COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF	)	
KENTUCKY UTILITIES COMPANY FOR	)	**CASE NO. 2025-00113**
AN ADJUSTMENT OF ITS ELECTRIC	)	
RATES AND APPROVAL OF CERTAIN	)	
REGULATORY AND ACCOUNTING	)	
TREATMENTS	)	

In the Matter of:

ELECTRONIC APPLICATION OF	)	
LOUISVILLE GAS AND ELECTRIC	)	**CASE NO. 2025-00114**
COMPANY FOR AN ADJUSTMENT OF ITS	)	
ELECTRIC AND GAS RATES, AND	)	
APPROVAL OF CERTAIN REGULATORY	)	
AND ACCOUNTING TREATMENTS	)	

DIRECT TESTIMONY OF
ELIZABETH J. "BETH" MCFARLAND
VICE PRESIDENT, TRANSMISSION
ON BEHALF OF
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: May 30, 2025

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INTRODUCTION

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

A. My name is Elizabeth J. ("Beth") McFarland. I am Vice President of Transmission for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, "Companies") and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 820 West Broadway, Louisville, Kentucky 40202. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes, I have sponsored discovery and offered testimony as a direct witness for the Companies in previous regulatory proceedings before the Commission, including in the Companies' 2018 and 2020 base rate cases,[1] and as a direct and rebuttal witness in KU's 2022 Application for a Certificate of Public Convenience and Necessity ("CPCN") to construct transmission facilities required to serve the electric vehicle battery plant being constructed by BlueOval SK in Hardin County, Kentucky.[2]

Q. Please describe your role with the Companies.

A. I have served in the role of Vice President of Transmission for the Companies since 2020. In my role I am responsible for the safe, reliable and strategic operation of the

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[1] *See, e.g.*, *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2018-00294, KU Response to CAC Initial Requests (filed Nov. 29, 2018); *Electronic Application of Kentucky Utilities Company for an Adjustment of its Electric Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00349, and *Electronic Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00350, Supplemental Rebuttal Testimony of Beth McFarland (filed Aug. 5, 2021).

[2] *See, e.g.*, *Electronic Application of Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of Transmission Facilities in Hardin County, Kentucky*, Case No. 2022-00066, Direct Testimony of Beth McFarland (filed Mar. 31, 2022).

Companies' electric transmission systems and for effectively meeting evolving operational demands. My responsibilities include transmission strategy & planning, capital project development, operations, policy and tariff administration, and reliability compliance. Due to recent organizational changes, both transmission and distribution substation operations and maintenance also fall under my responsibility.

Q. What is the purpose of your testimony?

A. I will discuss the Companies' transmission operations and provide operational context to support their applications for an increase in electric base rates. Additionally, I will describe the Companies' recent transmission performance in key operational areas, and relay what the Companies are doing to operate safely and deliver reliable power to Kentucky customers at a reasonable cost. I will summarize the status of ongoing transmission reliability and resiliency plans and I will provide context and overview for a portfolio of investments in the Transmission system, entitled the Transmission System Hardening and Resiliency Plan ("TSHARP"). I will also describe and give examples of how Transmission operations are supporting an active and robust economic development climate in Kentucky, including providing critical new infrastructure to innovative businesses locating or seeking to relocate here. I will also summarize the Companies' past and planned capital expenditures in Transmission operations and describe steps taken to make Transmission operations more efficient, particularly as it relates to substation and line operations and maintenance. Finally, I will summarize the status of depancaking expenses incurred by the Companies and provide an update on the Companies' recent analysis concerning avoided transmission capacity costs arising from Rider NMS-2 customers.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit BJM-1	System Map of Companies' Transmission Lines
Exhibit BJM-2	Transmission System Hardening and Resiliency Plan ("TSHARP")
Exhibit BJM-3	Expected NM DER Impact on the Transmission System

TRANSMISSION SYSTEM OVERVIEW, SAFETY AND PERFORMANCE

Q. Please describe the Companies' transmission system.

A. The Companies operate and maintain more than 5,200 line miles of transmission lines in Kentucky ranging from 69kV to 500kV, and an additional 200 line miles of transmission lines in far western Virginia. They also maintain 173 transmission substations and 483 distribution substations system-wide. Those systems serve over 1,000,000 Kentucky electric customers. The total transmission plant had a net book value of approximately $1.8 billion as of the end of 2024. A map showing the Companies' transmission lines and substations is attached to my testimony as **Exhibit BJM-1**.

Q. Please describe how the Companies are demonstrating their commitment to the safety of transmission operations.

A. The safety of the public and the Companies' employees and contractors is of paramount importance. To put into action this commitment to safety, the Companies continuously look for ways to improve safety in all areas, including transmission operations. In recent years, this has taken the form of increased hazard recognition training for employees and contractors, incorporation of an energy wheel that divides up hazards into energy groups into pre-job briefings, stronger field presence of management measured through annual field observation targets, creation of a dedicated contractor oversight position for transmission and distribution operations, including oversight of the Contractor Safety Management Program, and strong emphasis on reporting and documenting incidents that are not recordable but which can provide valuable education and training opportunities, including Near Miss and Good Catch programs. The Companies have also implemented cross-operational safety reviews and effective feedback training for all frontline employees and management.

Q. Have those safety practices and other established practices resulted in safe work for transmission employees and contractors?

A. Yes. Transmission employees and contractors have demonstrated adherence to safe work practices, resulting in very few recordable injuries over the past several years relative to total hours worked. For the five-year period from 2020 through 2024, Transmission employees achieved an average employee Recordable Injury Incident Rate ("RIIR") (rate of recordable injuries per 200,000 employee hours worked) of 0.69 and average days away/restricted transferred per 200,000 hours worked ("DART") rate of 0.35. For that same period, transmission contractors achieved a RIIR of 0.92 and DART rate of 0.36, over a far greater number of total hours worked. These numbers compare very favorably to an average RIIR of 1.7 and DART of 1.0 for the Electric Utility Transmission and Distribution industry according to Bureau of Labor Statistics data from 2023.[3] Like all of the Companies' business operations, Transmission puts safety first and its performance of safe work through employees and contractors reflects that commitment.

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[3] https://www.bls.gov/iif/nonfatal-injuries-and-illnesses-tables/table-1-injury-and-illness-rates-by-industry-2023-national.htm

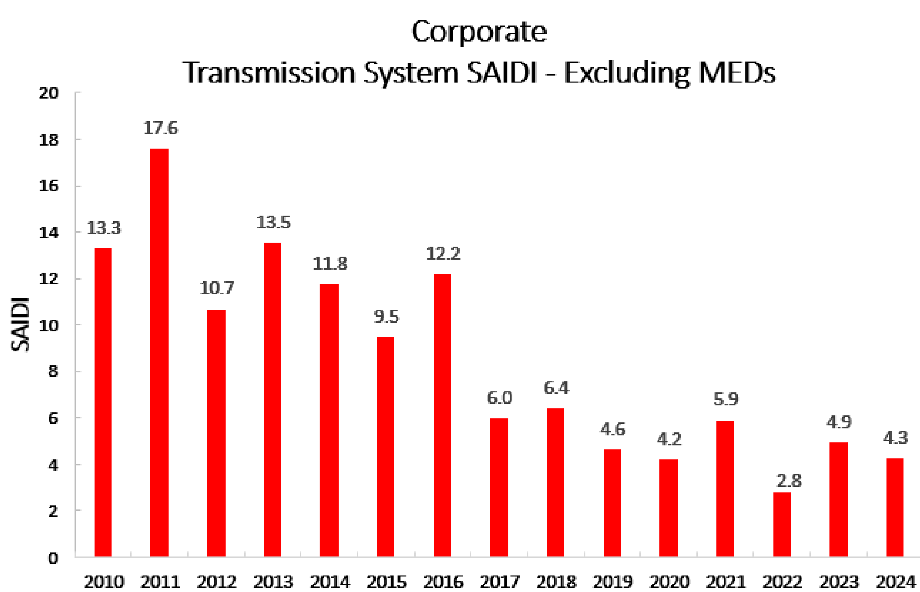
Q. How have the Companies performed in recent audits of NERC enforceable Reliability Standards?

A. SERC (the Company's regional entity reporting to NERC) typically audits the Companies every three years and the Companies have performed extremely well. For example, NERC's FAC-008 standard requires utilities to ensure that facility ratings used in the planning and operation of the bulk electric system are based on sound principles for determination of system operating limits. It is one of the most frequently violated Operations and Planning ("O&P") standards across NERC regions, including SERC. It consistently ranks among the top three most reported non-compliances over recent years. The companies successfully completed a SERC audit and walkdown of FAC-008 compliance in August 2023 with no negative findings.

The Companies were also recently audited by SERC for Critical Infrastructure Protection ("CIP") and received SERC's final audit report in October 2024. The results were overall very positive. The CIP audit found only a single, minor potential item (a documentation issue that was immediately addressed), nine recommendations in the spirit of continuous improvement, and eight positive observations. The SERC Audit team was complimentary of the Companies' Subject Matter Experts ("SMEs") and commented on their in-depth understanding of NERC Reliability Standards. Because of the Companies' long history of successful audit results, in 2024 SERC elected to skip the routine O&P NERC Reliability Standards Audit, normally performed every three years, due to the Companies' history and excellent culture of compliance. These results exemplify the Companies' careful and steadfast approach to regulatory compliance.

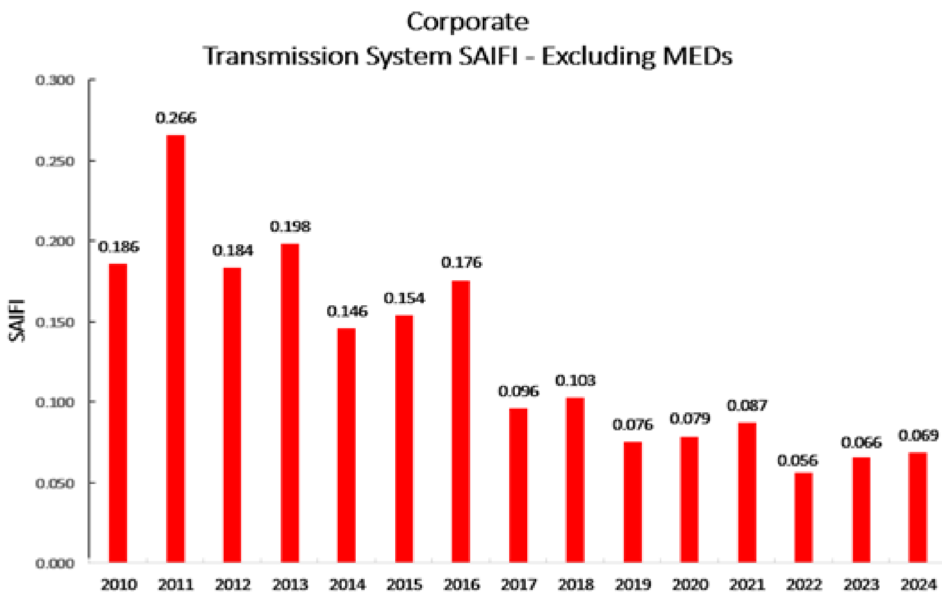
Q. How is the Companies' transmission system performing?

A. In recent years, the Companies have demonstrated sustained commitment to investing in reliability and system integrity and modernization of their transmission system, including with programs like the Transmission System Improvement Program ("TSIP"). In large part because of those investments and ongoing investments in the transmission system after TSIP, transmission reliability continues to trend toward more reliable performance over time. The Transmission System Average Interruption Duration Index ("SAIDI"), which measures transmission reliability by quantifying the average electric service interruption in minutes per customer for a particular system, is a metric used to track system reliability. The Companies' combined transmission SAIDI, excluding major event days, is reflected below:



Thus, as seen in the chart above, the Companies' Transmission SAIDI, excluding major event days, went from a system average of 12.6 from 2010 to 2016 to a system average of 4.9 from 2017 – 2024 (61% improvement).

Likewise, the Companies' Transmission System Average Interruption Frequency Index ("SAIFI"), which measures the average frequency of power disruptions per customer over the course of a year, has declined from a system average of 0.19 from 2010 to 2016 to a system average of 0.08 from 2017 – 2024 (58% improvement):



Importantly, system performance during extreme weather events as measured by SAIDI and SAIFI, **including** major event days, has also improved from a system average of 17.7 and 0.23 respectively from 2010 to 2016 to a system average of 10.6 and 0.12 respectively from 2017 – 2024, representing a 40% and 49% improvement, respectively.

The Companies' continued careful planning and prioritization of investments in their transmission infrastructure have been effective in improving both day-to-day reliability and reliability during extreme events that may involve widespread ice, wind, and extreme heat or cold, when customers need their power the most.

Q. What kind of investments were included in the TSIP?

A. The TSIP consisted of $118.3 million in reliability improvements and $601.3 million in resiliency improvements to the transmission system, representing both O&M and capital investments. Reliability improvements included switching to a cycle-based vegetation management plan to ensure proper clearance around transmission lines and installing motor-operated switches with automatic remote sectionalizing which minimizes customer exposure and reduces service interruption time by automating the process to sectionalize transmission lines after a fault. Resiliency and system modernization improvements included replacing aged and obsolete substation and line equipment with newer, more resilient equipment that produces long-lasting hardening benefits to the transmission system. The assets in that replacement plan included wood poles, underground lines, circuit breakers, insulators, and line arresters at substations. While not all were part of TSIP, the Companies have replaced approximately 10,000 poles on the transmission system with steel poles since 2017. Steel poles are structurally stronger than wood poles and can support enhanced design standards, including the ability to withstand 100 mile per hour winds or up to 1” of ice. Steel poles have a longer expected life than wood poles, are more resilient to hazards and severe weather events, and do not deteriorate like wood poles.

Q. Have the Companies’ stated reliability goals been achieved through the TSIP and other recent system investments?

A. Only in part. Continuous improvement of the transmission system is needed to keep pace with customer expectations for safe and reliable power. Notwithstanding the success of programs like TSIP in improving the overall reliability and resiliency of transmission, many aging and end-of-life assets remain on the system. Sudden failure of those assets can cause or contribute to widespread and prolonged power disruptions, especially in extreme weather events and heavy loading periods when physical and electrical stresses contribute to equipment failure. Those disruptions have the potential to not only affect Kentucky customers but also all interconnected customers served through the Companies' transmission system. The stated goal of the TSIP was to achieve the combined companies (LG&E and KU) as second quartile performers as benchmarked by industry SAIDI within 5-10 years, and first quartile performers within 15-20 years. The Companies have achieved the medium-term goal in the early part of the planned time horizon, with 2023 combined system SAIDI falling within second quartile performance. However, the longer-term goal of making the combined Companies national first quartile performers in transmission reliability has not yet been achieved and will not be achieved without intentional and carefully planned action by the Companies.

Q. How do the Companies plan to maintain the current level of Transmission reliability performance achieved through TSIP and move toward their longer-term goal of national first-quartile transmission reliability performance as stated in the TSIP?

A. To continue the progress started by the TSIP, the Companies have created a risk adjusted portfolio of transmission system investments called the Transmission System Hardening and Resiliency Plan, or TSHARP. A complete copy of the TSHARP is attached as **Exhibit BJM-2** to my testimony. TSHARP is designed as a robust data-driven, risk-based investment strategy that reduces reliability risk, guides replacement of aging assets, eliminates obsolete technology, and builds a resilient grid, all while efficiently delivering value to the Companies' customers. Investments made as part of TSHARP will continue progress toward national first quartile transmission reliability performance as measured by SAIDI by 2036, delivering optimized value to the customer. Transmission reliability and resiliency is crucial as the transmission network is the backbone of the broader electric power system, playing a critical role in delivering electricity from generation sources to distribution systems, and ultimately to the end use customer. This plan is the natural continuation of TSIP investments begun in 2017 and it continues the trend of improving transmission reliability as well as maintaining the integrity of the critical networked system. The TSHARP value model quantifies risk in terms of probability of failure and consequence of failure and compares benefits and cost in a repeatable and reusable way, delivering consistent outcomes.

Q. Please identify the investments included in the TSHARP analysis.

A. Like its predecessor, TSHARP includes both system modernization and integrity plans (asset replacements) that harden the system against disruptions, and resiliency programs that help minimize the frequency and impact of outages. The asset replacements included are: (1) circuit rebuilds; (2) transformer replacements; (3) circuit breaker replacements; and (4) relay panel replacements. This infrastructure makes up most of the core transmission assets that provide high levels of reliability and support regional transmission stability. The resiliency programs included in TSHARP are: (1) hardening of radial taps and (2) continued expansion of automatic remote sectionalizing through installation of motor-operated switching.

Q. Why are more asset replacements needed on the transmission system?

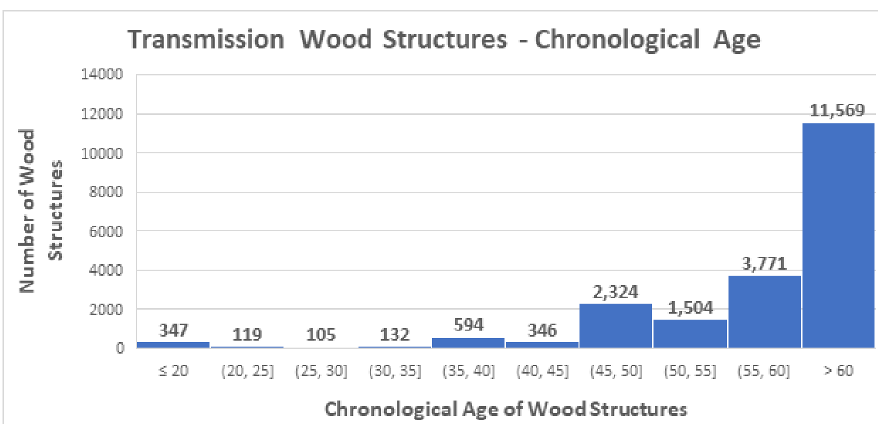
A. Despite more aggressive replacement of transmission assets on the system in the past decade due to TSIP and other programs, many legacy assets that are near end-of-life remain in service and present significant risks to the system. Proactive replacement of these assets must not only continue, but accelerate. Running components to failure does not comport with modern standards for transmission system reliability in the national and regional landscape or with customer expectations. Prudent replacement of end-of-life assets over time is imperative to avoid cumulative failures that have the ability to significantly impact customer reliability with outage events as well as system integrity of the broader transmission interconnected system. Many high voltage components, particularly in the substation environment, are very costly and take many months, even years, to procure and replace. TSHARP recognizes the cost benefit of planned replacement versus replacement upon failure within its value model in order to optimize investments.

Q. How were the programs selected and prioritized within TSHARP?

A. The Companies worked to develop a benefit cost analysis for each program considered. The approach evaluated two types of benefits for proceeding with the investment: risk reduction benefits and financial benefits. Risk reduction benefits consider the risk that critical assets pose to the transmission system if they fail. Risk is quantified in terms of probability of failure multiplied by the consequence of failure. Risk reduction is the difference between the risk calculated for the current asset and residual risk after the asset is replaced. Financial benefits are part of the benefit equation that are realized through replacement of assets, and include the reduced maintenance and reduced capital cost achieved by replacing high risk assets. The Companies then compared the total combined benefits (risk reduction benefits and financial benefits) of replacement to the present value of the cost of the proposed project to calculate a benefit to cost ratio ("BCR") for each project. BCRs were then used to prioritize projects with the highest benefits for the least cost. BCRs above one were considered positive benefit-cost projects.

Q. Describe the need for transmission circuit rebuilds as part of TSHARP.

A. Wood poles are a significant asset that make up many transmission circuits. A majority of the Companies' transmission wood poles are near the end of their service life or have exceeded it, posing a significant risk to the transmission network. Specifically, of the roughly half of all transmission structures on the Companies' system that are wood, more than fifty-five (55) percent are beyond their service life of sixty (60) years and more than eighty (80) percent of them will be beyond their service life over the next decade:



Without planned asset investment programs like TSHARP, the Companies replace on average about 900 transmission structures per year due to age, failed inspections, or equipment failures. At that rate, the Companies will not be able to replace all wood structures on the transmission system for 23 years. Rather than replacing wood structures with steel only after failures, a structured and prioritized replacement approach will strengthen the transmission system, reduce outage risk, and improve grid resilience more cost-effectively.

Q. Summarize the importance of the "hardening" aspect of TSHARP as it relates to transmission circuits.

A. Circuit hardening involves replacement and upgrades of assets, including replacement of wood transmission structures with structurally stronger steel, installation of new insulators and hardware, and upgrades to other components, such as conductors and shield wires. The benefits of circuit hardening are not limited to simply installing a new asset and restarting the useful life for that asset to prevent unplanned failures. The asset replacements themselves are in many cases designed to a higher current standard and built to withstand extreme weather events that legacy equipment was not designed to withstand. In other words, where an older asset – even a healthy one – would be prone to failure under certain severe conditions, a newer asset designed to a current higher standard may not be.

Hardening the transmission system against severe weather events is more imperative now than ever before, as storms like those that hit Southern Kentucky earlier this month with devastating consequences have become all too frequent. In addition to the tragic loss of life and homes, the severe May storms caused eight KU transmission structures to break, eight downed wires, and impacts to 38,000 KU customers due to transmission disruptions, including major system damage from an EF-4 tornado in and around Laurel and Pulaski Counties. While no feasible design standard may have protected utility equipment against the severity of those particular storms, hardened infrastructure like steel transmission poles can and does protect customers against power disruptions in similar severe weather events.

Q. What other hardening benefits, particularly the replacement of wood poles with steel, do circuit rebuilds have on the transmission system?

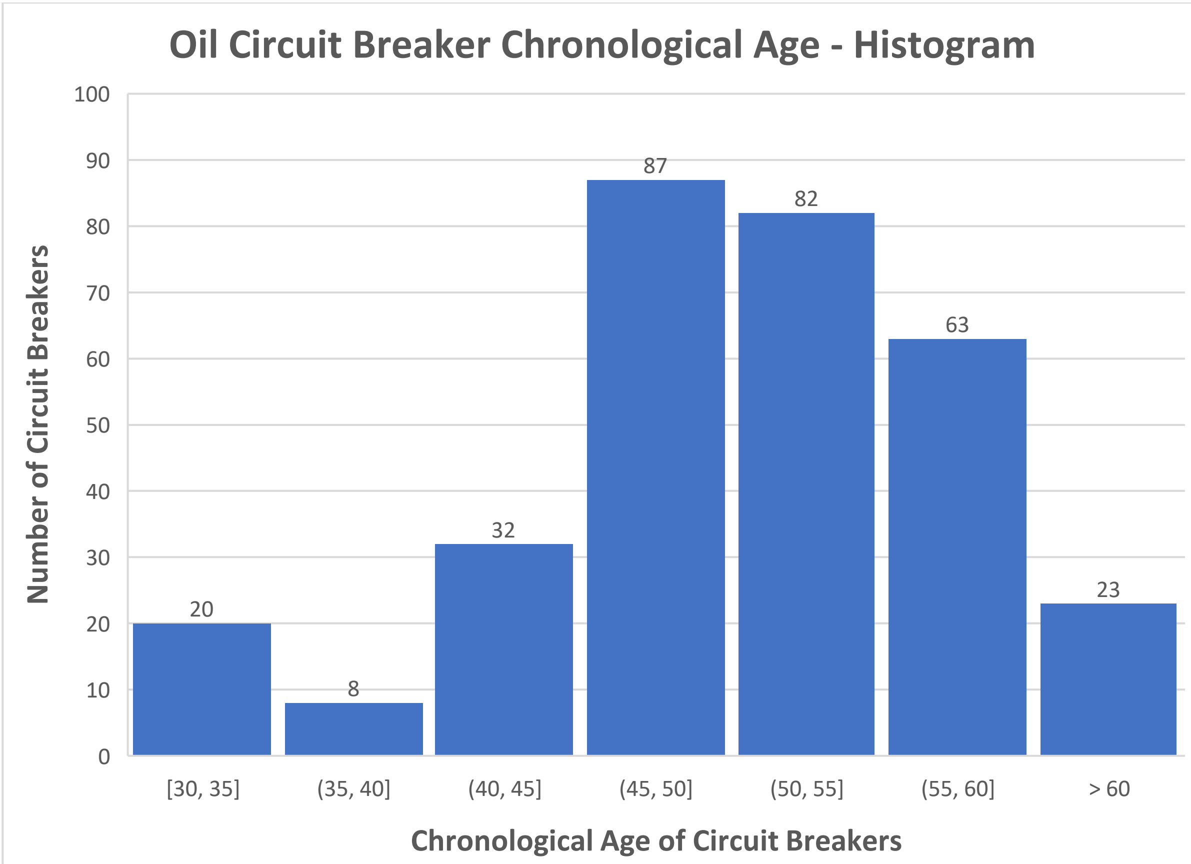
A. New steel structures used by the Companies offer greater strength and durability against wind and ice, improved clearances, upgraded components, and, in some cases, additional shield wire for enhanced lightning protection. The transmission system also benefits from the significantly longer life expectancy of steel structures due to the lack of damage expected from woodpeckers, insects or pole rot. In hazardous conditions, the resiliency of steel structures minimizes catastrophic or domino effect failures along the line due to their increased ability to withstand impact from extreme weather. For example, in January 2023, strong winds caused significant damage, including multiple wooden structure failures and broken conductor. Due to the remote location of the damaged structures on a tap with no alternative back feed from either distribution or transmission, more than 1,300 customers in the towns of Owenton and Scholls remained without power for over 13 hours until repairs were completed. Hardened infrastructure like that contemplated by TSHARP may have prevented this outage or lessened its impact on these customers.

Q. Describe the need for transformer replacements proposed as part of TSHARP.

A. Transformers are a critical part of the bulk electric system that convert voltage to higher levels so that more power can be transmitted over long distances on transmission circuits and then step down voltage to lower levels so that energy can be delivered to local distribution substations. 15 of the 133 (11.3%) Transmission transformers considered for replacement in TSHARP are at or older than their service life of 60 years, and 73 of the 133 (54%) are older than 40 years. Transformer failures can compromise the ability of the transmission grid to immediately react to loss of a transmission component without interrupting customers. Additionally, the long lead time for transformer replacements poses a significant risk, as extended procurement and installation timelines can delay restoration efforts, increase system vulnerability, and escalate the impact of an initial failure, potentially leading to prolonged outages and increased operational challenges.

