Public Version

Exhibit No.:	
Issue:	Reliability, Storm Reserve
Witness:	Bruce Akin
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Evergy Missouri West
Case No.:	ER-2022-0130
Date Testimony Prepared:	January 7, 2022

MISSOURI PUBLIC SERVICE COMMISSION

CASE NOS.: ER-2022-0130

DIRECT TESTIMONY

OF

BRUCE AKIN

ON BEHALF OF

EVERGY MISSOURI WEST

Kansas City, Missouri
January 2022

DIRECT TESTIMONY

OF

BRUCE AKIN

Case No. ER-2022-0130

Q: Please state your name and business address.

A: My name is Bruce Akin. My business address is 818 S. Kansas Avenue, Topeka, Kansas.

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

A: I am employed by Evergy Metro, Inc. I serve as Vice President, Transmission and Distribution ("T&D") for Evergy Metro, Inc. d/b/a as Evergy Missouri Metro ("Evergy Missouri Metro"), Evergy Missouri West, Inc. d/b/a Evergy Missouri West ("Evergy Missouri West"), Evergy Metro, Inc. d/b/a Evergy Kansas Metro ("Evergy Kansas Metro"), and Evergy Kansas Central, Inc. and Evergy South, Inc., collectively d/b/a as Evergy Kansas Central ("Evergy Kansas Central") the operating utilities of Evergy, Inc.

Q: Who are you testifying for?

A: I am testifying on behalf of Evergy Missouri West. I will refer to Evergy Missouri Metro and Evergy Missouri West collectively as "Company" or "Evergy" in my testimony.

Q: What are your responsibilities?

A: I am responsible for oversite of construction, operation, and maintenance functions for T&D throughout all of Evergy's jurisdictional territories including the execution of T&D projects identified as part of Evergy's capital plan, as well as all customer outage restoration field activities.

Q: Please describe your education, experience and employment history.

A: I received a Bachelor of Business Administration degree with a major in Accounting from Washburn University in 1987 and a Master's Degree in Business Administration in 1998. I have worked for Evergy, including one of its predecessors, Westar Energy, for 34 years with broad experience across many functions in both administrative areas and utility operations. My present position is Vice President, Transmission and Distribution, which includes responsibility for all transmission, substation and distribution plant and operations.

Q: Have you previously testified in a proceeding at the Missouri Public Service Commission ("MPSC" or "Commission") or before any other utility regulatory agency?

A: Yes, I have previously testified before the MPSC and the Corporation Commission for the State of Kansas ("KCC").

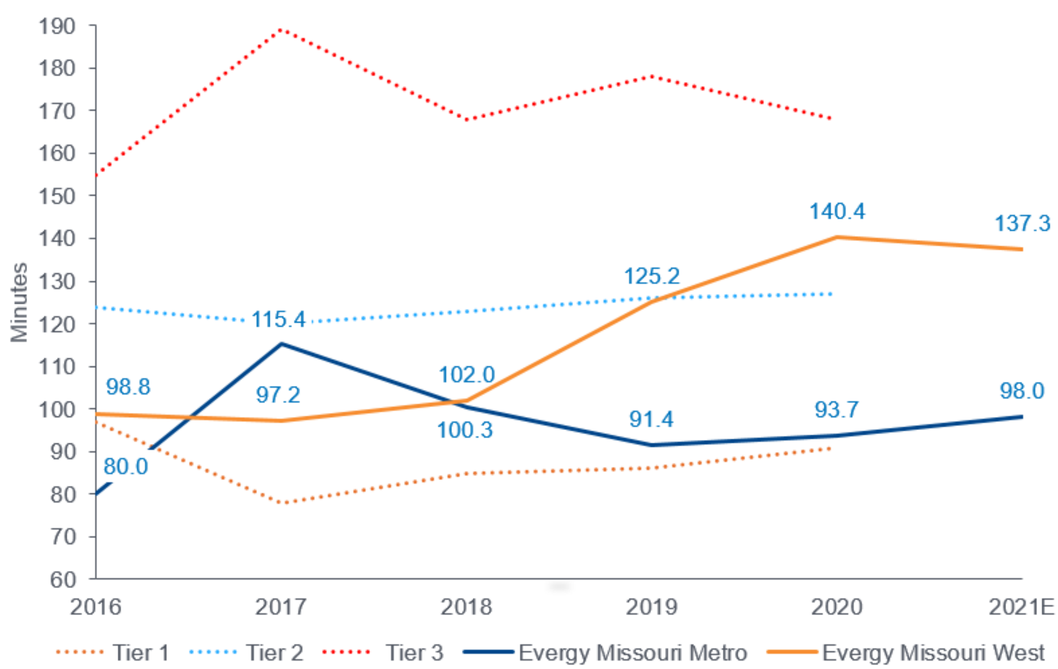
Q: What is the purpose of your testimony?

A: I will discuss the current state of Evergy's T&D infrastructure and reliability performance. Then I will describe Evergy's processes to prioritize and execute T&D capital improvement projects along with anticipated benefits that customers can expect to receive. I will also discuss the benefits of establishing a storm reserve.

Q: How is Evergy's T&D system currently performing?

A: From a reliability metric perspective, Evergy and the companies that formed Evergy have a track record of solid performance. Figure 1 illustrates consistent reliability performance within Tier 2 of peer utilities based on System Average Interruption Duration Index ("SAIDI"). SAIDI averages the total of all customer interruption durations across the total number of customers served and is the most common reliability indicator used in the electric utility industry.

Figure 1 – Historical IEEE Normalized SAIDI Comparison



Q: What drives reliability performance?

A: There are a number of factors. The largest factors include weather, vegetation management, age and asset condition, and response time. While we cannot control the weather, through proper vegetation and asset management, along with limiting the duration of outage events, we can attempt to mitigate the impact of weather and other causes of outages on our system.

Q: Describe Evergy's vegetation management strategy.

A: In the broadest sense, Evergy's vegetation management strategy is one of continual improvement through a proactive focus on reliability, safety, productivity, and regulatory compliance. We deploy program strategies centrally and tailor our approach based on regional variation across the service territory. Management decisions are informed through extensive data collection specific to vegetation conditions as part of our circuit assessments and trimming operations; allowing us to optimize key elements of the program such as workload, labor needs, finances, customer impact, etc. on a year over year basis. Additionally, the data collection allows for analyses of contract labor productivity and efficiency that we utilize for performance-based incentives and penalties.

Q: What sort of improvements have recently been made to vegetation management at Evergy?

A: Two recent examples of programmatic improvements specific to vegetation management are the deployment of a digital, geospatially based work management software in 2020, and the completion of a large data analytics project focused on vegetation outage risk modeling. This work management software allows for more precise and granular data capture as well as a move to a paperless work stream. The vegetation risk modeling project resulted in vegetation induced outage risk scores at the circuit and sub-circuit level across the distribution network. It is our aim to refine existing vegetation assessments and trimming operations by combining the geospatial capabilities of the work management software with risk mapping produced in the data analytics project.

Q: Have Evergy Missouri Metro and Evergy Missouri West opted into Plant In Service Accounting ("PISA")?

A: Yes. After the legislature passed Senate Bill 564 on May 16, 2018 (signed by Governor June 1, 2018), Evergy Missouri Metro and Evergy Missouri West filed to adopt PISA on December 31, 2018. We have been actively investing in our system with a focus on reliability and grid modernization under capital investment plans that have been provided to stakeholders and the Commission annually in February with our latest capital investment plan filed on February 26, 2021.

Q: Please provide summarizing comments regarding your team's processes and approach to capital asset management planning?

A: We take seriously our obligation to be good stewards of customer dollars in strategically investing in our system to provide the safe and reliable service our customers deserve and expect. With that in mind, I will describe in more detail below a significant number of targeted programmatic system investment areas and the range of benefits they provide. I will also describe our process for evaluating and prioritizing specific project investments beyond the programmatic investments. Our objectives are to invest the right dollars, in the right assets at the right time through data and experience driven analysis to achieve optimal outcomes for reliability, resiliency and customer experience.

Q: Why are T&D capital investments in the public interest and necessary in addition to effective vegetation management practices?

A: A safe, reliable electric system is expected by our customers and stakeholders. As the electric system ages, modern upgrades and improved grid resiliency need to be built into the system to meet those expectations.

Q: What is grid resiliency?

A: Grid resiliency refers to a utility's ability to recover quickly from damage, when it does inevitably occur. "Resiliency measures do not prevent damage; rather they enable facilities to continue operating despite damage and/or promote a rapid return to normal operations." Edison Electric Institute, "Before and After the Storm" (January 2013).

Q: What is system hardening?

A: System hardening refers to replacing assets with those that are more likely to withstand major storm impacts such as high wind or ice accumulation.

Q: What are some types of equipment typically used for system hardening and grid resiliency?

A: There is a range of investments; everything from simply replacing existing obsolete equipment with equipment built to modern standards, to upgrading switches for automation with real time intelligence that communicate condition and circumstances. A one-size-fits-all solution does not exist. What we deploy depends on the circuit, the load, the number of customers served by it, and the nature of the service they are taking.

Q: What is Evergy's asset management strategy?

A: Evergy's asset management strategy is focused on identification of high impact assets that can be maintained or replaced prior to failure to minimize or prevent customer outages. Ranking methodologies have been developed based on data and analytics to support the identification of lines, circuits, laterals, substations, and individual assets at risk. These methodologies utilize asset data - such as age and manufacturer model; asset condition data – from inspections and testing; historical outage information; and various other inputs. The risk scores are used to prioritize individual asset replacement and as an input to prioritize larger capital projects.

Q: What types of asset management programs exist for distribution assets?

A: Within Distribution there are multiple programs that support our asset management strategy.

- The Lateral Improvement Program targets aging infrastructure, excessive lateral outage events, and customer complaints generated from these events. In 2019, a risk-based investment model (AssetLens) was developed to identify overhead distribution primary conductor and poles for replacement in Missouri. The model uses several sources of data, including asset characteristics, asset condition, and historical outage information. In 2021, the risk-based investment model was expanded to include underground and network equipment across all areas.
- The Wood Pole Life Extension and Replacement Program is a capital program focused on wood pole replacement or pole reinforcement based

on the results from the annual intrusive wood pole inspections. These inspections are required per the MPSC on a 12-year cycle. The intrusive inspection includes ground line inspection via soil excavation, bore/plug, and chemical treatment. This program improves the reliability and resiliency of our system by replacing or reinforcing poles at an increased risk of failure.

- The Proactive Cable Replacement/Rehabilitation Program targets direct buried underground residential distribution ("URD") primary cables that are shown to have elevated risk of failure based on historical cable failure analysis. The program targets high risk URD cables which are identified based on age, condition, performance among other factors. High risk cable segments are evaluated using partial discharge testing to determine the cable's condition. Based upon the results of these tests, cable segments are selected to be replaced. Replacement of these cable segments prevents failures on the system and reduces customer outage minutes.
- The Manhole Vault Top Replacement Program focuses on degraded underground manhole ceilings identified during the detailed manhole inspections. The manholes are inspected on an 8-year cycle as mandated in Missouri by the MPSC. Replacement of these manhole vault tops prevents damage to installed underground electrical equipment and reduces public safety concerns.
- The Network Rehabilitation Program uses Evergy craft knowledge and results from the detailed manhole inspections mandated in Missouri by the

MPSC to identify structures for replacement or remediation. Evergy uses an independent contractor who is an expert in manhole restoration and high-voltage electrical repairs. The work is prioritized based on greatest risk to worker/public safety and impact to customer reliability.

- The High Outage Count Customers Program, also known as the "Worst Performing Circuit" Program, is a circuit-based program addressing service reliability issues associated with customers experiencing abnormally high outage counts, based upon MPSC regulatory standards. Evergy identifies high outage count customers, investigates their outage events, and develops solutions to improve their circuit reliability. Analyzing annual outage management system records and field ultrasound inspection results assists in understanding root causes and the ensuing action required to mitigate future incidents.
- The CEMI Improvement Program focuses on making repairs and improvements for customers experiencing 6 or more interruptions over a 12-month period. Interruption cause code data is analyzed to determine the root causes and appropriate corrective actions required to mitigate future incidents. This program was developed and rolled out in 2021 in the Missouri jurisdictions.
- The Feeder Improvement Program is a new program starting in 2022. This program will target feeder segments identified as being high risk through data driven tools like AssetLens. Corrective actions that will be considered will include undergrounding, rebuilding and reconductoring.

Q: What types of asset management programs exist for substation assets?

A: Our substation asset management strategy is focused on the key asset types of transformers, breakers, and station batteries. For each of these asset types, unique risk scores have been developed based on inspection data, testing data, asset characteristics, and criticality information. As an example, for substation transformers the risk score is primarily driven on dissolved gas test results and trends identified over multiple test results. Specific gases monitored include acetylene, methane, hydrogen, and the carbon dioxide to carbon monoxide ratio. These risk scores are used to identify assets at increased risk of failure. The identified assets are evaluated and prioritized for replacement. Replacement of these assets prior to failure minimizes or eliminates potential outages to customers.

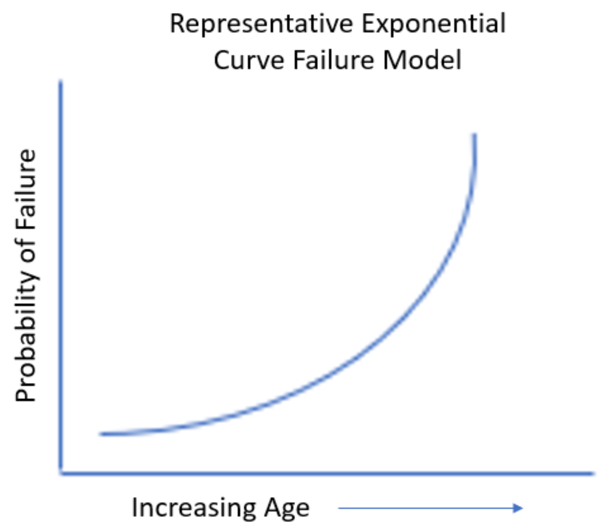
Q: What types of asset management programs exist for Transmission assets?

A: There is separate program for wood pole inspections that is very similar to the program for distribution poles.

Q: How does asset age factor into the previously mentioned asset management programs?

A: Expected asset lives are gathered from a variety of industry sources and input in the asset management programs. A common characteristic of all asset classes is that as they age the rate of failure increases dramatically at a nearly exponential rate. An example of this 'hockey stick' failure curve can be seen in figure 2.

Figure 2



Q: What can be learned from the failure curves of various asset classes?

A: To prevent reliability issues associated with aging infrastructure we should replace assets at a pace that stays ahead of the failure curve of each respective asset.

Q: Have historical asset replacement levels been adequate to address system needs related to aging infrastructure?

A: No. In Missouri, the pace of replacement of aging assets was not keeping up as evidenced by the two tables below which show the average age for major assets for T&D and compared to expected life of such assets.

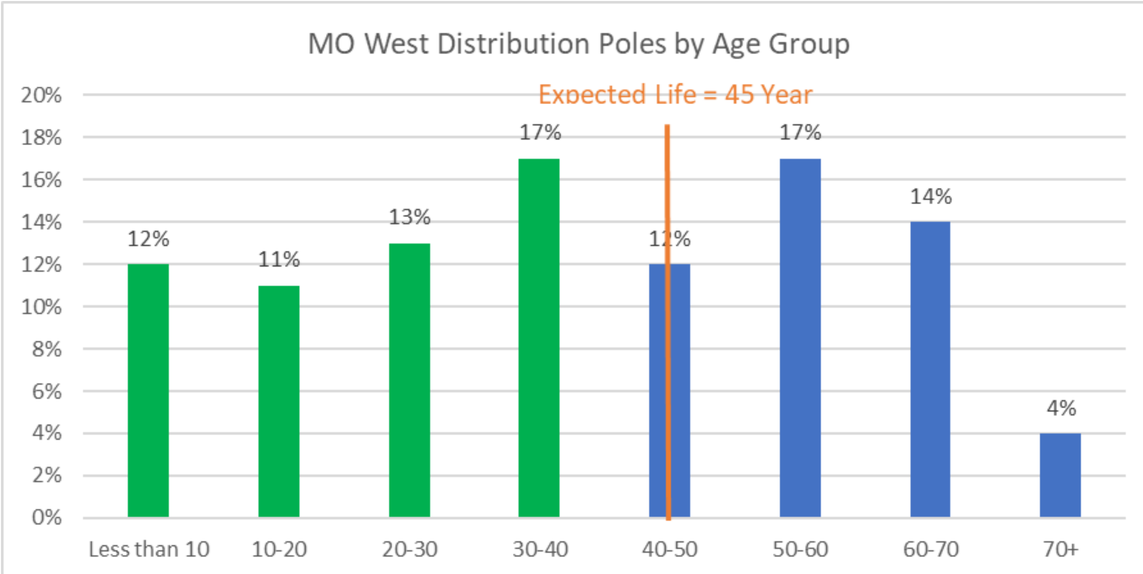
Table 1 - Transmission Assets Age Comparison

Key Asset Types	Average Age (years)		Expected Life (years)
	MO West	MO Metro	
Wood Poles	44	43	40-45
Overhead Conductor	39	34	50
Substation Transformer - Non-LTC	31	42	45-50
Circuit Breakers - Air	41	43	40
Circuit Breakers - Oil	52	54	40

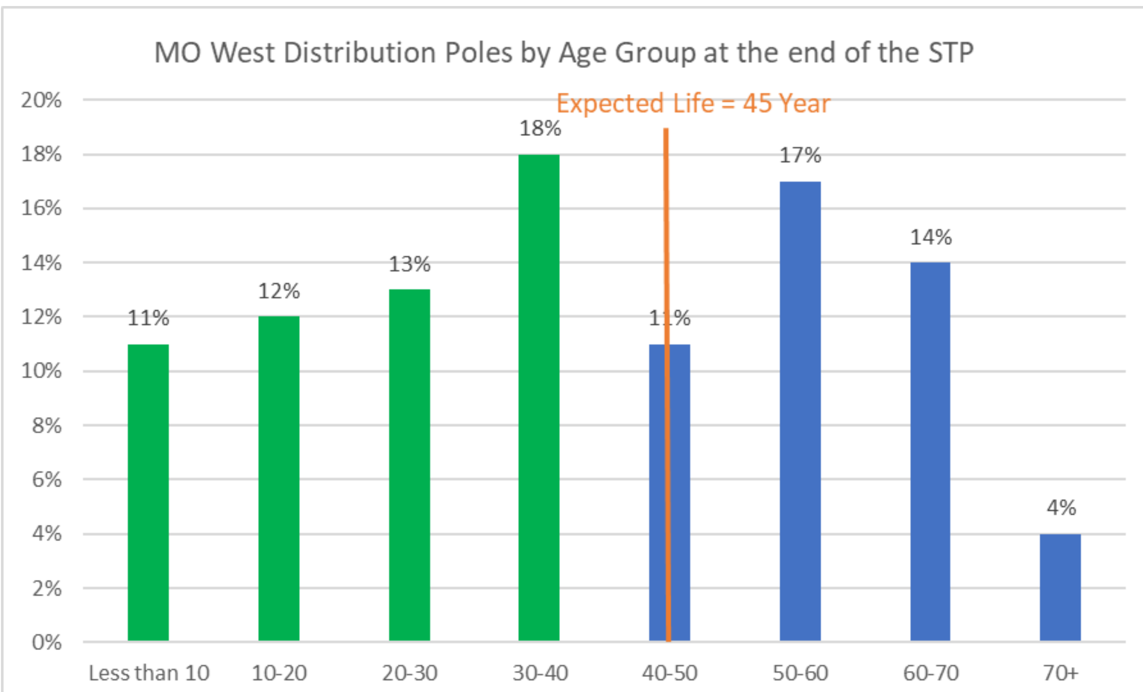
Table 2 - Distribution Assets Age Comparison

Key Asset Types	Average Age[1] (years)		Expected Life (years)
	MO West	MO Metro	
Overhead Conductors	38	37	30
Underground Conductors	29	22	30
Poles	37	39	40-45
Line Transformers	35	34	20
Padmount Transformers	33	25	20

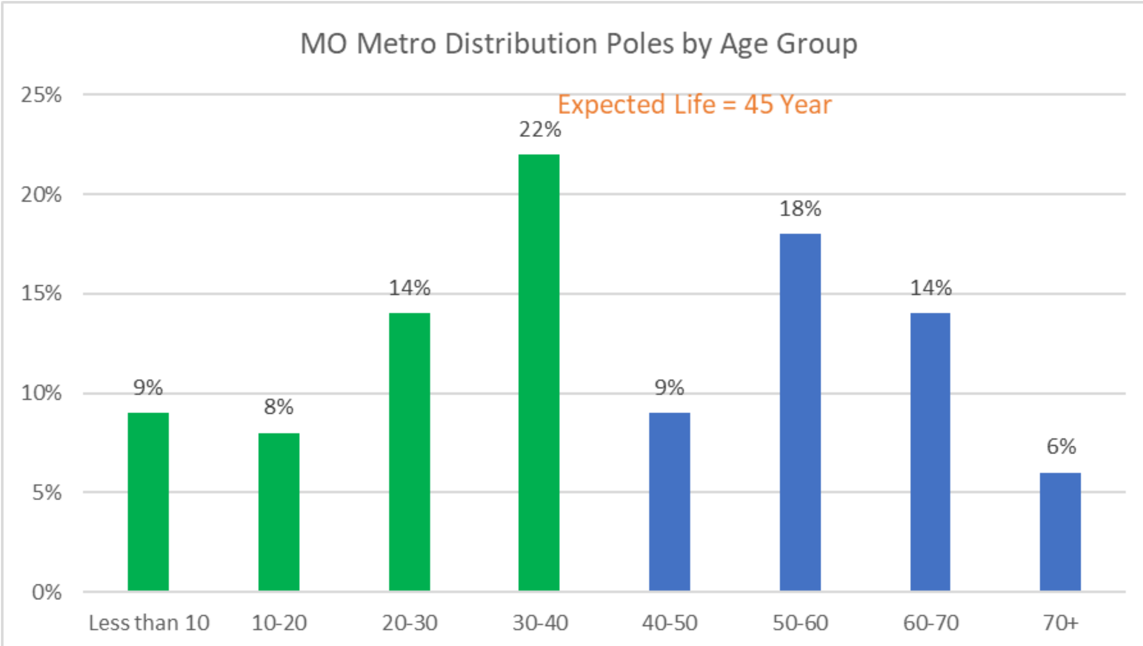
What the table above shows is that the average age of assets is nearing or exceeding expected life of such assets. Currently, approximately 47% of Evergy Missouri Wests's and 47% Evergy Missouri Metro's distribution poles are either nearing or exceeding their expected useful life. We expect the rate to drop to 46% by the end of 2024 as shown in the figures below.


