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Case No.:	ER-2026-0143

DIRECT TESTIMONY

OF

DAVE SHAPLEY

Submitted on Behalf of the Office of the Public Counsel

EVERGY METRO, INC. D/B/A EVERGY MISSOURI METRO

CASE NO. ER-2026-0143

June 30, 2026

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DIRECT TESTIMONY

OF

DAVID C. SHAPLEY

EVERGY MISSOURI METRO

CASE NO. ER-2026-0143

I. INTRODUCTION

Q. Please state your name, title and business address.

A. My name is David C. Shapley. My business address is Wired Group, P.O. Box 620756, Littleton, CO 80162.

Q. Please describe your education and employment background.

A. I have a BSEE from Widner University, Chester, PA, I worked in distribution engineering for Potomac Electric Power (PEPCO) from 1989-1993, and for Delaware Electric Co-op from 1993 through the present.

Q. Do you have any professional designations?

A. Yes, I am a Professional Engineer licensed in the State of Delaware

Q. Have you previously provided testimony before the Missouri Public Service Commission (Commission)?

A. No.

Q. Have you previously served as an expert consultant in a utility rate case proceeding?

A. No. However, based on my education and professional experience, I am qualified to provide testimony for the Commission's consideration. Please see my CV attached as Schedule DCS – 1. Also attached is Schedule DCS-2, a selection of EMM responses to my data requests.

Q. What party do you represent?

A. In this proceeding, I represent the Missouri Office of the Public Counsel (Public Counsel).

Q. Are any other members of the Wired Group filing testimony in this proceeding?

A. Yes. Expert Paul J. Alvarez will also be filing testimony on behalf of Public Counsel. Mr. Alvarez and I worked together closely in this proceeding. As a result, Mr. Alvarez's testimony frequently refers to my testimony, and my testimony frequently refers to his.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to examine the spending of Evergy Missouri Metro (EMM) for prudence on behalf of Public Counsel and to provide recommendations to the Commission regarding EMM's discretionary spending.

Q. Would you please provide a summary of your recommendations?

A. I provide two recommendations for the Commission's consideration.

1) The Commission should order the disallowances summarized in the table below:

($ in millions)	2022	2023	2024	2025	2026	Total
Lateral Rebuild Projects	$7.107	$2.014	$0.218	$5.426	$6.951	$21.806
Substation Projects	4.427	7.987	8.684	4.331	3.996	29.424
Totals	$11.534	$10.091	$8.902	$9.757	$10.947	$51.230

2) The Commission should adopt the recommendation in expert Alvarez's testimony to require discretionary investments that EMM makes or proposes to make pass a risk-informed benefit-cost analysis test of customer cost-effectiveness.

Q. Would you please provide a brief preview of your testimony?

A. After this Introduction, in Section II I will provide an overview of standards employed by utilities in conducting objective equipment tests and inspections. These tests and inspections are critical to providing safe and reliable service, but can also help avoid replacing equipment unnecessarily. In Section III I testify to my evaluation of EMM's lateral rebuild program and support my recommended disallowances regarding that program. In Section IV I testify to my evaluation of EMM's substation equipment replacement projects and support my recommended disallowances regarding that program.

II. OBJECTIVE EQUIPMENT TESTS AND INSPECTIONS UTILITIES ROUTINELY EMPLOY

Q. Would you please preview this section of your testimony?

A. Electric utilities routinely employ standardized, objective inspections and tests to identify equipment for repair or replacement. In this section I will explain the two biggest categories of such tests and inspections: A) tests and inspections of poles and overhead equipment; and B) tests of critical substation equipment.

A. Objective pole and overhead equipment/conductor inspection and testing

Q. In your experience, how often do utilities perform inspections and test of wood poles?

A. In my experience, utilities routinely complete objective inspections and tests of wood poles on a periodic basis, and as part of those practices, also inspect other overhead equipment such as conductors. EMM reports that it makes visual inspections every four-to-six years, and diagnostic (pole bore) testing every 12 years.[1] In my experience these are typical inspection and testing schedules. Poles or other overhead equipment (including conductors) which fail objective inspections or tests must be repaired or replaced. Such repairs are not discretionary.[2]

Q. Does EMM also make discretionary spending?

A. Yes. In addition to replacing poles and other overhead equipment as required based on the results of objective tests and inspections, EMM has a significant discretionary lateral reconductoring program.