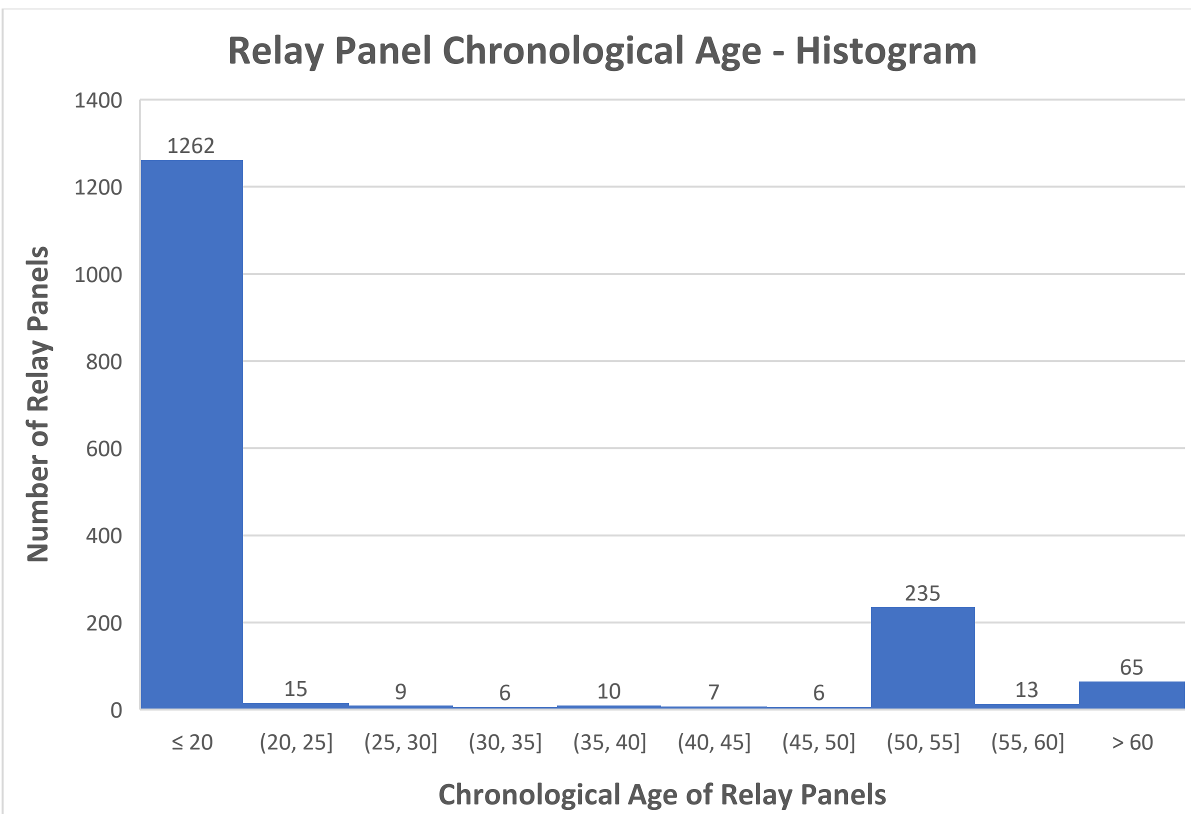
Q. Describe the need for circuit breaker replacements proposed as part of TSHARP.

A. Circuit breakers are deployed to remove faults from the transmission system as quickly as possible to protect equipment from the damaging effects of large fault currents and to protect the public from energized conductors and equipment. 168 of the 1,296 circuit breakers considered in the TSHARP risk assessment are oil circuit breakers that are at the end of their service life or within 10 years of their 60-year service life. Failure of oil circuit breakers can impact public property, result in serious environmental consequences as well as present the risk of damaging other high value transmission assets. Additionally, when circuit breakers fail to operate, surrounding breakers must step in and clear the fault, resulting in de-energization of larger sections of the transmission grid, further putting the transmission network at risk for thermal and voltage issues and potentially impacting more customers. For example, in 2020, a 48 year-old oil breaker failed in the urban Lexington area resulting in a bus lockout and interrupting over 6,600 customers for multiple hours. Replacing assets at or near the end of their service life based on asset health and before failure can help mitigate these risks.



Q. Describe the need for relay panel replacements proposed as part of TSHARP.

A. Relays work in conjunction with circuit breakers to isolate faults when they occur on the system. In combination with circuit breakers, relays protect and keep high value critical transmission assets from being damaged when faults occur. While many relays on the Companies' transmission system are modern micro-processor relays, a significant number of electromechanical relays remain. These legacy relays degrade over time and require frequent maintenance and repair. Misoperation of relays can cause damage to equipment or widespread outages during fault conditions. The TSHARP risk assessment shows that 248 relay panels of the 1,629 (15%) considered in the study are within 10 years of the end of their service life of 60 years and an additional 65 relay panels (4%) are at or beyond their service life. Replacing them systematically reduces the risk and impact of failure while in service. The transition from electromechanical to microprocessor relays significantly improves grid reliability, reduces maintenance efforts, and enhances data-driven decision-making using advanced monitoring functions such as oscillography, sequence of events, and distance to fault. These advanced relays provide utilities with greater operational flexibility, improved fault response times, and better overall system performance. Over the past three years, 21 outages caused by failures in protection systems using electromechanical relays have led to widespread outages and equipment damage, which can be avoided with use of microprocessor relays.



Q. Please summarize why hardening of radial taps is included in TSHARP's portfolio of resiliency programs.

A. Because it traverses many miles of rural terrain, KU's transmission system in particular includes radial tap architecture in which a distribution substation is tapped from the mainline transmission circuit and includes only one transmission source. This potentially exposes customers to long outage durations when faults occur on the transmission circuit and relies on distribution switching to restore customers, if available. Often providing an alternative transmission source to the tapped substation is not feasible due to cost, proximity of an alternative source, or both. In that case, hardening the radial taps with steel poles, expanded rights-of-way, and additional switching capabilities will reduce the frequency and duration of outages for customers served from radial taps. For example, in 2024, a broken structure on a radial line in rural Kentucky, with no alternative back feed, resulted in a long outage that lasted 22 hours and impacted customers in the towns of Nortonville and Mortons Gap.

Q. Please summarize why automatic remote sectionalizing ("ARS") is included in TSHARP's portfolio of resiliency programs.

A. ARS involves installation or configuration of motor operated line disconnect switches on the transmission system paired with Energy Management System ("EMS") platform programming to automatically sectionalize the system during fault events. The TSHARP analysis considers all transmission circuits serving customers that do not already have ARS in use and are not radial circuits. 148 of the Companies' 473 transmission circuits meet these criteria. Of the 148 circuits, the TSHARP analysis concludes that 88 had a positive benefit-cost ratio and would be prudent, cost-effective candidates for addition of motor operated switches with ARS.

Q. Describe the reliability benefits of ARS.

A. Motor operated switches with ARS are highly effective both for reducing customer exposure to outages and minimizing restoration times. When damage or failure on a transmission line causes a line fault, motor operated transmission switches automatically open, isolating the fault condition, allowing substation circuit breakers to close back on the unfaulted section of line thus restoring customers within seconds. The reliability impact of installing ARS can be seen acutely on specific lines. For example, by installing ARS on the Beattyville to West Irvine 69 kV line in 2016, the Companies achieved savings of more than two million customer minutes interrupted in the ensuing six years (2018-2024). Likewise, for the East Frankfort to Tyrone 69kV line, nearly 1.5 million customer minutes interrupted were saved during the same time period by installation of ARS in 2018. System wide, from 2018 to 2024, over 20 million customer minutes were saved as a result of motor operated switches and automatic remote sectionalizing, which averages 3 million customer minutes avoided per year.

Q. What are the conclusions of the TSHARP analysis?

A. The analysis concludes that transmission circuits pose the largest risk to reliability and resiliency on the Companies' transmission system. Nearly 1,300 total miles of transmission circuits are ranked with the highest risk score. The high-risk ratings are driven primarily by the large population of wood poles that are well beyond their service life, making these transmission circuits vulnerable to widespread damage during extreme weather conditions such as tornadoes, high winds, wildfires, and ice storms. While rebuilding 1,300 miles of transmission circuits immediately is not feasible, TSHARP's risk analysis is used to prioritize strategic pole replacement projects as well as opportunities to rebuild entire circuits. The analysis also concludes that investment in substation equipment is needed. There are high-risk transformers, circuit breakers and relay panels that must be replaced and for which the risk-reduction benefits of replacement outweigh the costs to replace them. The Companies consider and prioritize these high-risk assets in coordination with circuit rebuilds to minimize outages.

The resiliency programs--radial tap rebuilds and ARS programs--return the greatest benefit-cost ratios amongst all investment types in the analysis and present more affordable solutions than rebuilding entire circuits, where they are feasible and appropriate, while delivering significant outage reduction benefits to customers.

Q. Summarize the benefits of the recommended investments in TSHARP to wildfire mitigation and how wildfire risk was considered.

A. KU's transmission system in Southeast Kentucky and Southwest Virginia includes facilities that are identified in the highest wildfire risk zones per the FEMA National Risk Index. The difficult terrain, right-of-way access issues, and other challenges in these areas pose an increased risk of power disruption and wildfires, while also making restoration and repairs challenging following an outage event. The Companies are carefully monitoring these risks and taking steps to mitigate them, including with the analysis in TSHARP. As discussed above, replacement of wood transmission structures with steel is an effective wildfire risk mitigation strategy and the Companies' plan to accelerate investment in line rebuilds where wood structures are used will mitigate the risk of wildfires more quickly than replacement of assets as they fail. Furthermore, as set forth in TSHARP, wildfire risk is a specific factor considered and quantified in the risk calculations for each type of asset. Thus, assets with higher wildfire risk in areas prone to wildfire are assigned a higher risk score than otherwise comparable assets and thus are prioritized for replacement and hardening before those other assets, all else being equal.

Q. How are the Companies using TSHARP to guide their transmission investment strategy?

A. The Companies are leveraging TSHARP, powered by a Risk Adjusted Project Prioritization tool, to guide transmission investment strategy by conducting regular risk assessments as part of the annual business planning process and portfolio reviews. This approach enhances the ability to manage aging infrastructure and address high-risk assets across the transmission system. The risk analysis plays a key role in balancing competing priorities and shaping future work plans. As an iterative and integral part of the annual budgeting process, it helps refine investment decisions over time in a consistent and repeatable way. By identifying high-risk assets where the benefits of replacement outweigh the costs, the Companies are prioritizing targeted asset replacements and resiliency projects that improve reliability, reduce customer outage frequency and duration, and deliver long-term value. These insights are expected to drive transmission investments through the business planning horizon and beyond.

TRANSMISSION INVESTMENTS TO SUPPORT ECONOMIC DEVELOPMENT IN KENTUCKY

Q. How are the Companies' Transmission operations supporting economic development in Kentucky?

A. We are in a period of unprecedented business and economic development activity in Kentucky. Governor Beshear's office recently announced that Kentucky has again placed in the top five for economic development projects per capita nationally according to Site Selection's 2024 Governor's Cup rankings.[4] In just the past few years, Kentucky has seen some of the most significant economic development projects in its history, including the construction of the BlueOval SK Battery Park in Hardin County. The Companies serve many of the largest economic drivers in the State already and are routinely fielding inquiries to support new business growth opportunities for existing and new customers. Many businesses locating or relocating to Kentucky have technology driven, energy-intensive operations, including advanced manufacturing and, more recently, data centers built for hyperscaling to support cloud-based computing and Artificial Intelligence ("AI") engines.

As Kentucky's economy grows, especially with large energy consumers, so does its dependence on reliable and reasonably priced power, including the infrastructure needed to get power to those customers. To respond to those challenges, Transmission works closely with the Companies' Business and Economic Development team to ensure that businesses seeking to locate in the Companies' service territory have access to reliable power to support their operations. Often, new transmission infrastructure is needed to serve those customers. Two recent examples involving the Companies are the BlueOval SK Battery Park and the Camp Ground data center project.

Q. Describe the BlueOval Battery Park Project.

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[4] Gov. Beshear: Kentucky Secures Another Top 5 Ranking in Economic Projects Per Capita in 2024 Governor's Cup, Marking 5 Years in a Row | Kentucky Cabinet for Economic Development

A. The BlueOval SK Battery Park is a joint venture between Ford Motor Company and SK On, a division of SK Innovation – one of South Korea's largest companies. The plants – two large industrial facilities with an announced $5.8 billion in capital investment – will ultimately create thousands of jobs in Kentucky. The first plant – known as Kentucky 1 – is expected to begin production in 2025. BlueOval SK has already hired at least 750 employees to work at the plant with many other well-paying jobs created by its construction and related suppliers and businesses.[5]

Q. What transmission infrastructure was needed to support the BlueOval project?

A. To accommodate the immense size and scale of the battery park project and to meet its expected energy needs, KU constructed two 345kV transmission lines, two 138kV transmission lines, and two transmission substations in Glendale, Hardin County.[6] KU filed and received from the Commission in 2022 a Certificate of Public Convenience and Necessity ("CPCN") for construction of these facilities.[7]

Q. Describe KU's performance in completing the project.

A. KU completed all required construction of electric facilities at a total cost of $183 million (Transmission and Distribution combined), within 1.5% of the original cost estimate. Moreover, the facilities were completed on schedule by the second quarter of 2024, enabling BlueOval SK to complete the buildout of the interior of the Kentucky 1 Plant and prepare it for commercial operation and jumpstart the associated economic impact to the region and the Commonwealth. KU and its contractors also built the

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[5] https://www.courier-journal.com/story/money/companies/2024/11/14/6-billion-ford-blueoval-sk-battery-production-to-start-soon-in-kentucky/76301742007/

[6] https://lge-ku.com/glendale

[7] *Electronic Application of Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of Transmission Facilities in Hardin County, Kentucky*, 2022-00066, Application, ¶ 4 (Mar. 31, 2022).

transmission facilities safely, with no lost workdays due to injury throughout the duration of the construction.

Q. Describe the Camp Ground Data Center Project.

A. In 2024, a joint venture comprised of PowerHouse Data Centers and Poe Companies, LLC notified LG&E of its plans to build a hyperscale data center campus on approximately 153 acres on Campground Road in Louisville. Hyperscale data centers consist of large-scale technology, data processing and computing infrastructure needed to support cloud computing and AI applications. The Camp Ground project will likely consist of multiple data center buildings on the site. The project is expected to create thousands of well-paying jobs in Louisville.[8] Hyperscale data centers are energy intensive. The proposed project was initially accompanied by a Transmission Service Request ("TSR") for 335 MW of permanent electric service, later amended to a total of 402 MW to be placed in service starting in 2026 and ramping up by 2028. This customer has most recently submitted a new TSR, requesting to increase permanent electric service to 525 MW in 2030. This TSR is currently being studied and has not been confirmed.

Q. What transmission infrastructure is needed to support the Camp Ground project?

A. To accommodate the Camp Ground TSR at the 402 MW load, the Companies expect to build a greenfield 138kV breaker and a half substation ("Lake Dreamland Substation") consisting of 9 – 138kV breakers, a control house, and other substation equipment required to serve the expected load. Two existing 138kV lines will be bisected to provide 4-138kV feeds into the new substation. Additionally, Transmission

[8] https://www.courier-journal.com/story/news/local/2025/01/17/data-center-project-aims-to-bring-big-tech-companies-to-louisville/77773993007/

has identified and will be making network upgrades in the area to serve this load – including terminal (substation) equipment upgrades at Cane Run and Paddy's Run substations and three 138kV transmission lines that will need to be reconductored for higher ratings. The direct total capital cost for these investments was projected in the confirmed TSRs to be $30.6 million over the next 5 years. The Companies have executed an Engineering, Procurement, and Construction contract with the developers of the Camp Ground project for construction of the transmission facilities, and construction is expected to begin in 2025.

Q. Are there other economic drivers increasing the need for new transmission infrastructure?

A. Yes, in addition to TSRs for large new customers, including the potential for more than 20 data center projects and more than 50 manufacturing projects in which the Companies' Economic Development Team is currently involved, the Companies are experiencing a high volume of transmission work for other customer and capacity driven projects. These include third-party generation interconnections for traditional and solar resources, and planning transmission projects for expansion of the Companies' own generation resources, including Mercer Solar, Mill Creek 5, and the Battery Energy Storage System for the Brown Generating Station. Many of these projects are tied to the same economic development trends I describe above.

CAPITAL INVESTMENT SUMMARY

Q. Please summarize the capital investments being made for Transmission-related projects.

A. From January 1, 2022 to June 30, 2026, the Companies have spent and plan to spend $1,024 million in capital on transmission-related projects.

LG&E and KU Transmission	LG&E	KU	Total Jan. 1, 2022 – June 30, 2026 ($mm)
Proactive Replacement	$97	$543	$640
Connect New Customers	$34	$136	$170
Transmission Expansion Plan	$36	$64	$100
Generation Expansion Plan	$5	$18	$23
Reliability	$3	$24	$27
Other	$10	$54	$64
Total	**$185**	**$839**	**$1,024**

EFFICIENT OPERATIONS

Q. What changes or new programs have the Companies adopted to ensure efficient operations of Transmission substations and lines?

A. Since 2021, Transmission continues to develop new programs and initiatives that promote efficient operations of substations and lines. Electric Substations, for example, has implemented a number of significant on-going efforts to optimize and re-engineer asset inspection and maintenance. In 2024, the management over transmission and distribution substations was reorganized to achieve more efficient operations. Historically, operations of transmission substations was managed by a separate substation group for Transmission and likewise for Distribution. Now, all assets, construction and maintenance of substations – whether transmission or distribution – fall under my purview as Vice President – Transmission. Through these consolidation and process engineering efforts, the Companies have achieved significant operational efficiencies, including:

- Labor cost savings through consolidation of working groups with a reduction of 4 headcount positions;

- Reduction in substation inspection cost by about 25 percent due to reduction from quarterly to a tri-annual schedule; and
- Ongoing replacement of legacy end-of-life power circuit breakers (oil, air-magnetic, & vacuum), allowing up to a 50% reduction in out of service diagnostic testing intervals and related costs.

Similar process engineering efforts have occurred in the Transmission Control Center ("TCC"). In 2023, TCC management implemented a strategic restructuring of Control Center shift personnel (those that operate, maintain, and balance generation to load on the transmission system in real time) to align staffing schedules more effectively with operational demands. This initiative enabled the Companies to achieve workforce optimization while maintaining operational efficiency, reducing headcount by three personnel.

Also in the TCC, significant efforts have occurred to transform volumetric tabular data into summary displays, thus conveying more information in an efficient digestible format. The development and utilization of customized and configurable displays within the EMS platform improves the transmission and balancing authority Electric System Coordinator's (Control Center shift personnel) situational awareness allowing them to make intelligent informed decisions leading to efficient transmission operations.

The Companies also expect to achieve significant operational efficiencies by changing the inspection cycle for steel transmission poles from every 6 years to every 12 years, a change that took effect in January 2025. Because steel poles are not subject to the same level of deterioration as wood poles, they do not need to be inspected as frequently. This change was not previously possible even where steel poles were installed due to the mix of legacy wood structures and newer steel structures on a given transmission circuit. Now, the Companies have a significant number of transmission circuits that consist entirely of steel structures, where the entire circuit can be transitioned to the longer inspection cycle.

Q. Has adoption of technology also made the operation and security of substations more efficient?

A. Yes. As legacy supervisory control and data acquisition ("SCADA") equipment and electromechanical relays at substations have reached the end of their useful lives, the replacement of that equipment with microprocessor-based devices has made operations of substations much more efficient. The newer devices allow for this increased cyber security capability in addition to remote connectivity, remote settings and firmware management, remote relay event data retrieval, and require far less maintenance. Managing this equipment remotely saves the cost of truck rolls, labor, and reduces the need for onsite management of the substations. Furthermore, replacement of these legacy assets with microprocessor relays provides more reliable equipment with increased functionality that also reduces overall maintenance expense.

The same is true for newer automated equipment like breakers and transformers, which are equipped with far more sophisticated remote-management functions than their legacy counterparts. Features of these more advanced systems include remote diagnostics and repair or "on alarm" responses to equipment failures, continuous equipment monitoring, monitoring of breaker and transformer health, load trending, fault interruption timing, accumulated fault interruption, distance to fault capability, and real time email or other notifications upon occurrence of major outages. Through these equipment upgrades and more streamlined management of substation operations, the Companies have been able to achieve significant cost savings.

Q. Are the Companies continuing to achieve operational efficiencies through ARS?

A. Yes, ARS continues to provide significant efficiency benefits on the 69kV Transmission system. Since inception in 2018, the Companies have avoided an estimated 20.3 million customer-minutes interrupted ("CMI") and have also benefited from lower operational costs associated with planned response versus emergency response, sending the right resources to address the issue at the right time. ARS continues to be programmed into the EMS platform in conjunction with applicable Motor Operated Switch ("MOS") installations. Leveraging logic in the existing EMS to automatically open line switches during the power circuit breaker reclose cycle, thus isolating and sectionalizing the faulted section of line and restoring customers within seconds, has provided tremendous benefits to the Companies' customers over time, and those benefits will continue to accumulate. Today the Companies have 75 69kV circuits equipped with ARS, with another 45 circuits planned for 2025-2029. As described in my testimony above, ARS is included within the Companies' TSHARP plan.

DEPANCAKING EXPENSE

Q. What is depancaking expense?

A. When the Companies withdrew from Midwest Independent System Operator in 2006, mitigation of FERC's concerns around access to potential suppliers for KU's wholesale power requirements customers was addressed through a transmission rate mechanism called Merger Mitigation Depancaking ("MMD") under then Rate Schedule No. 402, now Rate Schedule No. 525. Under MMD, the Companies are required to provide recipients of MMD, including those municipal customers receiving wholesale power requirements service when the Companies merged in 1998, with certain depancaked transmission rates. The goal behind the original MMD mechanism was to continue to expand the geographic scope of suppliers able to reach these KU customers, thus ultimately eliminating horizontal market power concerns.

Q. How have depancaking expenses evolved over time?

A. In recent years, MISO transmission rates have continued to be significantly higher than the rates on the Companies' system, resulting in net payments by the Companies to MMD recipients each month for the difference (MISO cost reimbursement less the Companies' transmission cost). This exposes the Companies to increased depancaking costs as MISO rates increase. For example, in June of 2024 MISO rates increased by ten percent, resulting in an approximately $4.5M annual depancaking cost increase for the Companies. Depancaking expense adds approximately $30 to $40 million per year to the Companies' transmission cost of sales. Absent changes to the MMD, the Companies expect MMD costs to continue to significantly outpace revenue from MMD customers over the coming years.

Q. What is the status of the Companies' efforts to reduce or eliminate depancaking expenses under the MMD?

A. The Companies received FERC approval to eliminate MMD subject to the implementation of a transition mechanism for certain power supply arrangements.[9] A

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[9] *Louisville Gas & Elec. Co.,* 166 FERC ¶ 61,206 ("2019 Removal Order"), *order on reh'g & clarification,* 168 FERC ¶ 61,152 (2019), *aff'd sub nom. Ky. Mun. Energy Agency v. FERC,* 45 F.4th 162 (D.C. Cir. 2022) ("KYMEA").

decision from the D.C. Circuit Court of Appeals largely affirmed FERC's analysis in the 2019 Removal Order, but it ultimately vacated the decision and remanded the matter back to FERC.[10] In its decision, the Court of Appeals agreed with FERC's decision that horizontal market power was no longer a concern but found that FERC failed to sufficiently consider all prongs in its analysis under Section 203 of the FPA, including omitting the prong to evaluate the potential impact on rates. In its order on remand, FERC reversed its decision allowing for the termination of MMD and required the Companies to reinstitute the MMD provisions of Rate Schedule 402.[11] The Companies complied with this directive by filing Rate Schedule 525. The Companies appealed FERC's orders on remand and the compliance filing to the D.C. Circuit Court of Appeals. Oral argument was held in the appeal on January 21, 2025, and the Companies expect a ruling sometime in mid-2025.

RIDER NMS-2 AVOIDED TRANSMISSION CAPACITY COST

Q. Have the Companies performed an analysis to determine the appropriate avoided transmission capacity cost component for Rider NMS-2?

A. Yes. Consistent with the analytical framework stated in the testimony of Peter W. Waldrab, the Companies performed an analysis that shows the appropriate avoided transmission capacity cost component for Rider NMS-2 is zero. As shown in **Exhibit BJM-3**, the Companies have not identified any transmission capacity projects that

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[10] The D.C. Circuit stated, "In short, the Commission's conclusion that sufficient competition would continue after [MMD] was based on substantial evidence from which it drew sensible inferences employing its expert knowledge of electricity markets. That is the 'kind of reasonable agency prediction to which we ordinarily defer.'" However, the D.C. Circuit faulted FERC for failing to evaluate the impact of the removal of MMD on rates and vacated the decision. *KYMEA,* 45 F.4th at 177.

[11] *Louisville Gas & Elec. Co.,* 183 FERC ¶ 61,122 (2023).

Rider NMS-2 customers will allow the Companies to avoid over the next ten years. Therefore, the appropriate Rider NMS-2 avoided transmission capacity cost is zero.

Q. If the avoided transmission capacity cost is zero, how will the Companies compensate Rider NMS-2 customers for the value of avoided transmission losses?

A. As the testimony of Charles R. Schram and Exhibit CRS-6 explain, the Companies include avoided transmission losses in calculating the avoided energy cost component of Rider NMS-2. Therefore, it would be duplicative to include avoided transmission losses in the Rider NMS-2 avoided transmission capacity cost component.

CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Elizabeth J. McFarland**, being duly sworn, deposes and says that she is Vice President, Transmission for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, that she has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of her information, knowledge, and belief.

Beth McFarland

Elizabeth J. McFarland

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 23rd day of May 2025.