MO West Distribution Poles by Age Group
Expected Life = 45 Year
20%
18%
16%
14%
12%
10%
8%
6%
4%
2%
0%
12%
11%
13%
17%
12%
17%
14%
4%
Less than 10
10-20
20-30
30-40
40-50
50-60
60-70
70+

1


MO West Distribution Poles by Age Group at the end of the STP
Expected Life = 45 Year
20%
18%
16%
14%
12%
10%
8%
6%
4%
2%
0%
11%
12%
13%
18%
11%
17%
14%
4%
Less than 10
10-20
20-30
30-40
40-50
50-60
60-70
70+

2


MO Metro Distribution Poles by Age Group
Expected Life = 45 Year
25%
20%
15%
10%
5%
0%
9%
8%
14%
22%
9%
18%
14%
6%
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10-20
20-30
30-40
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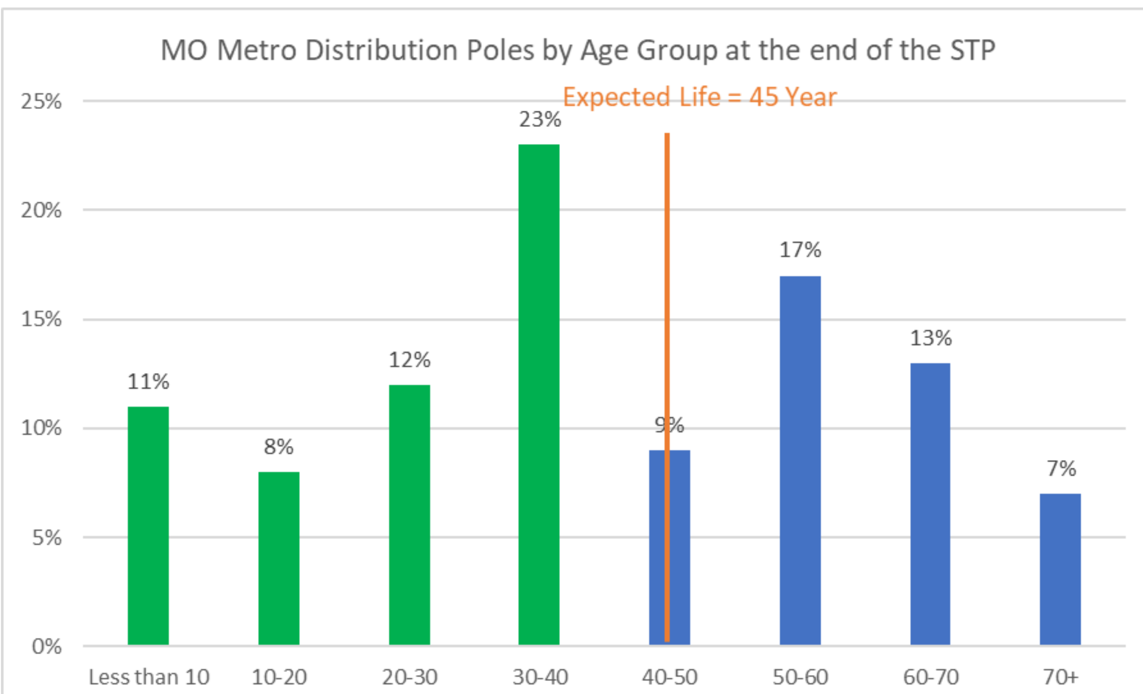
50-60
60-70
70+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Expected Life = 45 Year
25%
20%
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11%
8%
12%
23%
9%
17%
13%
7%
Less than 10
10-20
20-30
30-40
40-50
50-60
60-70
70+

Q: Have customers benefitted from the historical asset replacement levels in Missouri by deferring asset replacements?

A: Yes, previous replacement levels have benefited customer rates by forestalling needed investments at some expense of reliability. However, the backlog of asset replacements is not sustainable at previous levels without a much larger negative impact on customer reliability as failure curves tend to increase exponentially over time.

Q: Will replacing aging infrastructure have a direct impact on reliability performance?

A: Yes, it will have a direct reliability impact on circuits or sections of the grid where work occurs, but it will not necessarily be reflected in a system-wide decrease of outage minutes experienced until we are much further down the road with our asset replacement programs. The majority of the benefit from asset replacements is to prevent future outages from happening that are not currently occurring on the system by replacing the assets right before the end of their useful life.

Q: What other types of capital investments is Evergy implementing to improve system performance?

A: In addition to programmatic asset replacement system improvements, specific projects are also prioritized and budgeted which focus on increasing system resiliency through: the addition of contingency options, ensuring sufficient capacity to meet expected future loads, and implementation of automation and communicating devices. These specific projects often also include replacement of aged assets, but do so as part of a larger, geographically-targeted project (as opposed to programmatic asset replacement which is prioritized across the service territory).

Q: How are these specific projects prioritized as part of Evergy's budgeting process?

A: As mentioned above, these projects can have a variety of potential benefits, from improving system resiliency through the addition of contingency options to replacing aged assets. As a result, these projects are scored across several differently weighted value dimensions to create an overall score which can be used to gauge the relative benefits provided by various multi-faceted projects. The benefits categories used in calculating these scores are outlined below:

- Customer Reliability: Within Customer Reliability, score is based on a composite of: Asset Criticality, Health and Risk, Power Quality Impacts, Risk of Potential Overload, and Availability of Contingency. Transmission projects also incorporate the benefits of relieving congestion.
- Public Impact: Includes potential benefits for critical customers or mitigation of public impact risks (e.g., environmental events).
- Employee Benefit: Benefits in reducing employee safety risk or improving workforce productivity.
- Growth & Technology: Benefits in implementing new, strategic technologies (e.g., automation) or supporting a strategic initiative in some way (e.g., conversion to standard voltages).

- Financial – Net Present Value ("NPV") of Revenue Requirements & NPV Net Income: These financial metrics are still being refined and do not currently impact the relative score of distribution projects because they essentially offset each other. Fundamentally, they are meant to represent the customer cost impact (revenue requirement) and the net income impact of capital expenditures.

Q: What are 'contingency options' in the context of Evergy's T&D system?

A: Contingency options are system configuration changes that can be implemented in the event of an outage to restore service without causing an overload for an effected area. Examples of contingency projects include, but are not limited to, building new ties between circuits, adding new switching options and capacity within substations, increasing circuit or line segment capacities to offer more switching options, and installing a new substation to provide an alternate voltage source for a particular area. The availability of contingencies is assessed through annual planning evaluations and budget projects are identified for prioritization as an output of these evaluations.

Q: What are the benefits of contingency-based projects to the T&D capital investment plan?

A: While adding contingencies does not mitigate the risk of outages occurring, they make the system more resilient and better able to respond, often reducing the duration of outages. Contingencies can often be added at a lower cost than a full rebuild or broad asset replacements.

Q: Are there other ways that Evergy's capital investment plan can impact the duration of outages?

A: In addition to traditional asset replacement and specific budget projects we have initiatives to install new communicating devices (ex: reclosers) that will integrate with existing and future software systems to provide real-time visibility into system performance as well as reduce or in some cases eliminate outage times experienced by our customers by automating some restoration activities.

Q: How do customers benefit from Evergy's investments in infrastructure?

A: There are a variety of benefits including lower operating costs, enhanced grid resiliency, upgraded system visibility for quicker outage response times, improved asset data quality to enable predictive maintenance (i.e., systemically replace aging infrastructure before the end of useful life), more flexibility to incorporate distributed generation into the system, meeting evolving expectations related to increasingly sensitive customer equipment and power quality requirements, and reducing energy losses experienced in older equipment.

Q: Has Evergy had any third party review of its current capital investment strategy?

A: We engaged the UMS Group, a firm specializing in enterprise-level value creation, performance management solutions, and utility asset management, to study our capital plan. A copy of the study is attached as Schedule BA-1.

Q: What were the results of the study conducted by UMS Group?

A: UMS confirmed Evergy's capital investment levels and prioritization processes that are designed to deliver benefits to customers. An excerpt from its executive summary reads: "The Plan, as presented, will produce commensurate benefits within a reasonable timeframe, while appropriately addressing the major risks that could affect the Company's ability to provide safe, reliable and cost-effective service to its Kansas and Missouri customers. Further, it positions Evergy for the impending energy transition that is expected to occur over the next decade, assuring a strong foundation with sufficient flexibility to manage through most foreseeable uncertainties."

Q: What benefits did UMS Group determine would be realized from Evergy's latest T&D capital investment plan?

A: UMS Group found reliability improvements, operational savings, and customer benefits, as summarized below in Table 3.

Q: How long does it take for the benefits listed in Table 3 to be realized?

A: There is generally a two to three-year lag between an increase in capital investment geared toward improving the delivery system and the actual realization of benefits. It should also be noted that UMS Group's study encompasses T&D infrastructure investment projects for fiscal years 2020 through 2024, of which only 24 months has been executed at the time of this filing. The calculated benefits in the table below only apply to assets impacted by the plan and does not consider overall system results.

Q: Are there any other benefits of Evergy's current capital plan?

A Yes, the current capital plan will have a positive effect on existing reliability levels by proactively replacing assets and hardening the system before components fail. Other benefits include operational efficiencies which consists of outage elimination savings and reduced reactive work savings. In addition, benefits include customer benefits which is made up of "Reduced Overtime Savings" and "Avoided Customer Interruptions Savings". All benefits are summarized in Table 3 below.

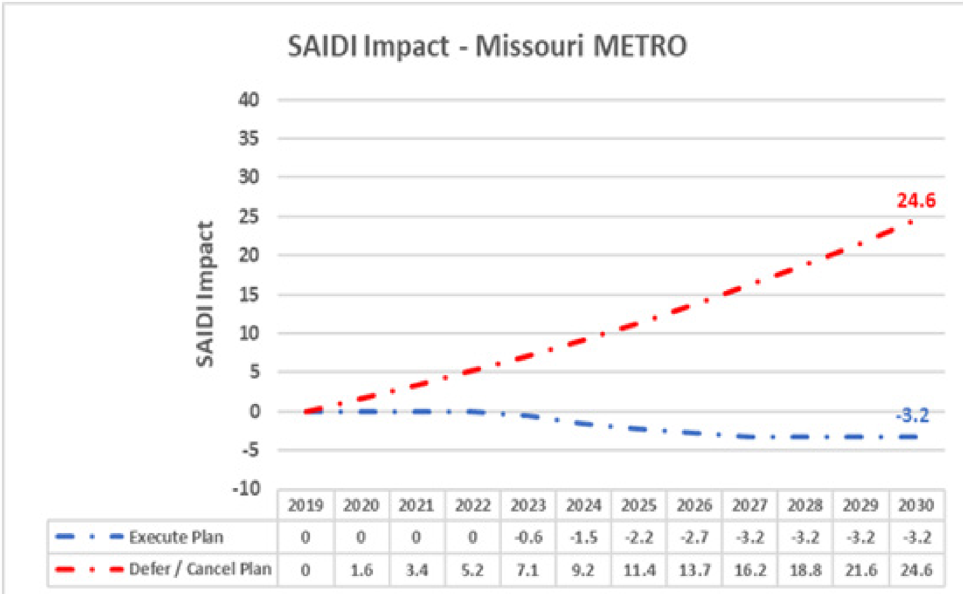
Table 3

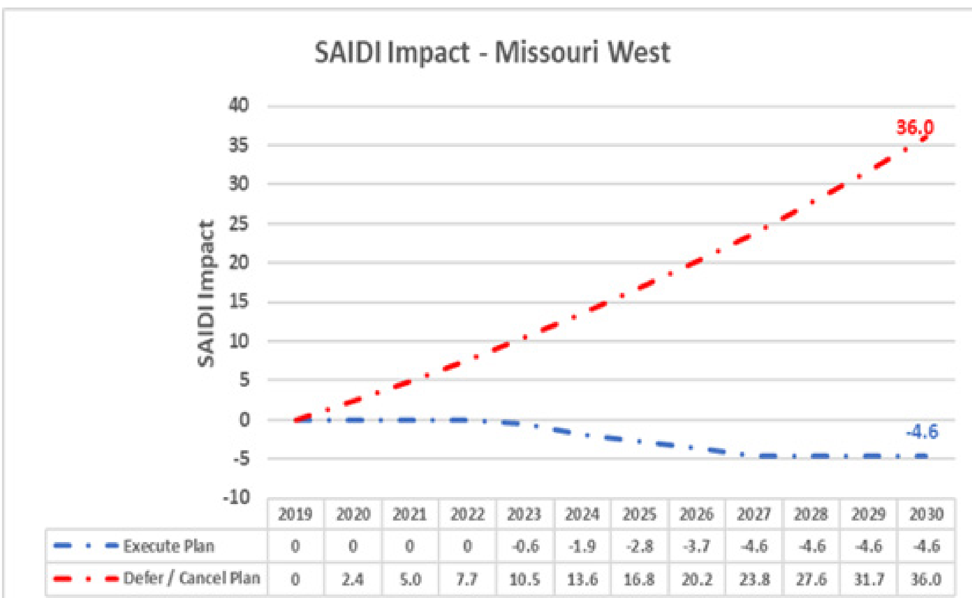
Category	Metric	End-of-Plan Incremental (Annual) Impacts (in millions)		
		Missouri Metro	Missouri West	Total
Operational Efficiencies	**Outage Elimination Savings**	$5.30	$8.80	**$14.10**
	Reduced Reactive Work Savings	$1.50	$1.70	**$3.20**
Customer Benefits	**Reduced Overtime Savings**	$4.20	$6.90	**$11.10**
	Avoided Customer Interruption Savings (DOE ICE Model)	$4.20	$7.10	**$11.30**
Total Operational Efficiencies and Customer Benefits		**$15.20**	**$24.50**	**$39.70**

Q: Is there a risk to the T&D system absent the increased spend in Evergy's capital plan?

A: Yes. If the current T&D capital plan were not in effect, both of Evergy's Missouri jurisdictions would have been at higher risk of experiencing a degradation of reliability compared to 2019 levels, according to UMS Group's analysis. The differences are shown in Figure 4.

Figure 2





Q: Were the T&D investments discussed in your testimony made consistent with Section 393.1400 RSMo. which allows certain utility investments to be deferred to a regulatory asset?

A: Yes, the T&D projects are qualifying electric plant. Please refer to Company witness Klote for more discussion regarding PISA requests in this case.

Q: Please describe the rationale for the storm reserve requested in this case?

A: A storm reserve is a systematic method to collect revenues from customers to be set aside to be used for extraordinary storm Operating & Maintenance ("O&M") expenses. Any non-labor O&M costs above $200,000 would be charged against the reserve. The adequacy of the reserve could be reviewed at each rate proceeding.

Q: How could a storm reserve benefit customers and the Company?

A: The storm reserve benefits customers by smoothing out major storm expenses year over year to be recovered in rates. This smoothing of storm expenses will create less rate volatility from rate case to rate case. The nature of storms create volatility in expense, and a reserve will help smooth these events in rates for customers. The Company receives a benefit from this mechanism through the fact that there is a smoothing of storm expenses from an operating perspective. By recording a levelized expense amount month over month creating a storm reserve when storm expenses occur they are able to be charged against this reserve creating less volatility in earnings year over year associated with these significant storm events.

Q: Do you have personal history operating with a storm reserve in place?

A: Yes, for many years and during the entirety of my time with Westar Energy, now doing business as Evergy Kansas Central we maintained a storm reserve and rates were set by the Kansas Corporation Commission supporting the maintenance of the storm reserve.

Q: In your experience, has the Evergy Kansas Central storm reserve been effective and operated as described?

A: Yes. We modeled the requested storm reserve in this case after the Evergy Kansas Central storm reserve. For many years we have found that the storm reserve operates as intended in smoothing the amounts requested from customers in rates while also providing the opportunity to smooth potential utility operating earnings volatility year-to-year that can result from variations in storm intensity.

Q: What is the proposed process associated with this request for Evergy in this case?

A: Please see the Direct Testimony of Company Witness Ronald Klote for a discussion on the establishment of the reserve, the management of the reserve and the plan to follow when the costs of storm damage exceed the storm reserve balance.

Q: Does this conclude your testimony?

A: Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Evergy Missouri West, Inc. d/b/a Evergy Missouri West's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2022-0130

AFFIDAVIT OF BRUCE AKIN

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Bruce Akin, being first duly sworn on his oath, states:

1. My name is Bruce Akin. I work in Topeka, Kansas, and I am employed by Evergy Metro, Inc. as Vice President, Transmission and Distribution.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Evergy Missouri West consisting of twenty-three (23) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Bruce A. Akin
____
Bruce Akin

Subscribed and sworn before me this 7th day of January 2022.

Anthony R. Westenkirchner
____
Notary Public

My commission expires: 4/26/2025

ANTHONY R. WESTENKIRCHNER
NOTARY PUBLIC - NOTARY SEAL
STATE OF MISSOURI
MY COMMISSION EXPIRES APRIL 26, 2025
PLATTE COUNTY
COMMISSION #17279952

Evergy, Inc.

Review of the Electric Transmission and Distribution (T&D) 2020 – 2024 Grid Modernization Plan

FINAL REPORT

Submitted by

UMS Group Inc.
111 Littleton Road, Suite 111
Parsippany, NJ 07054

(973) 335-3555
www.umsgroup.com

January 2022

Contents

1.0 Executive Summary

1.1 Introduction

Evergy Inc. (hereinafter referred to as "Evergy" or "the Company") has submitted its Electric Transmission and Distribution (T&D) Grid Modernization Plan for 2020 – 2024[1] (hereinafter referred to as "Plan") as part of a long-term and Company-initiated objective (also termed the Sustainability Transformation Plan or "STP") to provide its customers with a T&D system that performs at a twenty-first century, world-class standard. As Evergy's T&D system is a component of Kansas' and Missouri's critical infrastructure, the Company is keenly aware of its responsibilities relating to maintaining and operating this vital public asset. Thus, consistent with the directives from the Kansas Corporation and Missouri Public Service Commissions, and requirements stipulated in Missouri Senate Bill 564 (PISA), Evergy is committed to delivering electric power at the highest levels of safety and reliability and is increasingly alert to the total environmental impact of its customers' electricity use. The Company's ongoing analysis of these responsibilities and objectives has led to this independent, third-party review of the need for and benefits of the Plan.

This review, conducted by UMS Group[2], an International Utility Management Consulting firm founded in 1989 to serve the global utility industry, identifies and analyzes the rationale and wide-ranging implications of this Plan on the Company, its customers, and the citizenry of Kansas, Missouri and neighboring states relying on Evergy's electric transmission system. Noting that the Company is committed to investing as wisely as possible on its customers' behalf, this report is intended to provide transparency to the proposed investments and decisions driving their selection, quantifying the benefits (most notably those pertaining to reliability) in terms of improved performance or avoided risks. In so doing, we strive to provide Evergy with the information necessary to develop informed views and make effective choices about the future of its T&D system.

With respect to reliability, at completion of the projects / programs that comprise the Plan, Evergy will solidify / improve upon its comparative positions in each Jurisdiction (i.e., reductions in annual SAIFI ranging between 0.02 and 0.05, and reductions in annual SAIDI ranging between 3 and 6.5 minutes); and even more noteworthy prevent significant deterioration in both measures (as much as 0.36 for SAIFI in Kansas METRO / Missouri West and 36.0 minutes for SAIDI in Missouri West)[3], and mitigate the unquantifiable, yet significant risk related to the comparatively high number of single contingency transmission lines and substations in Kansas. The balance of this section expands upon these and other key elements of the Plan, whereas Sections 2 and 3 (along with the Appendices) present details around the development of these benefits and risks, including explanations of the technical assumptions and computations used in developing this report.

1.2 Grid Modernization Plan Overview

As stated in previous filings, Evergy's Grid Modernization Plan focuses on opportunities to strengthen grid resilience, harden assets, and apply advanced digital technologies to increase visibility, enhance control, and enable automation, while adhering to legal and regulatory requirements with respect to new customers and safety. Specific areas include:

[1] Since the Plan addresses years 2020-2024, the analyses, for the most part, reviewed trends and comparisons over the three to four years preceding 2020.

[2] Appendix A provides a summary of UMS Group's background and experience.

[3] These ranges are further illustrated by Jurisdiction in Figures 1-10 and 1-11.

- **Distribution Grid Resiliency**: With the goals of ensuring a robust distribution infrastructure (i.e., greater ability to withstand severe storms) and reducing the likelihood of outages due to equipment failure / maintenance costs, Evergy will upgrade / replace distribution line assets (e.g., conductor and poles), distribution transformers, circuit breakers and reclosers. Improving power quality falls under this category as well, for which Evergy will replace aging voltage regulators and capacitors used to keep voltage within limits for its customers.
- **Distribution Automation and Technology**: With the overarching objective of supporting digitization, automation and optimization of its infrastructure, the Plan calls for Grid Devices (to measure, monitor and adjust electric power parameters in the distribution system), Systems (software and supporting hardware to provide situational awareness, evaluate control options, and regulate the operation of grid devices), Telecommunications (to deliver data and information between grid devices, control systems and people), and Data, Models, and Analysis Tools (to support information about and digital representations of the distribution system and its operating environment).
- **Transmission Grid Resiliency**: This area includes the targeting of aging transmission infrastructure for replacement and rehabilitation, including station transformers and circuit breakers, and investing in technologies that will support critical cyber and physical security to protect the bulk electric system. In providing newer, healthy assets, Evergy strives for lower risk of equipment failure, improved reliability for customers, and lower maintenance costs. The Plan also drives towards a robust and flexible transmission systems to enable better power import / export capabilities, helping Evergy integrate more renewable energy and facilitate a transition to a cleaner, greener energy supply mix.
- **Asset Hardening and Contingency**: This area addresses those portions of the power system, losses of which can cause large scale disruptions to the system or Evergy's customers. Specific interventions include building redundancy into the system (i.e., contingencies), hardening to prevent damage from wind, ice, heat, wildlife or flooding. In addition to preventing outages, these efforts seek to avoid emergency repair and replacement costs.

With this as a backdrop, the context is set to present the expected benefits and should the Plan not proceed, associated risks.

1.3 Expected Benefits

Most electric customers and other stakeholders are keenly aware of the vast innovations, improvements, and cost reductions that have occurred in their telecommunications networks, and they clearly recognize the benefits they have realized from them. In contrast, few recognize the potential for significant improvement in electric service or the growing risks that are associated with the entire nation's (and Evergy's) aging T&D infrastructure. That said, the Plan is geared towards ensuring Evergy's customers and the citizens of Kansas and Missouri enjoy the substantial benefits of a truly modern electric delivery network, thus setting the stage for a system that will be more automated and highly resistant to outage incidents. As provided in previous presentations / workshops, this Plan addresses / offers the following requirements / benefits:

- Creates lower long-term operating costs, greater grid resiliency and enhanced security from threats,

- Promotes continued operational efficiencies through improved reliability and asset data quality for predictive analytics (Transmission) and increased automation (Distribution),
- Enhances grid operational flexibility and resilience to allow for quicker restoration of power after extreme (severe) weather or other unplanned events,
- Improves technology to monitor the condition of substation equipment (Transmission) and achieve better system awareness and real-time visibility (Distribution) for quicker response and improved reliability
- Upgrades aging and deteriorating electric transmission and distribution infrastructure nearing or exceeding end of useful life,
- Enables future decarbonization of the system by improving renewable deliverability and strengthening the grid for future generation requirements,
- Links capital investments to customer-centric performance and benefits,
- Provides operating flexibility to meet the requirements of the changing generation landscape (i.e., integration of less dispatchable resources, such as wind, solar, and storage capacity),
- Responds to changing load nature with customer equipment increasingly sensitive to interruption of service,
- Reduces energy losses, by replacing older less efficient power equipment, and
- Supports economic development.

In so doing, measurable and substantial benefits will be realized:

Table 1-1: Grid Modernization Plan Benefits Summary – Base Case

Category	Metric	End-of-Plan Incremental (Annual) Impacts[4]				
		Kansas Central	Kansas Metro	Missouri Metro	Missouri West	Total
Reliability Improvement	SAIFI Reduction	0.04	0.03	0.02	0.04	**NA**
	SAIDI Reduction	6.0 minutes	3.0 minutes	3.2 minutes	4.6 minutes	**NA**
Operational Efficiencies	Outage Elimination Savings	$23.8m	$4.3m	$5.3m	$8.8m	**$42.2m**
	Reduced Reactive Work Savings	$7.9m	$0.8m	$1.5m	$1.7m	**$11.9m**
Customer Benefits	Reduced Overtime Savings	$18.8m	$3.4m	$4.2m	$6.9m	**$33.3m[5]**
	Avoided Customer Interruption Savings (DOE ICE Model)	$18.6m	$4.2m	$4.2m	$7.1m	**$34.1m**
Total Operational Efficiencies and Customer Benefits		**$69.1m**	**$12.7m**	**$15.2m**	**$24.5m**	**$121.5m**

[4] There is generally a 2 to 3-year lag between an increase in capital investment geared towards improving system resiliency and the actual realization of benefits. Appendix B summarizes a study that provides a basis for this projection. *The calculated impacts in the table above show incremental changes from projected future state, after normal degradation is considered, and therefore apply to the assets addressed by the Plan, and not overall system results.*

[5] Reduced overtime savings includes both Capital and O&M.