Q. What is a lateral conductor?

A. A lateral conductor is a branch line that taps off the main distribution line (feeder) to deliver electricity to a specific neighborhood, street, or portion of a service area.

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[1] Company response to OPC data request 5004.

[2] For a further discussion of discretionary versus required spending, please see the direct testimony of Public Counsel witness Paul J. Alvarez from 9:19 to 13:5.

Q. What is meant by reconductoring?

A. Reconductoring means a replacement of the existing overhead infrastructure. This replacement could also include larger conductors, poles or more advanced technologies.

Q. Would you please describe EMM's lateral reconductoring program?

A. In EMM's lateral reconductoring program, laterals are selected for reconductoring by EMM's AssetLens software. In addition to the laterals, any defective poles identified as part of lateral reconductoring project scoping are also replaced. As further described in expert Alvarez's testimony, EMM's AssetLens software uses a proprietary algorithm to create a risk score and prioritize laterals for reconductoring.[3] These reconductoring projects are not identified through objective inspections or testing. Therefore, these projects are discretionary.

Q. Is it a best practice to replace equipment for reasons other than test or inspection failure?

A. Not in my experience, no. In my experience, equipment that fails to pass an objective test or inspection is repaired or replaced, whereas equipment that passes an objective test or inspection is sufficiently safe and reliable to remain in service. I am concerned by expert Alvarez's observation that the AssetLens software's ability to accurately predict reliability improvements has not been validated.[4] I also am concerned by EMM's inability to produce

[3] Alvarez Direct, from 14:17 to 15:11.
[4] Alvarez Direct, from 16:15 to 17:2.

risk scores or benefit-cost analyses for lateral reconductoring projects EMM has completed since its last rate case.[5]

B. Objective substation equipment diagnostic and functional testing

Q. Do utilities conduct periodic diagnostic and functional tests on critical substation equipment?

A. Yes. I believe all utilities routinely and periodically complete diagnostic and functional tests on critical substation equipment, including power transformers and circuit breakers.

Q. In your experience, how often would utilities complete these diagnostic and functional tests?

A. In my experience, substation equipment is typically inspected monthly, but tested annually or every few years depending on the equipment type. For example, diagnostic tests of transformer oil are typically completed once a year, whereas functional tests of circuit breakers are typically completed every 2-3 years. The oil in oil-filled circuit breakers is typically also tested periodically in the same manner as transformer oil.

Q. What is a power transformer?

A. A power transformer is a significant piece of substation equipment that steps down the higher voltage of transmission circuits to the more moderate voltages at which distribution circuits operate. This is a very critical role; electricity cannot be distributed without functioning power transformers. As a result, substation power transformers are designed to be extremely durable, lasting multiple decades, and built to exacting specifications.

[5] Alvarez Direct, from 15:6 to 15:10.

Most utilities design and maintain substations with multiple transformers and redundant capacity across transformers, so that if one fails (an extremely rare occurrence), service to customers will continue uninterrupted. Substation power transformers typically cost millions of dollars apiece.

Q. How do utilities test power transformers?

A. Power transformers are tested diagnostically. The insulating oil that fills transformers can be tested for certain gasses that are dissolved in the oil (called dissolved gas analysis, or DGA). Increases in the levels of certain dissolved gasses indicate that power transformer repair or replacement is required.[6]

Q. What is a circuit breaker?

A. A circuit breaker is a device used to interrupt electrical currents based on system conditions and thus control the flow of electricity. When an abnormality is detected, circuit breakers are designed to open (interrupt power flow) almost instantly. This protects equipment upstream of the circuit breaker from damage, but interrupts power flow to customers downstream of the circuit breaker. Circuit breakers (and similar types of equipment known as switchgear) are known as protective devices, and are configured with other equipment to form what are known as protection schemes.

