement With the SR Charge Set at Break-even Amount

Line No.	Year	Non-LLPS Customer Production Function Revenue Req't Before Impact from New LLPS Customers ($M)[1]	Non-LLPS Production Function Revenue Req't Impact from New LLPS Customers ($M)[1]	**Non-LLPS Customer Share of "Accelerated" New Production Resource ($M)[2]**	**Non-LLPS Customer Share of "Avoided" Future Production Resource ($M)[3]**	Non-LLPS Customer Benefit of Calculated Break-even $2.97 SR Charge ($M)[4]	Non-LLPS Customer Production Function Revenue Req't After Impact from New LLPS Customers ($M)	Non-LLPS Customer Production Function Net Cost/ (Benefit) from New LLPS Customers ($M)
	(a)	(b)	(c)	[redacted]	[redacted]	(f)	(g)	(h)
1	Yr 1	$616.6	($95.9)	[redacted]	[redacted]	($23.7)	$706.0	$89.4
2	Yr 2	$616.6	($95.9)	[redacted]	[redacted]	($23.7)	$697.9	$81.3
3	Yr 3	$616.6	($95.9)	[redacted]	[redacted]	($23.7)	$692.5	$75.9
4	Yr 4	$616.6	($95.9)	[redacted]	[redacted]	($23.7)	$687.3	$70.8
5	Yr 5	$616.6	($95.9)	[redacted]	[redacted]	($23.7)	$682.5	$65.9
6	Yr 6	$616.6	($95.9)	[redacted]	[redacted]	($23.7)	$677.9	$61.3
7	Yr 7	$616.6	($95.9)	[redacted]	[redacted]	($23.7)	$673.4	$56.9
8	Yr 8	$616.6	($95.9)	[redacted]	[redacted]	($23.7)	$669.0	$52.5
9	Yr 9	$616.6	($95.9)	[redacted]	[redacted]	($23.7)	$664.6	$48.1
10	Yr 10	$616.6	($95.9)	[redacted]	[redacted]	($23.7)	$660.2	$43.7
11	Yr 11	$616.6	($95.9)	[redacted]	[redacted]	($23.7)	$387.9	($228.7)
12	Yr 12	$616.6	($95.9)	[redacted]	[redacted]	($23.7)	$392.7	($223.9)
13	Yr 13	$616.6	($95.9)	[redacted]	[redacted]	($23.7)	$396.0	($220.5)
14	Yr 14	$616.6	($95.9)	[redacted]	[redacted]	($23.7)	$397.0	($219.5)
15	Yr 15	$616.6	($95.9)	[redacted]	[redacted]	($23.7)	$398.5	($218.0)
16	NPV @ 6.76%	$5,703.2	($887.4)	[redacted]	[redacted]	($219.0)	$5,703.2	$0.0

Data Sources:

1. See Sch. KCH-2, p. 5, herein.
2. Evergy "CONF System Support Rider Model_CCGT_01.27.25" Workpaper, "Summary MO" Worksheet.
3. Evergy "CONF System Support Rider Model_CCGT_01.27.25" Workpaper, "Summary MO" Worksheet. Resource cost adjusted to account for 10-year cost difference in timing of new resource.
4. Break-even SR Charge times Evergy's projected annualized LLPS peak load.

Illustrative Non-LLPS & LLPS Share of Existing Production Revenue Requirement (Excluding Fuel)
Using Evergy MO Metro Utility's 2021 General Rate Case Information

Line No.	Description			
1	**Evergy MO Metro Existing Production Revenue Requirement**			
		Amount[1]		
2	Production Energy ($M)	$ 241.0		
3	Production Demand ($M)	$ 375.5		
4	Total Production ($M)	$ 616.6		
5	**Customer Revenue Requirement Before LLPS Customers Take Service**			
6	*Load Ratio Share Before LLPS Customers Take Service*			
7	Non-LLPS Customer Share		100.00%	
8	New LLPS Share		NA	
9	Total		100.00%	
10	*Annual Revenue Requirement*		Amount	Derivation
11	Non-LLPS Customer Revenue Req't ($M)		$ 616.6	= Ln. 4 x Ln. 7
12	New LLPS Revenue Req't ($M)		NA	
13	Total Existing Production ($M)		$ 616.6	
14	**Customer Revenue Requirement After LLPS Customers Take Service**			
15	*Load Ratio Share After LLPS Customers Take Service*[2]			
16	Non-LLPS Customer Share		84.44%	
17	New LLPS Share		15.56%	
18	Total		100.00%	
19	*Annual Revenue Requirement*		Amount	Derivation
20	Non-LLPS Customer Revenue Req't ($M)		$ 520.6	= Ln. 4 x Ln. 16
21	New LLPS Revenue Req't ($M)		$ 95.9	= Ln. 4 x Ln. 17
22	Total Existing Production ($M)		$ 616.6	
23	Non-LLPS Customer Benefit from New LLPS Customers		$ (95.9)	= Ln. 20 - Ln. 11

Data Sources:

1. **Evergy Response to DCC Data Request No. 16 - "QDD16_Evergy MO Metro 2021 CCOS Model 202106" Workpaper, "Unbundled RR" Worksheet.**
2. **Evergy "CONF System Support Rider Model_CCGT_01.27.25" Workpaper, "Summary MO" Worksheet.**

evergy

Evergy MO Metro and MO West
Case Name: 2025 Approval of Large Load Service Rate Plan and Associated Tariffs
Case Number: EO-2025-0154

Requestor Greenwald Alissa -
Response Provided May 12, 2025

Question:DCC-11

[redacted]

RESPONSE: (do not edit or delete this line or anything above this)

Confidentiality: CONFIDENTIAL

[redacted]

evergy

[redacted]

Information provided by: John M. Grace; Sr. Dir. Corporate Planning and Financial Performance

Attachment(s):

<u>Missouri Verification:</u>
I have read the Information Request and answer thereto and find answer to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signature /s/ *Brad Lutz*
Director Regulatory Affairs

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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 New and Modified Tariffs for Service to Large Load Customers	)))))	File No. EO-2025-0154

AFFIDAVIT OF KEVIN C. HIGGINS

STATE OF UTAH)
) ss
COUNTY OF SALT LAKE)

My name is Kevin C. Higgins, and on my oath I declare that I am of sound mind and lawful age; that I prepared the foregoing Rebuttal Testimony; and further, under the penalty of perjury, that the same is true and correct to the best of my knowledge and belief.

/s/ [signature]
Kevin C. Higgins

Subscribed and sworn before me this 18 day of July 2025.

KEIRSTEN DAWN IKEY
Notary Public State of Utah
My Commission Expires on:
April 10, 2029
Comm. Number: 742507

[signature]
Notary Public

My commission expires: April 10, 2029