The following table provides a low and high range for each of these benefit categories, the details of which (including jurisdictional information) are provided in Appendix G:

Table 1-2: Grid Modernization Plan Benefits Summary – End of Plan Incremental (Annual) Impacts – Low and High Case

Category	Metric	Low	High
Reliability Improvement	**SAIFI Reduction**	.02	.05
	SAIDI Reduction	2.7 minutes	6.5 minutes
Operational Efficiencies	**Outage Elimination Savings**	$38.0m	$46.0m
	Reduced Reactive Work Savings	$10.8m	$13.0m
Customer Benefits	**Reduced Overtime Savings**[6]	$30.1m	$36.3m
	Avoided Customer Interruption Savings (DOE ICE Model)	$30.7m	$37.2m
Total Operational Efficiencies and Customer Benefits		**$109.6m**	**$132.5m**

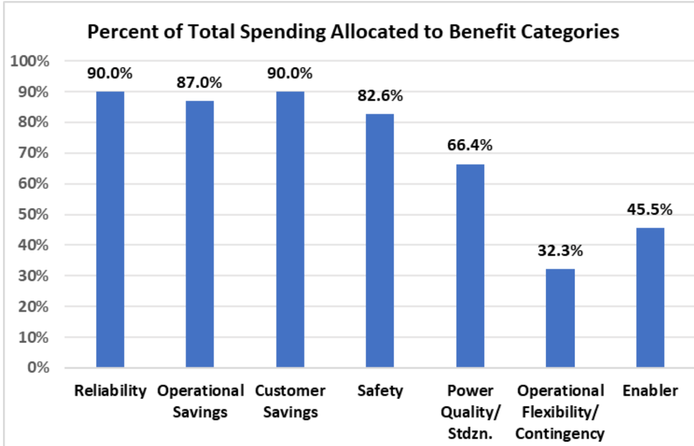
NOTE: Definitions for and approach in monetizing the Operational Efficiencies and Customer Benefits categories are provided in Section 2.3.

The above-mentioned SAIFI and SAIDI reduction figures (Tables 1-1 and 1-2) reflect the portfolio's contribution to reliability improvement (as opposed to providing the bases for projecting absolute SAIFI and SAIDI improvement relative to the current baseline), as there are, in fact, factors outside of those addressed by the Plan that affect these metrics (most notably tree-caused outages, effect of storm hardening initiatives on criteria for defining excludable events, and location / severity of weather events).

In addition to the benefits that present quantifiable and verifiable value to Evergy and its customers, there are other roles that the various capital investments will play in either supporting the plan or contributing value to other organizational priorities. The chart below (Figure 1-1) summarizes the *percent of total projected expenditures (CAPEX) assigned to each of the seven general categories of value* established for this program (three of which relate to the above quantifiable benefits that can be tracked and verified). Also note that many of the program components provide benefits in multiple areas (e.g., an investment which improves reliability, increases Evergy's operational efficiency through reduced emergent work, and benefits the customer through experiencing fewer and shorter interruptions).

[6] Reduced overtime savings includes both Capital and O&M.

Figure 1-1: Evergy Benefit Capture Profile



1.4 Expected Risks

As Figure 1-1 illustrates, most of the proposed investments will contribute directly to improving reliability, capturing operational efficiencies, and benefiting the customer through fewer and shorter service interruptions. In addition to providing tangible benefits in these and other categories, the Plan also addresses several areas of risk (the avoidance of which, in and of itself represents benefits), which left unabated, can compromise Evergy's ability to provide safe, reliable, and cost-effective service to its customers, namely:

- System Performance (Reliability),
- Safety and Related Liabilities, and
- Financial Sustainability.

1.4.1 System Performance (Reliability)

The ability to predict and / or prevent future outages and improve upon service restoration requires the optimum blend of investments presented in this plan, targeted to strengthen the system backbone where needed (i.e., transmission with a focus on Kansas) and improve distribution reliability (particularly in Missouri). The proposed Plan will (1) reduce unplanned transmission outages that directly impact Evergy's customers, (2) stem the impending "bow wave" of equipment caused customer interruptions, and (3) counter the reality of reliability degradation inherent in any electric transmission and distribution system, often stated to range between 2 and 5 percent annually. More explicitly, the analyses (refer to Section 3.2) show that absent these initiatives, starting in 2021 and projecting out to 2030, Evergy will experience the following:

Table 1-3: System Performance (Reliability) Risk Impacts (2020-2030)[7]

Jurisdiction	Cumulative Increase in Customer Interruptions (SAIFI Impact)	Equivalent Cumulative Customer Impact	2030 SAIFI Impact	2030 SAIDI Impact
Kansas Central	828,157	$38.4m	0.19	21.2 minutes
Kansas METRO	511,862	$23.7m	0.36	25.2 minutes
Missouri METRO	482,609	$25.4m	0.30	24.6 minutes
Missouri West	639,944	$33.7m	0.36	36 minutes

NOTE: In calculating *Equivalent Customer Impact*, the costs were extracted from the DOE ICE Model for both Kansas and Missouri, weighted based on the profile of Residential, Commercial, and Industrial customers in each State, using the average outage duration for each state (1.6 hours in Kansas and 1.63 hours in Missouri).

In addition to the immediate system performance risks summarized in Table 1-3, there are additional strategic risks related to the transmission system and the degree of redundancy required to ensure continued delivery of power, even when individual elements of the grid are interrupted (i.e., when individual transmission lines "trip" out of service due to damage from weather or other external forces). Most transmission lines can experience an outage, (i.e., be removed from service) without affecting the ability of the rest of the system to deliver power to meet customer load demand across the system. This is because the system is designed as an interconnected network, with multiple transmission supply paths to most distribution substations. Such redundancy is referred to as N-x service, reflecting that the system can withstand the loss of x transmission elements (i.e., lines, breakers, transformers, etc.) before customer load will be lost. The standard for US utility transmission planning is generally N-1 for most customer load. For systems so designed, as the number of unplanned transmission outages increases (thus removing levels of redundancy or "protection"), so does the likelihood that customers will experience outages (typically much larger, more disruptive events than outages involving a single distribution feeder).

In the more remote sections of most US transmission grids, typically those serving sparsely populated rural areas, normal transmission system redundancies (N-1, N-2, etc.) are often reduced, to the point where only a single transmission line serves load to such small rural communities. Additionally, some substations with two transmission line feeds are designed so that switching must be performed manually to restore load when a forced outage occurs on one of the transmission lines. Both situations can be referred to as Single Contingency where when a single transmission line trips out, or transformer is lost, some customer load will be lost, at least temporarily. Because of the long distances to reach these remote communities with transmission service and the relatively few customers across which to spread the associated expenditures, the cost to serve these customer groups is often higher than for the average utility customer. Building additional redundancy in these areas to improve reliability and resilience for storms would translate to even higher costs and has traditionally given way to less expensive strategies which can be described as "*build / maintain and replace with like-for-like assets at end of life*". Historically, these tradeoffs have been considered prudent and aligned with the more modest rural customer expectations for reliability. However, several factors are now shifting this calculus, including growing frequency and severity of extreme weather events, the scale of damage experienced which often requires

[7] Due to the different outage durations and mix of customers (and therefore different cost factors for service interruptions) the information contained within Table 1-3 does not include the potential impact of single contingency risk, summarized below in Table 1-5.

significantly longer repair / restoration times than those required to address typical distribution line failures, increased customer expectations regarding reliability, and the likelihood that electrification (of transport and buildings) may be right around the corner.

The following table summarizes the current state of the system, presenting a view of Evergy's exposure in this critical area, and where alternative approaches should be evaluated.

Table 1-4: Transmission System Reliability Contingency Summary

Contingency	No. of Substation	Substation %	No. of Customers	Customer %
Kansas Central				
Single Contingency	244	50.8%	421,080	42.7%
Multiple Contingency	236	49.2%	565,720	57.3%
Kansas TOTAL	480	100.0%	986,800	100.0%
Metro / Missouri West				
Single Contingency	57	19.9%	65,265	10.4%
Multiple Contingency	230	80.1%	564,390	89.6%
Missouri TOTAL	287	100.0%	629,655	100.0%

The implications of Table 1-4 are significant and reflected in the Plan:

- A high portion (over 42 percent) of Evergy's end use customers in Kansas Central are served from substations where an outage would result from a transmission line fault ("contingency risk"). Across the US, the percent of most utilities' customer base served in this way (i.e., single contingency line) is typically small (i.e., less than 10 to 20 percent). However, in the case of Evergy Kansas Central, where a significant portion of its territory is rural, (i.e., 90+ percent of the population lives in half the counties across the State), we would expect this number to be a bit higher, perhaps as much as 20 to 25 percent.
- Further, approximately 29 of these single-contingency substations serve Industrial load across the State and are the only source of supply to some industrial plants. For these sensitive customers, even a short interruption to electrical supply can result in great disruption to the process flows and outputs of the plant. Customer benefits of improving reliability to these facilities are often far greater than to the average customer served.
- Conversely, the "contingency risk" in Missouri West and Metro is lower, as less than 20 percent of the end use customers are served from substations which would be impacted by a single transmission line contingency.

Our grid modernization plan addresses some of these concerns above, but in no way fixes all the issues in this short timeframe. Transmission investment prioritizes non-discretionary projects that are needed to meet regulatory (SPP, NERC, etc.), safety or other requirements. Then the discretionary portion of the remaining resources gets allocated across projects that are ranked from highest to lowest score. These scores include considerations for safety and customer reliability.

In summary, the commitment to allocate a portion of Evergy's planned investments toward improving the robustness of its Kansas Central transmission grid – with the benefits created in additional robustness and resiliency is warranted even though this resiliency benefit is not quantifiable in the same way as other reliability benefits.

1.4.2 Safety and Related Liabilities

Almost 83 percent of the proposed capital investment plan represent projects and programs that address in one form or another, safety. Though we are reticent to apply a value to human life, there are risk management issues to consider, particularly given the increased propensity to exact fines on utilities even for situations previously categorized as force majeure or otherwise considered outside the control (i.e., responsibility) of the utility.

1.4.3 Financial Sustainability

Absent the proposed Plan, the resulting increases in transmission and equipment caused outages would result in a larger number of storm restoration / damages / "break-fix" interventions (currently budgeted at an average annual amount of $78 million per year). If the percentage of emergent repair and replacement activities is allowed to increase as a portion of the daily workload, these blankets would increase (with the effect of diverting workforce from planned work), and a premium on costs (estimated to range between 20 and 40 percent), would be incurred, attributable to the following:

- Industry-wide, equipment caused outages, often longer in duration than other power outage causes, will account for an increasing portion (and frequency) of customer-experienced outages,
- Unplanned disruptions will produce inefficiencies in the productivity of crews and delays in executing work to pre-established schedules,
- Often forced to make temporary fixes, crews frequently need to be remobilized to effect permanent repairs / replacements,
- Unavailability of proper equipment and material will lead to suboptimal work practices and / or unplanned cost premiums, and
- Excessive overtime will increasingly become the norm, further reducing workforce productivity.

Our analysis, explained further in Section 3.2.3, indicates that this increase is of the order of $7.0 million ($2.7 million in Kansas and $4.3 million in Missouri) per year, translating to an annual 2030 budget nearly double that in the Plan (i.e., increase of nearly $70.0 million).

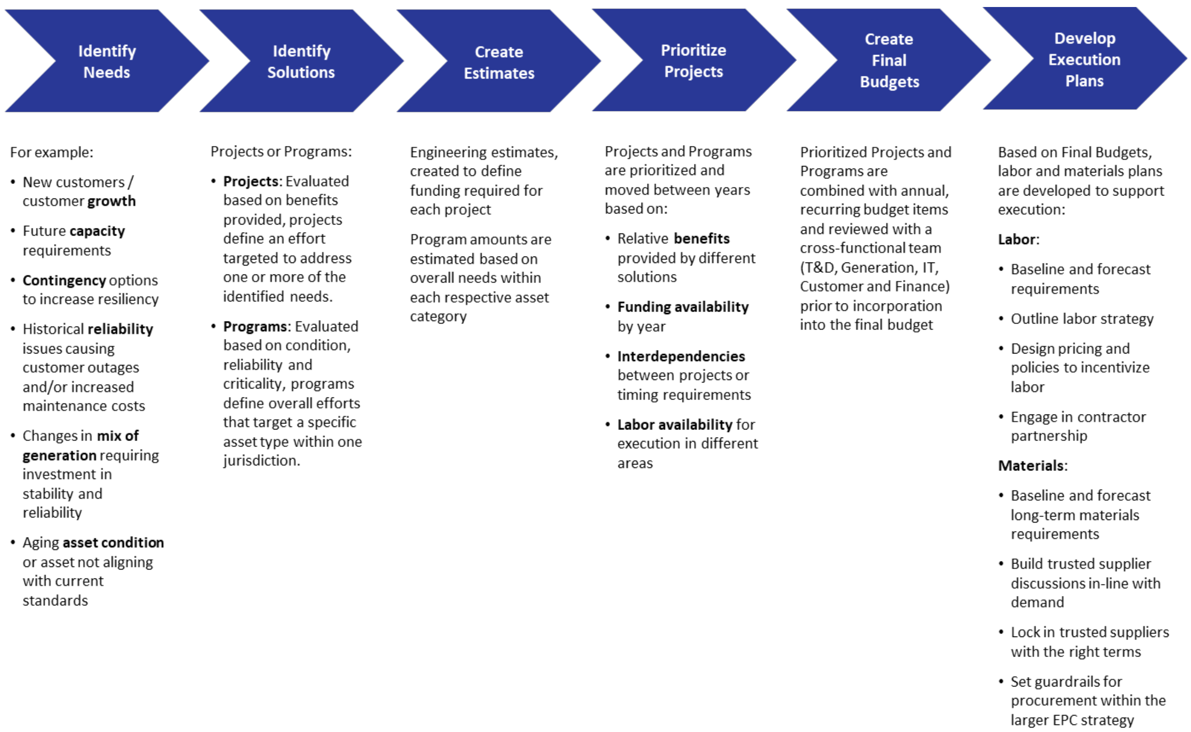
1.5 Development of the Plan

In developing the Plan, Evergy conducted a disciplined process, starting with the identification of specific needs to align with the Sustainability Transformation Plan (STP) objectives, and ending with a prioritized list of executable projects and programs. Figure 1-4 summarizes this process, resulting in a comprehensive and objective evaluation of all proposed solutions and a resulting portfolio that balances and optimizes the investments across a broad range of competing objectives, namely:

- Ever-increasing customer expectations with respect to reliability and utility responsiveness,
- Current requirements to ensure a resilient infrastructure (i.e., addressing technical legacy issues and keeping ahead of the "bow wave" of unplanned equipment failures),
- Growing uncertainties regarding projected load growth and available resources,

- Emerging need to modernize the electric system vis a vis the Utility of the Future (in particular, impacts of shifting weather patterns, EV penetration and DERs), and a
- Preponderance of legislative and regulatory mandates.

Figure 1-4: Evergy Planning Process

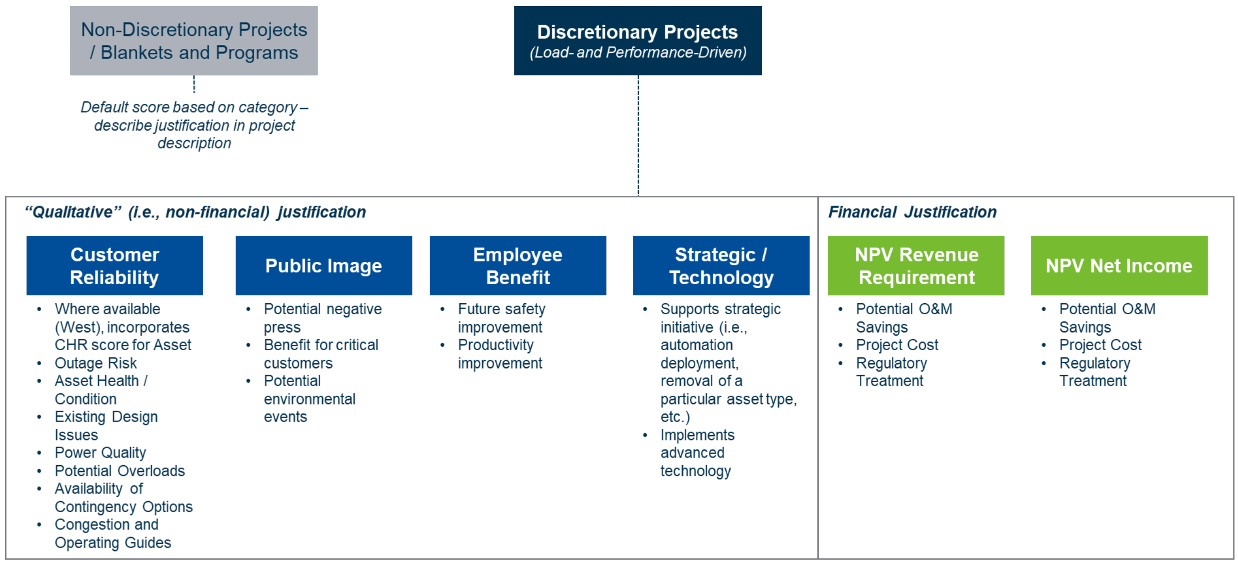


To assist in this process, Evergy deployed its System Improvement (SIMP) process for all specific T&D projects, which among several uses, facilitated the scoring and ranking (and subsequent selection) of proposed solutions (i.e., projects and / or programs). As a first cut, the proposed solutions were categorized as:

- Non-Discretionary Projects / Blankets and Programs
- Discretionary Projects (Load and Performance Driven): Projects which were not required for new customers, regulatory, or safety.

Non-discretionary projects and programs were scored based on category with justification specified in the project description, while proposed discretionary projects were scored across four qualitative and two quantitative (financial) categories.

Figure 1-5: SIMP Scoring Framework



For transmission and substation projects, a rather robust and comparatively sophisticated risk measurement process was used to further direct the execution of this capital investment portfolio:

- For transmission lines, risk was calculated based on customer count, commercial and industrial key customer, line connectivity, historical Transmission line and station outages (TADS and 69kV data), known design issues, average equipment health, line length, line direction, and lightning density, whereas the *Structure* (i.e., wood and steel) and *Span* (i.e., the length of conductor between two adjacent structures) scores were calculated based on inspection deficiencies, corrective work orders and age. This is a noted advancement beyond the normal utility practice of measuring and maintaining records of risk at the overall line or line section level (i.e., switchable sections of transmission line comprised of numerous sequential spans that together represent the portion of the line between two switching devices).

- For substations, risk was calculated based on an extensive array of factors including key customers served, revenue, maintainability, potential for collateral damage, known hazards, SAIDI contribution, equipment health, substation design, and corrective maintenance costs. Replacement decisions have been made within each asset class, and then optimized across voltage levels and substations based on overall failure probability and criticality within the system. Risk for each asset class was determined based on the risk factors considered most relevant to potential failure of that particular asset type. Looking at two of the more important asset classes (breakers and transformers), Evergy determined (1) breaker risk scores based on historical maintenance costs, equipment age, manufacturer models that have been designated as poor performers, and breaker mechanism type, and (2) transformer risk scores based on dissolved gas test results and trends over multiple test results.

Other analytical tools were used to direct investments in the distribution system, including a pilot in Missouri using Asset Management analytics software to drive a new Worst Performing Lateral Program. Although still maintaining a Worst Performing Circuit initiative, this extension to analyze condition and risk of the laterals on each feeder has the potential of providing far better benefit-to-cost ratios, by targeting specific assets to replace based on risk of failure, where:

- The probability (likelihood) of failure is determined for poles and conductor using survivor curves to estimate the percentage of the population in each asset class that will survive over time based on current asset age and condition, and
- The consequence of failure includes a range of factors relevant to specific parts of each lateral, including: a safety factor for overhead primary that is close to a building, customer factors based on customer outage information and counts of public safety issues and commercial / industrial customers served, an environmental factor for poles with transformers, and a financial factor for incremental repair costs over time.

As Evergy continues to advance its Asset Management initiative, the foundation for aligning investment decisions with corporate strategy and customer or regulatory priorities, as well as for applying advanced analytics to refine or direct Capital investments, is already in place.

The resulting portfolio of 28 initiatives (consisting of over 1200 projects and programs to be executed between 2020 and 2024), will strengthen grid resilience, harden assets, and apply advanced digital technologies to increase visibility, enhance control, and enable automation across the grid. These projects are in addition to those necessary projects created each year by the Transmission and Distribution Planning groups to enable the system to meet overall system requirements for load growth, security of supply, system security, voltage control, etc. The overall program totals $5.8 billion of capital investment.

Table 1-6: Proposed 2020 – 2024 Grid Modernization Plan Budget ($m)

Jurisdiction	2020	2021	2022	2023	2024	TOTAL
Transmission						
Missouri West	$12.0	$163.9	$135.8	$110.8	$131.6	**$554.1**
Missouri METRO	$4.4	$43.6	$45.7	$44.8	$40.4	**$178.9**
Kansas METRO	$3.9	$33.6	$40.5	$39.8	$35.8	**$153.6**
Kansas Central	$215.7	$331.3	$340.1	$369.7	$503.9	**$1,760.7**
Transmission TOTAL	**$236.0**	**$572.4**	**$562.1**	**$565.1**	**$711.7**	**$2,647.3**
Distribution						
Missouri West	$223.9	$191.7	$166.6	$148.9	$132.6	**$863.7**
Missouri METRO	$143.2	$184.1	$147.4	$98.1	$107.6	**$680.4**
Kansas METRO	$71.8	$85.6	$135.6	$133.4	$89.1	**$515.5**
Kansas Central	$211.1	$192.8	$211.0	$244.5	$244.3	**$1,103.7**
Distribution TOTAL	**$650.0**	**$654.2**	**$660.6**	**$624.9**	**$573.6**	**$3,163.3**
Total Grid Modernization Plan Budget						
Grand Total	**$886.0**	**$1,226.6**	**$1,222.7**	**$1,190.0**	**$1,285.3**	**$5,810.6**

1.6 High-Level Review of the Plan

In reviewing the Plan, one can quickly observe the following:

- Over 65 percent of the projected transmission capital expenditures occur within the Kansas Central jurisdiction, and unlike the other three jurisdictions, its total transmission capital budget exceeds that assigned to distribution,
- While the plan provides support for all elements of Evergy's diverse customer group, as would be expected, where customer densities are greater, there is proportionately more investment (i.e., the Missouri distribution system on a per customer basis than in Kansas), and
- The average annual capital expenditures for the plan ($1,167 million per year) are significantly higher than those for the preceding four years ($623 million).

1.6.1 Kansas Central Transmission

In understanding the allocation of Transmission-related capital across the four jurisdictions, one need only look at the sheer amount of transmission required to serve each service area:

Table 1-7: Transmission System Scope

Jurisdiction	Miles of Transmission	Tx Mile %	No. of Substations	Substation %
Kansas Central	6,461	71.4%	390	54.9%
Kansas METRO	501	5.5%	65	9.1%
Missouri METRO	766	8.5%	74	10.4%
Missouri West	1,327	14.7%	182	25.6%
Evergy TOTAL	**9,055**	100.0%	**711**	100.0%

Narrowing our focus to Kansas Central, the split between the proposed transmission and distribution capital budget warrants commentary on the appropriateness of the level and mix of such investments, particularly given the relatively small (compared to distribution) number of transmission-caused customer interruptions across the system, and Evergy's focus on improving the customer experience (typically demanding more focus on distribution). There are several relevant points to emphasize:

- First and foremost, a reliable, resilient transmission system is the backbone of the electricity grid and enables electric utilities to deliver affordable power where and when it is needed. Transmission investments within the Plan are designed to help: (1) protect the grid from extreme weather and cyber-attacks, (2) predict and prevent outages, (3) respond to and restore power faster when outages do occur, (4) connect customers to large-scale generators as well as wind / solar power, and (5) prepare the grid for the anticipated increase in load from electric vehicles, building electrification and the emergence of a broad array of smart technologies to better serve customers and communities.
- System resilience is the ability to operate normally under abnormal conditions, particularly in an increasingly dynamic threat environment. In short, it's about preparedness and planning for successfully responding to, and recovering from, adverse events or third-party actions. Though

not reflected in the specific customer-facing reliability statistics (e.g., SAIFI and SAIDI), a hardened / robust transmission system is mandatory to assure a sufficiently resilient energy supply to the State.

- As the backbone of the energy grid, transmission efficiently:

  (1) delivers safe and reliable energy, often going unrecognized because of its amazing reliability and contribution to resilience (a recent NERC annual "State of Reliability Report" noted that firm load was served on the bulk power system 99.92 percent of the time and while extreme weather events continue to challenge the grid, we are seeing quicker restoration times and reduced outage severity), and

  (2) provides optionality (alleviating costly congestion, providing access to lower cost generation, eliminating the need for additional generation, increasing reliability / resilience of electricity delivery, and offering flexibility in adapting to changes in public policy and sources of electricity generation).