Q. How do utilities test circuit breakers?

A. Circuit breakers, and the relays that control their operation, are subjected to functional testing on a periodic, routine basis. Typically completed in the spring and fall when loads

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[6] *IEEE Guide for the Interpretation of Gasses Generated in Mineral Oil-Immersed Transformers.* IEEE Power and Energy Society Standard C57.104™. 2019.

are low, the loads associated with the breakers and relays to be tested are temporarily routed to other circuits, breakers, and relays. A known fault current is passed through the now-isolated breakers and relays, and the response time of the breakers and relays (typically in cycles or milliseconds) is compared to performance specifications established by each item's manufacturer. Failure of a breaker or relay to respond (open) within specifications indicates that the breaker or relay must be repaired or replaced.[7][8]

Q. What is the general course of action if a piece of infrastructure fails testing?

A. If a piece of critical substation equipment fails a test, it must be repaired until it passes the test. If repairs do not resolve the test failure, the equipment must be replaced. Repair or replacement of equipment that fails testing is required, not discretionary.

Q. What is the general course of action if a piece of equipment passes its tests?

A. If a piece of equipment passes its tests, the equipment should remain in service, as it is likely to continue providing safe and adequate service. As I see it, decisions to replace substation equipment that has passed objective diagnostic and/or functional tests are discretionary.

Q. Could there be reasons why the replacement of equipment that has passed its test be justified?

A. Yes, there may be some other justification to replace equipment that has passed its tests. For example, there may be a need to increase capacity due to bona fide load growth

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[7] *IEEE Standard for Relays, Relay Systems, and Control Devices….Requirements and Tests.* IEEE Power and Energy Society Standard C37.90.1™. 2924.

[8] IEEE Standard Test Procedures for AC High-Voltage Circuit Breakers with Maximum Voltage Above 1000 V. IEEE Power and Energy Society Standard C37.09(a)™. 2025.

forecasts. Sometimes, equipment must be relocated to accommodate public works projects, or customers may request (and pay for) equipment relocations. Equipment repair and replacement can also be required after damage caused by storms. While these types of repairs and replacements are required for safe and reliable service, I consider replacement of substation equipment that has passed its objective functional and diagnostic tests to be discretionary.

Q. What have you concluded from your review of EMM's substation projects?

A. It appears that many of EMM's substation projects are discretionary, and replace equipment that has passed functional and diagnostic tests.

Q. Besides the other justifications mentioned above, could there be justification to undertake this type of discretionary spending?

A. Possibly. To my way of thinking, replacing a piece of equipment that has passed its objective tests could be justified if it can be shown that the benefits of the discretionary replacement are likely to exceed the costs of the discretionary replacement to customers. However, while EMM appears to have increased discretionary decisions to replace equipment that has passed its tests in recent years, EMM does not complete any benefit-cost analyses on substation equipment replacement projects or programs.[9]

Q. Should substation equipment or other plant be replaced because it is "old"?

A. No. First, if by "old" you mean it their expected useful lives then that measure is an inappropriate yardstick. Expected useful lives are based on the *average* length of time

[9] Company response to OPC 5023 (a)(iv), (b)(iv), (c)(iv), and (d)(iv).

equipment of a certain type is likely to remain in service. For example, if the average length of time a wood pole is expected to remain in service is 45 years, I would expect half of the poles a utility has in service to be less than 45 years old, and half to be older than 45 years. According to Mr. Mulvany's testimony, far less than half of EMM's poles are older than 45 years.[10] Thus, I do not consider the age of EMM's poles to be problematic.

Second, expected useful lives are used to establish equipment deprecation rates as set forth in Generally Accepted Accounting Principles. Expected useful lives were not established to guide equipment replacement decisions, nor should they be employed in that manner.

Depreciation rates are important from an accounting perspective, as utility customers cover depreciation expense in rates, and the undepreciated value of the Company's equipment (rate base) is used to calculate the amount of the profit the Commission authorizes in a utility's rates. Depreciation rates are based on survivor curves which estimate, for different types of equipment, how long equipment of that type can be expected to remain in service on average. *It is critical to note that equipment survivor curves are different from equipment failure rates.* This is because equipment can be removed from service for many reasons other than failures in service, including to accommodate load growth or public works projects as described above.