Caroline J. Davison

Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

APPENDIX A

Elizabeth J. (Beth) McFarland
Vice President, Transmission
Louisville Gas and Electric Company
Kentucky Utilities Company
820 West Broadway
Louisville, Kentucky 40202

Previous Positions

LG&E-KU

Vice President – Customer Services	2017 – 2020
Director, Asset Management, EDO	2013 – 2017
Manager, Substation Construction and Maintenance, EDO	2010 – 2013
Lead Engineer, Louisville Arena Project	2007 – 2010
Various Engineering Positions	1997 – 2007

Ford Motor Company

Automation Engineer - Body	1996 - 1997
Maintenance Supervisor - Paint	1994 - 1996

Professional/Trade Memberships

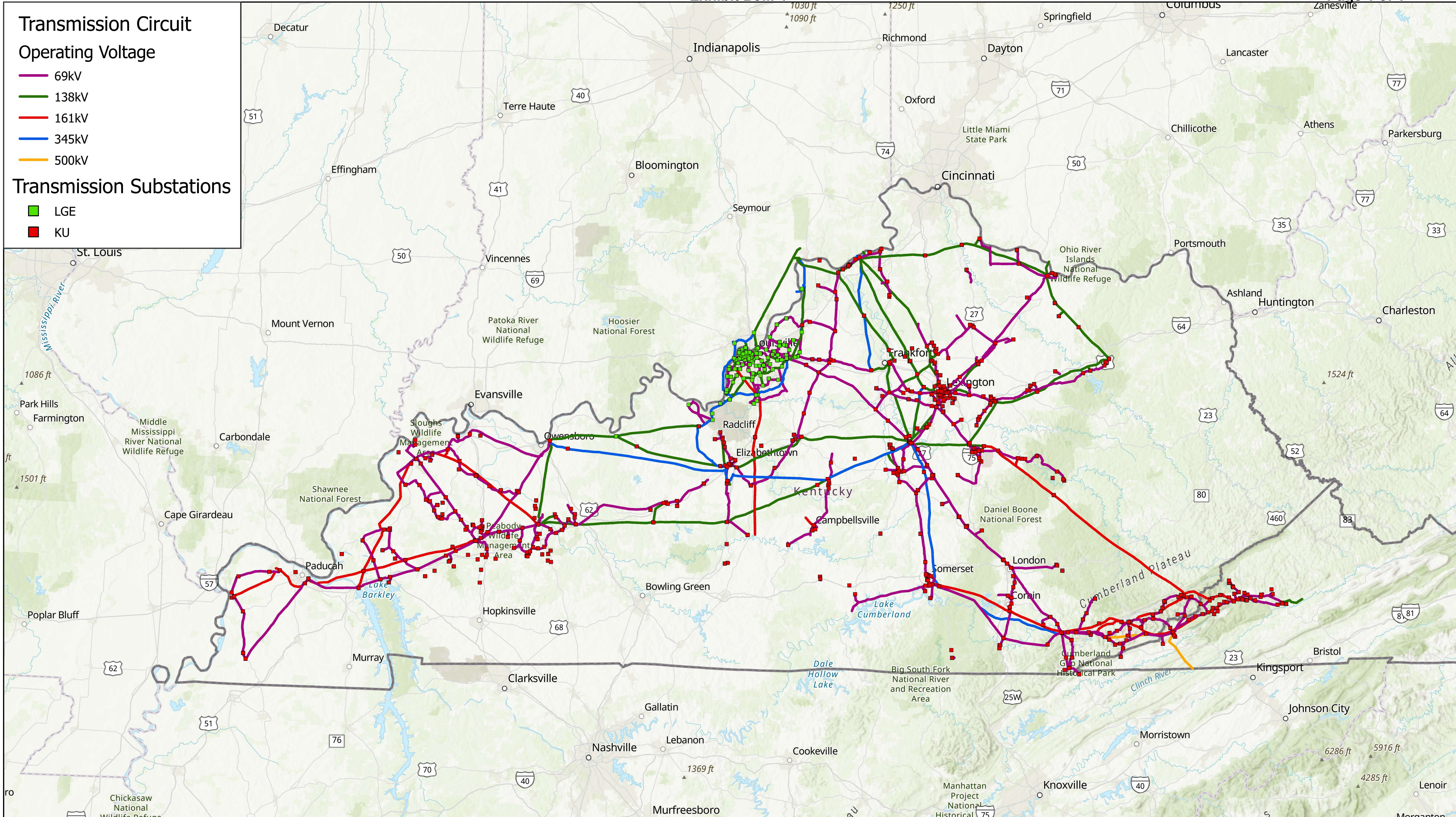
Edison Electric Institute-Reliability EAC	2020 – present
SERC Reliability Corporation-Member Company Representative	2020 – present
SERC Reliability Corporation-Board of Directors	2024 – present
North American Transmission Forum-Member Representative	2020 – 2024
EPRI: Power Delivery and Transmission Sector Council	2022 – 2024

Education

Executive Education Program, Tuck School of Business, Dartmouth College	2017
Master of Engineering, University of Louisville J. B. Speed Scientific School	1994
Bachelor of Science in Engineering Science, University of Louisville J. B. Speed Scientific School	1992

Civic Activities

University of Louisville, J. B. Speed School of Engineering, Industrial Board of Advisors	2019 – 2024
Leadership Kentucky Board of Directors	2019 – 2021
Leadership Kentucky Class Member	2019
Leadership Louisville Class Member	2010
ACE Mentoring Board of Directors	2017 – 2024



Transmission System Map

LG&E KU

Scale: 1:2,000,000 Feet

User: e027998

Plot Date: 2/24/2025

TRANSMISSION SYSTEM HARDENING AND RESILIENCY PLAN (TSHARP)

Risk and Benefit/Cost Analysis

PREPARED IN COLLABORATION WITH

LG&E & KU Energy

2 JANUARY 2025

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1.0 Executive Summary

In 2016 Louisville Gas and Electric and Kentucky Utilities (LG&E/KU) proposed the Transmission System Improvement Plan (TSIP) to improve system reliability and maintain system integrity over the five-year window from 2017-2021 through several targeted programs. The Companies stated two reliability goals at the beginning of this initiative: a short-term (5-10 year) goal of achieving second quartile reliability performance as measured by LG&E/KU transmission system average interruption duration index (SAIDI), and a long-term (15-20 year) goal of achieving first quartile reliability performance by the same metric. SAIDI represents the impact of any given outage on an average customer and is used across the electric utility industry as a measure of reliability performance. The TSIP program was successful in achieving the first of these goals. The Transmission System Hardening and Resiliency Plan (TSHARP) will build on the success of TSIP to maintain the current level of reliability performance and propel us toward our ultimate goal of becoming a first quartile performer in Transmission SAIDI according to industry benchmarking.

TSIP included two broad categories of projects: reliability programs and system integrity programs. These programs were prioritized based on historical performance, so circuits that experienced higher SAIDI historically were prioritized for strategic investment. Additional details regarding the program selection for TSIP are available in the associated report[1] and annual updates[2] on file with the Kentucky Public Service Commission.

Whereas TSIP focused on the worst offenders of historical outages, TSHARP looks forward, using a risk assessment and cost/benefit analysis to target the most impactful projects. The projects evaluated fall into two broad categories—asset replacement and resiliency programs. While replacing aging infrastructure before failure significantly contributes to improved system integrity, investing in resiliency programs enables the system to recover faster and minimize the impact of the disruption. Investing in both asset replacement and resiliency programs ensures a more robust and efficient system with long-term reliability benefits. The prioritization tool provides two critical data points for prioritizing projects: risk reduction benefit and benefit to cost ratio. These two values were calculated for each project and provide a concrete way to quantify relative priority across the portfolio.

This report describes the analysis and presents the results. Many of the high-risk assets that exist on the transmission system today should be replaced, and the analysis concludes that benefits of replacing the high-risk assets outweigh the cost to replace them. The risk and benefit cost analysis highlights that transmission circuits need the most funding to reduce risk on the LG&E/KU transmission system. The asset classes of circuit breakers, relay panels and transformers also have high risk assets that need replacement. Transmission circuits have a large population of high-risk wood poles that make the transmission system vulnerable to widespread outages and transmission instability during extreme weather conditions. The analysis also identifies resiliency focused programs of Reinforcing Radial Taps and expanding the use of an Automated Restoration Scheme (ARS) to be cost effective. These two investment programs target transmission circuits that cause customer outages when faults occur.

A risk-adjusted portfolio of asset replacement projects in conjunction with new resiliency projects prioritized based on risk and benefits is imperative to sustain and improve transmission system reliability and resiliency. LG&E/KU firmly believes that this plan, which quantifies benefits and costs to identify high risk assets and prioritize investments, is the best path forward while striking an appropriate balance between benefits and costs to customers.

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[1] 9 - KU Testimony and Exhibits - Staffieri to Sinclair - FINAL.pdf (ky.gov)
[2] 20170622 PSC ORDER.pdf (ky.gov)

2.0 Case for Action

2.1 System Overview

In 1998, LG&E and KU's transmission operations were merged after LG&E Energy acquired KU Energy. Today, LG&E and KU together operate the largest Transmission System in Kentucky. The Transmission System serves more than 1,000,000 retail customers, and an additional 125,000 electric customers connected either directly or through interconnections with other smaller distribution companies (cooperatives) and municipal utility systems. The Transmission System spans more than 5,400 miles with voltages from 69kV to 500kV.

Since the LG&E and KU merger in 1998, the Transmission Systems of both utilities have been jointly planned, operated, and maintained as one combined system under the LG&E and KU Joint Pro Forma Open Access Transmission Tariff ("OATT") on file with the Federal Energy Regulatory Commission (FERC). However, the KU portion of the Transmission System and LG&E portion of the Transmission System vary significantly in both design and performance due to dissimilar geography and customer bases. The KU portion of the Transmission System is mostly rural, with low customer density, long circuits and more infrastructure required to serve customers. The LG&E portion of the Transmission System is more compact, serving a mostly urban customer base in and around Louisville. Both transmission systems were planned, designed, and constructed with redundant transmission capacity over the years based on transmission planning criteria and in accordance with FERC and SERC requirements. The main difference between the LG&E and KU systems is related to the way distribution substations, ultimately customers, are served on the 69 kV system. KU's 69 kV system consists of a much larger non-contiguous service area where multiple distribution substations are directly connected to transmission lines with a radial (one-way) feed to the substation. The non-contiguous nature of the KU system limits the ability to restore customers through distribution backfeed, whereas the LG&E's 69 kV system has more redundancy through circuit ties that provide backup in case of an outage. Figure 2-1 below shows the LG&E and KU service territory.

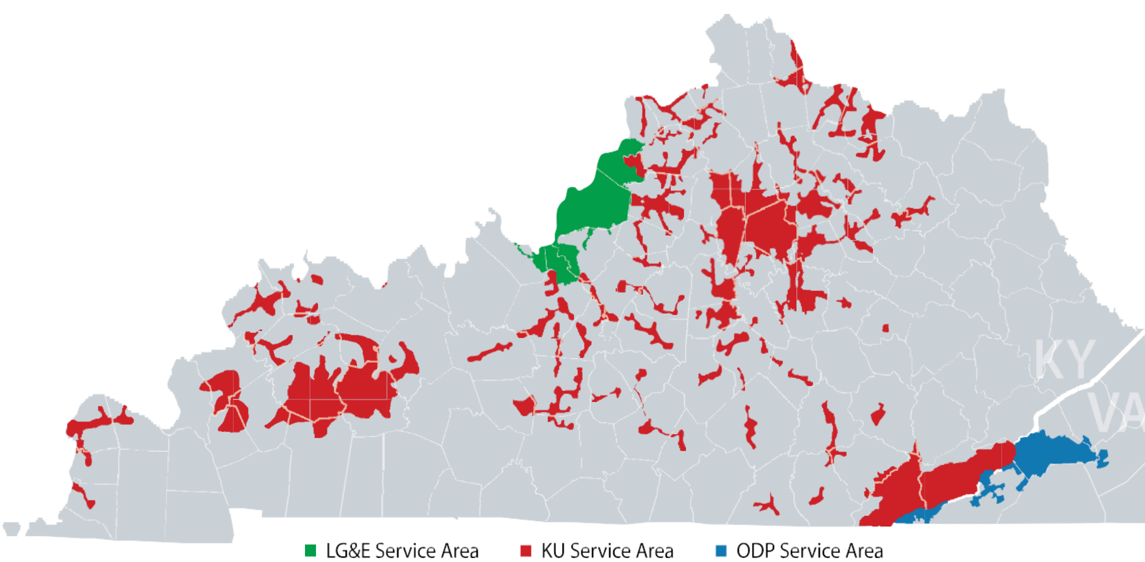

Figure 2-1 LG&E / KU Service Territory

2.2 Transmission System Improvement Plan (TSIP 2016) Goals & Results

In 2016, LG&E/KU developed an investment plan for improvements of their combined transmission system. This plan, entitled the Transmission System Improvement Plan ("TSIP"), projected $108.3 Million in spending on reliability investments over a five-year period from 2017-2021, and $429.5 Million in system integrity and modernization investments over the same period. Reliability enhancement programs were identified for the most impactful outage event causes and the worst performing transmission circuits. System integrity investment programs were based on condition, technical obsolescence, age, and consequence of failure of various assets on the transmission system.

At that time, the LG&E system was a 1st quartile performer for system SAIDI exclusive of major event days (MED). The KU system was a 4th quartile performer. The TSIP was a targeted program to improve reliability performance with a long term (15-20 year) goal of becoming a combined (LG&E/KU) first quartile performer in transmission SAIDI and a medium term (5-10 year) goal of becoming a combined 2nd quartile performer. The program set a goal of improving system SAIDI by 3-6 minutes over the 5-year window 2017-2021 and exceeded this goal by achieving an average of 7.8-minute reduction. In addition to the reliability targets, LG&E/KU targeted critical aging infrastructure for replacement to address the risk posed from these assets failing while in service.

Transmission's investments through the TSIP resulted in significant reliability improvements and enhanced resiliency that benefit customers. Specifically, as a result of these efforts the Companies have seen a decline of Transmission SAIDI from a system average of 12.6 from 2010 to 2016 to a system average of 4.9 from 2017 – 2024 (61% improvement) as well as a decline of Transmission system average interruption frequency index (SAIFI) from a system average of 0.19 from 2010 to 2016 to a system average of 0.08 from 2017 – 2024 (58% improvement) as seen in Figure 2-2 and Figure 2-3. Where SAIDI measures the duration of outage experienced by the average customer, SAIFI represents how often the average customer experiences an outage. Both outage frequency and duration are important measures of reliability which are reflected in customer satisfaction.

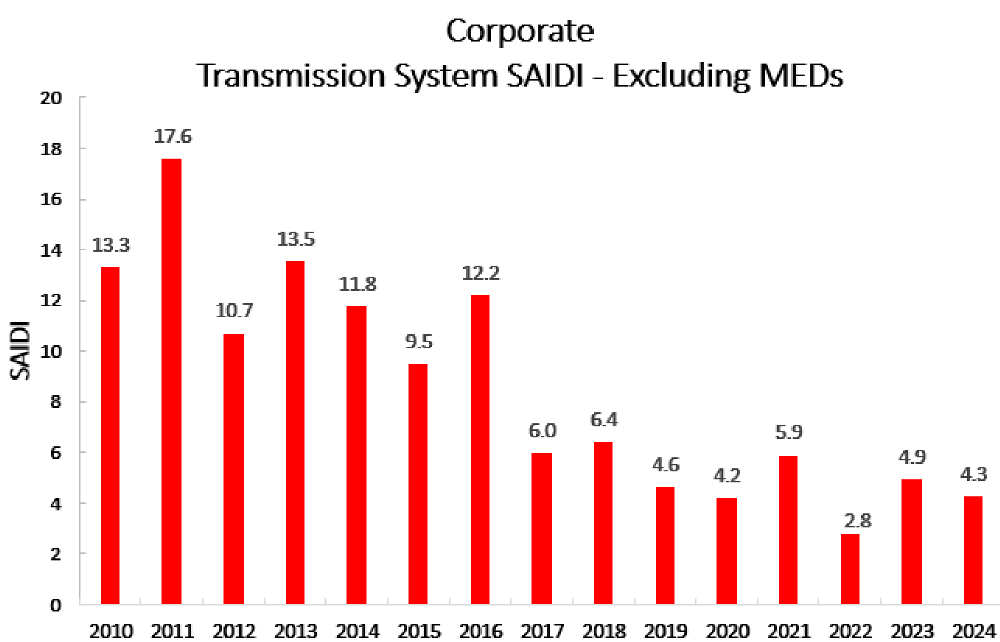

Figure 2-2 LG&E/KU Transmission SAIDI

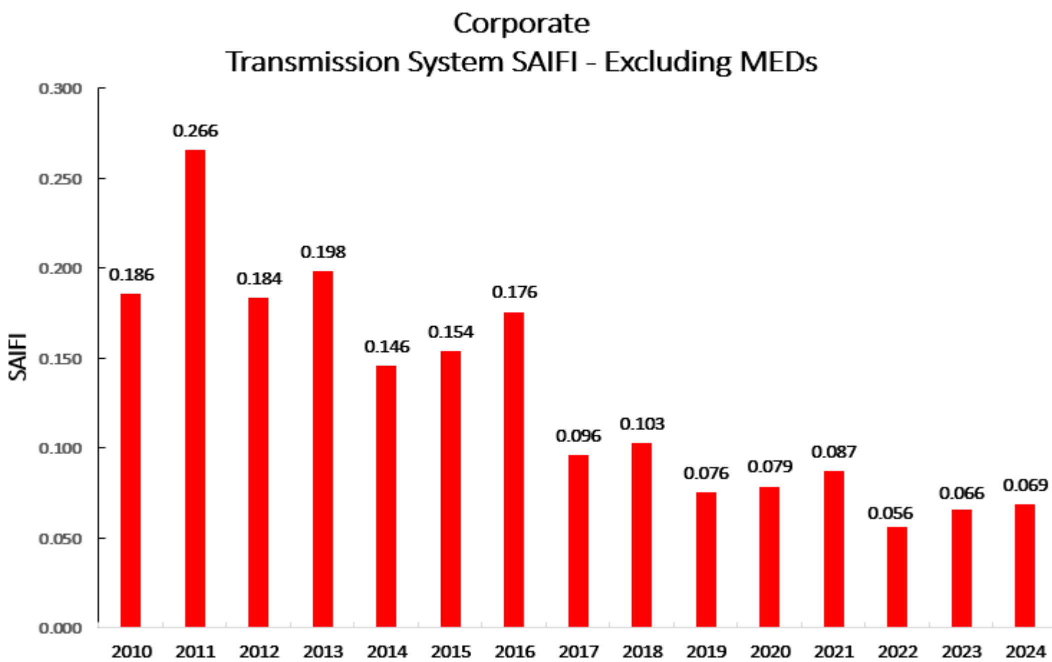

Figure 2-3 LG&E Transmission SAIFI

Prior to the TSIP program, the top ten worst offenders for total SAIDI, exclusive of MEDs had a total of 29.05 minutes of SAIDI from 2010-2016. By contrast, the top ten worst offenders from 2017-2023 had a combined total of 11.16 minutes of SAIDI. This is reflective of system-wide improvement.

2.3 Criticality of Transmission

Transmission is the backbone of the electric power system, playing a crucial role in delivering electricity from generation sources to distribution systems. Transmission systems are planned, designed, and constructed as a network with redundant capacity. This redundant capacity benefits both LG&E/KU customers as well as customers served by other interconnecting utilities. Utility customers in North America and around the world have grown accustomed to high levels of reliability produced by transmission systems. Maintaining high levels of both reliability and resiliency on transmission systems is paramount as new loads and energy sources are added to the grid.

Investments based entirely on traditional reliability metrics, such as SAIDI and SAIFI, are typically identified and prioritized based on a project's ability to lower the frequency and/or duration of customer outages. Distribution systems are made up primarily of radial circuits whose purpose is to provide service to end-user customers and benefit greatly from this prioritization method. These lower voltage circuits typically experience a larger number of outages in more localized areas. Transmission investments, on the other hand, require consideration of additional factors. Thus, the proposed TSHARP project portfolio goes one step farther than TSIP by focusing not only on direct customer impact of any single outage, as measured through traditional reliability metrics, but on the transmission system's resiliency, or ability to maintain its network configuration for any given outage. The methodology used to prioritize TSHARP projects incorporates the risks associated with delaying any given project with the goal of replacing high-risk assets before a failure occurs.

North America is comprised of three power transmission grids or "Interconnections" as illustrated in Figure 2-4 below. The Eastern Interconnection reaches from Central Canada Eastward to the Atlantic coast (excluding Québec), South to Florida and West to the foot of the Rockies (excluding most of Texas). All the electric utilities in the Eastern Interconnection are electrically tied together during normal system conditions and operate at a synchronized frequency operating with a target of 60Hz.[3]

LG&E/KU are one of the many utilities that make up this interconnection and are in the SERC Reliability Corporation (SERC) region. The connected nature of the interconnection makes sharing resources easier, but this comes at the cost of possible cascading failures that can impact tens of millions of customers across many utility service territories.

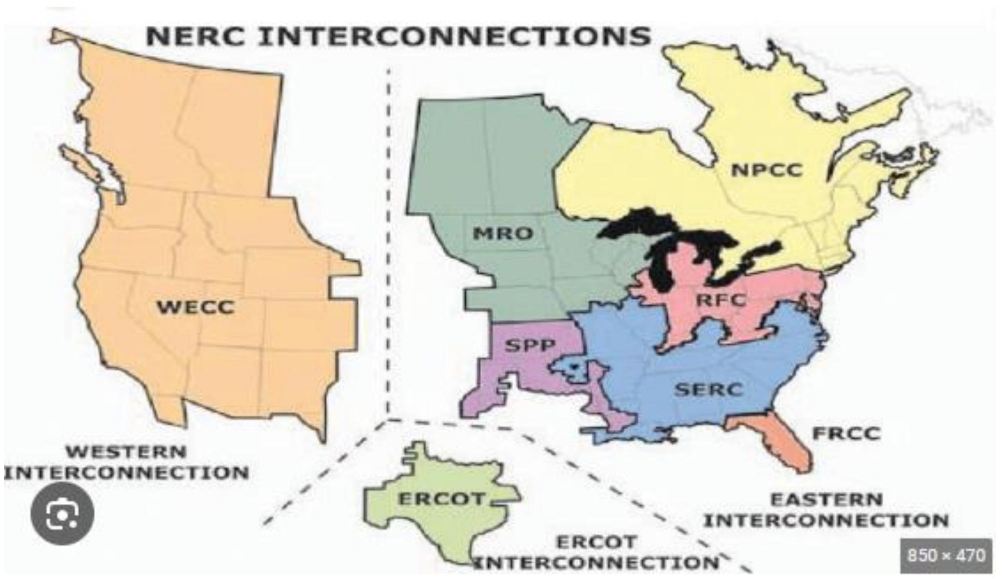

Figure 2-4 NERC Interconnection Geographical Area

One of the most significant examples of such a cascading failure occurred on August 14, 2003. A transmission line fault in Ohio caused by contact with a tree cascaded into what would become one of the largest outages in North American history. The "Northeast Blackout" affected 50 million people and approximately 61,800 megawatts of electric load in 8 states and 1 Canadian province.[4] As a result of this event the federal energy regulatory commission (FERC) certified the North American Reliability Corporation (NERC) to mandate reliability standards, which had previously been voluntary only. Additional standards have been implemented over the intervening years.

Specific to LG&E/KU, the Hurricane Ike Windstorm (2008) and the Kentucky Ice Storm (2009) caused the most significant system damage in history for LG&E/KU. These storms caused 130.74 minutes of SAIDI (inclusive of MED) and 0.0576 minutes of SAIFI (inclusive of MED). The storms impacted 479,999 and 654,122 customers respectively. Due to the significant system damage from these two storms, restoration took multiple days resulting in significant cost of approximately $203 million.

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[3] https://www.energy.gov/oe/learn-more-about-interconnections
[4] D:\0myfiles\DOE Policy (LBL) Blackout Final\final-blackout-body-xx.vp (nerc.com)

More recently, winter storm Uri in 2021 and winter storm Elliott in 2022 have brought winter weather preparedness into the national spotlight. In Kentucky, winter storm Elliott set a record for December electric peaks.[5]

Similarly, events in Hawaii and California have spurred wildfire risk assessments at utilities across the nation, including LG&E/KU. According to the FEMA National Risk Index, portions of LG&E/KU's service territory in eastern Kentucky are among the most at risk for wildfire in the southeastern portion of the United States. Tornadoes and other severe weather events can also impact operations. According to the National Oceanic and Atmospheric Administration (NOAA), Billion-Dollar Weather and Climate Disasters in Kentucky have increased from an average of 1.9 events per year from 1980-2023 to 4.2 events per year in last five years (2019-2023).[6]

The LG&E/KU transmission system in Southeast Kentucky and Southwest Virginia includes facilities that are identified in the highest wildfire risk zones per the FEMA National Risk Index. The difficult terrain, right-of-way access issues, and other challenges in these areas pose an increased risk of power disruption and wildfires, while also making restoration and repairs challenging following an outage event.

Without continued and increasing investments to replace aging infrastructure, hardening of the system, and installing automation, negative impacts to transmission reliability and resiliency should be expected. The value of the transmission system redundancy becomes more apparent under extreme events. Extreme weather events and heavy load periods impose both physical and electrical stresses to the transmission system that contribute towards equipment failures.

With redundant pathways and capacity, the transmission system can automatically redirect power flows when critical equipment fails without causing power interruptions. The redundant pathways and capacity reduce the likelihood of cascading failures, provide operational flexibility, and ensure economic and safety benefits. Redundancy ensures that power continues to flow uninterrupted even when parts of the system fail or need to be taken offline for maintenance. It also helps ensure that the system can be operated within limits for any unplanned contingency on the system. Transmission Operations studies the next worst single outage of a generator or transmission component (N-1). When a real-time or N-1 System Operating Limit (SOL) violation is identified, action must be taken (up to and including load shed) to mitigate the issue, in accordance with NERC Reliability Standards. Redundancy is a key element in maintaining the long-term resilience and stability of the grid, particularly as demand grows and as more renewable energy sources are integrated.

2.4 Purpose of the TSHARP Investment Analysis

The purpose of the TSHARP investment analysis is to prioritize continued investments in replacing aging infrastructure and enhance system resiliency to build upon the success of TSIP. The TSIP targeted aging infrastructure replacements and added line sectionalizing equipment based on historical transmission reliability performance. The TSIP investments proved to be effective based on the improved transmission reliability performance since these investments have been made. LG&E/KU recognized that further investments in aging infrastructure are needed to maintain and improve transmission reliability performance, but historical outage data only identifies weakness in the system after the damage has been done. To identify the most critical aging infrastructure to target for replacement, LG&E/KU partnered with Black & Veatch to conduct a risk analysis on its population of critical transmission assets. Figure 2-5

[5] 03-AG_DR1_LGE_KU_Attach_to_Q13(l) - Att_1_Winter_Storm_Elliott_LKE_Event_Summary.pdf (ky.gov)
[6] Billion-Dollar Weather and Climate Disasters | Kentucky Summary | National Centers for Environmental Information (NCEI) (noaa.gov)

below shows the asset classes assessed as part of the TSHARP investment analysis. Whereas substation assets were analyzed and presented at the asset level, line assets were analyzed at the asset level (Structure, Overhead Conductor, and Underground Cable) and presented at the circuit level in an effort to identify which transmission circuits pose the highest risk to the system.

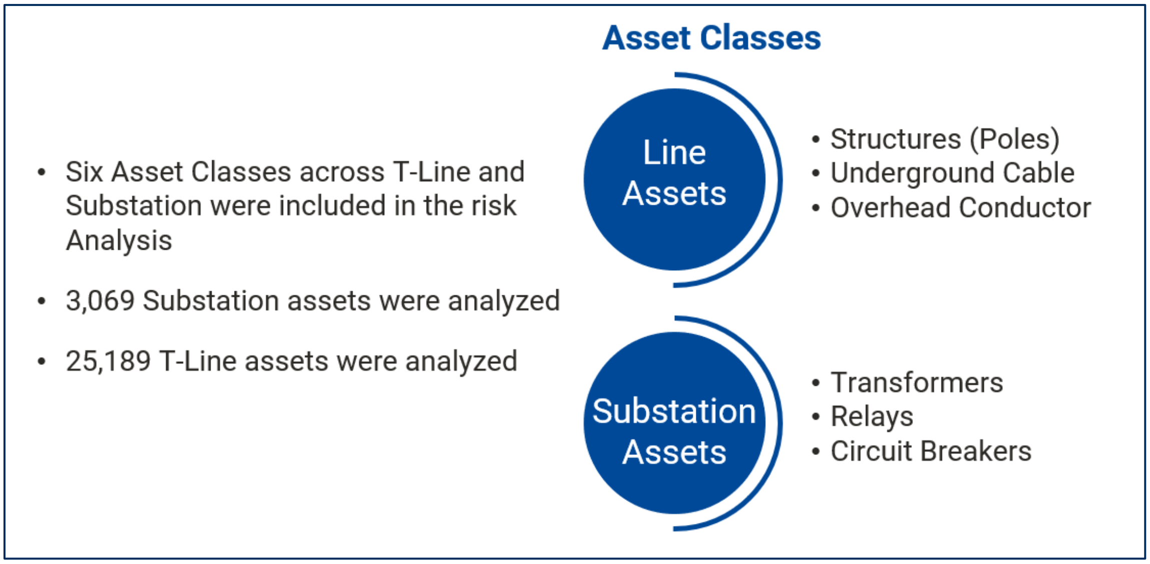

Figure 2-5 LG&E/KU Asset Register Summary

The risk analysis quantifies the benefits of replacing high risk aging infrastructure and compares it to the cost of replacements, enabling LG&E/KU to make risk-informed decisions. By identifying high risk assets for replacement which produce benefits that outweigh cost, LG&E/KU can deploy capital effectively and efficiently while reducing the risk of degrading transmission reliability performance. The TSHARP investment analysis powered by Black & Veatch's Risk Adjusted Project Prioritization tool will enable LG&E/KU to perform updated risk assessments when required as part of the annual business planning process or other portfolio reviews to better manage aging infrastructure and high-risk assets that make up the transmission system.