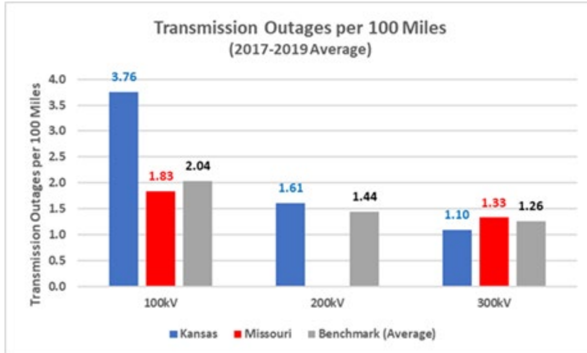
- Although major bulk power system transmission outages can and have led to widespread blackouts, they are rare. Certainly, like distribution, transmission networks experience a wide variety of natural disturbances, such as lightning, fire, wind, ice, wildlife, and vegetation. However, transmission planning standards require the bulk system (>100kV) to be built so that any single (and many double) points of failure do not result in cascading outages or uncontrolled islanding. While lightning and non-lightning weather causes are among the largest number of recorded transmission outages, protective devices and other designed-in contingency measures can clear and restore these momentary events quickly, reducing their impact, if any, on system reliability. To illustrate this point, more than half of Evergy Kansas' transmission line outages from lightning over the past five years lasted less than one minute. That said, a transmission outage can increase the vulnerability of the system to additional outages, moving the utility one-step closer to what could be a catastrophic / widespread outage event and at its extreme, set the stage for a cascading blackout affecting customers widely in many states.

- We are not suggesting that electric distribution is "less important" than electric transmission. But it is important to explain the logic behind sequencing transmission projects ahead of distribution projects, particularly in Kansas Central where the transmission grid has less redundancy and experiences a greater number of transmission line outages. Evergy is tasked with balancing near-term customer expectations regarding provision of safe and reliable service, with the longer-term goal of providing steadily improving and sustainable reliability. Providing a strong backbone while ensuring continuation of good reliability (Kansas Central is currently 2nd quartile in SAIFI and SAIDI; and Kansas Metro is even stronger[8]) represents an effective approach to meeting this standard. Section 3.1 further substantiates the relevance of these statements in comparing transmission capital investments across the four jurisdictions, illustrating that in the years preceding the full execution of the Plan:

- Normalized comparisons of unplanned transmission outages (i.e., number of unplanned transmission outages per 100 miles) below 300 kV show Kansas well above the benchmarks with an even wider disparity when compared to Missouri.

[8] The source of benchmark comparisons is the annual IEEE Benchmark Reports issued by the Distribution Reliability Working Group.

Figure 1-6: Unplanned Transmission Outage Comparisons (2017-2019)



- Between 2017 and 2019 there were more than double the number of transmission outages impacting customers in Kansas than in Missouri (236 vs. 104).

Figure 1-7: Unplanned Sustained Transmission Outages Impacting Customers (>1 minute)

Note: 34kV is considered transmission in Kansas. If this voltage class were included above, the numbers would increase.

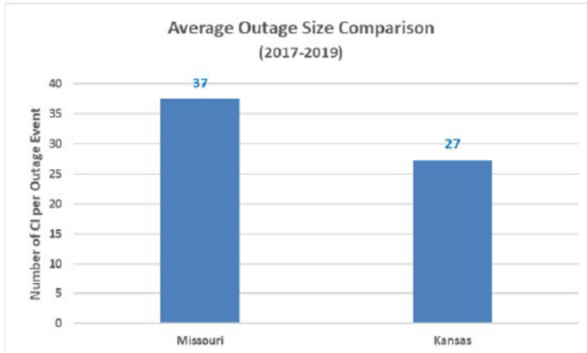
- As can be observed in the above Figure 1-7, voltages below 200kV and specifically the 69kV represents a prime opportunity for improvement and have a direct impact on customer outages more than voltages above 200kV
- And as can be deduced from the Transmission System Contingency Summary (Table 1-3 and accompanying discussion), the embedded transmission-related reliability risk is significant.

1.6.2 Missouri Distribution Investment Levels

Missouri, on the other hand, is in a stronger position with respect to Transmission but more exposed in Distribution, thus warranting a larger proportionate allocation of Distribution Capital in the Plan (nearly $2,500 per customer in Missouri as compared to approximately $1,650 per customer in Kansas currently planned over the 5-year period).

- The average size of a distribution customer outage in Missouri is 37 percent larger than that in Kansas, suggesting the need for more investment in the Missouri system.

Figure 1-8: Outage Size Comparison



NOTE: Our observations during the conduct of multiple Reliability Assessments of US utilities over the last decade point towards a well-sectionalized system that serves moderately sized population centers and large rural areas experiences average outage sizes in the range of 25 to 30 customers.

- In comparing equipment caused outages between 2017 and 2019, both States experienced increases (24 percent in Missouri and 19 percent in Kansas). However, more noteworthy is the difference in the contribution trend of equipment caused outages to SAIFI and SAIDI, a difference that is more pronounced in Missouri[9].

Table 1-8: Equipment Caused Outage SAIFI and SAIDI Comparisons

State	Contribution to SAIFI			Contribution to SAIDI		
	2017	2019	Difference Increase / (Decrease)	2017	2019	Difference Increase / (Decrease)
Missouri	0.26	0.36	**37%**	23.5	33.5	**42%**
Kansas	0.33	0.37	**11%**	33.0	38.5	**16%**

Though a steady effort is called for in both Missouri and Kansas, these comparisons certainly point towards the appropriateness of near-term investments proportionately more focused on Distribution in Missouri than in Kansas.

[9] In analyses conducted for other Midwest utilities, UMS Group has observed similar trends regarding Equipment Caused outages contribution to SAIFI and SAIDI. However, the significant increase experienced in Missouri between 2017 and 2019 is comparatively higher than experienced elsewhere (including in Kansas).

1.6.3 Stepped Increase in Capital Expenditure Levels

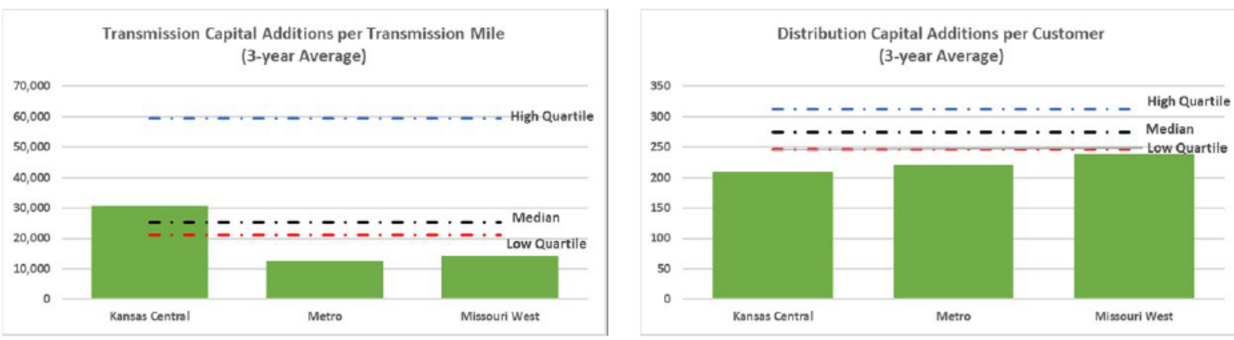
The Plan represents a significant increase in capital expenditure levels, particularly in comparing its average annual expenditures with those of the previous four years.

Table 1-9: Comparison of Capital Investment Levels ($m)

Timeframe	Transmission (Average per Year)	Distribution (Average per Year)	TOTAL (Average per Year)
2017 – 2019	$238	$385	$623
2020 - 2024	$534	$633	$1,167
Percent Increase	124%	65%	87%

As context for analyzing these increases, we first looked at utility peer group comparisons of past capital investment levels with a sampling of 14 other Midwestern electric utilities (refer to Appendix E):

Figure 1-9: Capital Investment Levels Comparisons (2017-2019)



Except for transmission capital investment levels in Kansas Central, the average transmission and distribution investment levels (normalized for line miles and number of customers, respectively) over the three years preceding the Plan have been in the lower quartile compared to peers. For Kansas Central transmission, only slightly above the median, one must also account for the above-mentioned reliability challenges illustrated in Figures 1-6 and 1-7 and further expanded upon in Section 3.1.1 below. Therefore, one can see that the Plan is focused on closing this gap with the expected attended benefits within a five-year timeframe.

Further, the Plan also warrants a discussion of timing of benefits realization versus changes in capital investment. Studies regarding the effect of capital investment levels on Transmission and Distribution systems demonstrate that there is up to a five-year lag between a stepped increase in capital investment and the resulting improvement in SAIFI / SAIDI. This correlation is even stronger when the increase is at least 50 percent, and the five-year timeframe can often be compressed to two- to -three years when the change in investment rises to between 75 and 125 percent (refer to Appendix B).

1.7 Cost / Benefit Review

Clearly the Plan offers significant benefits to Evergy's customers (in the form of monetized savings and avoided risk), which when accumulated between 2020 and 2030, will total $895 million.

Table 1-10: Accumulated Monetized Benefits (By Jurisdiction) (2020 – 2030)

Jurisdiction	Projected Monetized Savings[10]	Avoided Reliability Risks[11]	Avoided Increase in Reactive Work[12]	TOTAL Benefits
Kansas Central	$395m	$38m	$20m	$453m
Kansas METRO	$71m	$24m	$7m	$102m
Missouri METRO	$94m	$25m	$9m	$127m
Missouri West	$145m	$34m	$34m	$213m
TOTAL	**$705m**	**$121m**	**$70m**	**$895m**

With respect to costs, the following table summarizes (by jurisdiction) the incremental increase in capital expenditures represented by the Plan:

Table 1-11: Incremental Increase in Capital Expenditures

Jurisdiction	Pre-Plan Capital Expenditures[13]	2020 – 2024 Proposed Plan	2020-2024 Normalized Plan	Normalized Increase / (Decrease)
Kansas Central	$1,827m	$2,864m	$2,350m	$523m
Kansas METRO	$347m	$669m	$343m	($4m)
Missouri METRO	$392m	$859m	$663m	$271m
Missouri West	$555m	$1,418m	$1,101m	$546m
TOTAL	**$3,121m**	**$5,810m**	**$4,457m**	**$1,336m**[14]

Therefore, comparing costs and benefits assigned to and risks avoided by the Plan, by 2030 the accumulated benefits will be within $440 million of the total costs, with full payback well within a 20-year timeframe.

Although the Plan's impact on reliability (both its execution and deferment / cancelation) is contained within the above monetized benefits, a graphic description of the Plan's impact on SAIFI and SAIDI is also

[10] Reflects cumulative Operational Efficiencies and Customer Benefits through 2030 presented in Table 3-7.

[11] Reflects "Equivalent Cumulative Customer Impact" figures presented in Table 1-3.

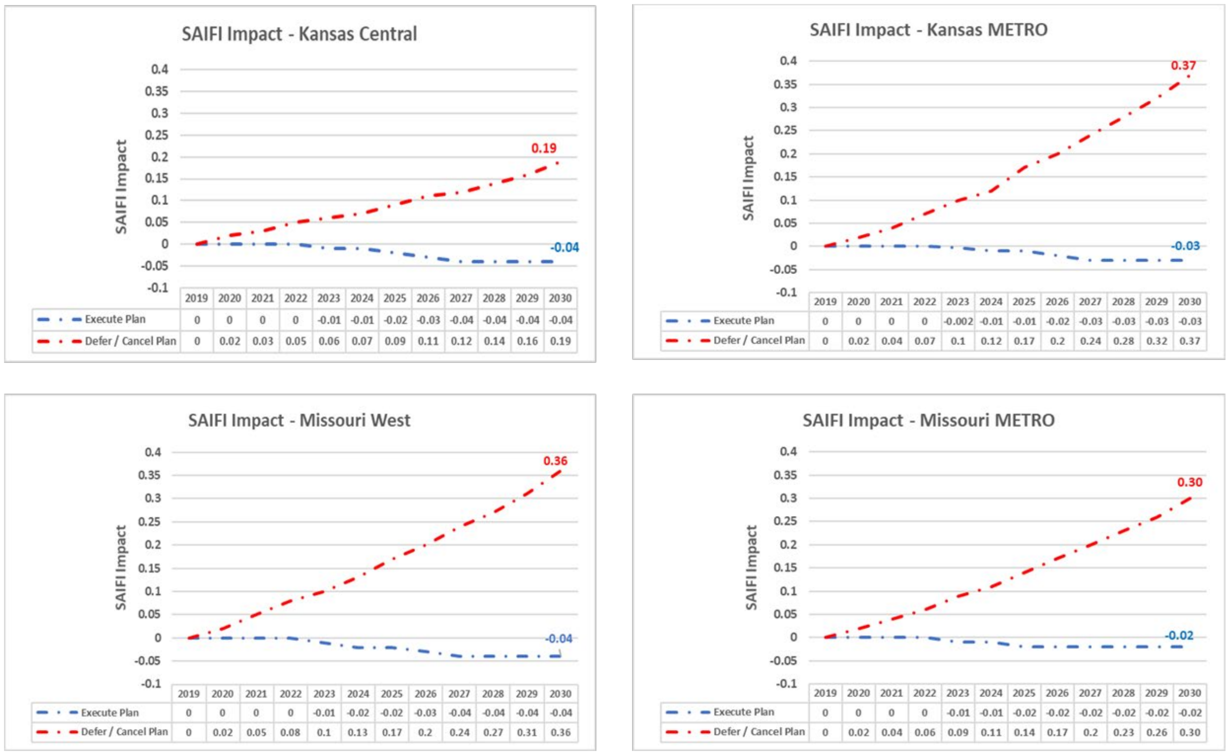
[12] Reflects information presented in Section 3.2.3 and summarized in Section 1.4.3.

[13] Pre-plan Capital Expenditures reflects the average over the 2017-2019 timeframe extended over five years. With FERC Form 1 data as the bases, Kansas METRO and Missouri METRO, reported as combined were split 47 / 53.

[14] The $1,226 million reflects the difference between the normalized plan (those budgeted items that comprise the previously mentioned 28 groupings) and Pre-Plan Capital Expenditures of $3,121 million.

instructive. The following figures illustrate its contribution to reliability if fully executed (blue line) and what is likely to happen if it is deferred or cancelled (red line).

Figure 1-10: SAIFI Impacts (by Jurisdiction)



SAIFI Impact - Kansas Central

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Execute Plan	0	0	0	0	-0.01	-0.01	-0.02	-0.03	-0.04	-0.04	-0.04	-0.04
Defer / Cancel Plan	0	0.02	0.03	0.05	0.06	0.07	0.09	0.11	0.12	0.14	0.16	0.19

SAIFI Impact - Kansas METRO

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Execute Plan	0	0	0	0	-0.002	-0.01	-0.01	-0.02	-0.03	-0.03	-0.03	-0.03
Defer / Cancel Plan	0	0.02	0.04	0.07	0.1	0.12	0.17	0.2	0.24	0.28	0.32	0.37

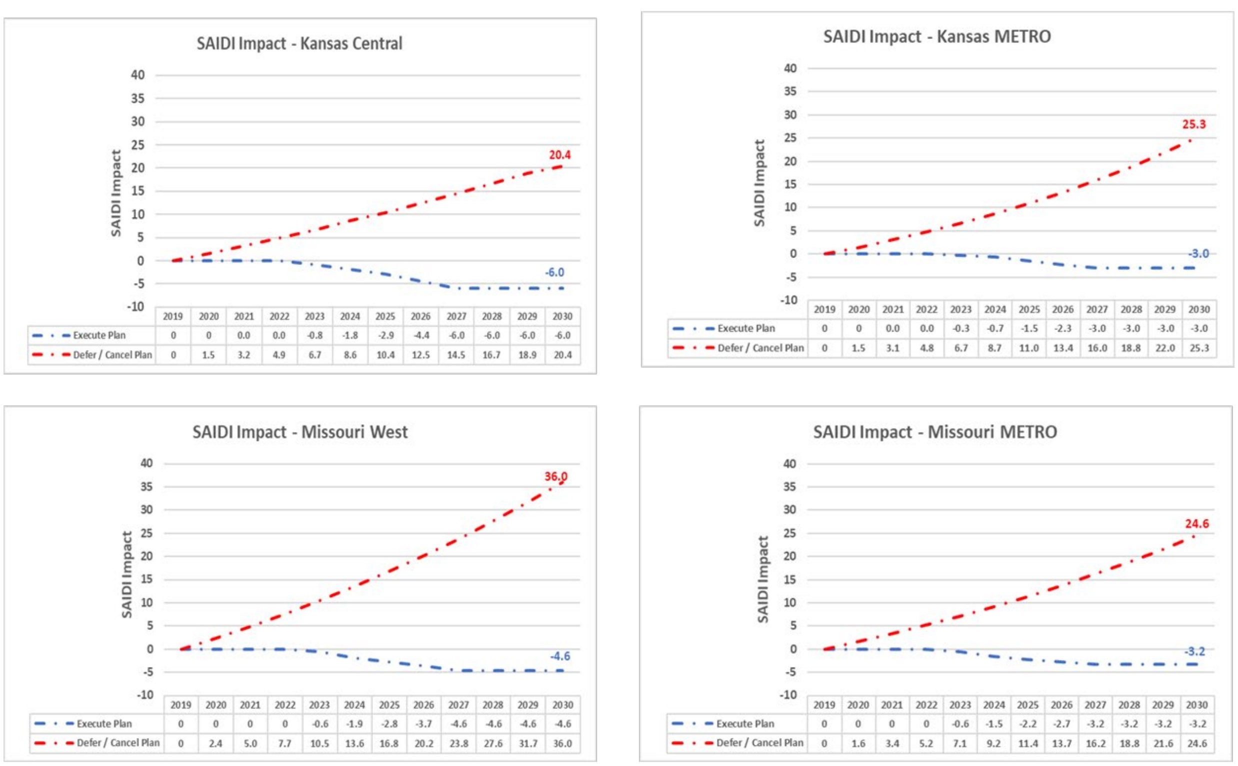
SAIFI Impact - Missouri West

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Execute Plan	0	0	0	0	-0.01	-0.02	-0.02	-0.03	-0.04	-0.04	-0.04	-0.04
Defer / Cancel Plan	0	0.02	0.05	0.08	0.1	0.13	0.17	0.2	0.24	0.27	0.31	0.36

SAIFI Impact - Missouri METRO

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Execute Plan	0	0	0	0	-0.01	-0.01	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02
Defer / Cancel Plan	0	0.02	0.04	0.06	0.09	0.11	0.14	0.17	0.2	0.23	0.26	0.30

Figure 1-11: SAIDI Impacts (by Jurisdiction)



SAIDI Impact - Kansas Central

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Execute Plan	0	0	0.0	0.0	-0.8	-1.8	-2.9	-4.4	-6.0	-6.0	-6.0	-6.0
Defer / Cancel Plan	0	1.5	3.2	4.9	6.7	8.6	10.4	12.5	14.5	16.7	18.9	20.4

SAIDI Impact - Kansas METRO

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Execute Plan	0	0	0.0	0.0	-0.3	-0.7	-1.5	-2.3	-3.0	-3.0	-3.0	-3.0
Defer / Cancel Plan	0	1.5	3.1	4.8	6.7	8.7	11.0	13.4	16.0	18.8	22.0	25.3

SAIDI Impact - Missouri West

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Execute Plan	0	0	0	0	-0.6	-1.9	-2.8	-3.7	-4.6	-4.6	-4.6	-4.6
Defer / Cancel Plan	0	2.4	5.0	7.7	10.5	13.6	16.8	20.2	23.8	27.6	31.7	36.0

SAIDI Impact - Missouri METRO

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Execute Plan	0	0	0	0	-0.6	-1.5	-2.2	-2.7	-3.2	-3.2	-3.2	-3.2
Defer / Cancel Plan	0	1.6	3.4	5.2	7.1	9.2	11.4	13.7	16.2	18.8	21.6	24.6

Note that the above charts present the Plan's impact on net reliability (as opposed to providing the bases for projecting absolute SAIFI and SAIDI performance targets). There are several factors that may affect the system wide value of these metrics beyond those addressed by the projects and programs that comprise Grid Modernization, such as:

- Vegetation Management,
- Location and severity of weather events, and
- As the system is storm hardened, events that would have qualified as exemptions fall below the exclusion criteria.

That said, one can see that the plan, when executed, will contribute to improved reliability, and absent the projects / programs that comprise the plan, reliability performance will be significantly degraded.

1.8 Summary

The Plan, as presented, will produce commensurate benefits within a reasonable timeframe, while appropriately addressing the major risks that could affect the Company's ability to provide safe, reliable and cost-effective service to its Kansas and Missouri customers. Further, it positions Evergy for the impending energy transition that is expected to occur over the next decade, assuring a strong foundation with sufficient flexibility to manage through most foreseeable uncertainties. In reviewing the above discussion, the following conclusions warrant emphasis:

- Evergy invoked sound Asset Management principles in formulating the Plan, effectively bridging its strategic goals to deliver measurable customer-related benefits while mitigating major risks to system performance, safety and financial sustainability,
- The significant increase in capital expenditures in transmission (particularly in Kansas Central) is warranted based on recent trends in transmission-caused outages and the strategic imperative to further harden the T&D system backbone.
- Though steady improvement is called for with respect to Distribution across all four jurisdictions, the results from recent distribution outages present a significant opportunity to improve the customer experience in Missouri (particularly given its lower risk profile vis a vis Transmission), and
- The stepped increase in Capital Expenditure levels represented by the Plan will support dramatic mitigation of transmission-related system risk and should produce "immediate" results in improved reliability.

2.0 Overall Approach

Between 2020 and the end of 2024 Evergy plans to invest $5.8 billion to address resiliency, harden the system, and apply advanced digital technologies to increase visibility, enhance control and enable automation, while adhering to legal and regulatory requirements with respect to new customer connections and safety. Within the five-year capital investment portfolio, many of the 1200+ projects / programs will produce measurable and verifiable benefits to Evergy, its customers and the public-at-large. Others fall into enabler or support categories, items that are necessary to support operations, but whose measure of value cannot be expressed in terms of quantifiable measures or metrics. In addressing the over-arching objective to quantify the benefits in terms of improved reliability and performance or avoided risks, yet maintain transparency / connection to the proposed projects / programs, UMS Group performed the following tasks:

1. Reviewed the projects / programs to discern which would produce tangible reliability and other quantifiable benefits.
2. For those so characterized, developed 28 Project / Program Groupings based on compatibility with prescribed benefit capture algorithms. A detailed mapping of individual Projects / Programs to the Groupings is available upon request.
3. By aggregating projects / programs within each specific Grouping, we then quantified the work based on the asset (s) included in the Grouping.
4. These "quantified" Groupings were evaluated, applying a computational model (provided separately) to (1) compute benefits, and cash flow (with an appropriate time delay to account for the lag between the completion of a project / program and the realization of benefits), and (2) develop a benefit capture profile over time.
5. Risk of deferral or suspension of the Plan was analyzed by reviewing recent system performance trends (by State or Jurisdiction) and projecting the impact of their continuation through year 2030.

The following discussion summarizes, from a programmatic perspective the outcomes of these tasks.

2.1 Categorization of Projects and Programs

As the first step to assigning benefits to the Plan, the 1,200 projects / programs that are directed at asset replacement / repair or system performance improvement were categorized into the following 28 Groupings. In this way, we were able to develop the algorithms that resulted in quantifiable benefits as portrayed in Table 1-1.