Thus, while expected useful lives are valuable as accounting constructs, they should NOT be used as an estimate of when equipment is likely to fail, or as a guide to equipment replacement. For example, while a utility may depreciate a pole over 45 years based on

[10] Ibid. Figure 1, page 4.

survivor curves, a pole can easily deliver safe and adequate service for 70, 75, 80 years, or more. Replacing equipment simply because it is older than the expected useful life deprives customers of years or decades of reliable service from the equipment for which customers have paid in rates. This is precisely why utilities have historically used the objective tests and inspections of conditions described earlier, rather than age, to make operational decisions to repair or replace equipment.

Q. Doesn't older equipment have a higher risk of failure?

A. It may be true that the older an item of equipment gets, the greater its risk of failure becomes. However, this generalization does not mean equipment should be replaced due to age. For example, consider that the likelihood that a 1-year old substation power transformer will not be in service in year 2 is 0.3%.[11] According to the Company's depreciation expert, the likelihood that a 50-year old transformer will not be in service in year 51 is 1.64%.[12] While the risk of not surviving for the 50-year-old item may be several times greater than when it was new, *it is still just 1.64% annually*. Further, recall that equipment survivor curves do not represent equipment failure rates, and that most substation equipment is backed up by excess capacity maintained on adjacent equipment (meaning that a failure of such equipment is unlikely to result in a service interruption). Put this all together, and it becomes clear that the opportunity to improve service reliability by replacing older equipment with new is fairly small to begin with.

[11]Direct Testimony of John Spanos dated February 6, 2026. Schedule JJS-1, "2025 Depreciation Study." Account 362 Station Equipment, page 173. 99.72% survival at year 1.5 less 99.42% survival at year 2.5 = 0.3%.
[12] Ibid, page 174. 57.85% survival at year 50.5 less 56.21% survival at year 51.5 = 1.64%.

Q. Is this why you and Mr. Alvarez recommend that the baseline risk of service interruptions, and the likely reduction in that risk associated with a proposed capital project or program, be quantified through the use of a risk-informed benefit-cost analysis?

A. Yes, it is precisely why. Basing hundreds of millions of dollars in capital project and program spending on an accurate, but over-simplified, observation that failure rates increase as equipment gets older is extremely inadequate, and does not lead to prudent equipment replacement decisions. The risk-informed benefit-cost analysis is about applying data and rigor to capital spending decisions, and this is in customer interest. As the father of modern quality management, W. Edwards Deming, once said, "In God we trust, all others bring data." The Commission should expect utilities with capital bias, like EMM, to practice data-driven decision-making, and risk-informed benefit-cost analyses constitute data-driven decision-making.

Q. Are a large part of EMM's service interruptions due to equipment failures?

A. Not in my opinion. In reviewing EMM data, I used MS Excel's "random array" function to select 100 service interruptions at random out of almost 69,000 on which EMM provided detail from 2019 through 2025.[13] I repeated this random selection of 100 service interruptions one dozen times. Of these dozen runs, I did not observe more than 23% of the 100 randomly selected service interruptions to be associated with cause code "equipment." One of the twelve runs produced just 18% of service interruptions associated with the cause code "equipment." Further, out of the 18-23 outages with a cause code

[13] Q2002_CONF_EMM_Outage_Data_2019_2025.

"equipment" I examined for each of the twelve runs of 100 randomly selected service interruptions, recorded employee comments indicated that a significant number of outages associated with cause code "equipment" did not result from equipment failures. For example, 4-5 outages out of the 18-23 with cause code "equipment" were typically the result of proper equipment operation, such as a blown cutout (a type of fuse). Typically, at least one outage out of the 18-23 with cause code "equipment" appeared from comments to be the result of vegetation contact, and at least one outage out of the 18-23 with cause code "equipment" was typically accompanied by the comment "OK on arrival" (i.e. a false report of a service interruption).