2.5 Aging Infrastructure

The LG&E/KU transmission system has many assets that have served customers for decades due to sound, effective and regular maintenance practices. However, many transmission assets on the LG&E/KU system are at, near or beyond their service life and are becoming a risk to reliability and resiliency performance of the transmission system. Allowing transmission aging infrastructure to fail while in service is both costly and inefficient. The risk to reliability and resiliency is caused by running these assets to failure. Maintaining high levels of reliability performance is jeopardized when critical transmission infrastructure becomes aged. The probability of assets failing and causing or contributing to unplanned outages increases as they near the end of service life. This risk is pronounced when large portions of the transmission assets are at, near or beyond their service life. Equipment failures ultimately become cumulative and have the ability to impact not only customer reliability but also system integrity in a significant way. Moreover, extreme weather conditions produce high levels of stress on critical infrastructure causing an increased likelihood of equipment failures during peak demand periods and extreme weather conditions. While interruption of electric service is never convenient, it is even less convenient during those times of extreme heat, cold or inclement weather. Strategically replacing aging assets through a risk analysis is an industry best practice and is a cost-effective way to maintain and improve reliability for customers and resiliency of a utility's system.

The LG&E/KU transmission system has circuit assets still in service which were constructed over 100 years ago. While this speaks to a commitment to being good stewards of these assets, they are well beyond their service life and need to be replaced and brought up to current design standards. Replacing these old and obsolete assets is a crucial element in the safe, reliable operation of the transmission system. For example, 48% of transmission structures are wood structures with a service life of 60 years. Over 55% of the remaining wood structures on LG&E/KU's transmission system are beyond the 60-year service life, representing 30% of all transmission structures. Figure 2-6 summarizes the age of transmission circuits by mileage.

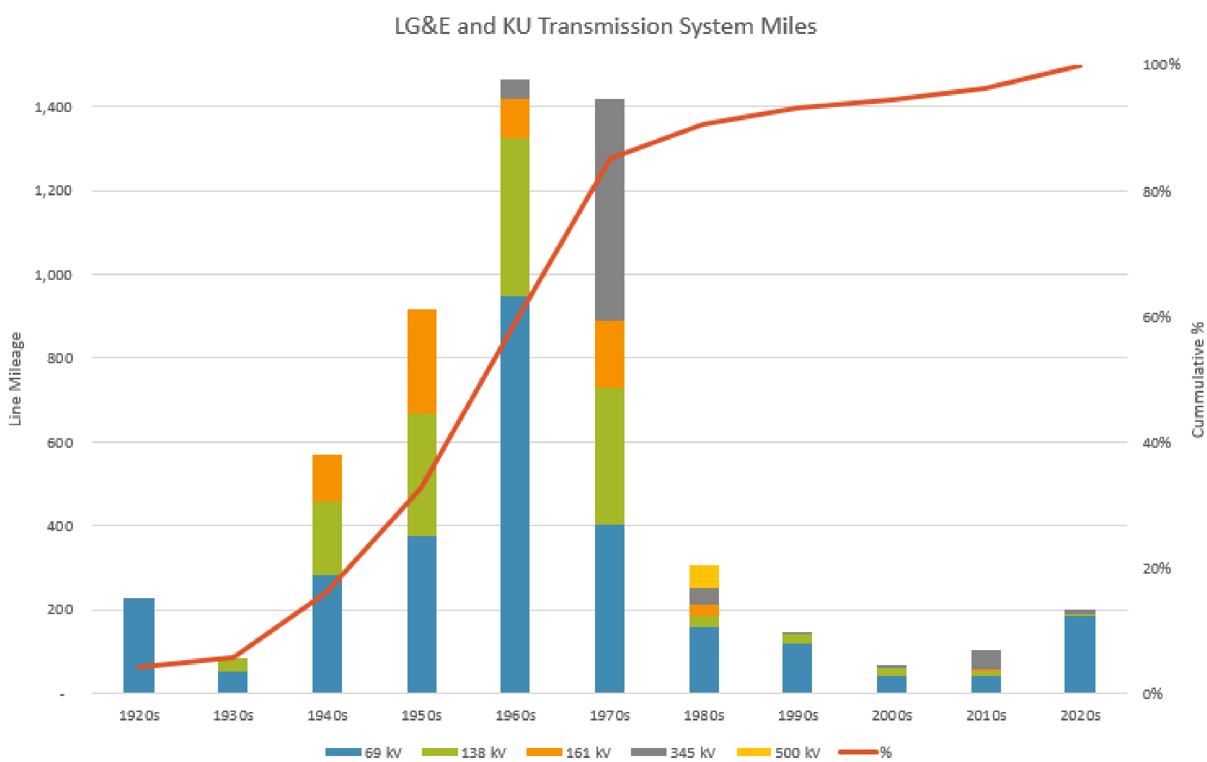

Figure 2-6 Cumulative Percent of Transmission Mileage by In Service Date

While wood structures have a service life of 60 years, from a depreciation and accounting perspective, it certainly does not guarantee poles will last that long. There are several factors that lessen the actual lifespan of a wood structure, such as: woodpeckers, fungal decay, and insect infestation. Figure 2-7 shows an LG&E/KU structure that was only 3 years old at the time of the inspection. This structure required replacement much earlier than expected.

Figure 2-7 Woodpecker Damage to Wood Structure

LG&E/KU has invested significantly in updating its transmission infrastructure and has managed to rebuild 133 miles of circuits and replace over 9,800 wood poles with steel poles since 2017. Steel poles are stronger than wood poles and are designed to withstand 100 mile per hour winds or up to 1" of ice per Company standards. Steel poles have a longer expected life than wood poles, are more resilient to hazards and severe weather events, and do not deteriorate like wood poles. For example, the Transmission system has been able to better withstand recent severe storms such as the March 2023 windstorm, thanks in part to proactive replacements of wood structures. To maintain the reliable performance our customers and regulators expect, proactive replacement must not only continue, but accelerate. LG&E/KU has approximately 21,000 (48%) wood structures remaining on its system and has replaced an average of 900 per year (2022-24). At the current replacement rate, it will take over 23 years to replace all remaining wood structures. The volume of circuits affected cannot be addressed simultaneously due to outage constraints, so prioritizing this work will be critical to the success of the wood pole replacement program. Replacing the remaining wood structures with steel over time in a measured and prioritized way will harden the transmission system and continue to improve the grid's resilience.

Similar to the wood to steel pole conversion, the substation department has prioritized replacement of aging oil circuit breakers with newer insulation technology over the last several years. Eliminating oil-filled circuit breakers addresses several key concerns. Oil breakers pose significant safety risks due to their flammability, the potential for oil spills, and the risk of collateral damage to adjacent equipment during a catastrophic failure. Additionally, maintaining older oil circuit breakers is costlier and more difficult due to the scarcity of replacement parts and the level of effort required for tasks like internal inspections and frequent contact replacements. Internal inspections, in particular, require specially trained personnel to identify failing components and often require entry into confined spaces for repairs. In contrast, newer breaker insulation technologies eliminate oil-related hazards, require reduced maintenance, and significantly reduce the need for specialized labor, making them a safer, more reliable, and cost-effective solution for modern systems. Oil circuit breakers make up 24% of the LG&E/KU transmission breaker population, with 23 oil circuit breakers beyond their service life of 60 years. Over the next ten years, 232 additional oil breakers will cross that threshold. Due to increasing equipment lead times and outage constraints, these equipment upgrades must be strategically prioritized to preserve the integrity of the transmission system, completely transitioning from legacy oil circuit breakers to newer insulation technologies. Like circuit upgrades, breaker replacements must not only continue, but accelerate. At the current replacement rate, it will take 7 - 10 years to replace all remaining oil circuit breakers. Figure 2-8 shows a 60+ year old LG&E/KU oil breaker in the KU service area. Each tank of this 138kV Westinghouse breaker holds 1,000 gallons of oil, and it is situated near a residential area.

Figure 2-8 Aged 138kV Oil Circuit Breaker

Structures and circuit breakers are not the only equipment on the transmission system, but they provide a snapshot of the age and condition of the transmission assets. While chronological age of assets is not always a good predictor of the risk or impact of a failure, chronological age combined with asset health data can be used to identify and prioritize high risk assets to avoid asset failures that will negatively impact customers and the transmission network. The TSHARP program provides a risk reduction and benefit cost analysis approach to prioritizing the LG&E/KU transmission project portfolio of infrastructures upgrades. This approach strategically targets asset replacements which will reduce the risk of aging infrastructure negatively affecting transmission system reliability.

2.6 Cost to Serve Compared to Industry

Historically LG&E/KU have been first quartile performers in cash cost per MWh sales and transmission line miles. Figure 2-9 and Figure 2-10 are graphs of Cost per Mile of Transmission and Cost per MWH Sales included in the TSIP report for the years 2011 through 2015.

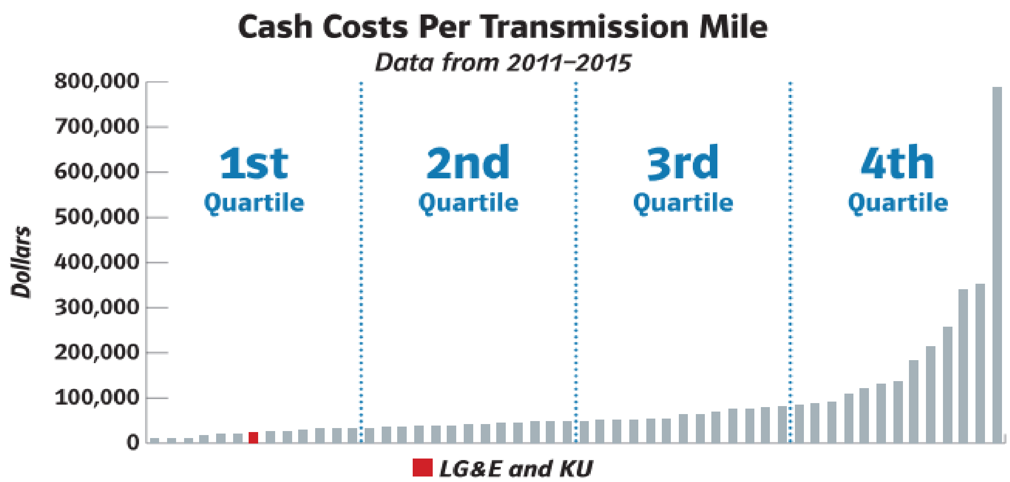

Figure 2-9 Cost per T-Line Mile

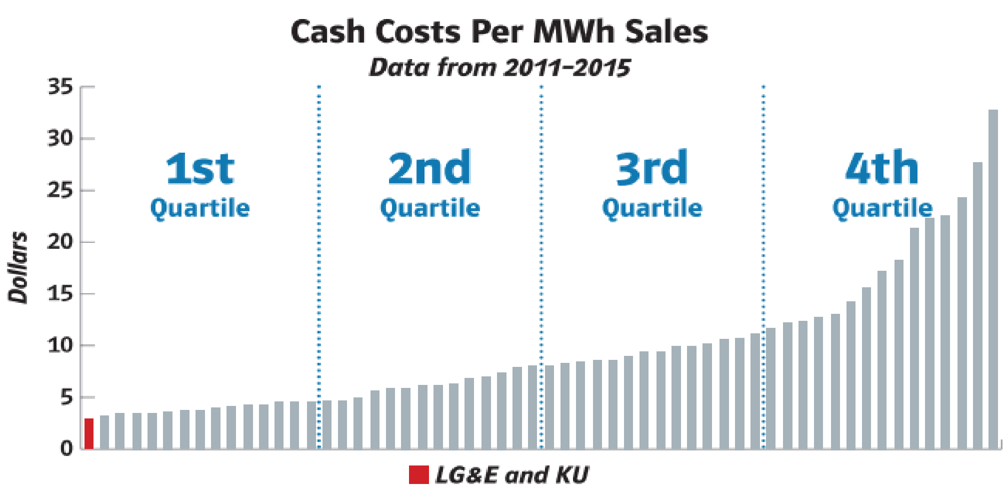

Figure 2-10 Cost per MWh Sales

Even with the increased investments as part of TSIP, LG&E/KU's costs continue to be among the lowest in the industry. For the previous five-year period of 2019-2023, LG&E/KU were first quartile in both cost per transmission line mile and cost per MWh sales. These results, along with the reliability improvements from TSIP, demonstrates a great value to customers by balancing system and reliability improvements with costs borne by customers (Figure 2-11 and Figure 2-12).

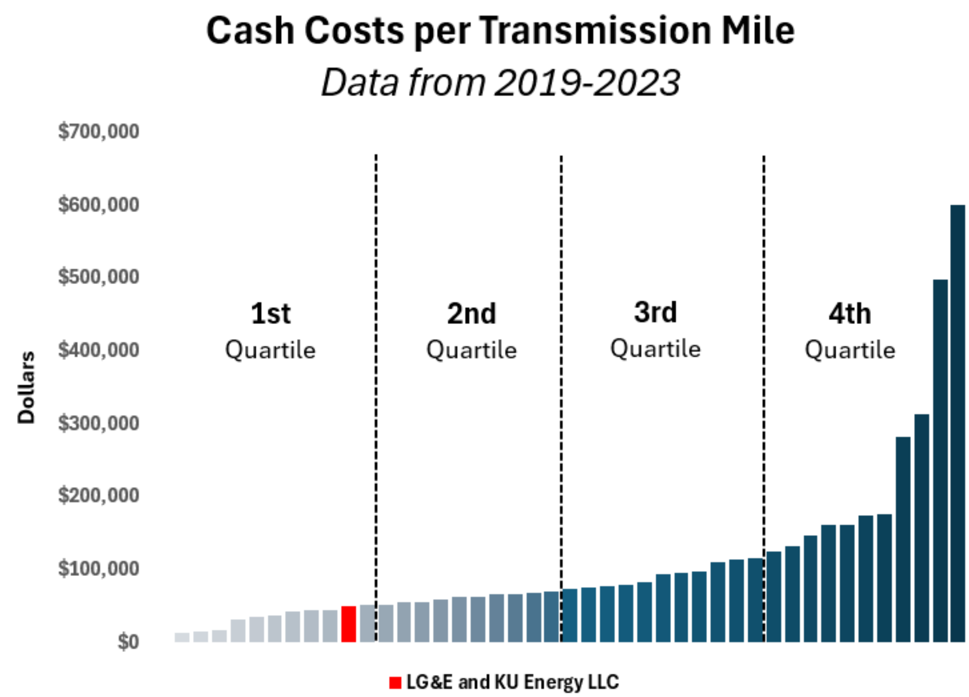

Figure 2-11 Cost per Transmission Mile 2019 through 2023

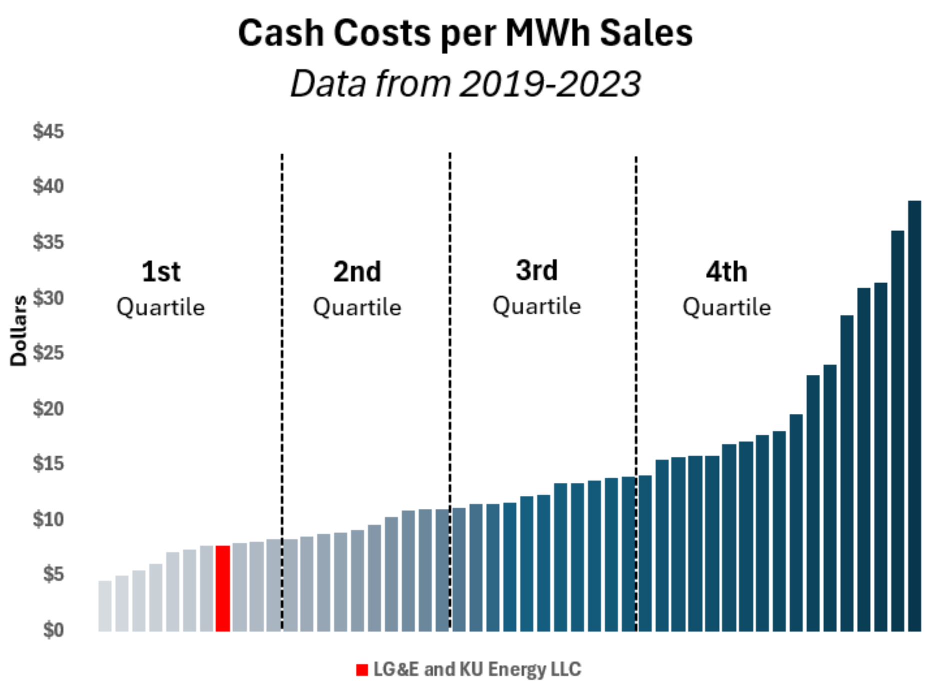

Figure 2-12 Cost per MWh Sales

The TSHARP program will continue balancing system and reliability improvements with costs borne by customers.

2.7 Case for Change

The reliability expectations of customers, whether LG&E/KU customers or other utility customers served directly from the transmission system, have steadily increased over the years. The widespread use of and reliance on technology, expected growth of artificial intelligence powered by data centers, expansion of electric vehicle use, and employees working remotely (spurred primarily by the COVID-19 pandemic) heighten customer sensitivity to outages. People need reliable power to their homes, not only for individual comfort, but also for their livelihood. Both commercial and industrial businesses rely on reliable power to operate their business and serve their customers. The acceptable standard for reliable service will rise as the electrification transition continues.

Surveys consistently show that reliability and power quality are central to customer satisfaction. Consistent, high-quality power delivery minimizes disruptions, protects customer equipment, supports critical operations, and builds trust between customers and utilities. Figure 2-13 shows the JD Power Quality and Reliability customer satisfaction index. The graph shows a strong correlation between customer dissatisfaction following extreme events, which clearly demonstrates the importance of reliable and high-quality power service. Higher numbers indicate greater customer satisfaction.

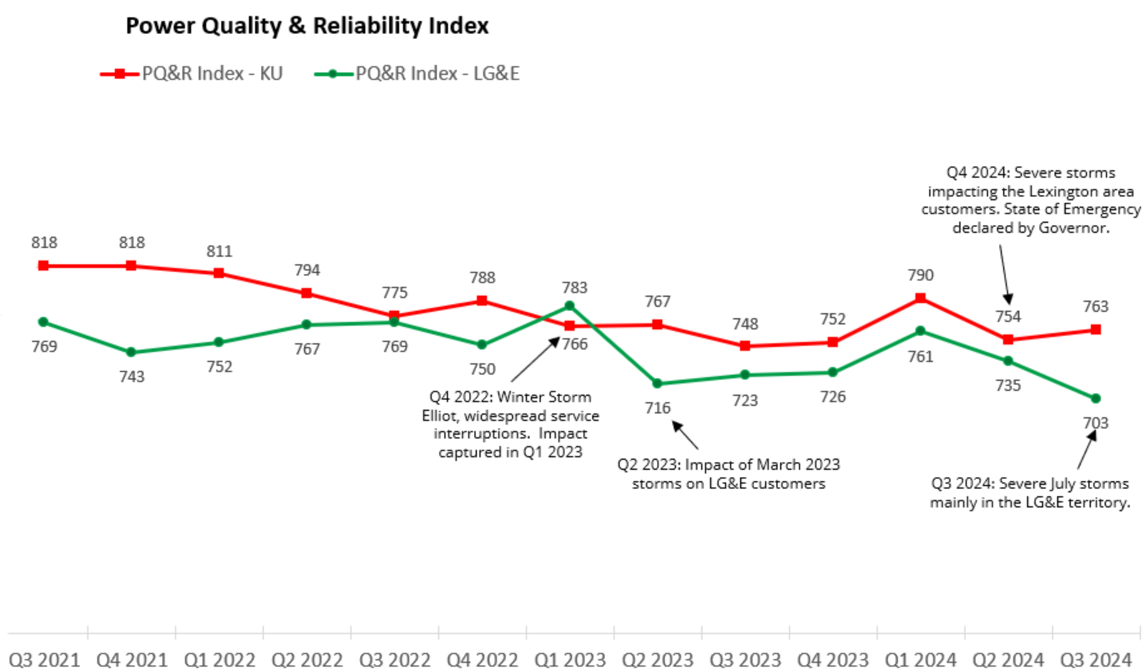

Figure 2-13 JD Power Quality & Reliability Index

Maintaining existing reliability performance and customer satisfaction will be impossible without targeted and strategic increased investments in aging infrastructure both on Transmission Lines and in Transmission Substations. Now is the time to continue the momentum achieved through TSIP to usher in decades of continued reliable electric service, not only for our customers in Kentucky and Virginia, but also as utilities of the larger Eastern Interconnect. To this end, TSHARP includes replacing wood structures with steel that will harden the system, prevent outages, and improve resiliency of the transmission system against major storms and wildfires. TSHARP also includes system enhancement to improve reliability for customers across the system through adding sectionalization equipment and fault detecting technology that will reduce customer exposure and outage durations. This broad collection of projects will collectively mitigate the likelihood and consequences of future events.

LG&E/KU believes that a carefully prioritized portfolio of asset replacement and new projects is imperative to sustain and improve transmission system reliability and resiliency in an efficient and affordable way. These conclusions are based on asset age, asset condition, and customer expectations. By prudently identifying and replacing high-risk assets over time, it will naturally smooth customer rate impacts while reducing impacts of future asset failures.

LG&E and KU's systems are no different, utilities across the country are making similar, much-needed targeted investments in transmission to reduce the frequency, duration, and impacts of outage events, replace outdated technology, and upgrade system intelligence and control. For example, in 2021, Duke Energy Indiana (DEI) proposed an incremental investment plan of approximately $800 million dollars of transmission investments over a 6-year window. Cost-benefit analysis and prioritization of the projects in the DEI portfolio were assessed in partnership with Black & Veatch consultants who are recognized as industry leaders in infrastructure investment planning. The DEI plan, specifically the Black & Veatch analysis that supported it, caught the attention of LG&E/KU leadership, and resulted in the engagement of Black & Veatch to assist LG&E/KU in the analysis and developing this TSHARP investment plan.

Much has been documented about the need to upgrade the nation's transmission grid, and LG&E/KU's grid is no different. As an example, the following was reported in the industry publication, Systems with Intelligence, in January 2023:

> Today, however, the grid has reached a tipping point. Originally built decades ago, much of the critical infrastructure is at or near the end of its life. At the same time, electricity demand is growing, and the grid is being asked to accommodate a far wider range of energy sources and generation technologies. […]
>
> In the US, a recent report by the Department of Energy found that more than 70 percent of transmission lines were more than halfway through their 50-year life. Similarly, the average age of large transformers exceeded 40 years, increasing the risk of catastrophic and costly failure. […]
>
> With so many opportunities to enhance and improve the grid, how can utilities decide where to allocate spending?
>
> One solution is to implement utility-grade visualization software with advanced data and analytics capabilities. By inputting data such as maintenance history, service records, the age and condition of components, and any restraints or requirements, the utility can calculate where to invest and how to optimize grid infrastructure to meet its strategic objectives. [7]

LG&E/KU firmly believes that this plan, that quantifies benefits and costs to identify high risk assets and prioritize investments, is the best plan forward while striking an appropriate balance between benefits and costs to customers.

[7] Transforming an Aging Grid – Where Should Utilities Focus Investments? (systemswithintelligence.com)

2.8 Performance Objective

The objective of TSHARP is to continue progress toward the long-term stated goals established with TSIP. TSHARP will not only sustain second quartile reliability performance, as measured by Transmission SAIDI, but make targeted investments designed to achieve first quartile performance in the timeframe of 2031-2036 while minimizing impact to ratepayers. This program is the natural continuation of investments begun in 2017 and will usher in the next decades of reliable service for LG&E and KU. The TSHARP program leverages all available data to drive down reliability risk, replace aging assets, eliminate obsolete technology, and build a resilient grid, all while maintaining reasonable cost balance for LGE/KU's customers.

3.0 Investment Plan Development

Black & Veatch is an industry leader in infrastructure investment planning in the power, water, and communication industries. Black & Veatch is an employee-owned engineering, procurement, construction, and management consulting company with over 100 years of innovations in critical infrastructure. The LG&E/KU cost benefit analysis was conducted leveraging Black & Veatch's industry knowledge of electric utility engineering, operations, and maintenance in conjunction with LG&E/KU's subject matter experts with broad industry knowledge and who have intimate understanding of their assets, system configuration and performance. The LG&E/KU investment plan was developed using the 4 progressive steps as illustrated in Figure 3-1.

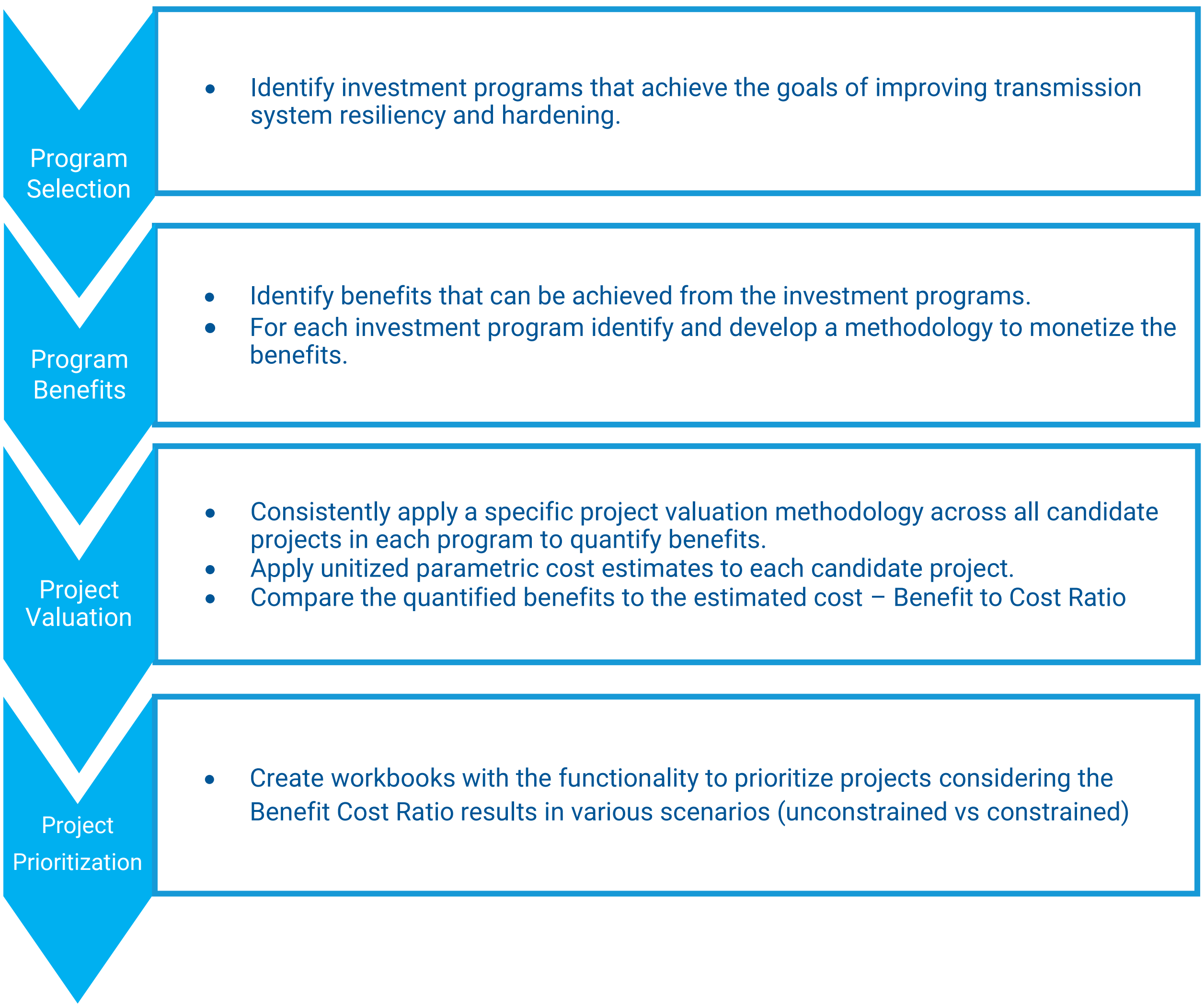

Figure 3-1 Investment Plan Development Process

LG&E/KU, with assistance from Black & Veatch, took a data-driven, risk-informed approach in developing LG&E/KU's risk and benefit cost analysis. As its name suggests, the approach compares the benefits of each project with the cost of the project. Benefits are categorized into risk reduction benefits and financial benefits. The project valuation process is further illustrated in Figure 3-2. Figure 3-2 illustrates that the risk analysis process was truly a collaboration between LG&E/KU and Black & Veatch.