Table 2-1: Plan Groupings

	Project / Program Grouping[15]	Total Estimate (Millions)	Primary Focus
New Assets	New Pole/Structure	$2.7	System Resiliency Improvements
	New Recloser	$132.6	System Resiliency Improvements
	New Overhead Line	$190.7	System Resiliency Improvements
	New Underground Line	$74.5	System Resiliency Improvements
	New Breaker/Switchgear	$26.8	System Resiliency Improvements
	New Substation	$89.3	System Resiliency Improvements
	New Load Center	$9.3	System Resiliency Improvements
	New RFL Relays	$17.1	System Resiliency Improvements
Asset Replacements	Proactive Pole/Structure Replacement	$533.0	Aging Asset Replacement
	Proactive Recloser Replacement	$0.6	Aging Asset Replacement
	Proactive Overhead Reconductor	$183.5	Aging Asset Replacement
	Underground Cable Replacement	$87.8	Underground Asset Hardening
	Proactive Breaker Replacement	$78.6	Aging Asset Replacement
	Proactive Switchgear Replacement	$51.0	Aging Asset Replacement
	Proactive Transformer Replacement	$312.8	Aging Asset Replacement
	Proactive RFL Relay Replacement	$0.4	Aging Asset Replacement
	Proactive Protection Relay Replacement	$13.0	Aging Asset Replacement
Rebuilds	Overhead Line Rebuild	$1,623.7	Overhead Asset Hardening
	Underground Line Rebuild	$50.9	Underground Asset Hardening
	Substation Rebuild/Replace	$668.6	Substation Infrastructure Upgrades
Other	Lighting	$56.0	Aging Asset Replacement
	Worst Network Vault Replacement	$4.0	Aging Asset Replacement
	Worst Sub Wildlife Protection	$4.4	System Resiliency Improvements
	4kV to 12kV Conversion	$22.0	System Resiliency Improvements
	RTU Communications Upgrades	$8.6	Substation Infrastructure Upgrades
	Purchase of Spare Transformers	$137.1	Aging Asset Replacement
	Other Enabling Investments – Aging Infrastructure	$6.7	Aging Asset Replacement
	Other Enabling Investments – Substation Infrastructure Upgrades	$66.5	Substation Infrastructure Upgrades
	Other Enabling Investments – System Resiliency	$4.8	System Resiliency Improvements
	Total:	**$4,457.1**	

[15] Refer to file Master Projects List – JL1008.xls for a cross-referencing of individual projects / programs to these groupings.

These Project / Program Groupings account for $4,457.1 million of the $5,810.6 million portfolio. The balance[16] of $1,353.5 million is included within the following general categories of work:

1. Facilities and Information Technology ($156 million)
2. Fleet ($142.6 million)
3. Generation Interconnection Agreement and Notice to Construct from SPP ($64.1 million)
4. Required (Regulatory, NERC, NESC, and Roadwork) ($309.2 million)
5. Load Growth and New Customers ($555.5 million)
6. Tools and Equipment ($20.2 million)
7. Storm Restoration, Damages and Break-Fix ($416.3 million)
8. Asset Removals, Relocations, and Reimbursements ($166.6 million)

2.2 Quantification of Work within the Project / Program Groupings

The quantification of work involved a review of each project / program and the capture of any information in the description that would aid in assigning quantities (by asset class). If not readily available in the description, a series of discussions ensued among the respective parties to (1) either directly determine the quantity, or (2) define a unit cost from which a quantity could be inferred. The following table summarizes the unit costs used to drive this portion of the process, where applicable.

[16] These amounts total $1.8 billion which, combined with the $4.5 million itemized in Table 2-1, exceeds $5.8 billion. The overage is part of the $723 million described in the filings as General Facilities and Other.

Table 2-2: Unit Costs

	Project / Program Grouping[17]	Unit Cost	Units
New Assets	New Pole/Structure	12kV/34kV: $7,500 69kV: $15,000 115kV: $35,000 138kV: $45,000 161kV: $55,000 230kV/345kV: $70,000	Per Pole/Structure
New Assets	New Overhead Line	12kV: $150,000 34kV: $250,000 69kV/115kV/138kV/161kV: $1,600,000 230kV/345kV: $1,750,000	Per Mile
New Assets	New Breaker	12kV: $75,000 34kV: $100,000 69kV: $140,000 115kV/138kV: $175,000 161kV: $200,000 230kV: $300,000 345kV: $600,000	Per Breaker
New Assets	New RFL Relay	$100,000	Per Relay
Asset Replacements	Proactive Pole/Structure Replacement	Same as 'New Pole/Structure' (Above)	
Asset Replacements	Proactive Recloser Replacement	$50,000	Per Recloser
Asset Replacements	Proactive Overhead Reconductor	12kV/34kV: $150,000 69kV: $600,000	Per Mile
Asset Replacements	Underground Cable Replacement	$500,000	Per Mile
Asset Replacements	Proactive Breaker Replacement	Same as 'New Breaker' (Above)	
Asset Replacements	Proactive Switchgear Replacement	Distribution Line Disconnect: $25,000 Transmission Line Disconnect: $75,000 Distribution Substation Disconnect: $7,000 Transmission Substation Disconnect: $20,000 Open Air Switchgear: $5,000 Transmission Circuit Switcher: $250,000	Per Switch/Switchgear
Asset Replacements	Proactive Transformer Replacement	Pole/Pad Mounted Transformer: $5,000 Substation Transformer (34/12kV): $600,000	Per Transformer
Asset Replacements	Proactive RFL Relay Replacement	$100,000	Per Relay
Asset Replacements	Proactive Protection Relay Replacement	$100,000	Per Relay
Rebuilds	Overhead Line Rebuild	12kV: $150,000 34kV: $250,000 69kV/115kV/138kV/161kV: $1,600,000 230kV/345kV: $1,500,000	Per Mile

[17] Refer to file Master Projects List – JL1008.xls for a cross-referencing of individual projects / programs to these groupings.

2.3 Computation of Benefits

With the quantification of work complete, the information was loaded into a Computational Model[18], which aggregated the benefits generated by each program/project grouping, within each jurisdiction, applying a split (where appropriate) between transmission- and distribution-related investments. The benefits were calculated across the following categories:

- **System Reliability Improvement**, based on the projected elimination of customer interruptions (CIs) and reduction of customer minutes (CMIs), and associated improvement in SAIFI and SAIDI, equating to each Investment Grouping. To arrive at these numbers, we calculated historical averages of CIs per event and CMIs per event for the asset classes / groupings assigned within each Investment Grouping. These unitized values (e.g., per breaker replaced, miles of line reconductored, etc.) were then translated to projected SAIFI and SAIDI improvements.
- **Operational Efficiency improvement (Internal to Evergy):** In addressing Operational Efficiency Improvements, we addressed the savings attributed to the elimination of outages and the difference between performing planned and reactive work.
    - **Elimination of Outages**: Drawing on the total number of CMIs and CIs for an asset / asset grouping over a predefined timeframe, we determined a typical duration for an outage driving its replacement. Based on an assumed crew size and fully loaded hourly base rate, this typical outage duration was then monetized:

      No. of Crews x *Crew Size* x *Base Hourly Rate* x *Avg. Outage Duration* x *CIs Avoided* where the *Average Outage Duration = CMIs per CI* and *CIs Avoided = Units of Work x CIs per Event*
    - **Reduced Reactive Work**: We applied a 20 percent efficiency factor in differentiating between planned and reactive work, using the labor component of unit cost to apply this factor (Section 1.4.3 provides rationale, substantiated by information gleaned from various UMS Group facilitated Global Learning Consortia):

      Unit Cost x *Labor Percentage* x *Efficiency Factor (20%)* x *Units of Work*
- **Customer Benefits**: In addressing Customer Benefits, we calculated savings attributed to the elimination of CIs in executing a Program Grouping as well as the reduction of any overtime, not accounted for in the Operational Efficiency Improvement calculation required to restore service.
    - The **Avoided Customer Interruptions** (often referred to as "Customer Savings") was calculated for each action and aggregated, consistent with the Plan's 2020-2024 projected work and cash flow. Driven by the number of Customer Interruptions (events) avoided, we used the DOE ICE / Berkley Model, using the tables and formulae in Appendix D that link the cost of an event (by customer type) to a range of outage durations.

      Savings per CI x *CIs Avoided* where *CIs Avoided = Units of Work* x *CIs per Event*
    - **Reduced Overtime** was calculated using an assumed percent of a specific asset's repairs resulting from unplanned outages outside normal working hours (70%) and an assumed duration to effect repairs. Additional assumptions include the typical overtime rate

[18] The Computational Model is a UMS Group developed repository of relevant data and algorithms to calculate benefits at the Program / Project Grouping level.

premium and number / size of crews, all documented along with all the above benefits (and available upon request).

No. Crews x *Crew Size* x *OT Hourly Rate* x *Avg. Outage Duration* x *CIs Avoided* x *70%* where the average *Outage Duration = CMIs per CI* and *CIs Avoided = Units of Work* x *CIs per Event*

In conducting the above-described benefit calculations, the following benefit capture rates (unitized factors to be applied to the number of units of work) were developed.

Table 2-3: Benefit Capture Rate (Per Unit)

	Project / Program Grouping[19]	Units	Reliability		Operational Efficiencies		Customer Benefits	
			CI	CMI	Outage Elimination	Proactive Work	CI	Reduced Overtime
New Assets	New Pole/Structure	535	1.2	166.6	$999.67	N/A	$586.44	$787.24
New Assets	New Recloser	2,209	N/A	390.9	N/A	N/A	$1,975.44	N/A
New Assets	New Overhead Line	349.1	18.5	1,843.6	$11,061.82	N/A	$8,961.06	$8,711.19
New Assets	New Underground Line	14.0	1.7	147.1	$882.88	N/A	$845.05	$695.27
New Assets	New Breaker	29	N/A	N/A	N/A	N/A	N/A	N/A
New Assets	New Switches	17	N/A	N/A	N/A	N/A	N/A	N/A
New Assets	New Substation	22	N/A	N/A	N/A	N/A	N/A	N/A
New Assets	New Load Center	10	N/A	N/A	N/A	N/A	N/A	N/A
New Assets	New RFL Relays	171	N/A	N/A	N/A	N/A	N/A	N/A
Asset Replacements	Proactive Pole/ Structure Replacement	38,665	0.9	114.2	$684.93	$16.45	$515.76	$539.38
Asset Replacements	Proactive Recloser Replacement	6	9.9	619.2	$34.03	$168.06	$4,776.54	$1,631.76
Asset Replacements	Proactive Overhead Reconductor	1,211.9	0.3	25.6	$153.81	$853.83	$135.54	$121.13
Asset Replacements	Underground Cable Replacement	174.3	0.6	52.8	$316.60	$1,692.43	$288.44	$249.33
Asset Replacements	Proactive Breaker Replacement	427	0.3	39.4	$315.06	$1.38	$136.14	$248.11
Asset Replacements	Proactive Switch Replacement	3,402	0.2	11.6	$87.77	$0.27	$109.04	$69.12
Asset Replacements	Pole/Pad Mounted Transformer Replacement	28,870	0.2	28.3	$226.70	$5.20	$90.85	$178.53
Asset Replacements	Substation Transformer Replacement	236	0.002	0.3	$2.12	$2.77	$0.93	$1.67
Asset Replacements	Proactive Protection Relay Replacement	130	0.2	31.8	$254.30	$0.78	$374.70	$200.26
Rebuilds	Overhead Line Rebuild	3,649.4	1.6	169.3	$1,015.58	$2,652.13	$781.55	$799.77
Rebuilds	Underground Line Rebuild	54.3	1.4	112.4	$674.41	N/A	$611.58	$531.10
Rebuilds	Substation Rebuild/Replace	168	1.0	86.7	$2,081.32	N/A	$744.19	$1,639.04

[19] Refer to file Master Projects List – JL1008.xls for a cross-referencing of individual projects / programs to these groupings.

Other[20]	Worst Network Vault Replacement	2	0.01	0.8	$8.44	N/A	$3.42	$6.65
	Worst Sub Wildlife Protection	25	0.1	5.7	$33.95	N/A	$37.94	$26.73

Included in the overall calculus, was a Benefit Weighting Factor, summarized below and applied to all the benefit calculations, addressing the probability that a specific asset / asset grouping will encounter an event that will preclude an outage which otherwise would have occurred.

Table 2-4: Benefit Weighting Factor

	Project / Program Grouping[21]	Jurisdiction				Rationale
		KS Central	KS Metro	MO Metro	MO West	
New Assets	New Pole/Structure	0.03964	N/A	N/A	N/A	Distribution Structure Events / All Events
	New Recloser	0.02706	0.03484	0.03647	0.04501	All Events per Circuit / Distribution Circuits
	New Overhead Line (Dx)	0.89490	0.73772	0.86894	0.79977	Overhead Distribution Events / All Events
	New Overhead Line (Tx)	0.00300	0.00050	0.00183	0.00626	Overhead Transmission Events / All Events
	New Underground Line	0.09416	0.24863	0.11583	0.18376	Underground Distribution Events / All Events
	New Breaker	N/A	N/A	N/A	N/A	N/A
	New Switches	N/A	N/A	N/A	N/A	N/A
	New Substation	N/A	N/A	N/A	N/A	N/A
	New Load Center	N/A	N/A	N/A	N/A	N/A
	New RFL Relays	N/A	N/A	N/A	N/A	N/A
Asset Replacements	Proactive Pole/Structure Replacement (Dx)	0.03964	0.03141	0.03154	0.03965	Distribution Structure Events / All Events
	Proactive Pole/Structure Replacement (Tx)	0.00076	0.00076	0.00003	0.00003	Transmission Structure Events / All Events
	Proactive Recloser Replacement	0.02706	0.03484	0.03647	0.04501	All Events per Circuit / Distribution Circuits
	Proactive Overhead Reconductor	0.12825	0.04483	0.08357	0.04568	Distribution Overhead Wire + Connector Events / All Events
	Underground Cable Replacement	0.01106	0.06895	0.02903	0.07363	Underground Cable Events / All Events
	Proactive Breaker Replacement (Dx)	0.00048	0.00110	0.00130	0.00136	Distribution & Substation Breaker Events / All Events
	Proactive Breaker Replacement (Tx)	0.00001	0.00001	0.00001	0.00001	Transmission Line Breaker Events / All Events
	Proactive SS Disconnect Switch Replacement	0.00029	0.00018	N/A	0.00006	Substation Switch Events / All Events
	Proactive Line Disconnect Switch Replacement (Dx)	0.01373	N/A	0.00204	N/A	Distribution Line Switch Events / All Events
	Proactive Line Disconnect Switch Replacement (Tx)	0.00004	0.00004	0.00038	0.00038	Transmission Line Switch Events / All Events
	Proactive Open Air Switchgear Replacement	*N/A*	0.00018	0.00018	0.00006	Substation Switch Events / All Events

[20] Seven Groupings have been excluded from this Table as they are enablers but direct generators of these benefits.
[21] Refer to file Master Projects List – JL1008.xls for a cross-referencing of individual projects / programs to these groupings.

	Proactive Circuit Switcher Replacement	0.00029	0.00018	0.00018	0.00006	Substation Switch Events / All Events
	Pole Mounted Transformer Replacement	0.04418	0.02107	0.02481	0.01931	Overhead Transformer Events / All Events
	Pad Mounted Transformer Replacement	0.00493	0.01660	0.00663	0.00767	Underground Transformer Events / All Events
	Substation Transformer Replacement	0.00022	0.00024	0.00014	0.00013	Substation Transformer Events / All Events
	Proactive Protection Relay Replacement	0.00026	N/A	N/A	0.00026	Substation Control Events / All Events
Rebuilds	Overhead Line Rebuild (Dx)	0.27408	0.13331	0.18964	0.14373	Distribution Overhead Line Equipment Events / All Events
	Overhead Line Rebuild (Tx)	0.00161	0.00046	0.00046	0.00129	Transmission Overhead Line Equipment Events / All Events
	Underground Line Rebuild	0.04361	0.11635	0.05454	0.10306	Underground Line Equipment Events / All Events
	Substation Rebuild/Replace	0.00154	0.00104	0.00107	0.00132	Substation Equipment Events / All Events
Other[22]	Worst Network Vault Replacement	0.00021	N/A	N/A	N/A	Underground Structure Events / All Events
	Worst Sub Wildlife Protection	0.00234	N/A	N/A	N/A	Animal Events / All Events

2.4 Quantification of Risk

In quantifying Risk (the expected outcome if the Plan is not funded), we considered three areas across each jurisdiction:

1. **Ever-increasing number of larger unplanned transmission outages (particularly the 69kV system in Kansas Central).** Having already determined that most unplanned transmission outages that affected customers were related to the 69kV system located in Kansas Central, we looked at the trends at that voltage in Kansas Central between 2017 and 2019 regarding customer interruptions and customer minutes. Factoring for the fact that not all assets have been in service past their expected service life, we adjusted the annualized increases (which ranged between 12 and 20 percent) to 6 percent. Applying those factors, we projected the number of customer interruptions and customer minutes that the system would experience in 2030, and from that calculated the net increase between 2020 and 2030 to ultimately produce an annualized increase of SAIFI and SAIDI, specific to Kansas Central.

2. **Increased number of equipment caused outages.** With respect to equipment caused outages, as in our approach for 69kV, we looked at trends for number of outage events between 2017 and 2019, within each of the four jurisdictions.

3. **Increased costs of reactive repair and maintenance.** To address these risks, we used the number of equipment failure events as a proxy for establishing an annual trend within each of the four jurisdictions. This trend was applied to the five-year average of the Storm Restoration, Damages and "Break-Fix" related items of the Plan to calculate the average annual increase in dollars attributed to more reactive maintenance and repair activities.

[22] Seven Groupings have been excluded from this Table as they are enablers but direct generators of these benefits.

Although not yet directly quantifiable with respect to the cost of risk, we also reviewed changes in the external environment and the impact on T&D system performance and resilience, and the methods employed by Evergy in measuring risks related to the Transmission System.

2.4.1 Changes in the External Environment

Evidence surrounds us of increasing frequency and severity of extreme weather events[23]. The unprecedented Winter Storm Uri that impacted large areas of the Midwest, including Missouri and Kansas, the growing scale and number of wildfire events across the west, the rapid succession of once-in-a-hundred-year storms buffeting the US Gulf region and east coast States, make it plainly clear that mother nature is imposing more severe strain on utility electric infrastructure, with associated negative impacts on both the Transmission and Distribution systems. To illustrate this point, the following table summarizes the number of Major Event Days (an indication of storm frequency and severity) in both Kansas and Missouri, showing an increase of 25 and 24 percent respectively.

Table 2-5: Number of Major Event Days

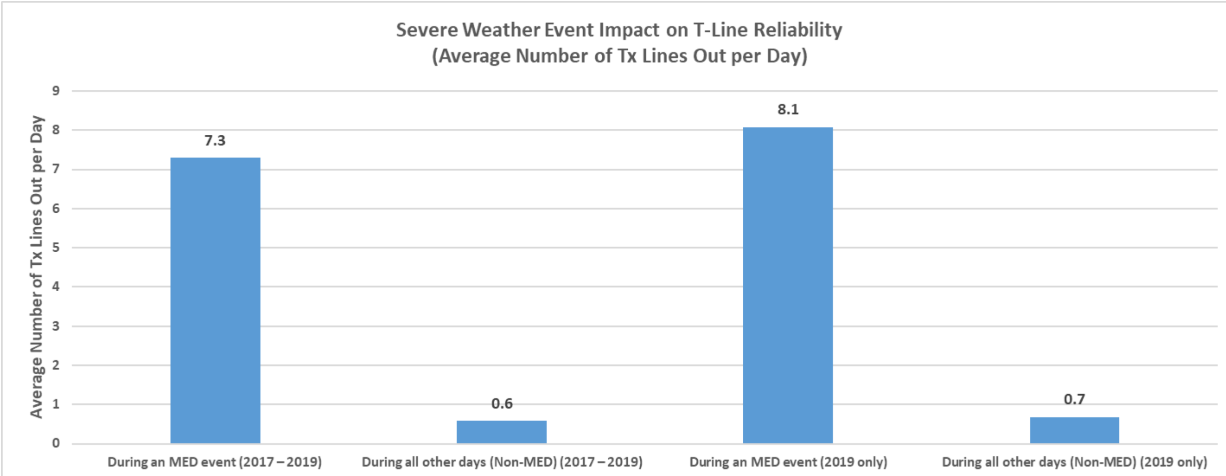
State	2017	2018	2019	3-Year CAGR
Kansas	30	31	47	25%
Missouri	40	53	62	24%

NOTE: Though the studies / sources cited below, and the data presented in Table 2-5 makes a strong case for Evergy's focus on resilience, due to the erratic nature of year-over-year Major Event Days categorization, this information was not factored into our risk calculations.

Underneath the customer-facing reliability metrics (i.e., SAIFI and SAIDI), we note that the transmission circuits are particularly vulnerable, with a growing trend to higher numbers of multiple lines tripping out on such days. Figure 2-1 below shows that this severe weather impact on transmission line reliability is significant and appears to be getting worse. The increase in frequency and severity of extreme weather can be expected to further erode transmission security of supply, where outages are likely to begin affecting N-1 and possibly N-2 transmission and distribution substations / delivery points.

[23] Several research studies including those sponsored by the Center for Climate and Energy Solutions (source: National Oceanic and Atmospheric Administration's National Climatic Data Center), U.S. Environmental Protection Agency (Climate Change Incidents), and Intergovernmental Panel on Climate Change (August 2021).

Figure 2-1: Severe Weather Event Impact on T-Line Reliability



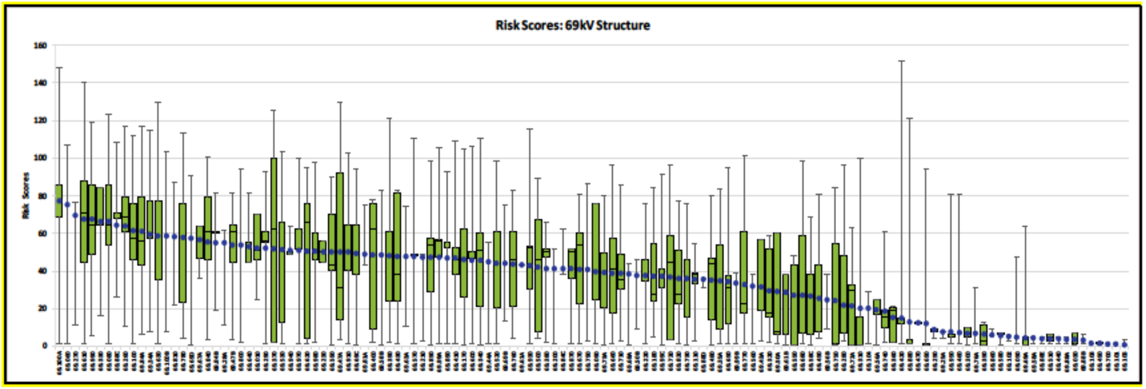
Weather is not an area in which utilities have any control, but many utilities (including Evergy) are making increasing investments in 'hardening' and increasing the resilience of their T&D systems. Numerous cases can be cited of utilities that are upgrading the ability of their network to withstand weather extremes and increasing their design flexibility to be able to restore service more quickly to customers after damage and outages occur. Examples include FPL changing out wood poles for concrete on the entire distribution primary mainline, and undergrounding all lateral distribution lines, SCE investing $2 billion for 4,500 miles of covered distribution wire over the next 5 years, PG&E undergrounding 10,000 miles of distribution lines for an estimated $15 to $30B, etc. Compared to these examples, Evergy's Plan is much more than a single large bet on how to harden the system. It represents a balanced portfolio of targeted interventions, each selected to achieve a specific set of important customer benefits, while overall improving the robustness and resilience of the transmission and distribution network to enable it to withstand much of the anticipated environment / weather stress coming over the next few years.

2.4.2 Additional Measures for Accounting for Transmission Risk

As stated in Section 1.4, we examined the methods employed by Evergy in measuring risks to the transmission system and noted that Evergy's approach to the identification and tracking of risks associated with transmission lines represented a significant advancement beyond the normal utility practice of measuring and maintaining records of risk at the overall line or line section level (i.e., switchable sections of transmission line comprised of numerous sequential spans that together represent the portion of the line between two switching devices). Figure 2-2 illustrates Evergy's risk assessment of transmission line structures along its 136 transmission lines in Kansas Central that are operated at 69kV.

Every structure has a risk score assigned to it based on inspection deficiencies, corrective work order count, and equipment age. This is a far more detailed level of granularity than is used by most US utilities. The advantage that this provides for customers is more precise targeting of rebuild projects, where only the highest risk elements / portions of each line need be rebuilt or replaced. This can provide far greater levels of risk reduction / reliability improvement per dollar spent than a process that rebuilds the entire line once it rises to the top of the risk register. Besides increasing the likelihood that the current plan will be more efficient than those in existence across the industry, this information aided in the identification of Contingency Risk.