Q. What is your conclusion on the amount of EMM's service interruptions that were caused by equipment failure?

A. Given that six to seven outages out of the 18-23 with cause code "equipment" in each random sample of 100 service interruptions between 2019-2025 did not actually result from equipment failure, it is possible that service interruptions resulting from equipment failure could have been as low as 12 – 16% from 2019-2025. In my experience, this is not an atypical proportion of service interruptions from equipment failure, and such a proportion indicates that cost-effective opportunities to reduce service interruption frequency through equipment replacement programs may be limited. I will examine EMM's two largest distribution equipment replacement programs in the next two sections of my testimony.

III. EMM's LATERAL RECONDUCTORING PROGRAM

Description of the program

Q. How does EMM prioritize laterals for reconductoring?

A. EMM uses its AssetLens software program to risk score and prioritize laterals for reconductoring. Mr. Alvarez's Direct Testimony offers a more in-depth review of the AssetLens software.[14]

Q. What is a lateral?

A. Laterals are relatively short sections of smaller conductor on a circuit that "tap into" larger conductor. In my experience, laterals typically serve just 30-50 or so residential customers each, though some laterals serve fewer customers and some laterals serve more. Occasionally some laterals even serve commercial customers.

Q. What is the general cost of lateral reconductoring?

A. Reconductoring is very costly. In 132 lateral reconductoring projects since EMM's last rate case, the average cost per project was a bit more than $165,000.[15] Assuming 30 – 50 customers served per lateral, the average lateral reconductoring project thus costs between $3,300 and $5,500 per customer. To justify projects of such high per customer costs, the associated reliability improvements must be very significant.

[14] Alvarez Direct from 14:17 to 17:15.
[15] Q5008_Lateral Info (a) and Q5008_Lateral Info (b). $21.806 million in project costs divided by 132 projects.

Q. Are the reliability improvements from lateral reconductoring worth the high cost?

A. It's doubtful. Complicating reliability improvement measurement is tree trimming. Reconductoring projects are typically preceded by tree-trimming efforts on those laterals, thereby facilitating efficient and safe conductor replacement work. It is difficult if not impossible to discern reliability improvements associated with tree-trimming from reliability improvements associated with reconductoring. Thus, any analysis indicating that lateral reconductoring delivers significant reliability improvements must be taken with a grain of salt. I further note that EMM provides no benefit-cost analyses that quantify the reliability improvements from lateral reconductoring projects completed historically.[16]

Q. How much has EMM spent on lateral reconductoring since its last rate case?

A. Since its last rate case, and through the post-test year period ending June 30, 2026, EMM has placed into service or expects to place into service $21.8 million worth of lateral reconductoring projects.[17]

Q. You testified that EMM has not quantified the reliability improvements from lateral reconductoring projects it has completed in the past. Have you conducted your own assessment of the effectiveness of any of EMM's past lateral reconductoring projects?

A. Yes. I isolated lateral reconductoring projects placed into service in 2022. I chose 2022 because it offered at least three years of pre-project and post-project reliability data. (Averaging reliability data over three years reduces the impact of weather variation on

[16] Company response to OPC Q5008 (c)(viii).
[17] Q5008_Lateral Info a ($10.272 million) and Q5008_Lateral Info b ($11.534 million).

service interruption frequency.). Thirty-nine projects were placed into service on circuits for which reliability data was available in 2022.[18]

Then, I examined the frequency of service interruptions (System Average Interruption Frequency Index, or SAIFI) for circuits[19] on which lateral reconductoring projects were completed in 2022. I averaged service interruption frequency three years pre-project and three years post-project. The pre-project and post-project averages for the circuits on which lateral reconductoring projects were completed in 2022 are presented in the following chart:

	Average SAIFI
SAIFI 2019-2021 on 39 circuits with lateral projects 2022	1.16
SAIFI 2023-2025 on 39 circuits with lateral projects 2022	1.33

As indicated, service interruptions on the circuits on which lateral reconductoring projects were completed in 2022 increased post-project. This increase indicates the reliability improvements delivered by EMM's lateral reconductoring program are unlikely to justify the cost. It also indicates that decisions to reconductor laterals as suggested by software that uses subjective scoring mechanisms over which EMM has no control,[20] and by software projections of unvalidated accuracy,[21] are imprudent decisions.