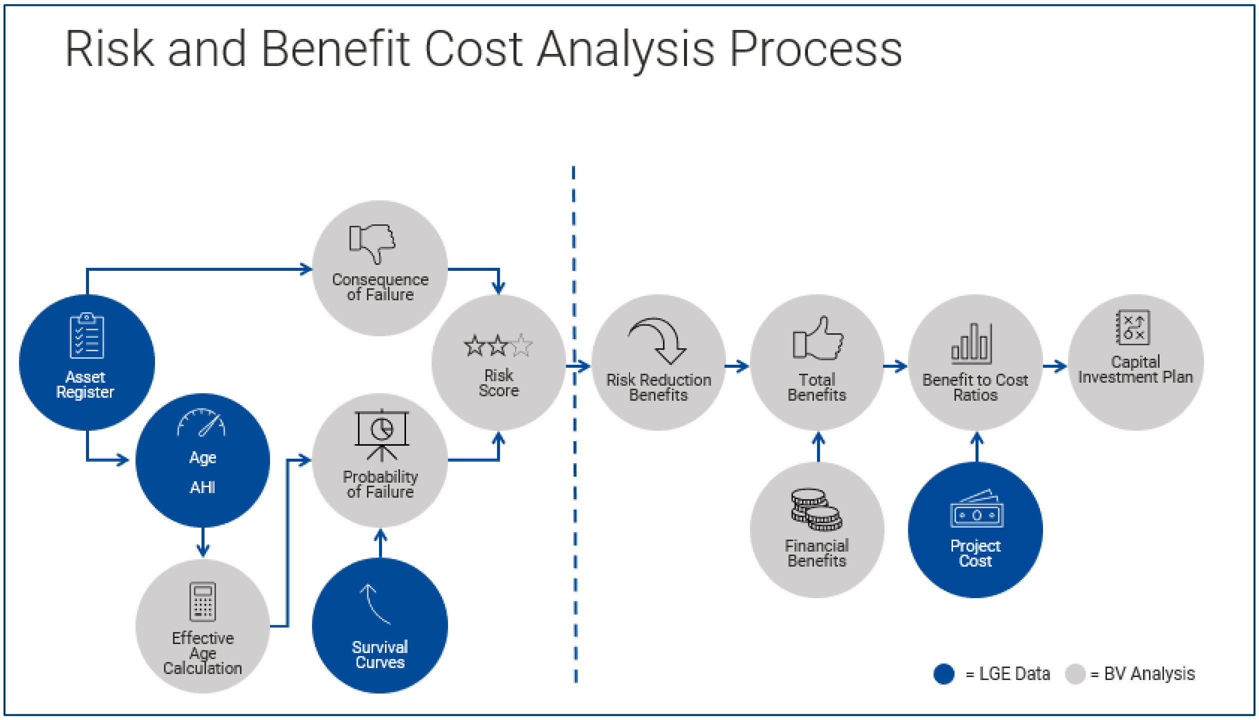

Figure 3-2 Risk and Benefit Cost Analysis Process

Analysis of risk reduction benefits considers the risk critical assets pose to the system if they fail and compares it to the residual risk posed to the system if the asset is replaced in kind with a new asset. Risk reduction benefits are not actual cash flows for the company. The risk reduction benefit is a buy down of risk that currently exists on the LG&E/KU transmission system. The risk reduction benefit is achieved by proactively replacing high risk assets before they fail. Unlike risk reduction benefits, financial benefits are actual cash flows for the company. They include reduced O&M expense and reduced capital cost achieved by replacing high risk assets. These financial benefits are combined with risk reduction benefits and then compared to the cost of replacing high risk assets.

To evaluate risk, Black & Veatch performed a risk assessment on transmission assets. LG&E/KU-specific asset data was used to derive asset risk scores that enabled the quantification of risk reduction benefits associated with asset replacements. This risk-based approach enables the prioritization of high-risk assets based on the probability of an asset failing and the consequence to the transmission system when it fails. The risk and benefit/cost analysis were enabled by Black & Veatch's Risk Adjusted Project Prioritization (RAPP) tool. The RAPP tool defines a baseline risk score for each asset and compares it to an outcome risk score. Risk scores are monetized by defining a common economic scale for consequences. The difference between these scores is the risk reduction benefit of replacing the high-risk asset. This methodology can be expressed as:

Baseline Risk - Risk with Existing Assets in Service

Minus

Outcome Risk – Residual Risk After Existing Asset is Replaced

Equals

Risk Reduction – Risk Removed from the System by Replacing the High-Risk Asset

Where:

Risk = Probability of Failure (PoF) X Consequence of Failure (CoF)

Additionally, financial benefits were also captured and added to the risk reduction benefits. The total benefits were then compared to the estimated cost to replace the asset which produced a benefit to cost ratio for each asset evaluated.

To evaluate the benefits of investing in new resiliency infrastructure, a review of the LG&E/KU transmission system was performed to identify areas on the transmission system that if reinforced would reasonably produce improved system performance. For Resiliency Programs candidate projects were selected by identifying the locations where the resiliency infrastructure is not in place today and performing a benefit to cost analysis of adding the infrastructure.

3.1 Program Selection

The first step in developing TSHARP is to identify investment programs that support the key objectives of maintaining reliability performance gains through TSIP and improving transmission system hardening and resiliency. To this end, LG&E/KU and Black & Veatch considered how aging infrastructure could negatively affect the transmission system reliability performance moving forward in time. Likewise, we considered new infrastructure investments that could be made to improve transmission system reliability performance. From this, two broad investment categories were established.

1. Asset Replacement - Replacement of high-risk transmission assets that pose a threat to system reliability and resiliency performance if not replaced.
2. New Resiliency Infrastructure - Adding new high reliability impact infrastructure that will reduce outage durations and frequency.

In collaboration with LG&E/KU subject matter experts (SMEs), Black and Veatch identified and mapped investment outcomes to address the objectives of the investment plan. To achieve the investment outcomes, six individual investment programs were identified. Of the six programs, four aging infrastructure replacement programs were identified to offset the negative impacts to system reliability, and two new investment programs were identified to reduce outage durations and frequency. Table 3-1 provides a summary of the investment programs mapped to each objective.

Table 3-1 Summary of Investment Programs

Investment Objectives	Investment Outcomes	Investment Programs
Asset Replacement Replacement of high-risk assets that pose a threat to system reliability and resiliency performance.	• Remove high risk assets from the system before they fail. • Maintain and improve system reliability and resiliency performance.	• Circuit Rebuilds • Transformer Replacements • Breaker Replacements • Relay Panel Replacements
New Resiliency Infrastructure Add new infrastructure that will reduce outage durations and frequency	• Reduce Outage Durations • Reduce Outage Frequency	• Deploy MOS & Auto Sectionalizing • Reinforcing Radial Tap Lines

3.2 Asset Replacement

The five core components that make up the transmission network are: (1) transformers (2) circuits (3) substation "bus work" (4) circuit breakers and (5) relay panels. Transmission substation "bus work" is comprised of I-beams, angle or tubing metal conductors, wire conductors, and connectors. It has few moving parts, is less likely to fail than the other components and can be easily and regularly inspected to determine potential points of failure. Therefore, substation "bus work" replacement was not considered for candidate projects in the analysis, and the TSHARP focuses on the four remaining asset categories for replacement: Circuit Rebuilds, Transformer Replacements, Circuit Breaker Replacements, and Relay Panel Replacements were identified.

The four asset replacement programs were chosen through collaboration with LG&E/KU subject matter experts and the Black & Veatch engineering and operations professionals. This infrastructure makes up most of the core transmission assets that provides high levels of reliability and supports regional transmission stability. Each program is summarized below.

3.2.1 Circuit Rebuilds

Transmission circuits provide two main functions to the electric system. Transmission circuits carry large amounts of energy over long distances to supply local electric loads, and they are an integral part of the electric transmission network that redirects power flows *without interrupting customers* when a transmission element or generating station is lost or taken out of service. Transmission circuit capacity is determined primarily by the amount of native load ("local load") served through the circuit. Transmission system planning is then required to account for certain other events or contingencies, such as a loss of a transmission system component on our system or certain events taking place on other transmission systems around us. This necessarily requires that our transmission system have some reserve capacity that is designed to be used when the transmission system needs to react immediately to such events to prevent interrupting customers.

The transmission circuits evaluated in the analysis consisted of 69kV, 138kV, 161kV and 345kV circuits. The focus for this evaluation was circuits containing wood and weathering steel structures. Circuits comprised of galvanized and painted steel were excluded due to many years of proven performance. While no circuits were excluded for larger conductor sizes, LG&E/KU has focused its testing program upon smaller conductors that have been problematic (See Section 6.1.2).

Many of LG&E/KU transmission wood poles have been in service beyond their service life of 60 years and pose considerable risk to the transmission network based on wood strength deterioration. For example, Figure 3-3 is a histogram of the chronological age of existing wood poles on the transmission system. The histogram shows that 11,803 of the 21,512 wood poles (54.9%) are at or beyond their service life of 60 years. Wood poles nearing, at, or above 60 years of age begin to lose, or have lost much of their initial strength. These poles pose a threat of failure the longer they are kept in service. The histogram also demonstrates that in the next 10 years an additional 6,079 poles will reach the end of their service life. This would result in 17,882 out of 21,512 wood poles (83.1%) at or beyond their service life. Absent proactive replacement of the aged and aging population of wood poles the LG&E/KU transmission system will be vulnerable to widespread damage during extreme weather conditions.

Wood poles are a significant asset type that make up many transmission circuits. Replacement of wood poles that are at or beyond their service life with steel poles will have a large positive impact on hardening the LG&E/KU transmission system. Other transmission asset types evaluated in the circuit risk analysis are overhead conductors, underground cable, and weathering steel poles. Steel lattice towers, galvanized steel poles, and painted steel poles were not included in the risk analysis due to their expected longevity and low historical failure rates, making them less likely to require replacement or repair in the near future.

LG&E/KU strengthens (hardens) infrastructure and reduces the likelihood of disruptions in the affected communities primarily with pole replacements. Replacement of wood transmission structures with upgraded steel structures improves resiliency in extreme weather, including wildfires. The transmission system also benefits from the significantly longer life expectancy of steel structures due to the lack of damage expected from woodpeckers (see Figure 2-7), insects or pole rot. In hazardous conditions, the resiliency of steel structures minimizes catastrophic or domino effect failures along the line due to their increased ability to withstand impact from extreme weather.

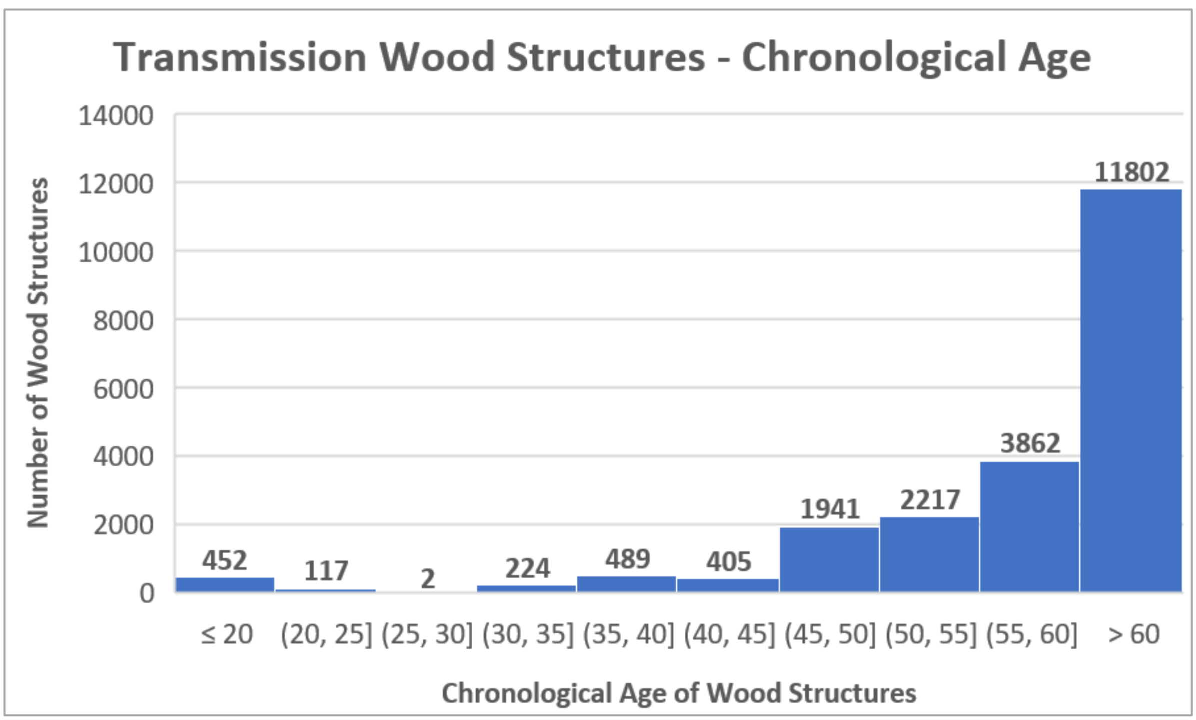

Figure 3-3 Wood Structures Chronological Age - Histogram

3.2.2 Power Transformer Replacements

Transformers convert voltage at generating stations to higher levels so that more power can be transmitted over long distances on transmission circuits and then converts voltage to lower levels so that energy can be delivered to local distribution loads. Voltage transformation enables the efficient transmission of power by reducing energy losses on transmission circuits, mathematically, the higher the voltage the greater the power flow (power increases by the square of the voltage). Transformer capacity is set by the amount of native load served through the transformer, the amount of regional load flowing through the system serving non-native loads and a reserve amount of capacity. The reserve transformer capacity is an integral part of the transmission network and is designed into the system so that the transmission grid can immediately react to loss of a transmission component without interrupting customers or causing the failure of additional equipment.

The transformers considered in the risk analysis have a primary voltage of 138kV through 345kV. Voltage transformations of 138/69kV, 161/138kV, 161/69kV, 345/161kV, and 345/138kV of varying MVA sizes make up the population of 133 transformers included in the risk analysis. Transformers with a primary voltage of 69kV serve distribution loads and are considered a distribution asset at LG&E/KU and therefore are not included in the risk analysis. LG&E/KU participate in two equipment sharing programs, RESTORE (Regional Equipment Sharing for Transmission Outage Restoration) and STEP (Spare Transformer Equipment Program) and leverages these programs to recover and mitigate the risk associated with the failure of its two 500 kV transformers. As a result, these two 500kV transformers were excluded from the analysis.

Figure 3-4 is a histogram of the chronological age of the 133 transformers included in the risk analysis. The histogram shows that 32 of the 133 transformers (24.1%) are less than 20 years old, indicating that investments in transformers over the last two decades have been consistent. On the other hand, 15 of the 133 transformers (11.3%) are at or above their service life of 60 years indicating that continued investments in transformers reaching end of service life will be needed moving forward. The histogram also demonstrates that there is a "wave" of transformers that are within 10 years of reaching their service life. Absent continued proactive replacements of the aging population of transformers in 10 years there would be a total of 45 transformers of the 133 transformers (33.8%) at or beyond their service life.

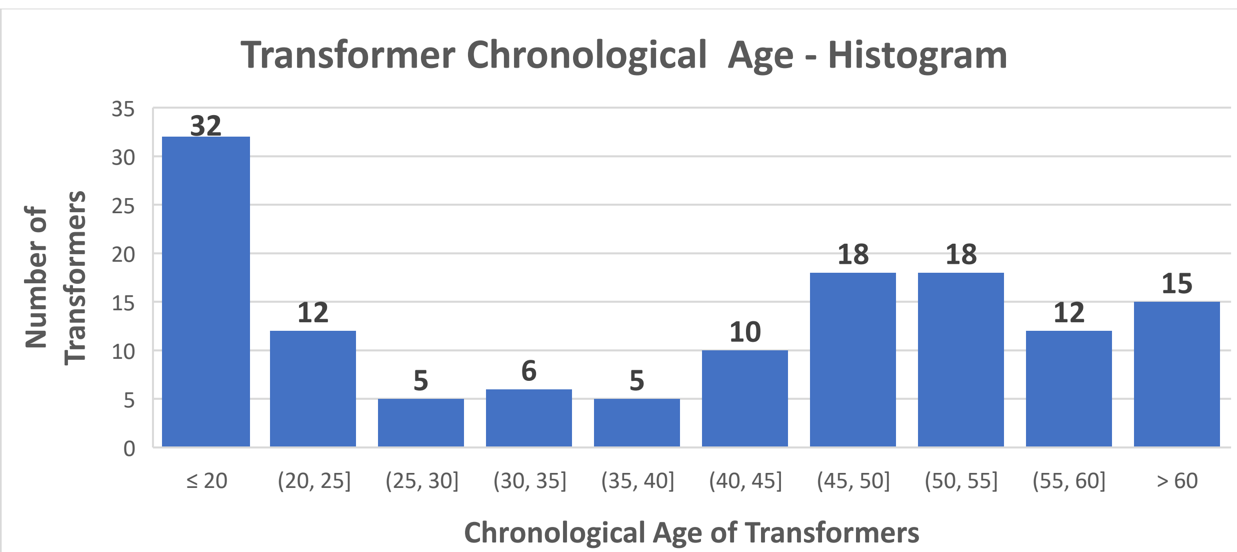

Figure 3-4 Transformer Chronological Age - Histogram

3.2.3 Circuit Breaker Replacements

Circuit breakers are deployed to remove faults from the transmission system as quickly as possible to protect equipment from the damaging effects of fault currents and to protect the public from energized conductors and equipment. Circuit breakers work in conjunction with relays and are controlled and operated by relays. Relays continuously monitor the current on the electric system and can very quickly detect fault currents. Circuit breakers are not needed to serve electric load, they are needed to protect the equipment that serves load. Circuit breakers protect transformers, circuits, capacitors, generators, and substation “bus work”. When a circuit breaker operates as designed it isolates and de-energizes only the section of the transmission system it was designed to protect. However, when a circuit breaker itself fails, the surrounding circuit breakers must operate to clear the failed or faulted circuit breaker. This results in larger sections of the transmission system being de-energized and isolated than is protected by the failed breaker. When circuit breakers fail additional transmission capacity is taken off the system while surrounding breakers clear the failed circuit breaker. Circuit breakers are capable of interrupting fault currents at multiples of normal load current.

Figure 3-5 is a histogram of the chronological ages of the 1,296 circuit breakers included in the risk analysis. Figure 3-6 and Figure 3-7 are histograms of oil and SF6 circuit breakers, respectively. There are a total of 40 vacuum circuit breakers included in the analysis all of which are under 5 years old.

Of the 1,296 circuit breakers 315 are oil filled type and 941 are SF6 gas type. Figure 3-5 shows that 818 of the 1,296 circuit breakers (63%) are less than 20 years old, all of which are SF6 or Vacuum type breakers. This indicates that proactive replacement of aged oil circuit breakers has been occurring over the last 20 years. These are prudent investments given that when oil circuit breakers fail eventfully there is risk of environmental and significant collateral damage. Furthermore, proactively replacing oil circuit breakers is a prudent investment knowing that a portion of oil circuit breakers are at, near or beyond their service life and keeping them in service increases the probability of them failing while in service. This places at risk the ability to protect the public by removing faults from energized equipment and high value transmission assets that serve load when they fail.

On the other end of the spectrum, 23 of the 1,296 circuit breakers (1.8%) are at or above their service life of 60 years, all of which are oil circuit breakers. The histogram also shows that there are a total of 232 circuit breakers of the 1,296 (18%) that are within 10 years of their service life of 60 years. This equates to 168 oil circuit breakers that are at, near or beyond their service life. Focused and continued investment in replacing oil circuit breakers should continue to reduce the risk of circuit breakers failing while in service.