Figure 2.2 – Evergy Transmission Line Risk Assessment



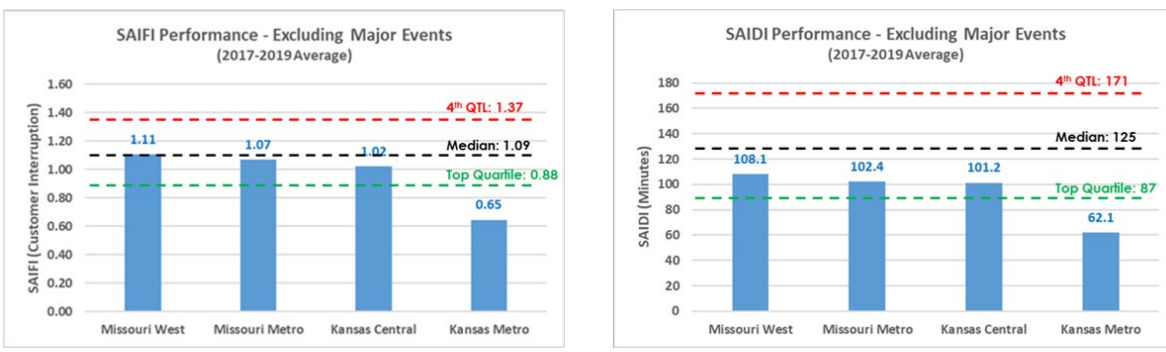
3.0 Program Benefits and Risks

In implementing the Plan as currently outlined, Evergy, its customers and other key external stakeholders can anticipate the tangible benefits of improved system performance and increased operating efficiencies while simultaneously setting the stage for the emerging energy transition. Additionally, there are risks embedded in the system (most notably an impending “bow wave” of equipment caused distribution outages and an increasing trend of unplanned transmission outages), the mitigation of which is also a noted benefit of the Plan. The following discussion provides context for both the “value” (extent to which an investment portfolio provides the tangible benefits described above) and “risk” (probable effect should the Plan not proceed as proposed) perspectives, the development of the previously presented risks should the Plan not be implemented, and various portrayals of the benefits summarized in Table 1-1.

3.1 Context

The Plan is appropriately focused on achieving sustained improvement in reliability (maintaining electric delivery to meet Evergy targeted levels of performance) and resiliency (designing a system to address threats and minimize any degradation in reliability), the foundation on which to build a truly modernized grid. From a high-level view, except for Missouri West, average reliability performance between 2018 and 2020 has hovered between top and second quartile.

Figure 3-1 System Reliability Performance Summary[24]



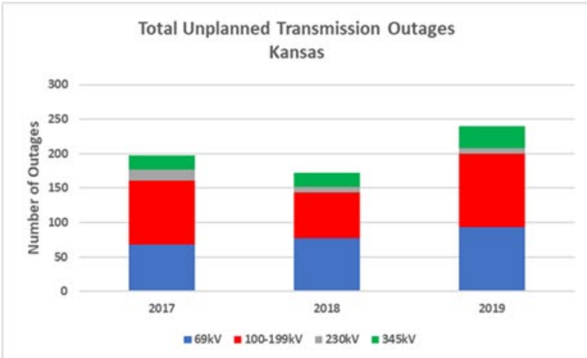
Within these numbers there are several trends and patterns to be aware of, remedies for which are addressed in the Plan.

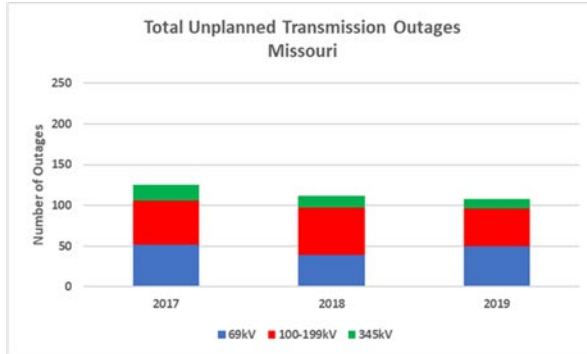
3.1.1 Unplanned Transmission Outages

Unplanned Transmission Outages, typically small contributors to customer interruptions, are increasing in Kansas (remaining steady in Missouri).

[24] The system average interruption frequency index (SAIFI) is the average number of times that a system customer experiences an outage during the year (or timeframe under study), and the system average interruption duration index (SAIDI), usually measured in minutes or hours, is the average outage duration for each customer served. The source of benchmark comparisons is the annual IEEE Benchmark Reports issued by the Distribution Reliability Working Group.

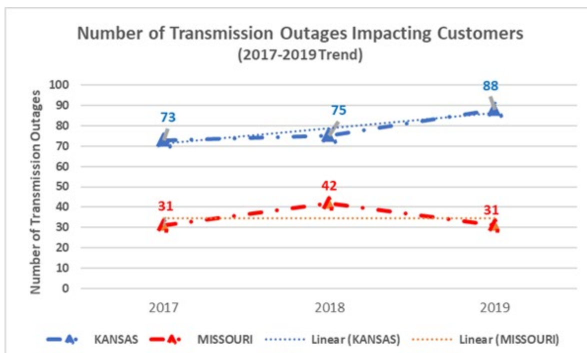
Figure 3-2: Unplanned Transmission Outage (Sustained > 1 Minute) Trends and Comparisons





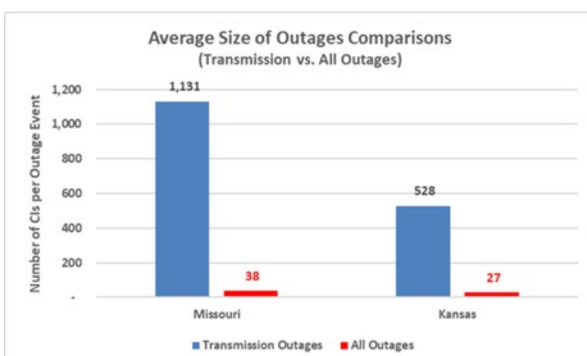
And similar trends / comparisons apply to those unplanned transmission outages that impact customers. Note that Kansas Central's customers represent a higher percentage of customer interruptions than those in the other three jurisdictions or the observed norm[25].

Figure 3-3: Transmission Outage Trends and Comparisons (> 5 Minutes)



Though the average size of a transmission customer impact outage in Missouri is over twice that in Kansas,

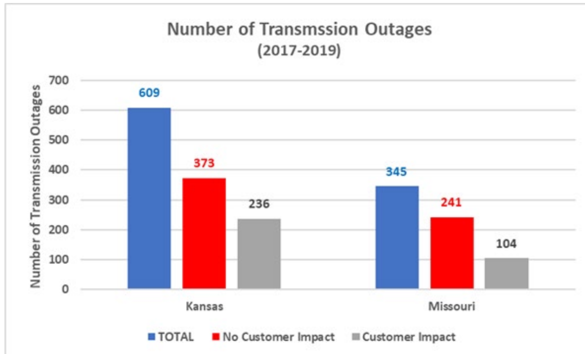
Figure 3-4: Transmission Outage Size Comparisons (>5 Minutes)
(Customer Interruptions per Event)



[25] The observed norm refers to several reliability assessments conducted over the past 10 years and the results of disaggregated analyses by stage of delivery (i.e., substation, transmission, sub-transmission, and distribution).

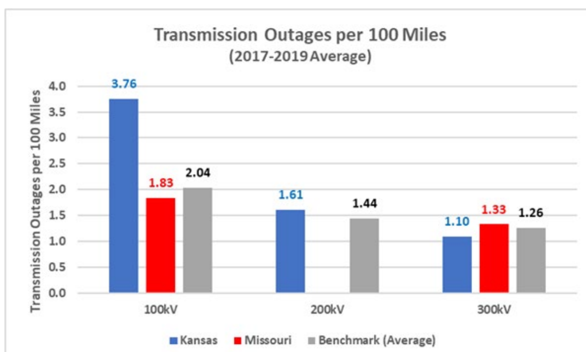
The number of unplanned transmission outages (sustained > 1 minute) affecting customers in Kansas – 236 vs. 104 in Missouri – counters the effect of this difference).

Figure 3-5: Transmission System Performance Comparisons (Sustained >1 Minute) (69kV and above)



Normalized comparisons of 100kV and above further support the notion that a greater focus for Evergy's capital investment strategy should be in Kansas (particularly less than 200kV).

Figure 3-6: Normalized Transmission System Performance Comparisons (Sustained >1 Minute)



NOTE: The Industry Benchmark reflects the average of an upper tier group of Transmission Operators, indicating significant challenges with Evergy's 115kV, 138kV and 161kV systems, particularly in Kansas.

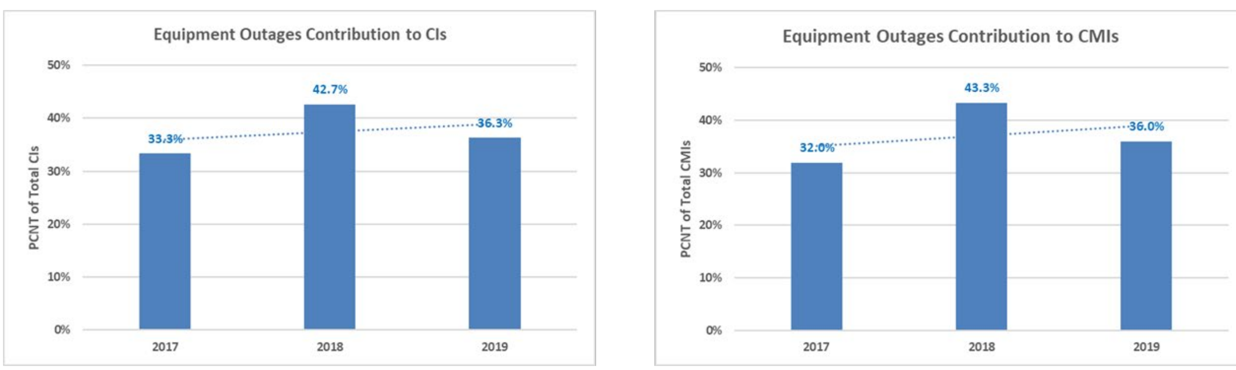
Another view of the interstate comparisons substantiates the challenges with voltages between 100kV and 199kV, but even more so, 69kV.

Figure 3-7: Transmission System Impact (Sustained > 1 Minute) on Customers by Voltage (Kansas and Missouri)

3.1.2 Equipment Caused Outages

Equipment Caused Outages, often the result of aging and deteriorating infrastructure, are becoming more dominant contributors to customer interruptions (SAIFI) and minutes of interruption (SAIDI).

Figure 3-8: Equipment Caused Outages Contribution



NOTE: Increases in CIs and CMIs directly relate to deterioration (increases) in SAIFI and SAIDI, respectively.

And, in comparing 2017 and 2019, those occurring in Missouri West showed the most dramatic increase as a percent of SAIFI and SAIDI.

Table 3-1: Equipment Caused Outage SAIFI and SAIDI Comparisons

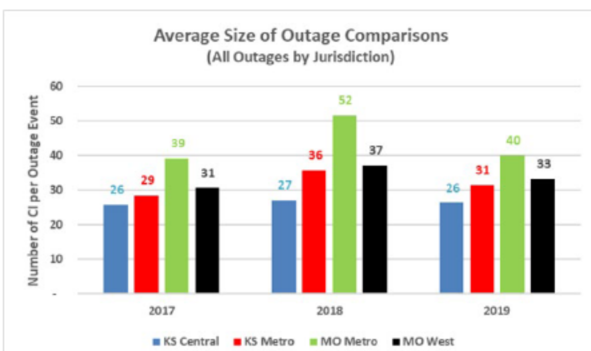
State	Contribution to SAIFI			Contribution to SAIDI		
	2017	2019	Difference Increase / (Decrease)	2017	2019	Difference Increase / (Decrease)
Missouri	0.26	0.36	**37%**	23.5	33.5	**42%**
Missouri West	0.21	0.40	87%	19.0	40.0	110%
Missouri METRO	0.32	0.32	0%	28.5	26.2	(8%)
Kansas	0.33	0.37	**11%**	33.0	38.5	**16%**
Kansas Central	0.40	0.41	5%	39.8	46.7	17%
Kansas METRO	0.17	0.25	48%	15.7	17.4	11%

Further, a review of the average age of the more critical asset classes (refer to Appendix C) suggests that these distribution outage trends may also accelerate for unplanned Transmission outages, as the system, on average, is (according to asset records and as indicated in previous submittals made by Evergy) more than 30 years old with some components nearing 100 years in age.

3.1.3 Average Size of Outages

Average Size (*number of CIs per event*) of Outages speaks to the effectiveness of / need for sectionalizing / circuit protection initiatives. We have observed that average sizes less than 30 are representative of a properly sectionalized system, suggesting that the Kansas jurisdictions are in better shape in this regard than the two jurisdictions in Missouri.

Figure 3-9: Average Size of Outage Comparison



3.1.4 Inherent SAIFI / SAIDI Degradation

Notwithstanding the above, reliability degradation inherent to any electric transmission and distribution system, often quoted in the range of 2 to 5 percent annually (e.g., left unaddressed and all things being equal, an annual SAIFI of 1.0 will increase to between 1.02 and 1.05 the following year; or an annual SAIDI of 100 minutes will increase to between 102 and 105 minutes the following year) will occur. Studies have been conducted that through inference support this claim. In particular, the Office of Electricity Delivery and Energy Reliability of the US Department of Energy contracted with Ernest Orlando Lawrence Berkely National Laboratory to examine the temporal trends in electricity reliability in 2012. Using industry data from 2000-2009, this study reported that the average duration and average frequency of power interruptions had been increasing over time at a rate of approximately two percent annually (i.e., reliability was getting worse). The timeframe (2000-2009) is relevant as many of the major electric infrastructure reinvestment programs had not yet been started, thus providing a strong indicator of this inherent degradation. The upper range (i.e., 5 percent) applies to utilities that have lagged in implementing infrastructure reinvestment-related programs, and thus are absorbing the effect of a "bow wave" of ever-increasing number of equipment caused outages.

3.2 Risk Remediation

The above discussion infers four primary risks, the remediation of which constitutes tangible benefits in avoiding customer outages and decreasing related restoration and / or "break-fix" costs:

1. Ever-increasing number of larger unplanned transmission outages (particularly the 69kV system in Kansas),
2. Increased number of larger equipment caused outages,
3. Related to the above increased number of larger equipment caused outages, increase in the amount of reactive repair and replacement activities, and
4. Factored in the above calculations, increasing frequency and severity of extreme weather events and associated impacts on Transmission Infrastructure.

3.2.1 Risks Related to Unplanned Transmission Outages

The number of unplanned transmission outage events and those that impact customers in Kansas (particularly on the 69kV system) is likely to increase (Refer to Figure 3-2 for Missouri / Kansas comparison).

Table 3-2: 69kV Transmission Outage Summary - Kansas

Measure	2017	2019	Annualized Increase / (Decrease)
Number of Unplanned Outages	68	93	17%
Impacting Customers	49	66	16%
PCNT Impacting Customers	72%	71%	NA
Customer Interruptions	29,846	37,476	12%
Customer Minutes	2,548,223	3,635,363	20%

Left unaddressed, these increases will offset a portion of any future improvements made and have the potential to degrade reliability in Kansas, as the average unplanned transmission outage in Kansas affects between 560 and 610 customers, a 20-fold higher impact than the average size of a typical nontransmission outage. Continuance of this trend is likely to result in year-over-year increases in customer interruptions and minutes, approaching numbers summarized in the following Table:

Table 3-3: Quantified Reliability Risks – Kansas 69kV

Measure	2019	2030 Projected	Assumed Annual Increase[26]
Customer Interruptions	37.476	71,141	6%
SAIFI Increase (Kansas)	-	0.03	6%
Customer Minutes	3,635,363	6,901,004	6%
SAIDI Increase (Kansas)	-	3.3 minutes	6%

3.2.2 Risks Related to Equipment Outages

With respect to equipment caused outages, the trends addressed in the previous Electric Distribution Resiliency Plan (EDGR) have continued, even more so in Missouri:

Table 3-4: Equipment Caused Outage Summary

Jurisdiction	No. of Events 2017	No. of Events 2019	Annual PCNT Increase
Kansas Central	7,549	9,029	9.3%
Kansas METRO	1,216	1,428	8.5%
Missouri METRO	1,636	1,848	6.2%
Missouri West	2,171	2,866	15.2%

Even modest extrapolations of 2017-2019 SAIFI and SAIDI trends suggest that if not aggressively addressed, equipment caused outages will overtake all other causes within the next five years, particularly in Missouri West where the average ages of critical distribution assets are nearing or have already exceeded their expected service lives (refer to Appendix C).

[26] Though the 2017-2019 trend indicates a 12 percent annual increase, UMS Group applied a 6 percent annual rate to preclude inadvertent overstatement of risks.

Table 3-5: Quantified Reliability Risks – Equipment Caused Outages

Measure	2019	2030 Projected
Kansas Central		
Customer Interruptions	294,545	407,719
SAIFI Increase	-	0.16
SAIDI Increase	-	17.9 minutes
Kansas METRO		
Customer Interruptions	67,803	166,332
SAIFI Increase	-	0.36
SAIDI Increase	-	25.2 minutes
Missouri METRO		
Customer Interruptions	95,222	184,547
SAIFI Increase	-	0.30
SAIDI Increase	-	24.6 minutes
Missouri West		
Customer Interruptions	131,407	249,450
SAIFI Increase	-	0.36
SAIDI Increase	-	36 minutes

3.2.3 Reactive Repair and Replacement

In addressing risks related to aging infrastructure, we used equipment failure events as a proxy for establishing an annual trend. Based on that, the following average annual increase between 2020 and 2030 can be applied to the Storm Restoration, Damages and "Break-Fix" blankets.

Table 3-6: Storm Restoration, Damages and "Break – Fix" Blankets Annual Increased Risk Calculation

Jurisdiction	No. of Events 2017	No. of Events 2019	Annual PCNT Increase	Adjusted PCNT Increase	AVG Annual Increase thru 2030	AVG "Break-Fix" Budget	Average Annual Increase
Kansas Central	7,549	9,029	9%	8%	12%	$16.5m	$2.0m
Kansas METRO	1,216	1,428	8%	4%	5%	$14.6m	$0.7m
Missouri METRO	1,636	1,848	6%	4%	5%	$18.3m	$0.9m
Missouri West	2,171	2,866	15%	8%	12%	$28.6m	$3.4m

3.3 Benefit Capture

In assessing the quantitative and qualitative benefits of the Plan for all stakeholders, we implemented a "bottom-up" approach to measure the diverse impacts that will result from the portfolio of the proposed capital investments, initially translating to the following major categories of benefits (defined and quantified at the Grouping level:

- Improved Reliability – As expected, the Plan presents a reduction in the frequency and duration of customer outages across the system by 2025, reductions that have been translated (applying the DOE ICE Model) into dollar savings from the perspective of Evergy's customers.
- Cost Reduction and Avoidance – Many of the resiliency investments will alter the way the Evergy T&D system will be operated and maintained, and over time will reduce operating costs as the plan progresses. Our analyses have addressed the more near-term aspects of cost avoidance, namely the impact of (1) reduction of unplanned outages, (2) improved service restoration times, and (3) a shift from reactive / emergency to planned / programmed repair / replacement activities, thus reducing overtime and improving efficiencies, savings that benefit both the utility and its customers. Longer-term benefits of being better able to seamlessly integrate with future Electric Vehicle (EV) penetration, operate to accommodate DERs, or enable the transactive energy market, though real, are not believed to be applicable within the timeframe of this analysis.

And, at the Grid Resiliency Program portfolio level:

- Statewide Economic Development – The revitalization program will provide significant economic development benefits, particularly if conducted on a moderately aggressive basis (i.e., new jobs, increased tax revenues, increased consumer spending).
- Risk Mitigation – An electric distribution revitalization program can also be viewed as an asset performance risk mitigation plan. Thus, in aggregating the benefits to be derived from this program, it is important to also quantify the level of investment (at the portfolio level) being assigned solely to mitigating high consequence, albeit low probability events that could lead to extended service interruptions, related escalations in overall investment and spending levels, or pose challenges to worker and employee safety.

We initially reviewed all proposed projects / programs, determined which would produce tangible benefits in support of this effort, consolidated these into Groupings, and indicated the role each would play across seven domains:

1. **Reliability** (looking both at reducing / avoiding customer interruptions and reducing customer minutes with corresponding improvements in SAIFI and SAIDI),
2. **Operational Efficiencies** (internal to Evergy, quantifying the extent to which a program component will eliminate costs related to an unplanned outage and improve efficiencies in transitioning to a more proactive / programmatic approach to repair and replacement of critical assets),
3. **Customer Benefits** (translating the reduction / avoidance of customer interruptions to potential customer savings predicated on DOE's ICE Model and identifying the amount of overtime attributed to the elimination / shortening of unplanned outages),
4. **Safety** (providing assurance that appropriate emphasis remains in driving the importance of safety), and

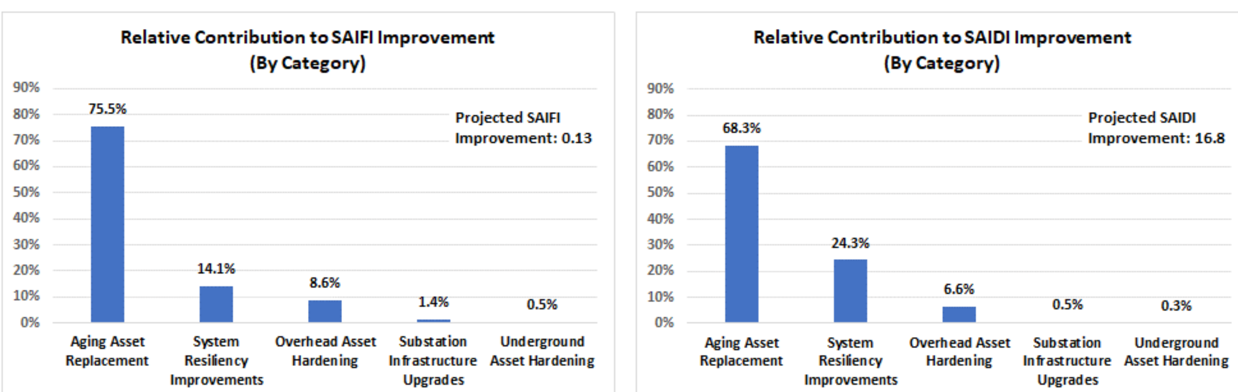
5. **Power Quality / Standardization**: this category of benefits relates to any work performed by Evergy to modernize its network and create consistency in terms of operating voltages, design standards, work practices, etc. A prime example of this is Evergy's "Small Town Rebuild" program which is designed to convert distribution lines from an older 4kV standard to a 12kV design.
6. **Operational Flexibility / Contingency**: This category of benefits relates to work performed by Evergy to distribute grid loads more effectively and isolate smaller portions of the network during outages to reduce customer impacts. For example, creating new ties between circuits or upgrading equipment on existing lines to handle larger energy loads to absorb outages occurring in that portion of the network.
7. **Enabler**: This category of benefits relates to projects that impact the deployment of other grid enhancements. For example, upgrading station equipment to support the installation of new overhead lines, or upgrading non-energized or structural equipment like relay panels. These items are necessary to support the continued renewal and enhancement of the network but will not likely result in direct reliability improvements or operational savings.

For Reliability, Operational Efficiencies, and Customer Benefits we developed a calculative approach (outlined below and supplemented in Appendix D) based on (1) reported reliability data by cause code and / or equipment type and (2) historical perspectives to project the level of efficiencies that can be expected in concert with the Plan. Benefit Capture Rates were computed and factored to account for the probabilities of a specific asset experiencing an event that would translate to the projected value (i.e., benefit). In projecting actual improvement in reliability, we imposed the gradual 2 percent degradation factor described in Section 3.1 as an offset, and a one-year lag as described in Appendix B.

The following charts and tables present these benefits from an overall portfolio perspective, providing "end-of-program" totals across each domain, after which the benefit capture profile is presented (Jurisdiction-specific charts are provided in Appendix F).