[18] Q5008_Lateral Info 'a' and Q5008_Lateral Info 'b'.
[19] Q2006_CONF-EMM_CIRCUIT_DATA_2019_2025.
[20] Company response to OPC data request 2020.
[21] There is an outstanding request for EMM to provide any validation studies completed on the accuracy of the AssetLens software's reliability improvement projections.

Recommendation

Q. What is your recommendation?

A. Based on the preceding discussion, I believe EMM's decisions to reconductor laterals were imprudent. I recommend that the Commission disallow $21.806 million in lateral reconductoring program costs since the Company's last rate case.

Q. Please summarize your basis for your proposed disallowance?

A. The basis for my recommended proposed disallowance is as follows:

1) Despite discovery, I found no evidence that EMM's lateral reconductoring projects were required for safe and adequate service, such as might be available through test or inspection results. I conclude that this means that the projects were discretionary;

2) Despite discovery, I found no evidence that the discretionary lateral reconductoring projects were likely to deliver reliability improvements of sufficient customer value to exceed costs; and

3) My analysis of 39 projects completed in 2022 indicates that the customer value of reliability improvements secured from the lateral reconductoring program are unlikely to exceed customer costs. I did not detect any reliability improvements on circuits on which such projects were completed.

IV. EMM's SUBSTATION EQUIPMENT REPLACEMENT PROJECTS

Q. Would you please preview this section of your testimony?

A. In this section of testimony I describe four reasons for recommending disallowances of EMM's substation equipment replacement projects. These reasons include the imprudence of EMM decisions to A) Purchase redundant power transformer spares (i.e., more than one spare); B) Replace rather than rebuild transformers; C) Replace transformers without adequate justification; and D) Replace circuit breakers without adequate justification. Recommended disallowances for substation replacement projects totaling $29.4 million, broken out by reason and by year placed into service, are presented in the table below.

Substation Projects ($ in million)	2022	2023	2024	2025	2026	Totals
Redundant Transformer Spares	-	-	1,571.4	1,931.0	-	3,502.4
Transformers Replaced vs. Rebuilt	2,052.0	4,474.7	1,421.9	-	-	7,948.6
Unsupported Transformer Replacement	2,374.7	3,512.2	2,990.6	-	3,995.6	12,873.1
Unsupported Circuit Breaker Replacement	-	-	2,700.0	2,400.0	-	5,100.0
Substation Project Totals	4,426.7	7,986.9	8,683.9	4,331.0	3,995.6	29,424.1

A. Purchase of redundant power transformer spares

Q. Is the purchase of spare power transformers prudent?

A. It can be. Given that power transformer failure rates are so low, and given that power transformers are so costly, prudency suggests a limit as to how many spare power transformers a utility should keep in inventory. But certainly, maintaining some number of spare power transformers in inventory is prudent.

There are a few factors to keep in mind when determining the optimal size of spare transformer inventory. One factor is the count of transformers of various specifications a utility has installed. Transformers vary by input voltage (known as the 'high side' of a transformer), output voltage (known as the 'low side' of a transformer), capacity, and other factors, and are not always interchangeable. Another factor is the number of mobile transformers that a utility has available to put into service temporarily when needed; the more mobile transformers a utility has, the smaller the spare transformer inventory should be.

Q. Is the size of EMM's spare power transformer inventory appropriate?

A. I did not examine EMM's spare power transformer inventory and so have no perspective on that, other than to note the Company has two mobile transformers.[22] Given EMM's size, I would expect a single mobile transformer to be enough; with two mobile transformers, the overall need for EMM to maintain spares in inventory is certainly reduced. However, since the last rate case, EMM has increased its spare power transformer inventory, and I did examine these additions.

Q. Were EMM's decisions to add spare transformers to its inventory since the last rate case prudent?

A. Not all of them, no. I identified two instances in which EMM appeared to add not just one, but two spare power transformers of the same specification. Given the rarity of power transformer failures, and the high cost of power transformers, I have never heard of a utility maintaining more than one spare of a particular specification. The cost of these second

[22] Q5023 a_CONF_Substation Plant Additions, lines 6 and 7.

spare power transformers over the initial spares at these two substations totaled $3.5 million,[23] and I recommend these costs be disallowed for lack of prudence.