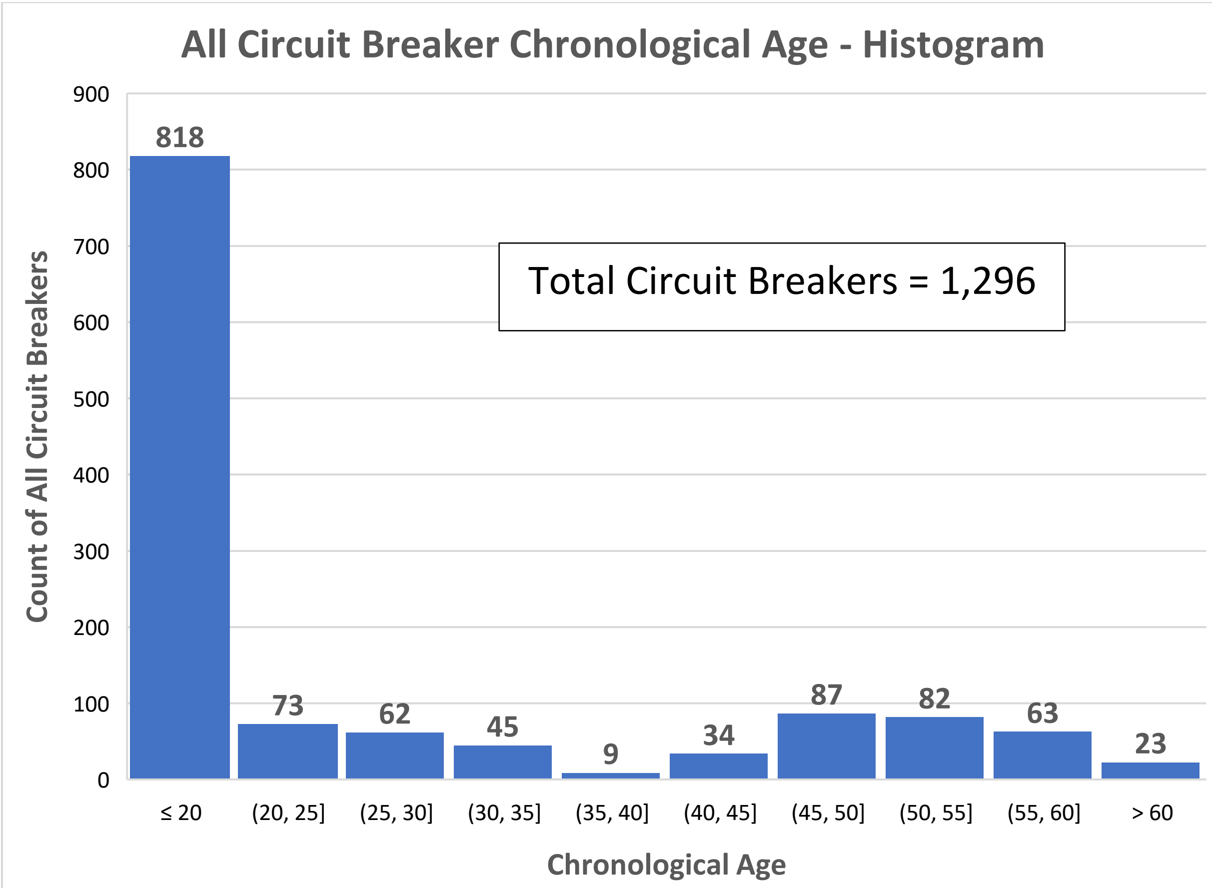

Figure 3-5 All Circuit Breakers Chronological Age - Histogram

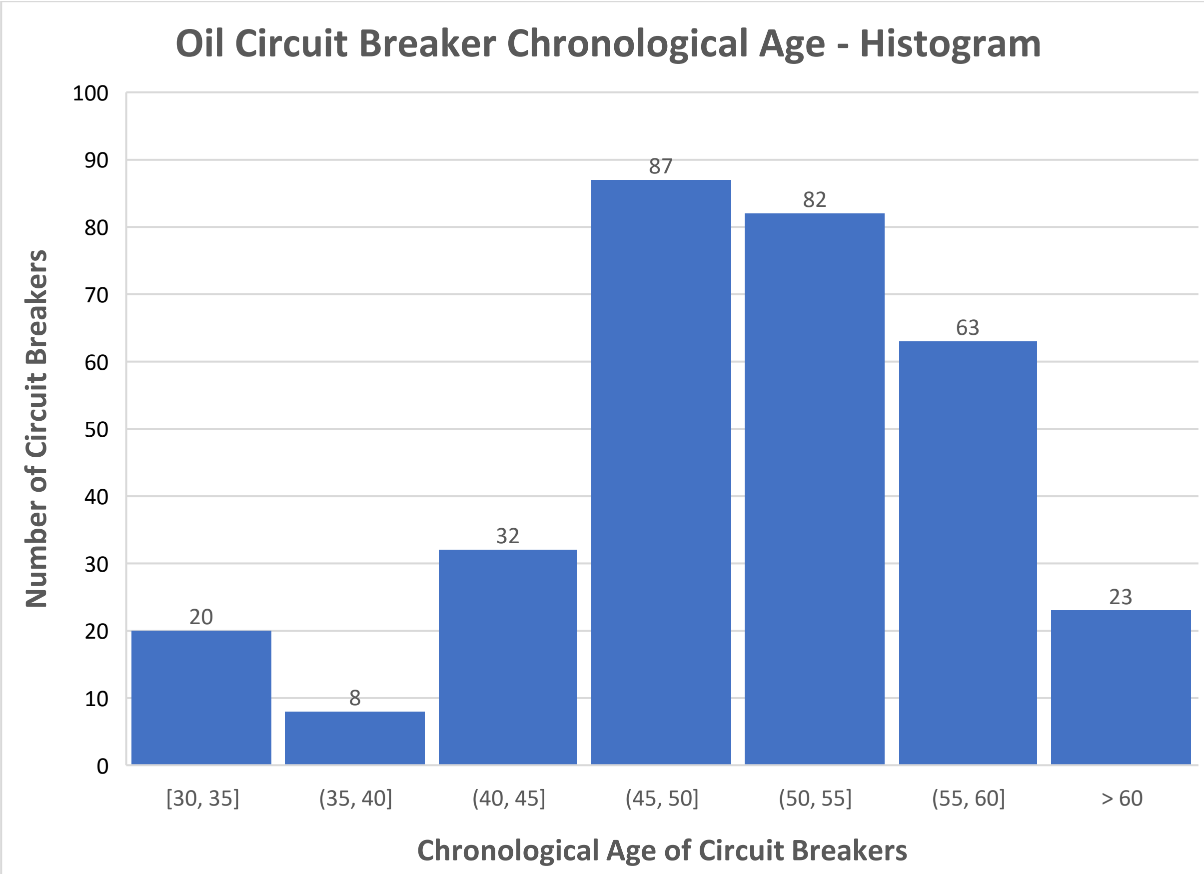

Figure 3-6 Oil Circuit Breakers Chronological Age - Histogram

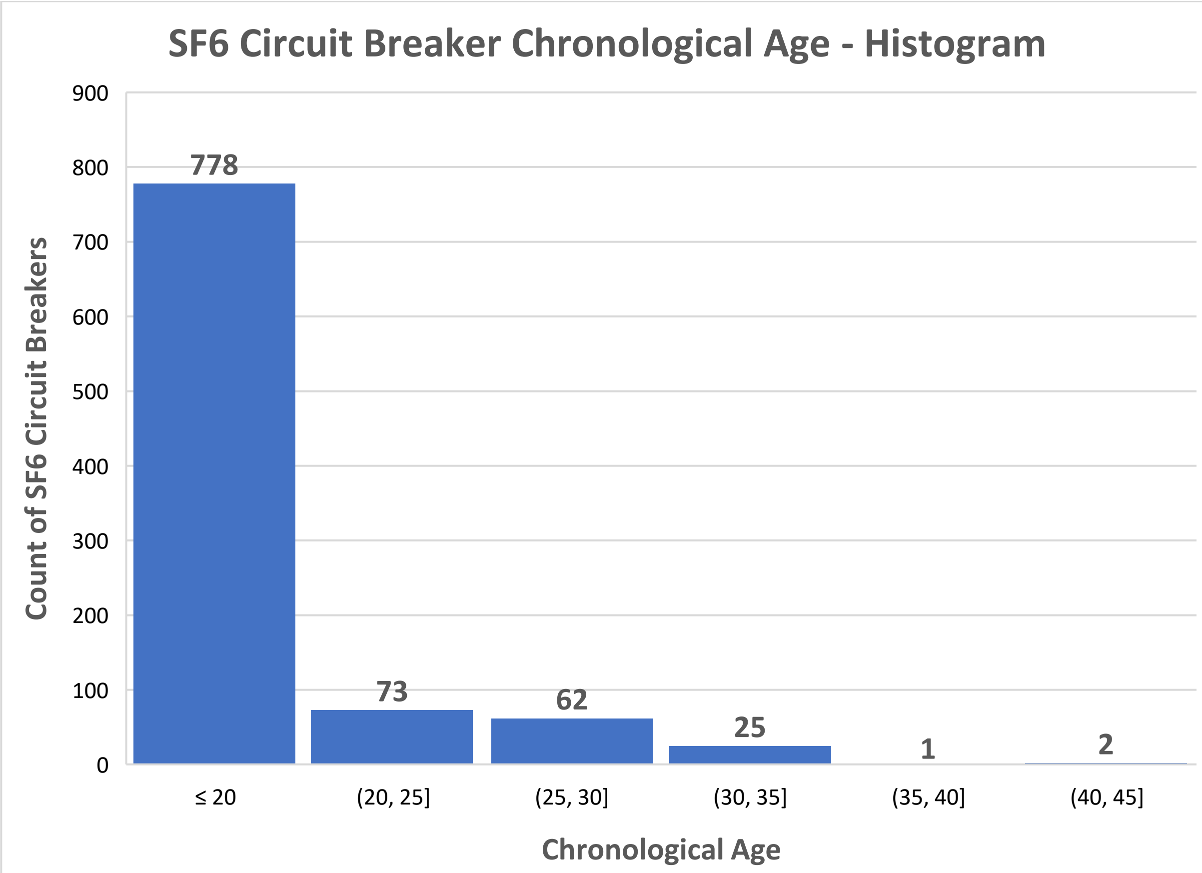

Figure 3-7 SF6 Circuit Breakers Chronological Age - Histogram

3.2.4 Relay Panel Replacements

Relays work in conjunction with breakers to isolate faults when they occur on the system. Relays are grouped together in panels to provide a specific function in a protection scheme. A relay protection scheme protects sections of the transmission system and is designed to have overlaps and layers of protection to ensure faults are removed from the system as quickly as possible avoiding cascading tripping and significant collateral damage. In combination with circuit breakers, relays protect and keep high value critical transmission assets from being damaged when faults occur on the system.

The LG&E/KU relays are comprised of older electromechanical relays and more modern micro-processor relays. Electro-mechanical relay accuracy degrades over time from wear and tear of the mechanical parts within the relay. They require frequent maintenance, repair, and testing. Micro-processor relays on the other hand do not have moving parts and do not require adjustment. They also have more functionality within a relay than electro-mechanical relays.

Relay panels, which consist of multiple relays, are replaced as a single unit for efficiency and effectiveness. There are 4,602 relays on the system, which are grouped into 1,629 panels.

Figure 3-8 is a histogram of the chronological age of the 1,629 relay panels included in the risk analysis. The histogram shows that 1,262 of the 1,629 relay panels (78%) are less than 20 years old. This indicates that proactive replacement of aged electromechanical relays has been occurring in conjunction with the oil circuit breaker replacements for the last 20 years. Because relays and circuit breakers work together to protect high value transmission assets and the public from energized equipment, replacing electromechanical relays while replacing oil circuit breakers is cost effective and prudent for the same reasons provided for replacing oil circuit breakers. While electromechanical relay failures may not appear to be as catastrophic, misoperation of relays can cause damage to equipment or widespread outages during fault conditions.

On the other end of the spectrum, 65 of the 1,629 relay panels (4.0%) are at or above their service life of 60 years. The histogram also shows that there are a total of 248 relay panels of the 1,629 (15%) that are within 10 years of their service life of 60 years. Similar to circuit breakers, LG&E/KU has proactively replaced electro-mechanical relays with micro-processor relays over the last 20 years. Again, a prudent investment based on the importance of protecting costly critical transmission assets. Also, similar to circuit breakers, there is a portion of the population of relay panels that are at, near or beyond their service life and continued investment in replacing these aged assets reduces the risk of them failing while in service.

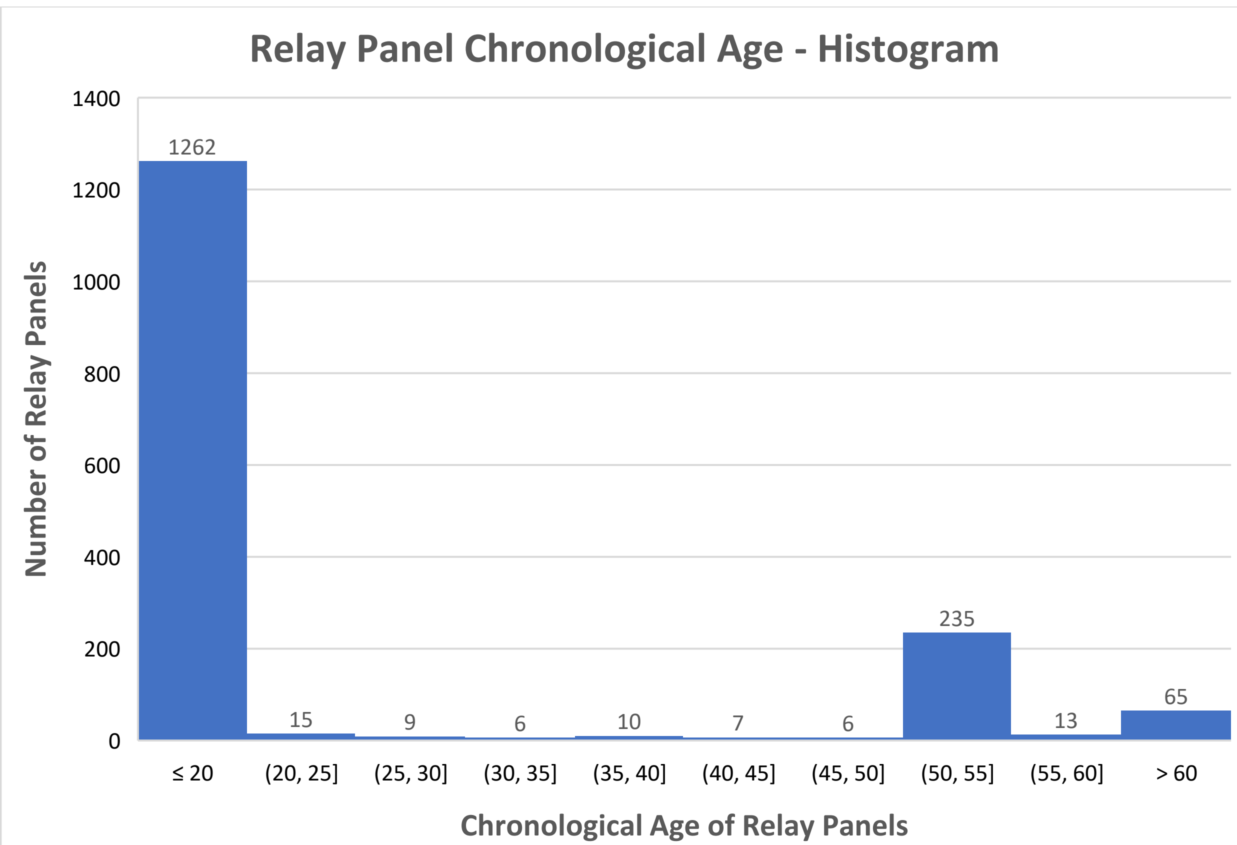

Figure 3-8 Relay Panels Chronological Age - Histogram

3.3 Resiliency Programs

There are two investment programs related to reducing the duration and frequency of outages on the transmission system. These two investment programs target areas of the transmission system where adding automation and control would improve system resiliency. It also targets reinforcing vulnerable circuit taps that cause long duration outages for customers when faults occur on the tap.

3.3.1 Rebuild Radial Taps

The purpose of this investment program is to reduce the frequency and duration of outages on substations served from transmission tap circuits. A transmission tap circuit is a sub-part of a larger transmission circuit that has two or more substation terminals and protected by circuit breakers at each substation terminal. The transmission tap circuit is a lateral off the mainline transmission circuit and has a terminal at a retail or large customer substation. Due to the rural nature of the KU service territory, with low customer density, and diverse geography that includes mountainous areas, this type of radial construction is typical design in the KU transmission system. Figure 3-9 depicts a tap circuit.

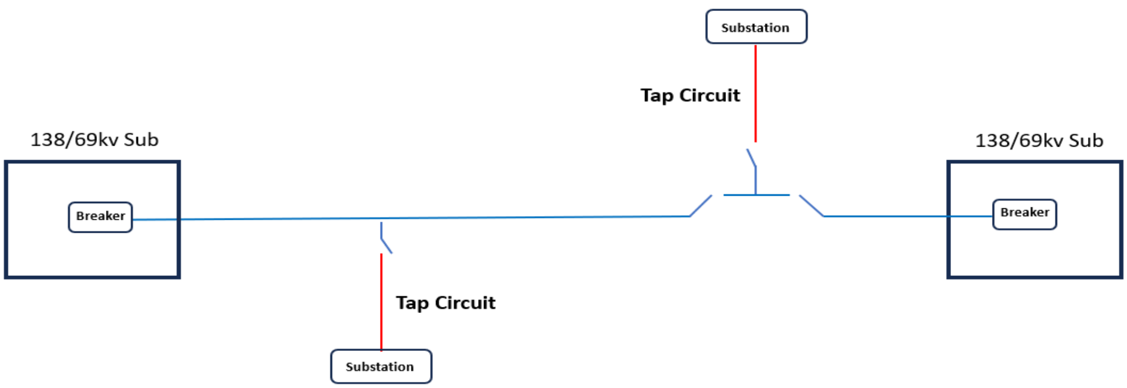

Figure 3-9 Illustrative Definition of Tap Circuit

For faults on transmission taps, power can be restored to customers not affected by the faulted tap through sectionalizing of the mainline circuit. However, the customers served from the tap must either be restored through distribution switching or remain out of service until the transmission system has been restored. This configuration places load served from tap circuits at much greater risk of long duration outages when faults occur. For each tap greater than 0.5 miles in length, LG&E/KU's distribution planning group studied the ability to restore each load through distribution switching in the event of a transmission outage. This list was then filtered to include only stations where distribution was unable to restore 5 MVA or greater to determine the list of candidate taps for hardening projects.

Bringing an alternative transmission source into a substation served off a tap would be ideal by providing two transmission sources for the substation. However, in many cases the alternative source is many miles away from the tap-served substation and would be cost prohibitive to construct. The benefit cost analysis was performed on the candidate tap circuits, using a cost estimate to rebuild the existing tap with a steel pole standard with three switches at the mainline tap point. Additional cost for widening right-of-way was also included in the cost to reduce the likelihood of vegetation caused outages. While not providing an alternative source for the load served from the tap circuits, this solution would reduce the frequency and duration of outages through reinforcement of the assets that make up the tap section of line.

3.3.2 Automatic Remote Sectionalizing (ARS)

This investment program installs additional Motor Operated Disconnect Switches on the transmission system to further sectionalize the system for fault events. It is advantageous to quickly isolate and restore power by reducing outage durations and improving customer reliability. All Transmission Circuits that had customers subject to extended outages and did not have ARS already installed were considered candidate projects for this investment, except for radial circuits. Radial circuits would not benefit from this technology and requires a different solution to reduce outage impacts.

The benefit cost analysis was performed on all candidate circuits, modeling a reduction in outage duration by 25% in the event of a Transmission Line asset failure (Structure or Conductor). The 25% outage reduction was used as an estimate, to consider the difficulty and uniqueness in modeling the specific impacts of all circuits across LG&E/KU's system. While in many cases, the reduction in customer outage duration could be 100%, we also recognize that in some cases the benefits of ARS might only benefit a portion of the total customers served off the circuit.

3.4 Program Benefits

The analysis generates monetized benefits with two main categories of risk reduction benefits and financial benefits. LG&E/KU and Black & Veatch SMEs worked together to identify the risks posed to the transmission system when critical assets fail. The team also identified financial benefits that can be achieved through completing projects under each program. A total of seven quantifiable benefit categories were identified for the six investment programs. The benefits were mapped to the investment program that produced the benefit. Table 3-2 summarizes how the benefits were mapped to each investment program that generated the benefit.

Table 3-2 Benefit Mapping Summary

	Financial		Risk				
	1.) Avoided Capital Costs	2.) Avoided O&M Costs	3.) Transmission Reliability Risk	4.) Collateral Damage	5.) Public Property Damage	6.) Wildfire Risk	7.) Environmental Risk
1.) Relays Panels	√	√	√	√	√		√
2.) Circuit Breakers	√	√	√	√	√		√
3.) Transformers	√		√	√	√		√
4.) Circuit Rebuilds	√	√	√	√	√	√	
5.) Automatic Remote Sectionalizing			√				
6.) Reinforcing Radial Taps	√	√	√	√	√	√	

3.4.1 Financial Benefits

Financial Benefits are represented in dollar as a positive or negative cash flow. They reflect the difference between the baseline and outcome costs associated with maintaining, replacing, and operating the assets. Financial Benefits assess the effectiveness of investments in reducing costs for the utility.

Baseline Financial Benefits represent the costs associated with maintaining assets in their current condition without any additional investment or improvement. The baseline is the status quo or the starting point against which the benefits of investments are measured. Outcome Financial Benefits represent the costs of maintaining new assets after replacement. The outcome is the result of the investments made to improve the health and performance of assets. The team also identified the operational parameters that would be used to quantify the financial benefits of each project. An example of this is reduced maintenance cycles from replacing an older asset in poor health with a new asset that requires fewer maintenance intervals. The operational parameters would be the duration to perform maintenance on the aged asset versus the new asset. By identifying and quantifying the risk reduction and financial benefits of each project, the analysis enables LG&E/KU to balance prioritizing investments between risk reduction and benefits to cost ratios of each candidate project.

Black & Veatch conducted several workshops with LG&E/KU's SMEs to identify the types of financial benefits that the organization can claim as a result of investments made on the Transmission system. Table 3-3 below summarizes the two financial benefits.

Table 3-3 Financial Benefit Definition Summary

Financial Benefit Type	Definition
Avoided Capital Costs	Avoided capital costs that will no longer be needed or reduced by implementing the project. • Capital Cost Reduction as a result of avoiding emergent work
Avoided O&M Costs	Avoided O&M costs that will no longer be needed or reduced by implementing the project. • O&M savings as a result of decreasing inspection cycle and/or reducing inspection cost

3.4.2 Risk Reduction Benefits

As mentioned previously, risk reduction benefits consider the risk a given asset poses to the system if it were to fail and compares it to the outcome or residual risk posed to the system if the asset is replaced in kind with a new asset. Risk reduction benefits are not actual cash flows for the company. The risk reduction benefit is a buy down of risk that currently exists on the LG&E/KU transmission system. These benefits are measured using a baseline risk assessment, which evaluates the asset's current state, and an outcome risk assessment, which evaluates the asset's state after it has been replaced with a new piece of equipment.

The baseline risk assessment serves as the starting point for evaluating the effectiveness of any investment made to mitigate or reduce risk. It considers factors such as the age, condition, and performance of the asset, as well as any potential hazards or threats that may be present. On the other hand, the outcome risk assessment evaluates the residual risk that remains after an investment has been made to reduce or mitigate the baseline risk. This assessment involves comparing the residual risk to an acceptable risk threshold to determine if further investment is needed.

Risk Reduction Benefits are represented in dollar terms as a positive value stream based on the difference between the baseline risk and the outcome risk. They capture the value of avoiding undesirable outcomes associated with leaving high-risk assets in service until they fail.

By considering both the baseline and outcome risk assessments, capital investment decisions can be made more effectively, and risks can be managed to a greater extent. Overall, the Risk Reduction Benefits assessment is an essential tool for assessing the effectiveness of investments made to mitigate risks.

3.4.2.1 Risk Types

Black & Veatch conducted several workshops with LG&E/KU's SMEs to identify the type of risks applicable to their organization and their transmission system. The workshops produced a set of consequences that could be mitigated if high risk assets were replaced. The emphasis was on the risks resulting due to Transmission assets failure.

Table 3-4 below defines the risk types that have been identified and are included in the TSHARP risk analysis.

Table 3-4 Risk Type Definitions

Risk Type	Definition
Transmission Reliability Risk	Transmission Reliability Risk is made up of two components. First, the risk associated with losing transmission capacity (MVA) when transmission assets fail. Secondly, the risk of causing customer outages when transmission assets fail.
Collateral Damage Risk	Collateral Damage Risk captures the reduction in risk of damaging adjacent LG&E/KU equipment when aging infrastructure fails eventfully. It represents financial losses due to damage to equipment or company owned assets if the investment is not completed.
Public Property Damage Risk	Public Property Damage quantifies the impact of mitigating risks of damaging public property for which a landowner or third-party files a claim for recovery.
Wildfire Risk	Wildfire Risk quantifies the reduction for utility infrastructure to ignite wildfires.
Environmental Risk	Environmental Risk quantifies the environmental risk mitigated by implementing the project. The risks may include hazards to protected areas and wetlands, oil spills into waterways, etc..

3.4.2.2 Asset Risk Analysis

LG&E/KU's asset management practices enable them to manage their transmission assets using the risk management principle of 'risk modeling' to guide their investment plans. The use of risk models in investment planning is an industry best practice, not only in the utility industry but also across other industries with large quantities of physical assets. As part of the plan development process, Black & Veatch's Risk Adjusted Project Prioritization tool was utilized to identify and prioritize high-risk assets for replacement. Risk is defined as Probability of Failure (PoF) multiplied by Consequence of Failure (CoF) and can be depicted in a heat map, as shown in Figure 3-10.

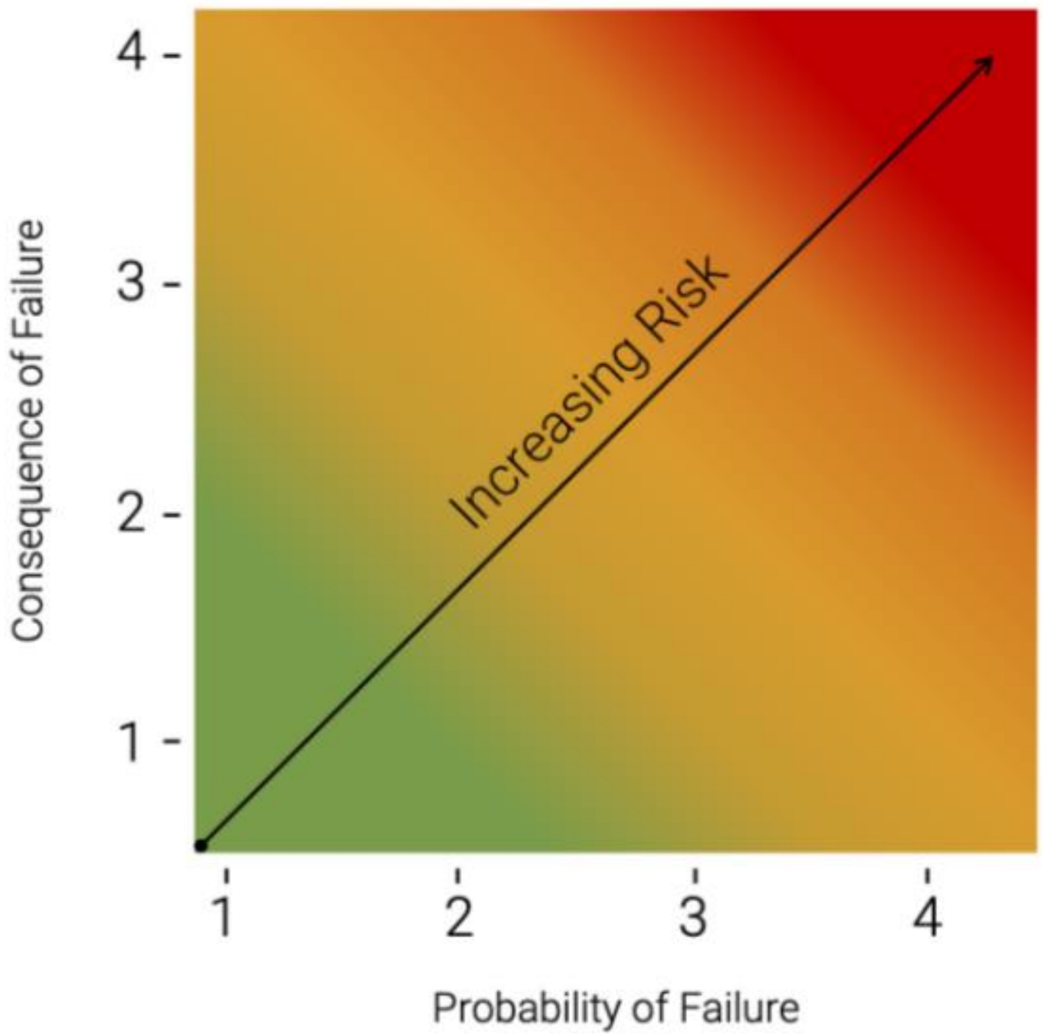

Figure 3-10 Conceptual Risk Heat Map

The Black & Veatch RAPP tool calculates the risk value for each candidate asset considered in the risk analysis. The output of the RAPP tool is the monetized value of the risk reduced on the system when an asset is replaced. Predicting an asset's end of life is based on asset survivor curves, combined with asset health data. Asset health data is used to adjust the chronological age of assets to an effective age of the asset. The effective age takes into consideration the asset's condition and represents its age once that condition is accounted for. From this effective age, the probability of failure is calculated based on the remaining life of the asset. The consequence of failure is derived either by using a consequence definition table and scoring it based on the severity of the consequence, or by using a formula-based methodology and scoring it based on asset inputs. The RAPP tool identifies high-risk assets, which enables prioritizing high-risk assets for replacement.

3.4.3 Probability of Failure

The Black & Veatch RAPP model first determines the Probability of Failure (PoF) for each asset considered in the analysis. The asset's PoF is determined, in part, by its associated survivor curve (also known as an Iowa curve). Survivor curves are used by utilities in depreciation studies to forecast the average service life of assets. Iowa curves are asset class-specific survivor curves developed by the Iowa State University. The survivor curve is a tool used to determine the average remaining life of an asset. Figure 3-11 shows a typical survivor curve for an electric utility asset.

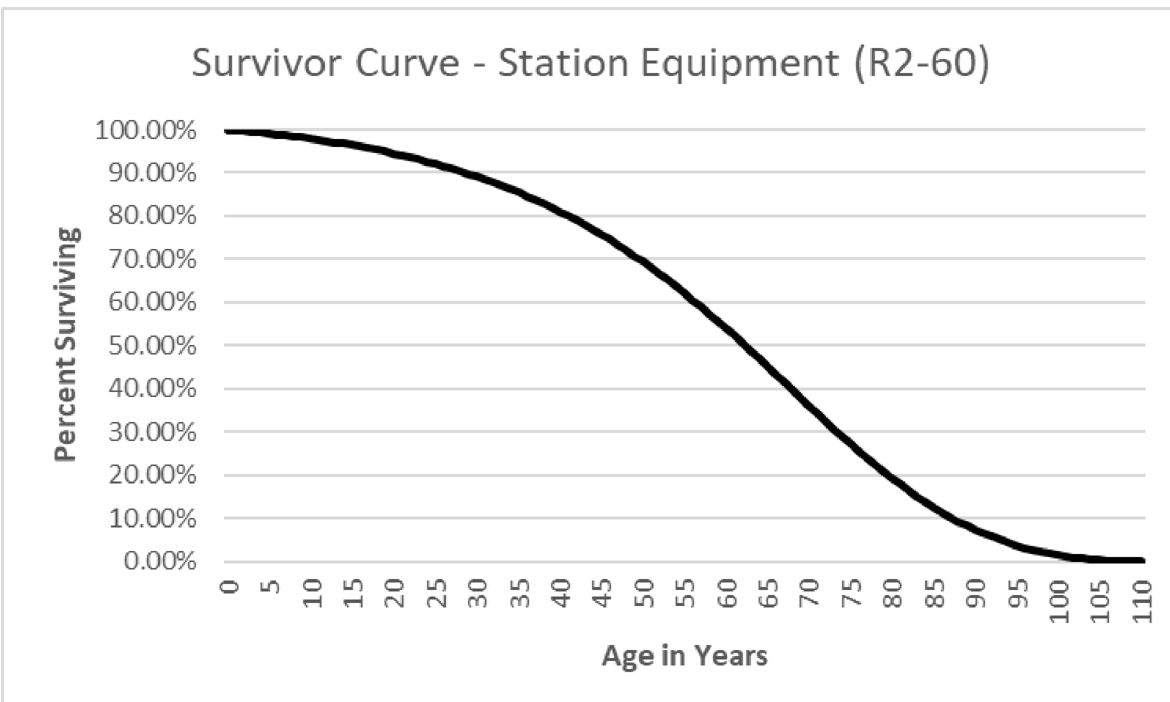

Figure 3-11 Survivor Curve for Station Equipment (R2 - 60)

The asset probability of failure is based on a 10-year cumulative PoF forward-looking forecast on the survivor curve from the effective age. The 10-year time frame is considered to be a reasonable planning horizon for asset investment planning, given the projects evaluated by this plan are under consideration for execution in the next 5-7 years. When the study is refreshed as part of the annual business plan process, the 10-year horizon will shift out accordingly. By using the 10-year cumulative probability of failure, LG&E/KU can estimate the financial impact of potential asset failures over the planning horizon and proactively replace high risk asset before they fail. This is illustrated in the example shown in Figure 3-12.