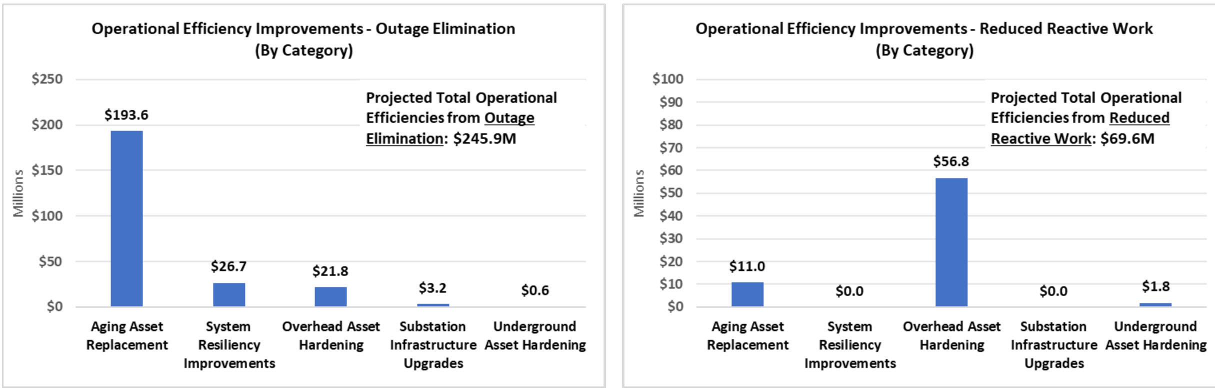
3.3.1 Projected Improvements in Reliability

Figure 3-10: Projected Improvements in Reliability



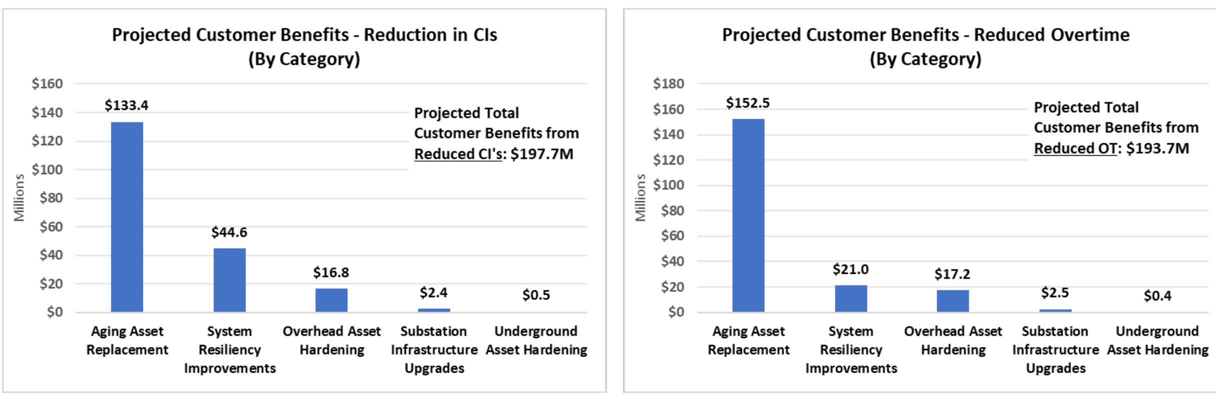
3.3.2 Projected Improvement in Operational Efficiency

Figure 3-11: Projected Improvement in Operational Efficiency



3.3.3 Projected Customer Benefits

Figure 3-12: Projected Customer Benefits



3.3.4 Benefit Capture Profile

Table 3-7: Benefit Capture Profile (2021 – 2030)

Category	Measure	2023	2024	2025	2026	2027	2030
	Kansas Central						
Annual Reliability Improvement	SAIFI Improvement (Reduction)	0.01	0.01	0.02	0.03	0.04	0.04
	SAIDI Improvement (Reduction)	0.8	1.8	2.9	4.4	6.0	6.0
Cumulative Operational Efficiencies	Outage Elimination ($k)	$3,563	$11,082	$23,083	$40,910	$64,759	$136,308
	Reduced Reactive Work ($k)	$1,293	$4,192	$8,596	$14,926	$22,779	$46,339
Cumulative Customer Benefits	Reduced Overtime ($k)	$2,806	$8,727	$18,178	$32,216	$50,998	$107,344
	Avoided Customer Interruptions (DOE ICE Model) ($k)	$2,445	$8,087	$17,369	$31,318	$49,945	$105,823
	Kansas METRO						
Annual Reliability Improvement	SAIFI Improvement (Reduction)	0.002	0.01	0.01	0.02	0.03	0.03
	SAIDI Improvement (Reduction)	0.3	0.7	1.5	2.3	3.0	3.0
Cumulative Operational Efficiencies	Outage Elimination ($k)	$500	$1,578	$3,725	$7,060	$11,375	$24,322
	Reduced Reactive Work ($k)	$55	$210	$638	$1,294	$2,063	$4,371
Cumulative Customer Benefits	Reduced Overtime ($k)	$394	$1,243	$2,933	$5,559	$8,958	$19,154
	Avoided Customer Interruptions (DOE ICE Model) ($k)	$429	$1,419	$3,529	$6,803	$11,024	$23,688
	Missouri METRO						
Annual Reliability Improvement	SAIFI Improvement (Reduction)	0.01	0.01	0.02	0.02	0.02	0.02
	SAIDI Improvement (Reduction)	0.6	1.5	2.2	2.7	3.2	3.2
Cumulative Operational Efficiencies	Outage Elimination ($k)	$1,000	$3,626	$7,322	$11,777	$17,075	$32,970
	Reduced Reactive Work ($k)	$249	$800	$1,851	$3,053	$4,563	$9,091
Cumulative Customer Benefits	Reduced Overtime ($k)	$788	$2,856	$5,766	$9,274	$13,447	$25,964
	Avoided Customer Interruptions (DOE ICE Model) ($k)	$768	$2,756	$5,665	$9,195	$13,380	$25,936
	Missouri West						
Annual Reliability Improvement	SAIFI Improvement (Reduction)	0.01	0.02	0.02	0.03	0.04	0.04
	SAIDI Improvement (Reduction)	0.6	1.9	2.8	3.7	4.6	4.6
Cumulative Operational Efficiencies	Outage Elimination ($k)	$1,349	$5,007	$10,244	$17,169	$25,944	$52,269
	Reduced Reactive Work ($k)	$211	$801	$1,782	$3,154	$4,820	$9,817
Cumulative Customer Benefits	Reduced Overtime ($k)	$1,067	$3,956	$8,090	$13,553	$20,472	$41,231
	Avoided Customer Interruptions (DOE ICE Model) ($k)	$964	$3,957	$8,326	$13,914	$20,996	$42,244

3.4 Project / Program Grouping / Benefits Cross-Reference

Broadening our view, the following table indicates, by Project / Program Grouping, applicability to these computed benefits as well as Safety, Power Quality / Standardization, Operational Flexibility / Contingency, and Enablement of other initiatives, thus forming the basis for generating Figure 1-1 in the Executive Summary.

Table 3-8: Project / Program Grouping and Benefit Cross-Reference

	Project / Program Grouping[27]	Reliability		Operational Efficiencies		Customer Benefits		Safety	Power Quality / STD	Operational Flexibility/ Contingency	Enabler
		CI	CMI	Outage Elimination	Proactive Work	CI	Reduced Overtime				
New Assets	New Pole/Structure	X	X	X		X	X	X		X	X
	New Recloser		X			X		X		X	X
	New Overhead Line	X	X	X		X	X			X	X
	New Underground Line	X	X	X		X	X			X	X
	New Breaker/Switchgear									X	X
	New Substation/Load Center								X	X	X
	New RFL Relays							X	X	X	X
Asset Replacements	Proactive Pole/ Structure Replacement	X	X	X	X	X	X	X			X
	Proactive Recloser Replacement	X	X	X	X	X	X	X		X	
	Proactive Overhead Reconductor	X	X	X	X	X	X	X		X	X
	Underground Cable Replacement	X	X	X		X	X			X	X
	Proactive Breaker/Switchgear Replacement	X	X	X	X	X	X	X		X	X
	Transformer Replacement	X	X	X	X	X	X	X	X	X	X
	Proactive RFL Relay Replacement							X	X	X	X
	Proactive Protection Relay Replacement	X	X	X	X	X	X	X	X	X	X
Rebuilds	Overhead Line Rebuild	X	X	X	X	X	X	X	X		
	Underground Line Rebuild	X	X	X		X	X		X		
	Substation Rebuild/Replace	X	X	X		X	X	X	X	X	
Other	Lighting							X			
	Worst Network Vault Replacement	X	X	X		X	X	X	X		
	Worst Sub Wildlife Protection	X	X	X		X	X	X	X		
	4kV to 12kV Conversion								X	X	

[27] Refer to file Master Projects List – JL1008.xls for a cross-referencing of individual projects / programs to these groupings.

	RTU Communications Upgrades								X	X	X
	Other - Aging Infrastructure										X
	Other - SS Infrastructure										X
	Other - System Resiliency										X
	Spare Transformers								X	X	X

APPENDIX A: UMS GROUP BACKGROUND AND EXPERIENCE

UMS Group is an International Utility Management Consulting firm founded in 1989 to serve the global utility industry. We specialize in enterprise-level value creation, performance management solutions and utility asset management. We are a private employee-owned company incorporated in New Jersey with headquarters in Parsippany, New Jersey, and major branch offices in Australia, The Netherlands, and The Philippines. We bring to our clients a unique knowledge of global industry best practices, an advanced library of diagnostic methodologies and performance benchmarking data, and a strong base of utility strategic and operational expertise. We combine experienced utility consultants and seasoned industry professionals with world class tools and intellectual capital to assist our clients in diagnosing problems, designing solutions, and managing change.

While our methodology, templates and personnel set us apart from other consultants, our greatest strength is our client references. We have accomplished similar projects with significant clients in various markets around the world. The UMS Group advantage is our commitment to partnering with our clients in performance improvement. We offer:

- A team of senior consultants who have "been there and done that" in implementing change in difficult cultural, political and labor environments.
- Strong insights into key trends and directions across the global utility industry, coupled with comprehensive understanding of the underlying drivers, emerging technology, and strategies for creating competitive advantage.
- Time-tested and accepted methodologies for conducting current state assessments in four core areas which we believe are the key to achieving best practices or best-in-class performance: Operating (and Accountability) Model, Business Processes and Practices, Competences, and Technology, Data, and Information Management.
- A comprehensive set of tools and approaches that quickly and effectively build on performance insights gained from assessments, to create actionable improvement strategies and plans.
- Experience in the successful development and implementation management of projects and initiatives that drive improvements in the performance of operations, business and financial, customer service, and asset management.

The keys to UMS Group's success have been our keen insights and analytical capabilities, our strong balance of operational and strategy expertise and our orientation to producing tangible outcomes rather than mere deliverables. Our clients rely on us to help them define and implement the changes necessary to succeed.

The following discussion provides a brief overview of our two primary practice areas (Performance and Asset Management).

Performance Management

UMS Group has developed a family of performance diagnostic and comparison programs applying multi-utility benchmarking. This has been accomplished by utilizing proprietary and masked client submitted performance and cost data, a two-dimensional assessment of asset management performance, and structured practices interviews. This approach has been applied throughout the electric utility industry, establishing the correlation of practices and employee productivity to performance – codifying the fact that "best practices" and a skilled/motivated work force are necessarily associated with only the perennial best performers. Specific services include:

- Performance Management Competency and Process Audits
- Performance Management Supporting Organization Design
- Strategy Formulation/Business Objectives Workshops
- KPI Measurement Design/Architecture
- Performance Management Process Design
- Advanced Business Performance Management Training
- Target Setting and Baseline Support
- Benchmark Diagnostics
- Lean Sigma Improvement Interventions
- Performance Management Technology and Tools
- Performance Management Culture Change Interventions

Asset Management

With respect to Asset Management, UMS Group has performed over 400 projects covering the full gamut of Asset Management since the early 1990s. Our position as an industry leader is evidenced by our designation as an endorsed assessor and trainer by the Institute of Asset Management, the professional body of those involved in the acquisition, operation, and care of physical assets – particularly critical infrastructure. Our approach is based on ISO 55000 (and its predecessor PAS 55), which provides a framework for assessing the extent to which organizations' policies and practices are aligned with the basic tenets of asset management. Though we do not necessarily advocate electric utilities be certified to all aspects of ISO55000, we do use it as a lens in ensuring all asset management activities within a utility support the achievement of its business plan, at optimal cost and on a sustainable basis.

Since the 2004 release of PAS 55 (and subsequent update in 2008 and issuance of ISO55000, of which UMS Group was an active participant), UMS Group has adapted its methodologies to align them with this standard, while retaining our proprietary tools and delivery systems. In assisting utilities in meeting the relevant aspects of PAS 55 / ISO55000 we provide added assurance that they have the programmatic elements in place to manage their assets, and most importantly, manage all known and implied risks, thus creating superior lifecycle value from their owned and/or operating asset base. In so doing, we have effectively crossed the threshold from theoretical knowledge to practical application.

Specifically, our experience spans several critical Asset Management domains; namely:

- Asset Management Business Architecture, Strategy and Planning
- Life-Cycle Investment Decision-Making and Optimization
- Life-Cycle Delivery (Acquisition, Maintenance, Operations and Disposal)
- Asset Information Strategy, Standard, Systems and Data
- Risk and Performance Management
- Leadership and Organizational Change Management
- Business Process Review, Re-engineering, and Standardization

APPENDIX B: INVESTMENT LEVEL IMPACT ON RELIABILITY

[redacted]

[redacted]

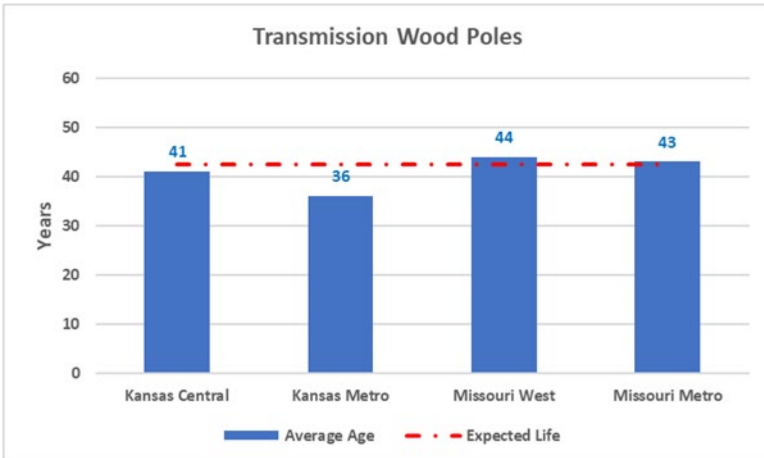
[redacted]

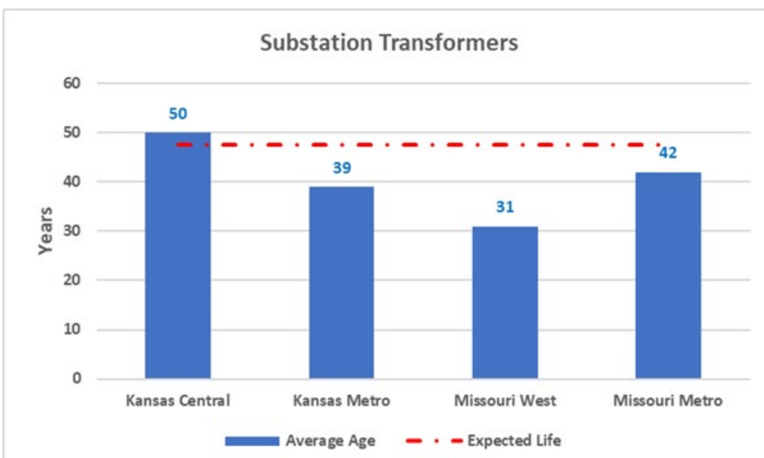
[redacted]

APPENDIX C: ASSET AGE COMPARISONS[28]

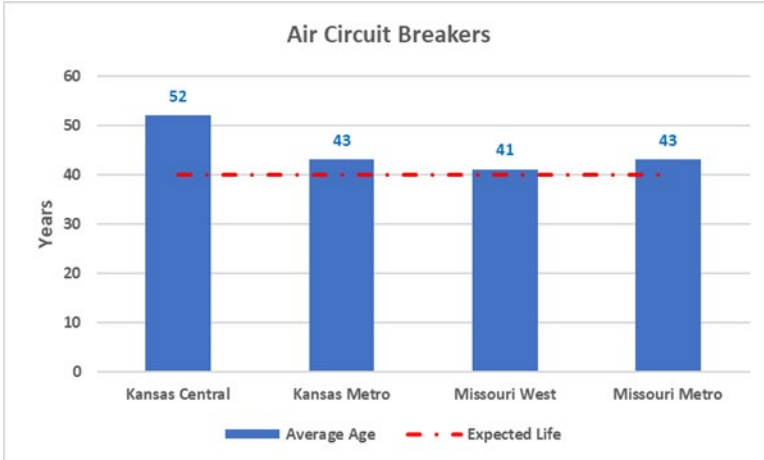
The following charts illustrate comparisons of the average age of a representative sample of asset classes to expected service life (by jurisdiction). Looking through the asset age lens (serving as a proxy for asset condition), there is sufficient rationale for the focus on Transmission in Kansas Central, and a more "steady strain" approach to Distribution across the four jurisdictions.

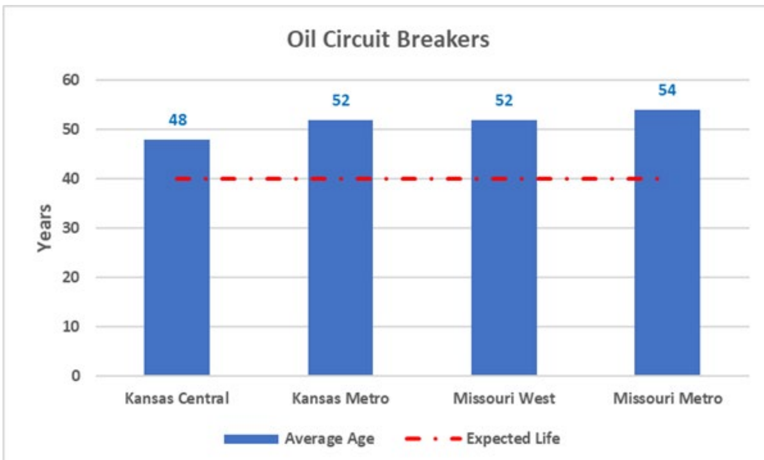
<u>Transmission Assets Age Comparisons</u>



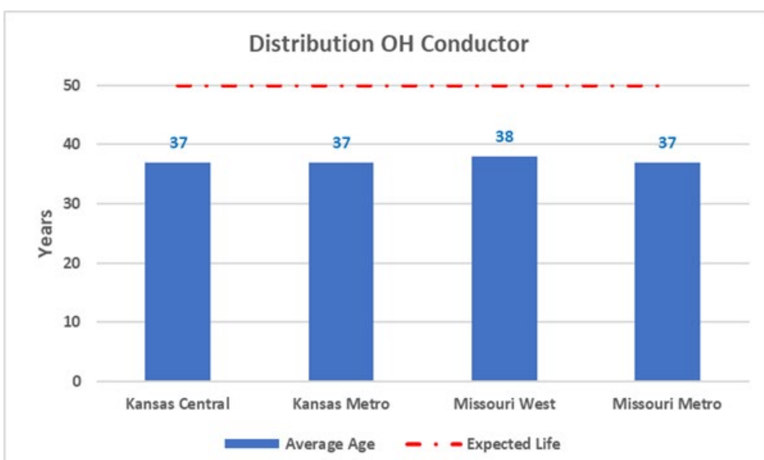


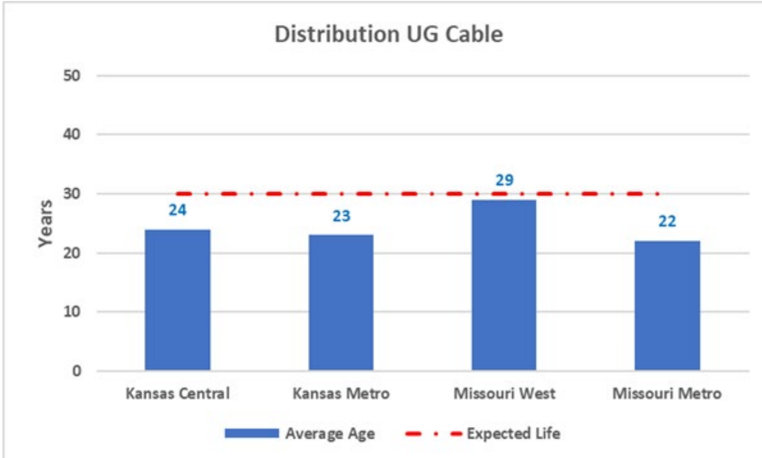
28 These charts reflect extracts from previous Evergy presentations made to the Kansas Corporation and Missouri Public Service Commissions.

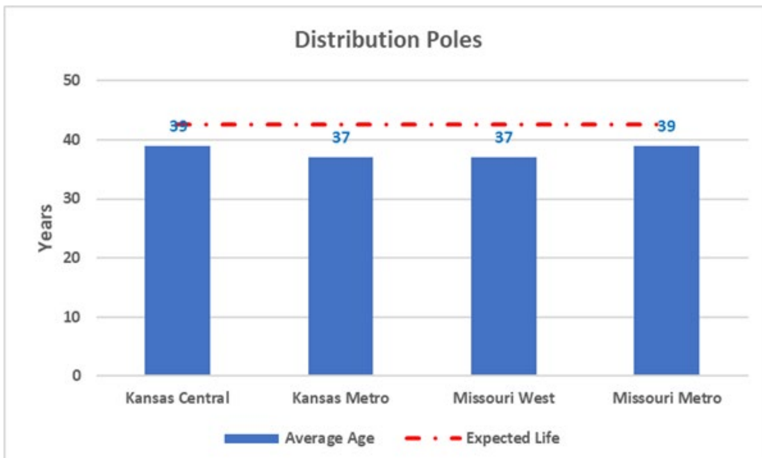


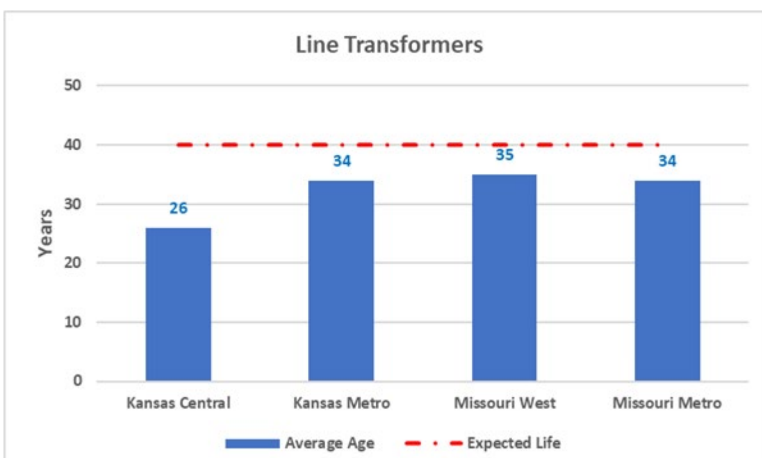


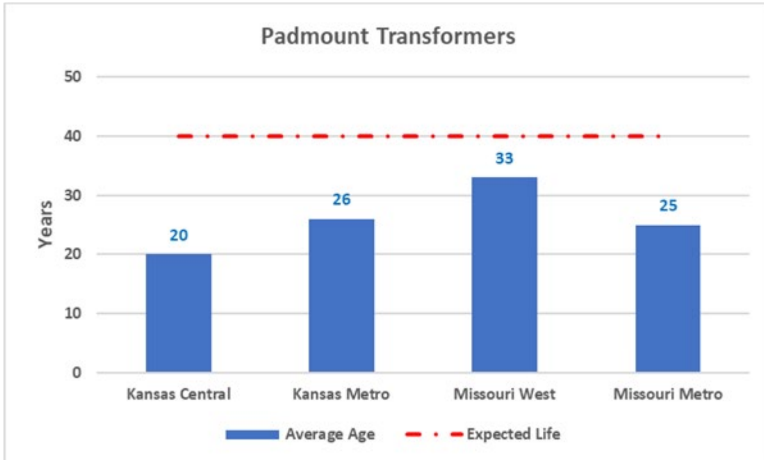
Distribution Assets Age Comparisons



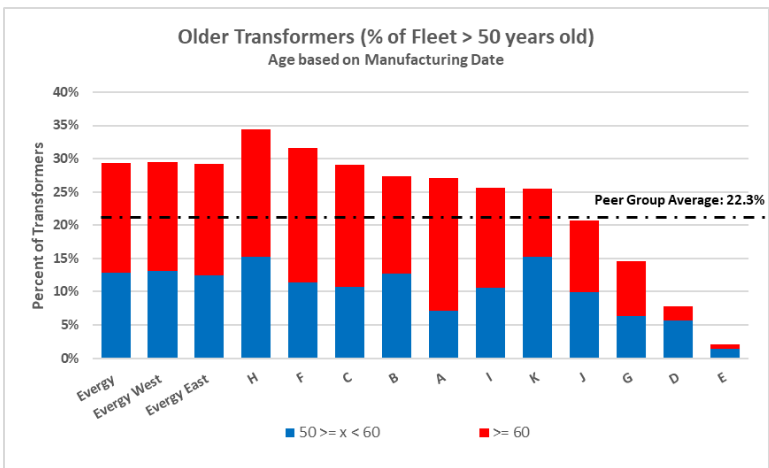

Distribution UG Cable
50
40
30
20
10
0
Years
24
23
29
22
Kansas Central
Kansas Metro
Missouri West
Missouri Metro
Average Age
Expected Life