B. Replacing Rather Than Rebuilding Power Transformers

Q. Please explain your concern that EMM is replacing rather than rebuilding power transformers.

A. In my experience it is a relatively common practice to send transformers off to specialty remanufacturers to be rebuilt. The lead times are shorter than securing new transformers, and the costs are about half. In my experience, rebuilt transformers are as good as new, and can be expected to provide safe and reliable service for as long as a new transformer would. When transformer performance on objective diagnostic tests fails to respond to repair efforts, rebuilding is a cost-effective alternative to replacing with new.

Q. Does EMM consider rebuilding as an alternative to buying new?

A. It's possible, but from information secured in discovery, it does not appear that EMM employs this option very often, if at all. In my review of substation power transformer replacements completed since EMM's last rate case, four transformers EMM replaced appeared to me to be candidates for rebuilding instead of replacement. The cost of these projects totaled $15.9 million.[24] Since rebuilding costs half as much as new, my recommended cost disallowance is 50% of this amount, or $7.95 million.

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[23] Q5023 a_CONF_Substation Plant Additions. Spreadsheet lines 9 (and 10) and 25 (and 26).
[24] Q5023 c_CONF_ Transformers. Spreadsheet lines 6, 21, 28, and 32.

C. Unsupported Power Transformer Replacements

Q. Please explain your concern that several EMM transformer replacement projects are unsupported.

A. It is my understanding that in Missouri, utilities bear the burden of proving that decisions to spend capital were prudent. I identified decisions to replace five power transformers for which support was inadequate, and recommend the Commission disallow the cost of these projects.

Q. Can you explain why the support EMM provided for these projects was insufficient?

A. There are a number of reasons that vary by project. In one project, EMM decided to replace a transformer simply because the transformer had been rebuilt twenty years earlier.[25] As indicated above, rebuilt transformers are generally good as new, and can be expected to deliver safe and reliable service for as long as a new transformer. Twenty years of operation is nothing for a new or rebuilt transformer. I note that one project on the Company's project list addressed a transformer installed in 1948, making it 78 years old in 2026,[26] and I don't perceive this to be particularly unusual. I recommend the $3.5 million cost of this project be disallowed.

In two other projects, EMM reported the presence of Acetylene gas in the transformer's oil.[27] The presence of Acetylene gas in transformer oil is evidence of arcing, and arcing can cause transformer failure. However, arcing can often be traced to relatively

[25] Q5023 c_CONF_ Transformers. Spreadsheet line 5.
[26] Q5023 c_CONF_ Transformers. Spreadsheet line 35.
[27] Q5023 c_CONF_ Transformers. Spreadsheet lines 14 and 15.

simple causes, such as loose connections between two components inside the transformer. Loose connections can be corrected simply by draining the transformer, identifying the loose connections, tightening them, and replacing the oil. The prudent course of action upon encountering power transformer issues is to attempt a low cost action first, such as repair, before proceeding to higher cost actions, such as replacement. In these two cases, EMM appeared to proceed directly to replacement. I therefore recommend the cost of these two projects, totaling $2.991 million, be disallowed.

In a fourth transformer replacement project, EMM justified its decision to replace a transformer by noting that the transformer's load tap changer was experiencing maintenance issues.[28] Load tap changers are separate and distinct components of a transformer, and can be repaired or replaced without replacing the entire transformer. As a result, I recommend the $3.996 million cost of this project be disallowed.

In the fifth transformer replacement project EMM replaced a transformer that was only 19 years old at the time.[29] Of interest to the Commission, the justification provided was "upper management decision." I am recommending the $2.375 million cost of this project be disallowed.

[28] Q5023 c_CONF_ Transformers. Spreadsheet line 29.
[29] Q5023 c_CONF_ Transformers. Spreadsheet line 42.