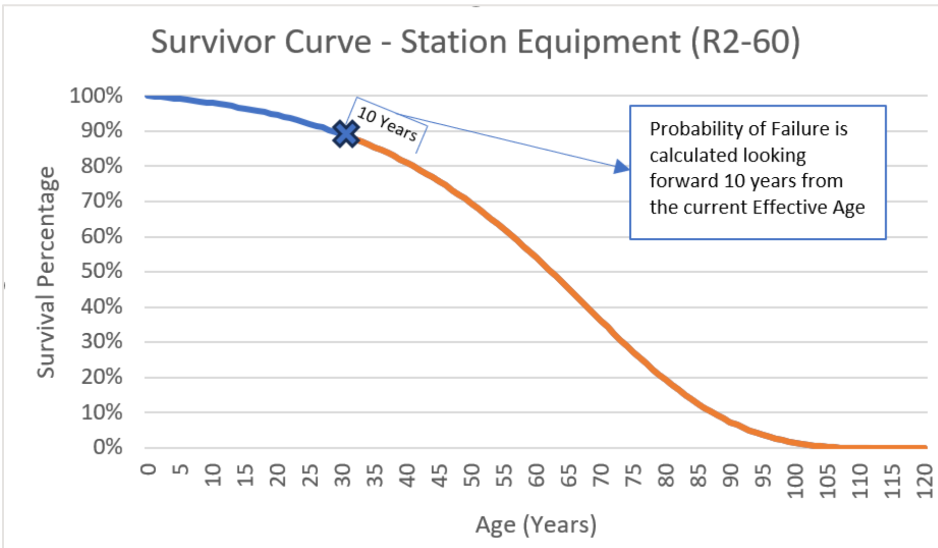

Figure 3-12 Survivor Curve for Station Equipment (R2 - 60) with 10 Year Look Forward

3.4.3.1 Asset Health Scoring Methodology

An asset health score is a metric that is used to assess the overall health and performance of an asset. This score is typically based on a range of factors such as the asset maintenance history, test results and inspection reports. By analyzing these factors, an asset health score is determined and can provide valuable insights into the likelihood of future failures of an asset. It is used in the analysis to adjust the chronological age of an asset to an effective age for the asset.

The RAPP tool calculates the remaining life of an asset by considering its health. To gather asset health data, LG&E/KU employees perform equipment tests and inspections on a regular basis to stay informed of asset conditions. This data is recorded in an asset management database. The risk analysis leveraged this data to determine the effective age of assets. However, if inspection or asset health data is not available, the Probability of Failure is determined solely based on the chronological age of the asset.

As an example, the scoring model mentioned below is designed to identify panels with multiple problematic relays. The formula is as follows:

As-Found Testing: This process checks if the relay is operating within the designed engineering parameters. It provides a baseline to understand the current state of the relay and identify any deviations from the expected performance.

As-Left Testing: As-Left testing ensures that the relay can be adjusted back to the designed parameters. This step confirms that the relay is functioning correctly and meets the required specifications.

Mis-operations Score: Relay models with the highest number of mis-operations receive 60 points, with a linear reduction applied to the remaining models associated to mis-operations.

- As Found Results: As Found Results x 120 points.
- As Left Results: As Left Results x 20 points.
- Known Mis-operations: Mis-operations Ratio x 60 points.

Table 3-5 outlines the asset health scoring methodology for Relay Panels (for the detailed methodology for each asset class, please refer to the Appendix 6.1).

Table 3-5 Relay Asset Health Scoring Methodology

Asset Factors	Min Score	Max Score	Asset Health Score
(AF Results *120) + (AL Results *20) + (Mis-operations Ratio * 60)	201	>201	4
(AF Results *120) + (AL Results *20) + (Mis-operations Ratio *60)	101	200	3
(AF Results *120) + (AL Results *20) + (Mis-operations Ratio *60)	21	100	2
(AF Results *120) + (AL Results *20) + (Mis-operations Ratio *60)	6	20	1
(AF Results *120) + (AL Results *20) + (Mis-operations Ratio *60)	0	5	0

3.4.3.2 Effective Age Calculation Methodology

To determine the effective age of an asset, Black & Veatch considers its Useful Life, how long the asset has been in service, and the current health of the asset. Asset health data is used to create an index that adjusts the chronological age of the asset to an effective age. The process for calculating the effective age is shown below. Figure 3-13 is the Health Score table applicable to transformers. Each asset class has its own unique effective age calculation methodology based on the asset class and the data gathered for the asset class.

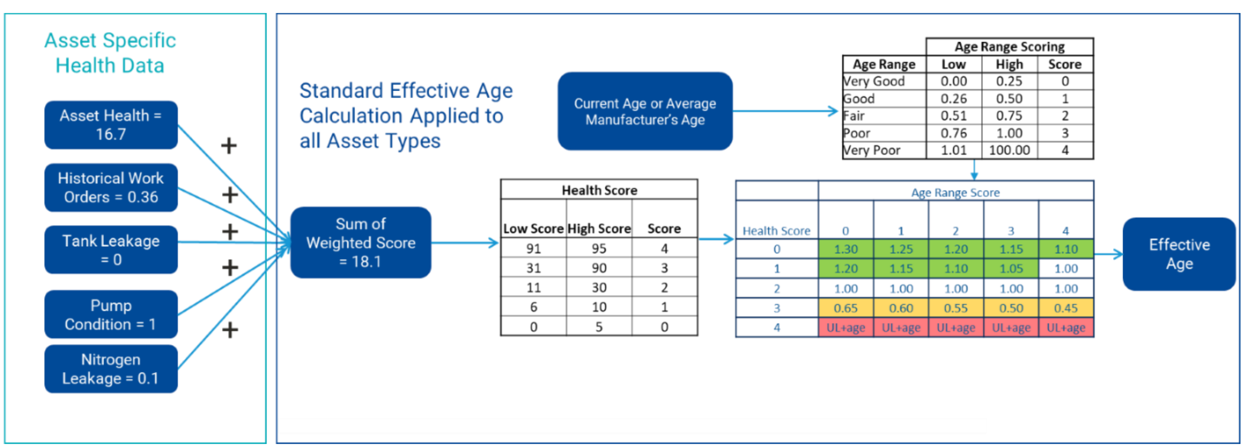

Figure 3-13 Transformer Effective Age Calculation Methodology

Depending on the asset's health, the effective age can be younger or older than the actual age, as shown in Figure 3-14 below. Fig 3-14 below is a survival curve that shows the probability of asset survival based on the asset age.

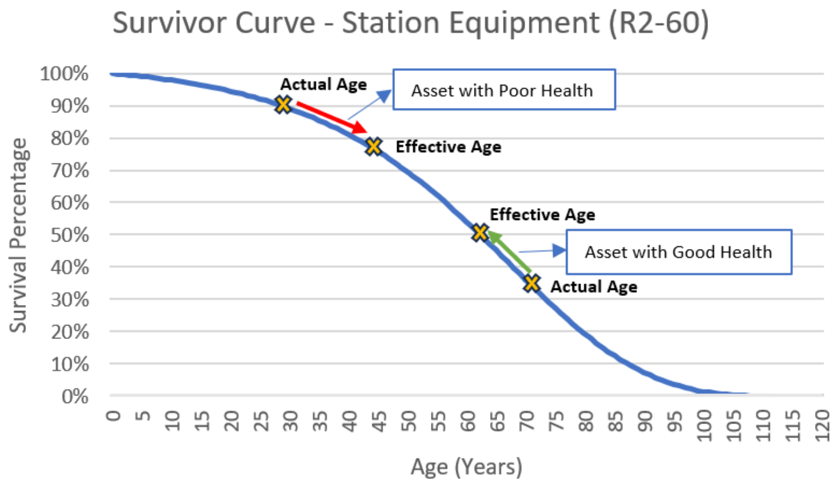

Figure 3-14 Illustrative Example of Adjusting Chronological Age to Effective Age Based on Asset Health Score

Once the effective age of the asset is determined, the Black & Veatch RAPP tool calculates the probability of failure based on the remaining life of the asset relative to the effective age and its associated survivor curve, as shown in the illustrative Figure 3-15. Figure 3-15 illustrates the inverse relationship between the survivor curve and the probability of failure curve. That is, the survivor curve and the probability of failure curve are complementary to each other. The survivor curve provides information about the proportion of the asset population that has not yet failed, while the probability of failure curve provides information about the proportion of the asset population that is expected to fail. In the illustrative example below, the probability of failure (PoF) percentage represents the cumulative PoF over the next 10 years. For example, the PoF value for 2025 represents the cumulative PoF percentage from 2025 until 2034.

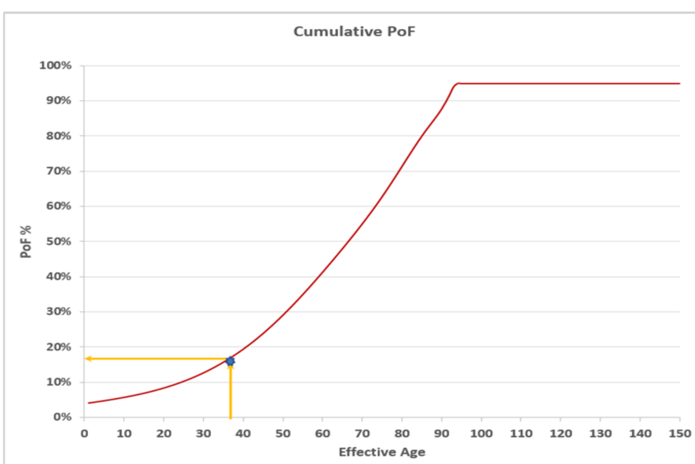

Figure 3-15 Cumulative Probability of Failure (PoF) Curve

3.4.4 Consequence of Failure

As mentioned previously, LG&E/KU has identified the following risk types applicable to their organization as a result of Transmission asset failure:

- Environmental Impact Risk
- Public Property Risk
- Collateral Damage Risk
- Wildfire Risk (LG&E/KU Caused)[8]
- Transmission Reliability Risk

Not all of these risk types are applicable to each Transmission asset class at LG&E/KU. For instance, Wildfire Risk doesn't apply to transformers or circuit breakers. Table 3-2 summarizes how the benefits were mapped to each investment program that generated the benefit.

Risk is comprised of the consequence of failure (CoF) and the probability of failure (PoF). The methodology for calculating PoF was demonstrated above. There are two methods of calculating the CoF: formula-based and logic-based. Table 3-6 below summarizes the risk type and the calculation methodology used in the risk analysis. By consistently applying both logic and formula-based consequence scoring to each candidate project a common economical scale is established for the benefit calculations. This enables the ability to evaluate project benefits within an investment program but also across investment programs on a common scale.

Table 3-6 Consequence Calculation Methodology Summary

Risk Type	Calculation Methodology
Environmental Impact Risk	Logic-based
Public Property Risk	Logic-based
Collateral Damage Risk	Logic-based
Wildfire (LG&E/KU Caused) Risk	Formula-based
Transmission Reliability Risk	Formula-based

3.4.4.1 Logic Based Consequence of Failure

The logic based CoF uses a Consequence Cost Table to monetize the consequence of asset failure. The consequence level of an asset failure is determined by LG&E subject matter experts and is based on historical experience with asset failures. Table 3-7 below summarizes the LG&E/KU Consequence Definition dollar ranges. The consequence levels are designed to have a significant increase between ranges to help delineate between each level of consequence. The analysis uses the mid-point value as the consequence score to calculate risk.

[8] LG&E/KU Caused is defined in Section 3.4.2.1.

Table 3-7 LG&E/KU Consequence Cost Table

Consequence	Low	Minor	Moderate	Significant	Major	Catastrophic	Extreme
Range ($)	< $100K	$100K - $500K	$500K - $1.5M	$1.5M - $5M	$5M - $15M	$15M - $50M	>$50M
Midpoint/ Representative Value	$50K	$300K	$1M	$3M	$10M	$30M	$100M

Black & Veatch conducted a series of workshops with the relevant SMEs at LG&E/KU to establish the methodology and asset-related attributes required to score the consequence of failure for each risk type and asset class. Table 3-8 provides an overview of the methodology used to score the environmental, public property, and collateral damage CoF for transformers. The CoF methodology for all asset classes is included in Appendix 6.2.

Table 3-8 Summary of Logic Based Methodology for Transformers

Asset Class	Environmental Impact Risk*	Public Property Risk	Collateral Damage Risk
Transformer	Proximity to waterway Volume of oil Oil containment (yes/no)	Minor consequence for transformers in urban areas Low Consequence for transformers in rural areas Generation transformer = zero Public Property Risk	Is transformer protected with high side circuit breaker? (yes/no) **If yes:** If transformer primary voltage = 345kV then consequence = moderate If primary voltage = 161kV then consequence = moderate If transformer primary voltage = 138kV then consequence = moderate **If no:** For all transformers primary voltages - consequence = minor

To score the environmental risk impact as a result of the transformer failure, three factors were taken into consideration:

- Is the transformer near waterway?
- What is the transformer oil tank capacity?
- Does the transformer have oil containment?

For example:

- Is the transformer near waterway? **No**
- The transformer oil tank capacity: **Below 10,000 Gallons**
- Does the transformer have oil containment? **Yes**
- Consequence Score: **Minor**

The environmental consequence scoring methodology is summarized in Table 3-9 below.

Table 3-9 Environmental Consequence Scoring Methodology Table

	Minor	Moderate	Minor	Significant	Moderate	Significant	Moderate	Significant
Close to water - No	X	X	X	X				
Close to water - Yes					X	X	X	X
Below 10,000 gallons of oil	X	X			X	X		
Above 10,000 gallons of oil			X	X			X	X
Oil Containment - Yes	X		X		X		X	
Oil Containment - No		X		X		X		X

3.4.4.1.1 Eventful Failures

The last step to calculate the CoF is to incorporate, where appropriate, the asset failure resulting in an eventful impact. For example, the probability of an oil circuit breaker failing is determined by its survivor curve. However, that does not mean each oil circuit breaker results in an environmental impact from spilled oil or any of the consequences identified. The breaker failure will most likely be cleared by the second layer of protection designed into the system to clear failed breakers. Some breaker failures do actually result in causing the consequences identified. Black & Veatch collaborated with LG&E/KU SMEs to determine the percentage of asset failure resulting in an eventful impact for each risk type. Table 3-10 below summaries the CoF eventful impact percentages of failures:

Table 3-10 Probability of Asset Failures Resulting in Consequence Identified as Risk

Asset Type	% of Failures Resulting in Environmental Impact Risk	% of Failures Resulting in Public Property Risk	% of Failures Resulting in Collateral Damage Risk	% of Failures Resulting in Transmission Reliability Risk
Structure - Wood	0%	3%	3%	100%
Structure - Wood - Mountain	0%	3%	3%	100%
Structure - Steel	0%	3%	1.5%	100%
Line Switch	0%	0%	0%	100%
Underground Cable	0%	2%	0%	100%
Conductor	0%	5%	1%	100%
Circuit Breaker	10%	10%	10%	100%
Relay	5%	5%	5%	100%
Transformer	10%	10%	10%	100%

3.4.4.2 Formula Based Consequence of Failure

3.4.4.2.1 Transmission Reliability Risk

Transmission Reliability Risk captures the value of avoiding the loss of transmission capacity and customer outages when critical transmission equipment fails. Transmission Reliability Risk reduction benefits make up over 90% of the benefits generated from the risk analysis. It represents the risk reduced to the transmission system, to function as designed, when assets fail. Transmission Reliability Risk is mitigated by replacing high risk assets with new in-kind assets.

Transmission systems throughout North America and around the world are planned, designed, and constructed to operate as a network with redundant capacity. The network design provides redundant capacity to absorb the loss of network components while not causing customer outages. Through the combination having transmission components connected in a networked fashion and having redundant capacity, transmission systems deliver high levels of reliability. Utility customers everywhere have grown accustomed to the benefits of having transmission systems that deliver high levels of reliability. However, absent the network design and the redundant capacity, each time a fault occurred on the transmission system large scale customer outages would occur.

The existing redundant transmission capacity has inherent value. The value is derived from:

1. The system's ability to automatically reroute power when faults occur on the transmission system while avoiding customer outages.
2. The system's ability to reroute power when generation stations trip offline while avoiding customer outages.
3. The system's ability to take transmission equipment out of service on a scheduled/emergent basis to perform preventative maintenance and repairs without causing customer outages.

[redacted]

To capture both Transmission Reliability Risks for each asset the following calculation methodology was applied as illustrated in Figure 3-16.

[redacted]

Figure 3-16 Transmission Reliability Risk Calculations

[redacted]

[redacted]

[redacted]

[redacted] [redacted]

3.4.4.2.2 Wildfire Risk

To quantify and monetize the wildfire risk caused by transmission assets, LG&E/KU and Black & Veatch leveraged the FEMA Wildfire National Risk Index Scores. These scores and ratings represent a community's relative risk and expected annual loss due to wildfires, as compared to other areas of the United States. Figure 3-18 below is the Wildfire Risk Index Score Calculation Methodology used by FEMA.

$$Risk = Expected\ Annual\ Loss \times Community\ Risk\ Factor$$

$$where\ Community\ Risk\ Factor = f\left(\frac{Social\ Vulnerability}{Community\ Resilience}\right)$$

Figure 3-18 Wildfire Risk index Score Calculations Used by FEMA

The above calculation methodology considers all possible causes of Wildfire ignition, both utility and non-utility caused. To capture the portion of risk caused by LG&E/KU owned assets failing, a 7% factor was used. Black and Veatch reviewed several industry reports and whitepapers, and determined that, on average, 10%[9] of wildfires in the US are caused by electric utilities. Based on the geographic position and vegetation density of Kentucky, as well as input from LG&E/KU's SMEs, the analysis applied a 7% factor to calculate the wildfire risk for the Transmission portion of the electric system. Three percent of the risk was removed from the electric utility-caused rate due to the possibility of Distribution caused wildfire. This factor is conservative and research-based, enabling the capture of wildfire caused by transmission electric utilities.

Black & Veatch has mapped the unique Wildfire Risk Index Score to each LG&E/KU assets (i.e., structures, conductors) using the assets' GIS Location attributes. Figure 3-19 below is the FEMA Wildfire Risk Area. The map highlights FEMA's wildfire risk ratings relative to LG&E/KU transmission circuit assets. LG&E/KU has identified 16 transmission wood structures in FEMA's Very High and 465 transmission wood structures in FEMA's Relatively High Wildfire Risk Areas and will use the TSHARP investment analysis to prioritize and plan for their replacement and hardening with steel structures.

[9] Source: https://www.cpuc.ca.gov/industries-and-topics/wildfires

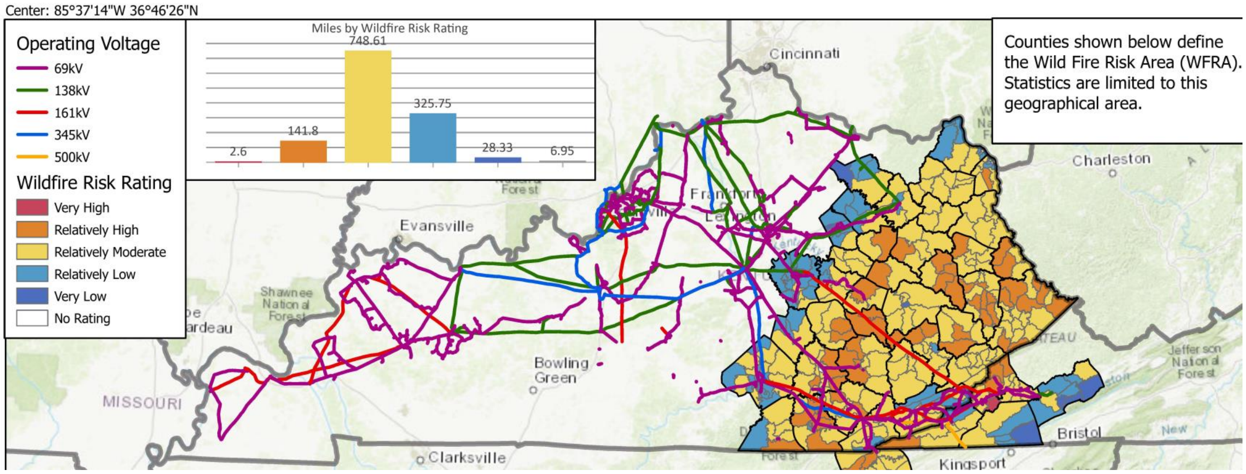

Figure 3-19 FEMA Wildfire Risk Area for LG&E / KU Service Territory

3.5 Risk Thresholds

Setting asset risk thresholds involves defining the level of risk that is acceptable for the utility, while still being able to effectively operate and maintain the transmission system. To accomplish this, definitions of risk levels need to be established along with a risk rating scale that compares risk levels across different asset types. Baseline risk levels are used to measure the existing risk level the transmission system is currently exposed to. The risk levels and mitigation measures defined at LG&E/KU are used to help ensure that the level of risk accepted on the transmission system is in alignment with the organization's risk tolerance and overall strategic goals. As stated in Section 3.0, risk is defined as:

Risk = Probability of Failure (PoF) X Consequence of Failure (CoF)

Table 3-11 below is LG&E/KU's defined levels of risk for their transmission system along with the mitigation actions to manage risk on the system.

Table 3-11 LG&E/KU Defined Levels of Risk

Risk Level	Definition	Mitigation Action
High	The risk of the asset failing places the transmission system in state that significantly reduces its ability to function reliably.	Replace
Increased	Repairs to the asset are needed to extend the performance and/or life of the asset.	Repair
Moderate	Increased asset inspection is needed to monitor/detect further asset condition degradation more closely.	Increased Inspections Cycles
Low	Maintain asset inspections cycles based on industry standards or equipment manufacturer's recommendations.	Normal Inspection Cycles

With these risk level definitions, each asset's risk score can be plotted on a common uniform risk matrix or a heat map, introduced in Section 3.4.2.2. The heat map plots the number of assets that fall under each of the defined risk levels. From the heat map an understanding of risk associated with the assets analyzed can be developed. Table 3-12 below is a common uniform risk matrix or heat map, used across all the transmission assets considered in the risk analysis.

Table 3-12 Common Uniform heat Map

Heat Map					
		PoF			
		1	2	3	4
CoF	4				
	3				
	2				
	1				

As seen from the heat map the vertical axis plots the Consequence of Failure (CoF) and the horizontal axis plots the Probability of Failure (PoF). The color coding represents the risk level defined in Table 3-9. Each asset has a PoF and a CoF to determine its risk score.

The actual PoF of the asset is scaled to determine its PoF score for the heat map. Table 3-13 below is the PoF scoring for all asset types used to create the heat map for each asset type. The PoF percentages can increase gradually when the asset is relatively young, but it will increase at a higher pace as the asset gets older, hence the reason defining the PoF ranges shown in the table below.

Table 3-13 Probability of Failure Scoring Matrix Used to Create Heat Maps

POF – All Asset Types		
POF Percentage		
Min	Max	POF Score
0%	15%	1
15%	30%	2
30%	50%	3
50%	100%	4

Similarly, the actual monetized value of CoF for an asset is scored to the heat map. Monetized values for CoF were divided into quartiles. Quartiles are often used to define ranges in a portfolio of assets because they provide a standardized way to compare the consequence of failure of different assets relative to each other. This approach can be useful in asset management because it allows LG&E/KU to identify assets that pose high or low impact to the organizations' operations relative to asset of a similar class. Because each asset type has its own unique set of consequences that generates the monetized value of the CoF, a unique CoF range for each asset type is used. Taking this approach would allow the appropriate distribution of investments across all asset classes. Table 3-14 below is the CoF scoring matrix for transformers.

Table 3-14 Consequence of Failure Scoring Matrix for Transformers Used to Create Heat Map

COF Scoring - Transformers				
COF Quartiles		CoF $ Value		
Min	Max	Min	Max	COF Score
0%	25%	$--	$9,453,853	1
25%	50%	$9,453,853	$11,328,663	2
50%	75%	$11,328,663	$27,703,920	3
75%	100%	$27,703,920	$237,963,496	4

By establishing risk thresholds, LG&E/KU is able to identify high risk assets among the population of assets considered in the analysis. Identified high risk assets can be prioritized based on their overall impact to the transmission system when they fail. By monitoring these thresholds, LG&E/KU can proactively identify and address potential risks on the system before they lead to more significant problems or failures.

3.6 Qualitative Benefits

In addition to the quantifiable benefits of the investment program as described above, there are additional qualitative benefits. For example, this risk analysis captures quantifiable wildfire risk reduction benefits achieved by rebuilding wood structures and old conductors with new steel poles and new conductors. This reduces the risk of LG&E/KU being the source of ignition when wood poles fail, and conductors fall to the ground. An added qualitative benefit is the fire-resistant quality of steel poles when LG&E/KU is not the source of ignition. Wildfires started by other parties can cause significant damage to wood poles. Constructing transmission lines using steel poles has the additional benefit of mitigating the effect of fires on transmission structures. While evaluating the structural impact of wildfires, the key consideration is the type of material. Generally, utility structures are comprised of combustible or non-combustible materials. Wood poles are the most common combustible and steel poles are the most common non-combustible material types used throughout the industry. During prolonged exposure to extreme wildfire temperatures, any structural material will eventually experience degradation and loss of strength. However, wood structures pose the greatest risk to system stability during a wildfire. Steel structures can endure longer periods of exposure and higher temperatures than wood counterparts. LG&E/KU will be replacing wood structures with steel to minimize the wildfire risk to its transmission system.

3.7 Project Valuation

For each asset replacement program, the risk reduction analysis was applied consistently across all candidate projects. After the benefits were mapped to each investment program a consequence scoring methodology was developed to monetize the consequences associated with each asset failure. A summary of the logic-based methodologies used in the analysis can be found in Appendix 6.2. The formula-based consequence scoring methodologies is described in Section 3.4.3.2. Excel workbooks were used to perform the risk analysis. A workbook was created for each asset replacement program risk analysis. The risk analysis produces a monetized risk reduction benefit using the probability of an asset failing over the next ten years. The risk reduction benefit is a one-time benefit in the year the asset is replaced. To analyze assets comparably and to provide flexibility in scheduling projects over the next 5-7 years, the year 2027 was selected as the in-service date for all asset replacements. Adjustments in asset replacement dates increase and/or decrease risk reduction benefits. The risk analysis will be updated, as needed, as project scheduling is further developed by LG&E/KU. The risk analysis results were combined with the financial benefits that captures the present value of cost savings and the present value of future project estimated costs. The output is a benefit to cost ratio (BCR) for each candidate project. The BCR will be used to identify the high-priority assets for investment, but additional engineering and design analysis is required to develop specific, individual projects with accurate cost estimates. Nonetheless, it does result in a prioritized view of which investment programs to pursue first, which can then be refined over time.

As mentioned earlier, LG&E/KU's benefits can be broadly classified into two categories: Risk Reduction Benefits and Financial Benefits. Risk Reduction Benefits resulting from the investments are captured throughout the planning horizon. One or more risk reduction benefits may apply to each project. The risk reduction benefits by each risk type are added together over the planning horizon to calculate the consolidated risk reduction benefit for each project. As mentioned previously, the risk reduction benefit is based on the difference between the baseline risk and the outcome (residual) risk. Moving forward, as LG&E/KU further develops their project schedule, asset replacement dates can be applied to the RAPP tool to develop a risk mitigation profile from asset replacement investments. An illustrative risk reduction profile is shown below in Figure 3-20.