Distribution Poles
50
40
30
20
10
0
Years
39
37
37
39
Kansas Central
Kansas Metro
Missouri West
Missouri Metro
Average Age
Expected Life


Line Transformers
50
40
30
20
10
0
Years
26
34
35
34
Kansas Central
Kansas Metro
Missouri West
Missouri Metro
Average Age
Expected Life



Offering another perspective, UMS Group compared the percent of Evergy's Transformers older than 50 years with those installed at 11 other utilities listed in Appendix E (part of its Substation Best Practices Forum):



APPENDIX D: REDUCED COST OF OUTAGES ANALYTICS

The following discussion summarizes the tables and formulae used to compute the reduced cost of outages to customers, where we first used the number of Customer Interruptions (events) avoided and the DOE ICE / Berkley Model, to developing the following tables linking the cost of an event (by customer type) to a range of outage durations:

Table D-1: Per Outage Costs (Kansas)

Type	Cost of an Outage	Incremental Cost per HR	1 HR Outage	2 HR Outage	4 HR Outage	8 HR Outage
Residential	$4.72	$1.05	$5.77	$6.82	$8.92	$13.12
Commercial	$480.07	$268.11	$748.18	$1,016.29	$1,552.51	$2,624.95
Industrial	$3,691.87	$1,562.01	$5,253.88	$6,815.89	$9,939.91	$16,187.95

Table D-2: Per Outage Costs (Missouri)

Type	Cost of an Outage	Incremental Cost per HR	1 HR Outage	2 HR Outage	4 HR Outage	8 HR Outage
Residential	$4.94	$1.09	$6.03	$7.12	$9.30	$13.66
Commercial	$457.41	$258.39	$715.80	$974.19	$1,490.97	$2,524.53
Industrial	$4,777.01	$1,953.08	$6,730.09	$8,683.17	$12,589.33	$20,401.65

Table D-3: Number of Customers (by Type)

Type	Kansas	Missouri
Residential	950,000	600,000
Commercial	27,684	18,391
Industrial	2,316	1,609
TOTAL	980,000	620,000

Given an average duration of an event of 96 minutes in Kansas and 98 minutes in Missouri, and applying weightings based on the number of each customer type (Table D-3), the information contained in these tables translates to the following factors for each State (factors to be used for each Grouping based on the category of customer (s) it affects):

Table D-4: Outage Costs per Customer for Typical Outage Duration (by Type)

Type	Kansas	Missouri
Residential	**$6.40**	**$6.72**
Residential and Commercial	**$483.75**	**$450.46**
Residential, Commercial and Industrial	**$1,859.07**	**$1,535.85**

Applying this information, the **actual calculation** adopted the following framework:

> No. of Customer Interruptions Avoided for each action per unit of measure) x (Savings factor listed above based on the projected exposure across the categories of customers) x (No. of Units of Work- e.g., poles replaced, reclosers repaired / replaced, etc.).

APPENDIX E: PEER GROUP COMPARISONS

In comparing Transmission and Distribution Capital Investment levels immediately prior to 2020, the following utilities were selected:

Table E-1: Capital Investment Levels Comparison Peer Group

Utility	States
Ameren Illinois Company	IL
Commonwealth Edison Company	IL
Consumers Energy Company	MI
Dayton Power and Light Company	IN and OH
Duke Energy Indiana, LLC	IN and OH
Duke Energy Ohio, Inc.	IN. KY and OH
Empire District Electric Company	AR, KS, MO and OK
Indiana Michigan Power Company	IN, MI and OH
Indianapolis Power and Light Company	IN, MI and OH
Northern Indiana Public Services Company	IN
Northern States Power Company	WI, MI and WI
Ohio Power Company	IN and OH
Southern Indiana Gas and Electric Company	IN and OH
Union Electric Company	IA, IL and MO

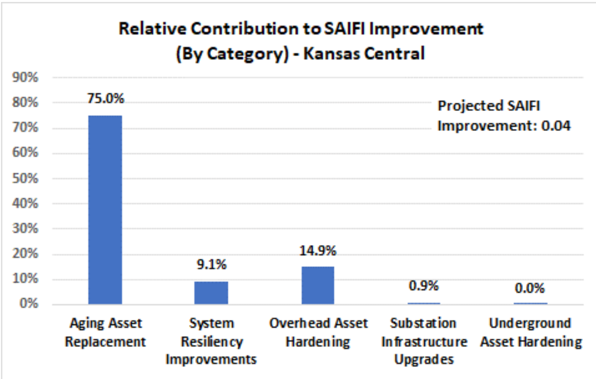
In comparing the Age of Transformers (presented in Appendix C), the following 11 utilities were selected from the Substation Best Practices Forum:

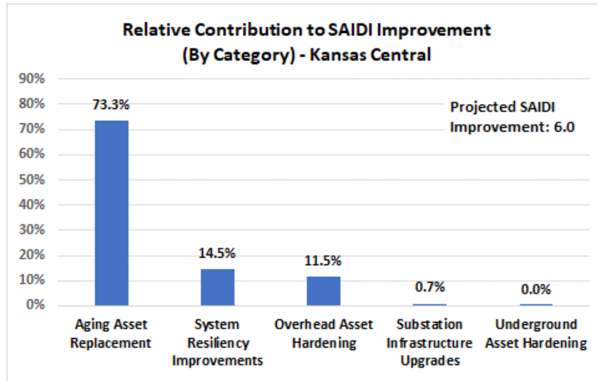
- ☑ Detroit Edison
- ☑ Central Hudson Gas & Electric
- ☑ Southern California Edison
- ☑ TRISTATE
- ☑ Pennsylvania Power and Light Company
- ☑ EMERA
- ☑ Baltimore Gas and Electric
- ☑ Indianapolis Power and Light Company
- ☑ Pacific Gas and Electric
- ☑ Public Service Electric and Gas Company
- ☑ Dayton Power and Light Company

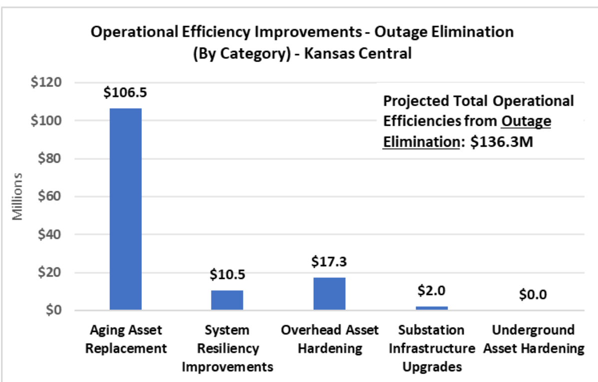
APPENDIX F: JURISDICTIONAL BENEFIT CAPTURE PROFILES

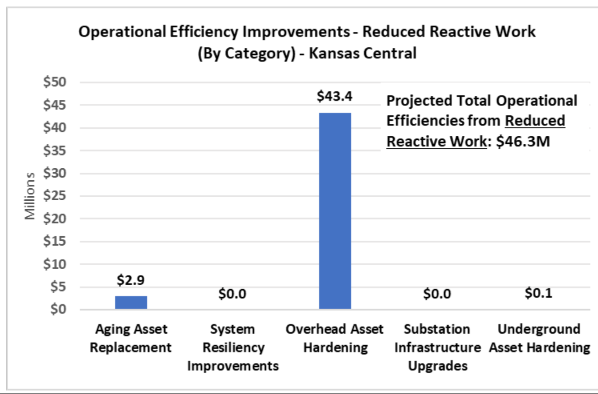
The following charts expand upon those presented in Figures 3-10 through 3-12, providing the Jurisdictional perspective.

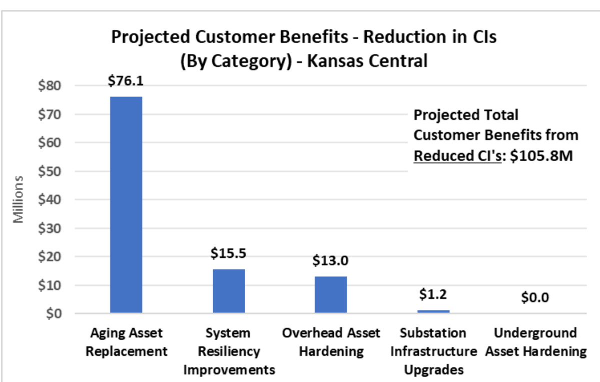
Kansas Central

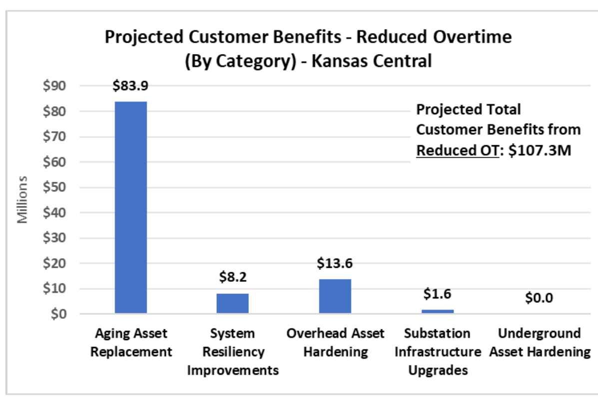




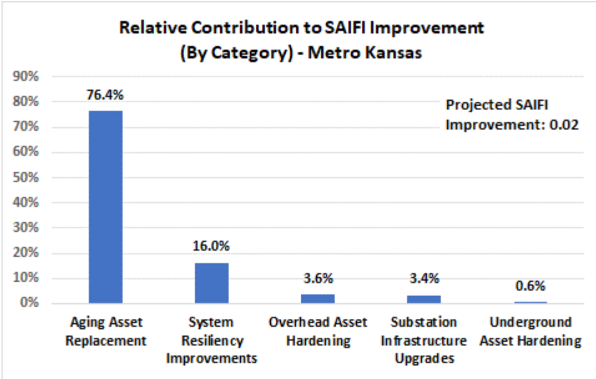


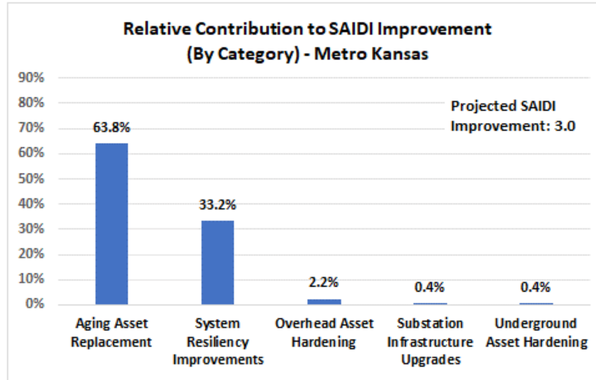


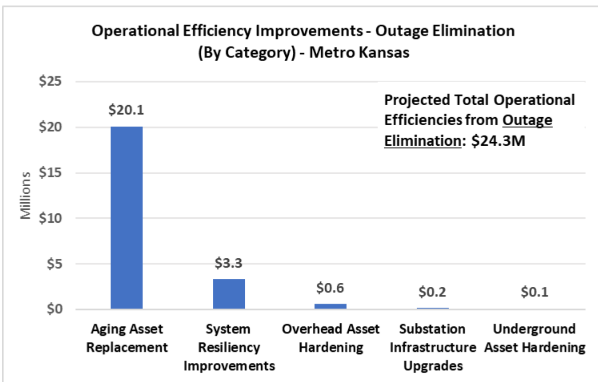


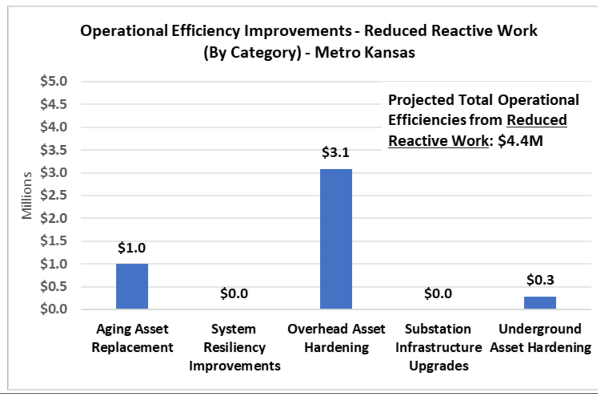


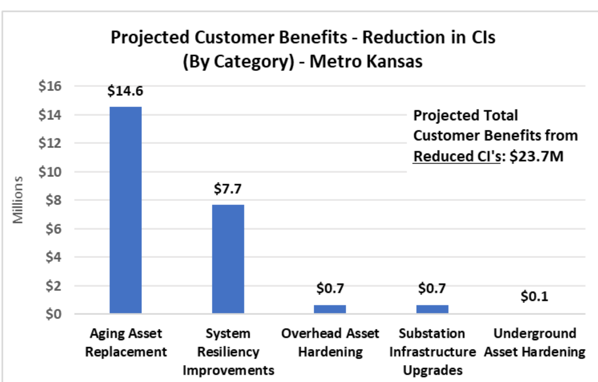
Kansas METRO

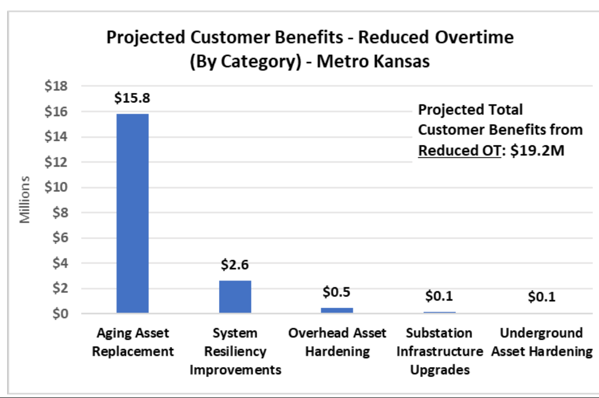




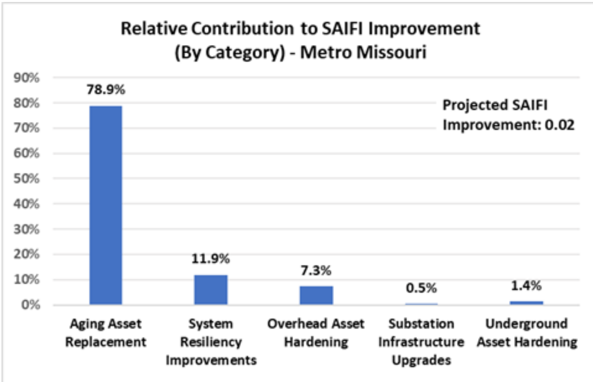


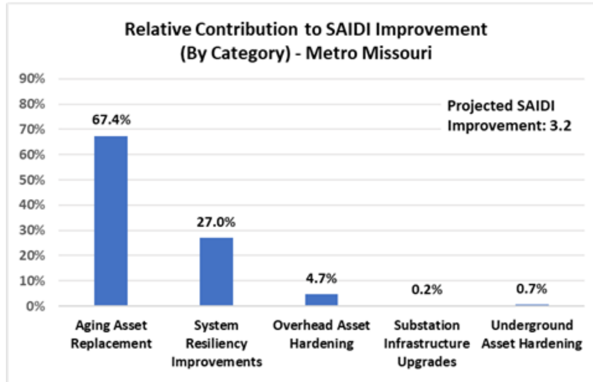


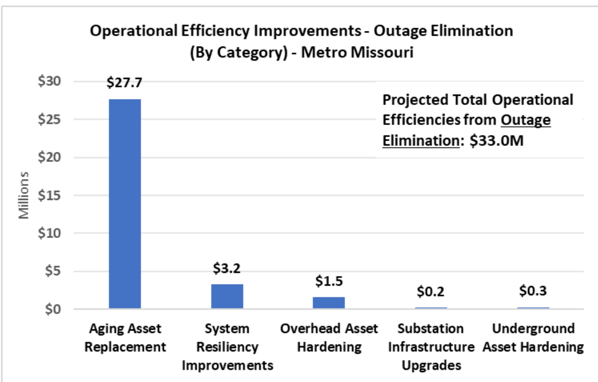


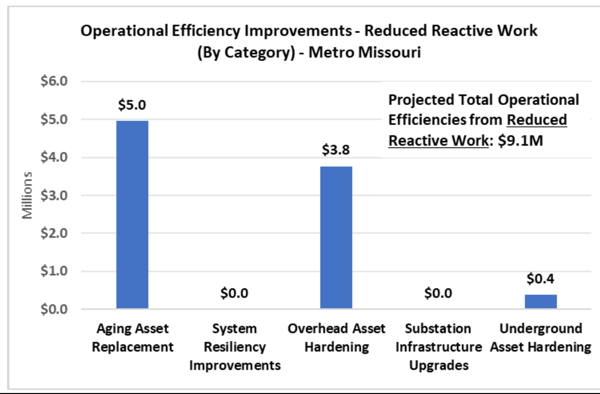


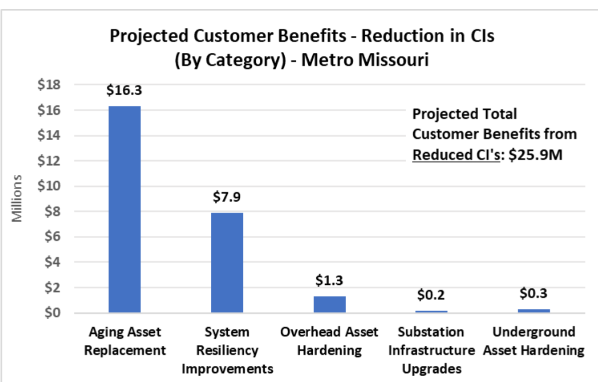
Missouri METRO

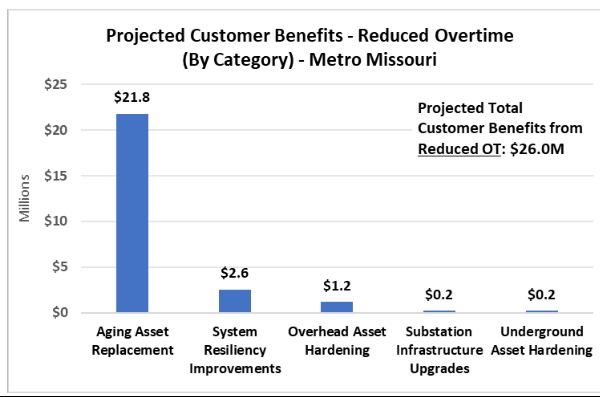




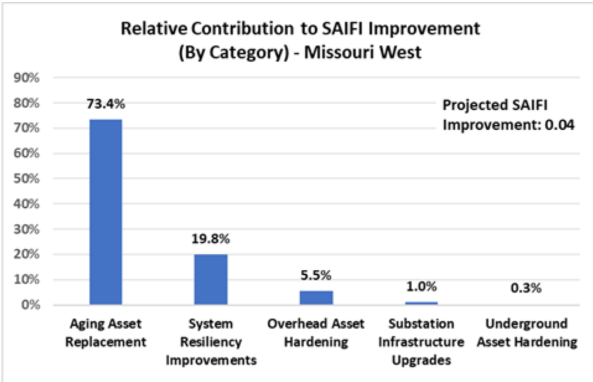


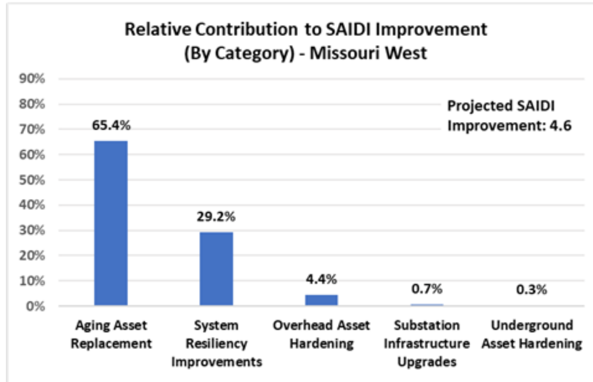


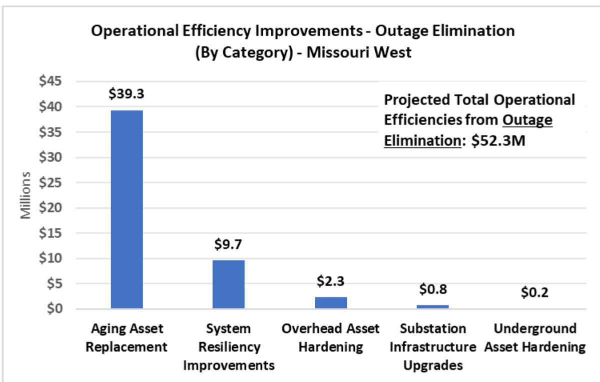


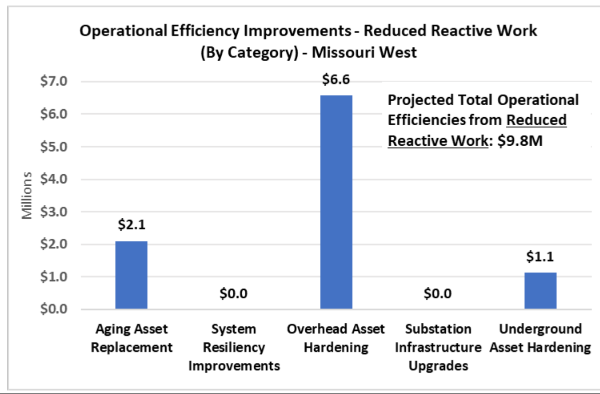


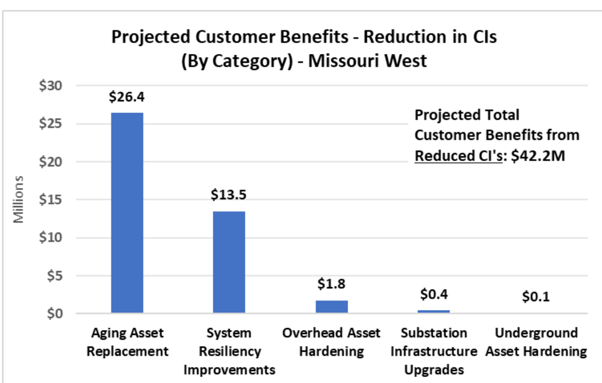
Missouri West

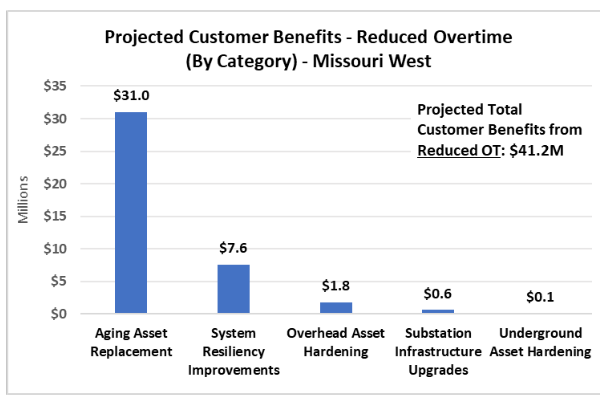












APPENDIX G: BENEFIT RANGE CALCULATIONS

[redacted]

[redacted]