D. Unsupported Circuit Breaker Replacements

Q. Did EMM also fail to support some circuit breaker replacement decisions?

A. Yes. EMM appears to have embarked on a program to replace all oil-filled circuit breakers, and I am concerned that such programs are not cost-effective. Despite my reservations, I do not recommend the cost of oil-filled circuit breaker replacement projects be disallowed. Instead, I identify only the most egregiously excessive circuit breaker replacement projects for disallowances. Of 28 circuit breaker replacement projects totaling $34.9 million, two stood out to me. In one $2.7 million project, six circuit breakers were replaced despite the fact that none was older than 19 years.[30] In another project of $2.4 million, switchgear (similar to circuit breakers) installed in 1993 and 2001 were replaced,[31] making them just 31 and 23 years old, respectively. The Company offered no justification for replacing circuit breakers of such comparatively young ages.[32]

Q. Why do you consider 19, 23, or 31 years a comparatively age for circuit breakers and switchgear?

A. I note that the Stipulation the Commission approved in EMM's last rate case authorizes the Company to depreciate distribution substation equipment (FERC Account 362) at a rate of 1.92% per year,[33] which is equivalent to an expected useful life of 52.08 years.[34] To replace such comparatively young equipment, I would expect the Company to provide

[30] Q5023 d_CONF_Breakers. Lines 36-41.
[31] Q5023 d_CONF_Breakers, Lines 43-48.
[32] Q5023 d_CONF_Breakers. Cells I36 and I43.
[33] Case No. ER-2020-0129. Stipulation and Agreement dated August 30, 2022. Exhibit 3, page 7.
[34] 100% divided by 1.92% = 52.08 years.

extensive justification. Observing none, I recommend the $5.1 million cost of these circuit breaker/switchgear replacement projects be disallowed.

V. REVIEW AND CONCLUSION

Q. Please summarize your testimony.

A. After the Introduction, Section II provided an overview of standards employed by utilities in conducting objective equipment tests and inspections. These tests and inspections are critical to providing safe and reliable service, but can also help avoid replacing equipment unnecessarily. Section III described EMM's lateral rebuild program and provided support for my recommendation to disallow $21.8 million in costs due to a lack or prudent decision making. Section IV described EMM's substation equipment replacement projects and provided support for my recommendations to disallow $29.4 million in costs due to a lack of prudent decision making.

Q. Do you have any concluding comments for Commission consideration?

A. Yes. I recognize that one popular screen for whether a project is prudent or not is to apply the 'used and useful' standard. That is, is the equipment installed through the project used and useful in delivering service to customers? I suggest the used and useful standard is inadequate when considering discretionary projects involving the replacement of equipment that was already used and useful, and deemed through objective inspections and tests to be sufficiently sound to provide safe and reliable service. I submit that in such instances a different standard is needed, which is that the value delivered to customers from such replacements must exceed the cost to customers of such replacements. This is precisely why I endorse Mr. Alvarez's recommendation that the Commission require risk-informed benefit-cost analyses be completed for all discretionary capital projects and programs in excess of $1 million, and I hope the Commission perceives the inherent logic of that recommendation.

Additionally, I wish to thank the Commission in advance for reviewing this testimony and considering my perspectives, observations, and recommendations.

Q. Does this conclude your testimony?

A. Yes, it does. However, given that responses to highly relevant data requests were not received in time to review and include in this testimony, I report that Mr. Alvarez's and my review of the Company's transmission, distribution and other plant capex projects is ongoing. In particular, I note that a complete response to OPC DR 5004, concerning at least $300 million in jurisdictional transmission capital projects and submitted to EMM on April 21, had still not been received in time to be evaluated for this testimony. I thus reserve the opportunity to append this testimony as necessary and appropriate.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

AFFIDAVIT OF DAVE SHAPLEY

STATE OF DELAWARE)
) ss
COUNTY OF SUSSEX)

Dave Shapley, of lawful age and being first duly sworn, deposes and states:

1. My name is Dave Shapley. I am a Consultant with Wired Group, having retained its principal place of business at PO Box 620756, Littleton, CO 80162. We have been retained by the Missouri Office of the Public Counsel in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes is my direct testimony.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

Dave Shapley

Subscribed and sworn to me this 29th day of June 2026.

Terry Lynn Watson
Notary Public

My Commission expires
11/12/2027

TERRY LYNN WATSON
NOTARY PUBLIC
STATE OF DELAWARE
My Commission Expires November 12, 2027