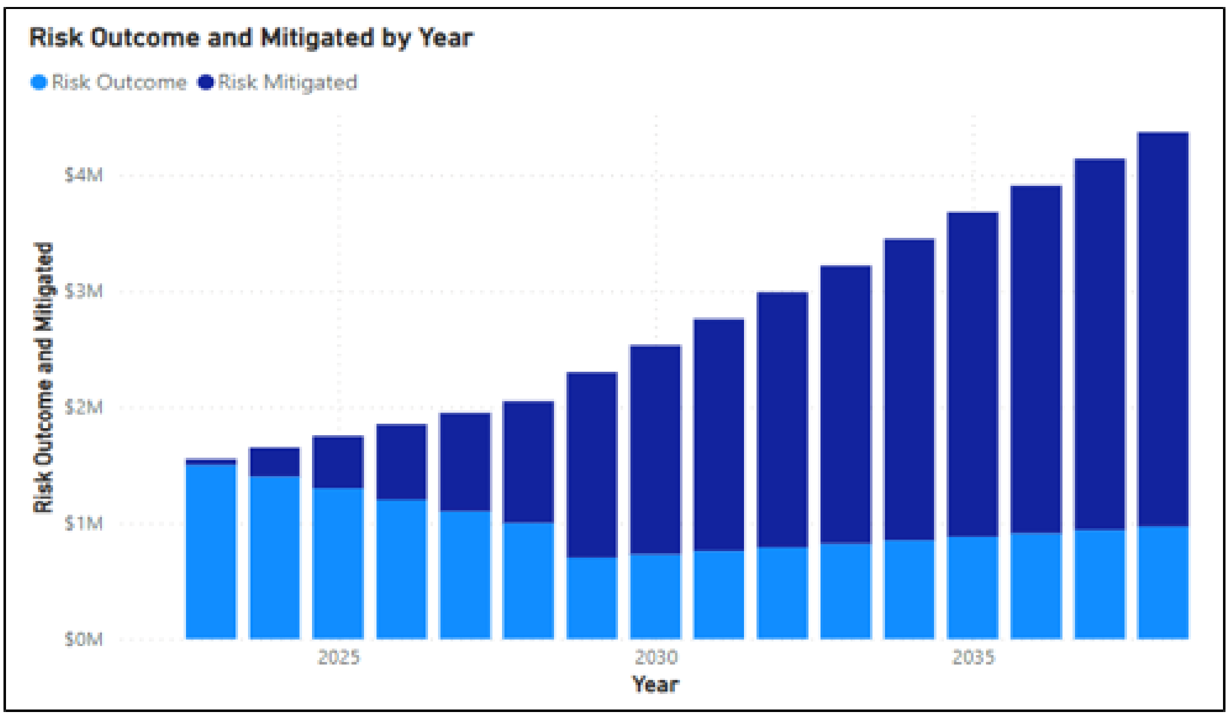

Figure 3-20 Illustrative Risk Reduction Profile

Resiliency project valuations were based on both customer avoided cost and company avoided costs. The avoided cost benefits were compared to the estimated cost of the project to produce a benefit to cost ratio.

3.7.1 Financial Benefits Calculation Approach

Financial Benefits resulting from the investments are captured throughout the 20-year planning horizon. One or more financial benefits may apply to each project. Financial Benefits are first normalized across the planning horizon and then discounted and inflated in order to calculate the Net Present Value, as shown in the illustrative Figure 3-21 below:

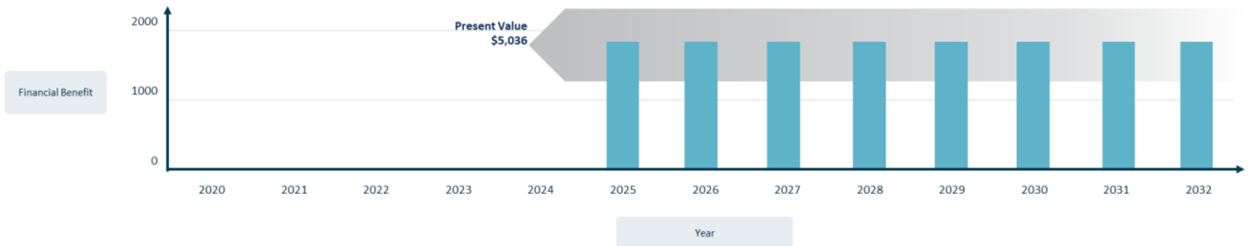

Figure 3-21 Illustrative Example of Annualized, Inflated, and Discounted Financial Benefit Cash Flows

The financial benefit types are added together over the planning horizon to calculate the consolidated financial benefit for each project.

3.7.2 Project Cost

Project costs used for the analysis are reflective of recent expenditures throughout the LG&E/KU system. Replacing existing substation assets with similar in-kind assets yields a relatively uniform expenditure across the system. However, the cost of transmission line construction varies greatly and is heavily dependent upon the terrain that is encountered. Kentucky's different geographical regions, as well as voltage (size) impacts, have all been taken into consideration during the analysis of project costs.

3.8 Project Prioritization

The fourth and last step in the development of the risk analysis is to prioritize projects. Project prioritization takes several factors into account. A summary of potential factors that drive prioritization of projects are listed below.

1. Transmission System Constraints – The LG&E/KU transmission operation team manages many requests for taking lines and equipment out of service from outside entities and internal operations. Critical high risk asset replacements will need to be prioritized, planned, and scheduled along with other priority transmission work on the LG&E/KU system in coordination with regional transmission operators.
2. Equipment Lead Times – Power transformers, breakers, relays, and steel poles have extended lead times in the market. A sourcing strategy with expected need dates for material is required for cost effectiveness.
3. Labor Resources – The sequencing of projects that keep contract labor resources engaged lowers costs and builds safety, system, and operational knowledge with labor resources. A sourcing strategy for both substation and line work labor resources that is coordinated with scheduled outages is required to be cost effective.

4. Removing Risk – The risk analysis has identified high risk assets for replacement that lowers the overall risk of the transmission system. Delaying the replacement of high-risk assets means accepting the risk associated with them.
5. Delivering Benefits – The risk analysis also identified benefits associated with each project. Delivering projects with the highest benefit to cost ratios means that capital is being deployed in an efficient manner.

A prioritized list of projects will be a balance of these factors and potentially other factors. It should be noted the prioritized list of projects does not consider any constraints, such as budget or resource constraints. LG&E/KU will use the risk analysis to help balance these competing factors in developing future work plans. This will be an iterative process and will be an integral part of the annual budgeting process moving forward.

4.0 Benefit Cost Analysis Results

4.1 TSHARP Portfolio Results

The TSHARP risk and cost benefit analysis is based on the six investment programs identified that support the key objectives of maintaining and improving transmission system hardening and resiliency. The results are based on an asset replacement year of 2027.

The benefit cost analysis results are presented below in Table 4-1 at the portfolio level by investment program for all candidate projects considered in the analysis. The analysis shows that the portfolio of candidate projects generates benefits that outweigh the cost of the projects. The risk and cost benefit analysis of the candidate projects considered in the analysis produced a portfolio benefit cost ratio of 3.96.

Table 4-1 Benefit Cost Analysis Summary Results – All Candidate Projects

Investment Program	Total Cost ($M)	Total PV Benefits ($M)	Benefit Cost Ratio (BCR)	Asset Count
Transformer Replacements	$568	$1,009	1.8	133
Rebuild Radial Taps	$236	$1,137	4.8	36
Relay Panel Replacements	$354	$1,137	3.2	1,629
Circuit Breaker Replacements	$736	$2,151	2.9	1,296
Circuit Rebuilds	$9,984	$40,507	4.1	306
Automated Remote Sectionalizing	$158	$1,718	10.9	131
Total	**$12,036**	**$47,659**	**3.96**	**3,531**

Table 4-2 below are the benefit cost analysis results containing only those candidate projects that produced a BCR greater than or equal to 1.

Table 4-2 Benefit Cost Analysis Summary Results - BCR's >= 1

Investment Program	Total Cost ($M)	Total PV Benefits ($M)	Benefit Cost Ratio (BCR)	Asset Count
Transformer Replacements	$261	$878	3.4	56
Rebuild Radial Taps	$206	$1,121	5.4	30
Relay Panel Replacements	$116	$1,070	9.2	535
Circuit Breaker Replacements	$371	$1,981	5.4	587
Circuit Rebuilds	$8,038	$39,281	4.9	246
Automated Remote Sectionalizing	$93	$1,705	18.3	78
Total	**$9,085**	**$46,036**	**5.1**	**1,532**

The risk analysis results are shown in the heat map as illustrated in Table 4-3 below. The heat map is a count of the assets' risk scores for each asset considered in the analysis. Of the 3,400 total assets (Automated Remote Sectionalizing is not included) analyzed, 758 assets (22.3%) have a high-risk score. These high-risk assets, that are spread across the transmission system, pose a threat to transmission reliability and resiliency. When these assets fail, they cause constraints and restrictions on the transmission system that can lead to local and regional system overloads causing equipment damage and customer outages. These high-risk assets should be targeted for replacement over the near-term planning horizon with the highest risk assets (PoF =4, CoF=4) prioritized first. By replacing these high-risk assets, the LG&E/KU transmission risk profile can be managed to a lower level minimizing any negative effect on transmission system reliability.

Table 4-3 Asset Replacement Portfolio and Taps Heat Map

All Assets		PoF			
		1	2	3	4
CoF	4	798	43	60	94
	3	479	70	86	151
	2	697	68	62	153
	1	368	49	51	171

4.2 Asset Replacements Programs Results

4.2.1 Circuit Rebuild Results

The circuit risk analysis was conducted on 306 circuits out of a total of 471 circuits. The results are shown in the heat map in Table 4-4 below. This heat map shows that 55 of the 306 circuits (18%) have a PoF of 4 and CoF of 4. Table 4-5 below is the same heat map but only includes the count of circuits that produced a benefit to cost ratio equal to or greater than 1. Table 4-5 shows that 55 of the 55 circuits that have a PoF of 4 and a CoF of 4, all produce a benefit to cost ratio greater than or equal to one. These circuits should be targeted for rebuild in the near-term planning horizon. In addition, Table 4-6 shows that 2,109 miles out of 3,423 circuit mileage have a PoF of 4 and CoF of 4 *and* produce benefits that outweigh the cost to rebuild the circuit.

Table 4-4 Circuit Rebuild Heat Map

Heat Map of Circuits		PoF			
		1	2	3	4
CoF	4	7	17	32	55
	3	13	21	43	34
	2	11	12	24	25
	1	3	2	4	3
		Total Circuits			306

Table 4-5 Circuit Rebuild with Benefit Cost Ratio Greater Than 1 Heat Map

Heat Map of Circuits with BCR >=1		PoF 1	PoF 2	PoF 3	PoF 4
CoF	4	6	15	32	55
	3	7	18	39	31
	2	1	8	16	16
	1	0	0	2	0
		Total Circuits			246

Table 4-6 Circuit Rebuild Mileage with Benefit Cost Ratio Greater Than 1

Heat Map of Circuits Miles With BCR >= 1		PoF 1	PoF 2	PoF 3	PoF 4
CoF	4	74	204	682	1281
	3	22	73	261	360
	2	1	28	28	75
	1	0	0	1	0
		Total Circuit Mileage			3091

Table 4-7 below is a summary of the benefits by category that make up the total benefits for the 99 circuits with BCR >=1.

Table 4-7 Calculated Benefits by Benefit Type

Asset Class	Avoided Capital Cost ($M)	Avoided O&M Costs ($M)	Transmission Reliability Risk ($B)	Collateral Damage ($M)	Public Property Damage ($B)	Wildfire Risk ($M)	Environmental Risk ($M)
Circuit	$3.1M	$4.6M	$37.3B	$1.0B	$1.0B	$2.8M	$0.0M

Figure 4-1 below is a summary of the cost to replace highest risk circuits (CoF= 4, PoF=4) with BCR's >1 by circuit voltage level and mileage.

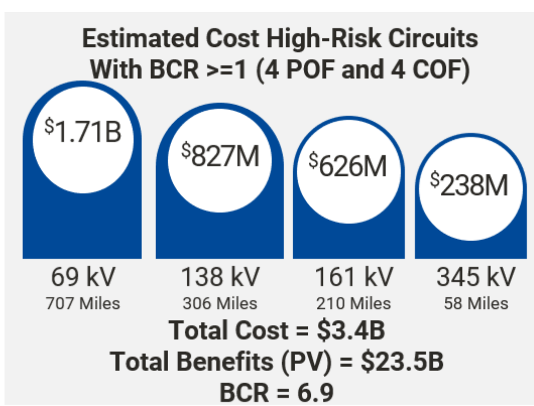

Figure 4-1 Cost Summary of High-Risk Circuits with BCR's >= 1

4.2.2 Transformer Replacement Results

The transformer risk analysis was conducted on the fleet of 133 transformers. The results are shown in the heat map Table 4-8 below. This heat map shows that 37 of the 133 transformers (27.8%) have a high-risk score. Table 4-8 below is the same heat map but only includes the count of transformers that produced a benefit to cost ratio equal to or greater than 1. Table 4-9 shows that 34 of the 37 transformers are high risk and produce benefits that outweigh the cost to replace the transformer. These high-risk transformers should be targeted for replacement in the near-term planning horizon.

Table 4-8 Transformer Replacement Heat Map

Heat Map of Transformers		PoF			
		1	2	3	4
CoF	4	21	12	0	2
	3	24	11	5	3
	2	2	10	6	4
	1	10	4	8	11
				Total Transformers	133

Table 4-9 Transformer Heat Map with Benefit Cost Ratio >= 1

Heat Map of Transformers with BCR >= 1		PoF			
		1	2	3	4
CoF	4	5	12	0	2
	3	0	7	5	3
	2	0	1	5	4
	1	0	0	4	8
				Total Transformers	56

Table 4-10 below is a summary of the benefits by category that make up the total benefits for the 34 transformers with BCR >=1.

Table 4-10 Calculated Benefits by Benefit Type

Asset Class	Avoided Capital Cost ($M)	Avoided O&M Costs ($M)	Transmission Reliability Risk ($M)	Collateral Damage ($M)	Public Property Damage ($M)	Wildfire Risk ($M)	Environmental Risk ($M)
Transformers	$19.1 M	$0.0 M	$734.8 M	$1.7 M	$0.3 M	$0.0 M	$1.5 M

Figure 4-2 below is a summary of the cost to replace high risk transformers with BCR's >=1 by transformer primary voltage level.

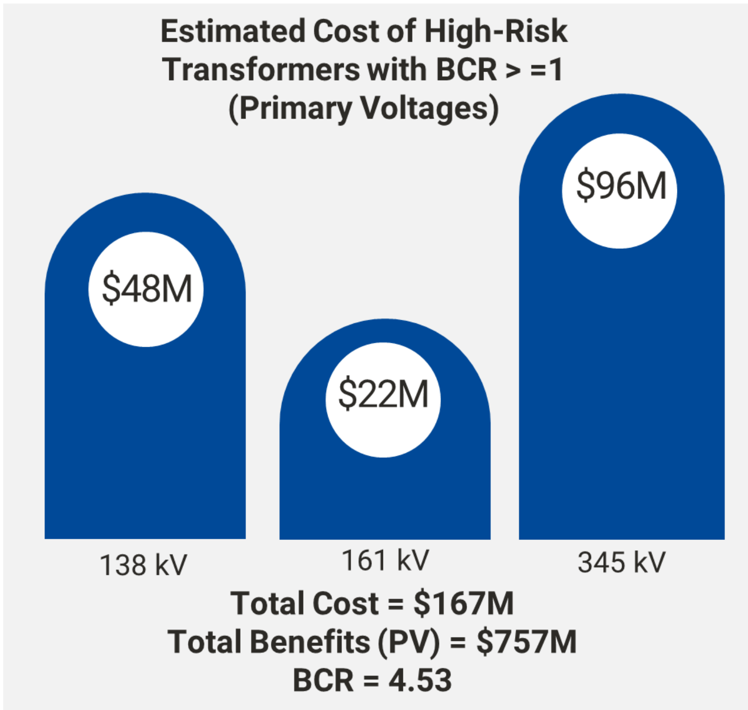

Figure 4-2 Cost Summary of High-Risk Transformers with BCR's >= 1by Primary Voltage

4.2.3 Relay Replacement Results

The relay panel risk analysis was conducted on the fleet of 1,629 relay panels. The results are shown in the heat map in Table 4-11 below. This heat map shows that 306 of the 1,629 relay panels (19%) have a high-risk score. Table 4-12 below is the same heat map but only includes the count of relay panels that produced a benefit to cost ratio equal to or greater than 1. Table 4-12 shows that 305 of the 306 relay panels are high risk and produce benefits that outweigh the cost to replace the panel. These high-risk relay panels should be targeted for replacement in the near-term planning horizon.

Table 4-11 Relay Panels Heat Map

Relay Panel Heat Map		PoF			
		1	2	3	4
CoF	4	350	4	20	34
	3	332	1	16	58
	2	288	14	10	95
	1	312	4	12	79
		Total Relay Panels			1629

Table 4-12 Relay Panels Heat Map with BCR >= 1

Heat Map – Relay Panels with BCR >= 1		PoF			
		1	2	3	4
CoF	4	176	4	20	34
	3	7	1	16	58
	2	9	14	10	95
	1	0	3	10	78
		Total Relay Panels			535

Table 4-13 below is a summary of the benefits by category that make up the total benefits for the 305 relay panels with BCR >=1.

Table 4-13 Calculated Benefits by Benefit Type

Asset Class	Avoided Capital Cost ($M)	Avoided O&M Costs ($M)	Transmission Reliability Risk ($M)	Collateral Damage ($M)	Public Property Damage ($M)	Wildfire Risk ($M)	Environmental Risk ($M)
Relay Panel	$12.3 M	$0.02M	$912.3 M	$6.9 M	$9.5 M	$0.00M	$6.9 M

Figure 4-3 below is a summary of the cost to replace high risk relay panels with BCR's >=1 by voltage level.

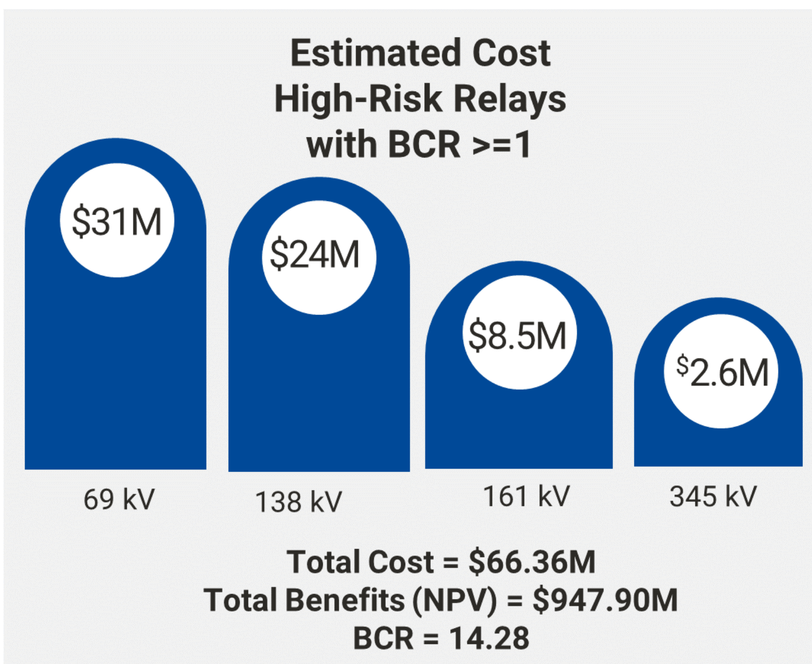

Figure 4-3 Cost Summary of High-Risk Relay Panels with BCR >= 1 by Voltage

4.2.4 Circuit Breaker Replacement Results

The circuit breaker risk analysis was conducted on a population of 1,296 breakers. The results are shown in the heat map in Table 4-14 below. This heat map shows that 189 of the 1,296 circuit breakers (14%)

have a high-risk score. Table 4-15 below is the same heat map but only includes the count of circuit breakers that produced a benefit to cost ratio equal to or greater than 1. Table 4-15 shows that 188 of the 189 circuit breakers are high risk and produce benefits that outweigh the cost to replace the breakers. These high-risk circuit breakers should be targeted for replacement in the near-term planning horizon.

Table 4-14 Circuit Breaker Heat Map

Heat Map Circuit Breakers		PoF 1	PoF 2	PoF 3	PoF 4
CoF	4	419	9	4	0
	3	107	36	21	52
	2	396	30	18	26
	1	41	37	23	77
		Total Circuit Breakers			1296

Table 4-15 Circuit Breaker Heat Map with BCR >= 1

Heat Map Circuit Breakers with BCR >= 1		PoF 1	PoF 2	PoF 3	PoF 4
CoF	4	171	9	4	0
	3	45	36	21	52
	2	33	30	18	26
	1	7	36	23	76
		Total Circuit Breakers			587

Table 4-16 below is a summary of the benefits by category that make up the total benefits for the 188 circuit breakers with BCR >=1.

Table 4-16 Circuit Breaker Replacement - Calculated Benefits by Benefit Type

Asset Class	Avoided Capital Cost ($M)	Avoided O&M Costs ($M)	Transmission Reliability Risk ($M)	Collateral Damage ($M)	Public Property Damage ($M)	Wildfire Risk ($M)	Environmental Risk ($M)
Circuit Breaker	$18.3M	$0.5M	$1258.2M	$6.1M	$2.2M	$0.00M	$6.0M

Figure 4-4 below is a summary of the cost to replace high risk circuit breakers with BCR's >=1 by voltage level.

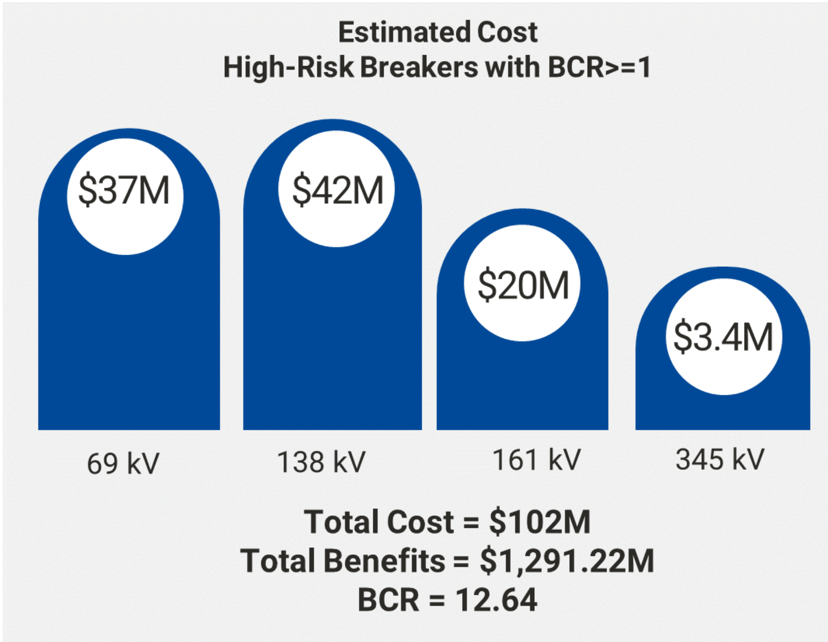

Figure 4-4 Circuit Breakers Cost Summary of High-Risk Circuit Breakers with BCR >= 1

4.2.4.1 Oil Circuit Breakers

The oil circuit breaker risk analysis was conducted on the fleet of 315 breakers. The results are shown in the heat map in Table 4-17 below. This heat map shows that 177 of the 315 circuit breakers (56%) have a high-risk score. Table 4-18 below is the same heat map but only includes the count of circuit breakers that produced a benefit to cost ratio equal to or greater than 1. Table 4-18 shows that 176 of the 177 oil circuit breakers are high risk and produce benefits that outweigh the cost to replace the breakers. These high-risk oil circuit breakers should be targeted for replacement in the near-term planning horizon.

Table 4-17 Oil Circuit Breakers Heat Map

Heat Map – Oil Circuit Breakers		PoF			
		1	2	3	4
CoF	4	2	2	0	0
	3	7	28	20	52
	2	0	22	18	26
	1	4	35	22	77
		Total Oil Circuit Breakers			315

Table 4-18 Oil Circuit Breaker Heat Map with BCR >= 1

Heat Map – Oil Circuit Breakers with BCR >= 1		PoF			
		1	2	3	4
CoF	4	2	2	0	0
	3	7	28	20	52
	2	0	22	18	26
	1	3	34	22	76
		Total Oil Circuit Breakers			312

Table 4-19 below is a summary of the benefits by category that make up the total benefits for the 176 oil circuit breaker with BCR >=1.

Table 4-19 Oil Circuit Breaker Calculated Benefits by Benefit Type

Asset Class	Avoided Capital Cost ($M)	Avoided O&M Costs ($M)	Transmission Reliability Risk ($M)	Collateral Damage ($M)	Public Property Damage ($M)	Wildfire Risk ($M)	Environmental Risk ($M)
Oil Circuit Breaker	$17.7M	$0.5M	$1152.9M	$6.0M	$2.2M	$0.0M	$6.0M

Figure 4-5 below is a summary of the cost to replace high risk circuit breaker with BCR's >=1 by voltage level.

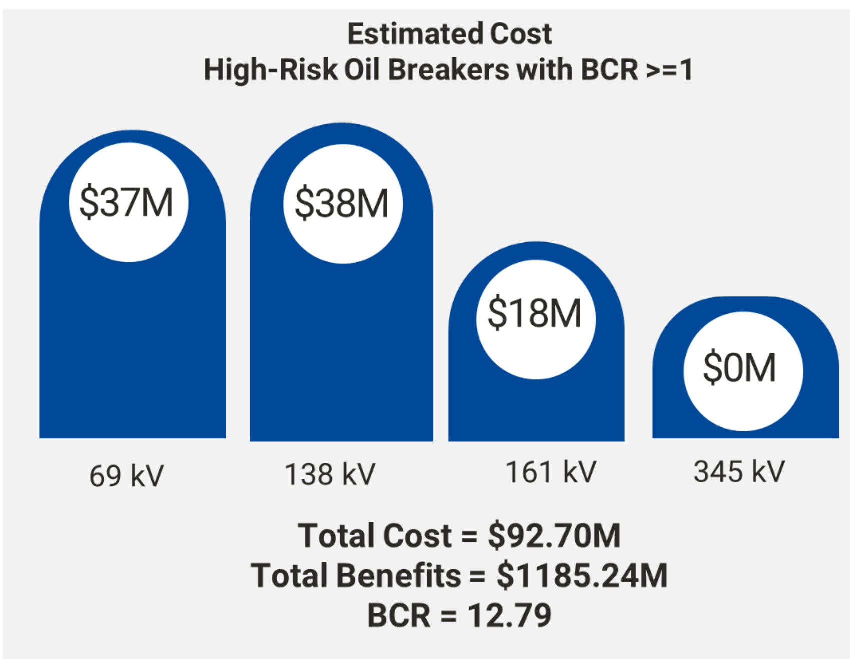

Figure 4-5 Cost Summary of High-Risk Oil Circuit Breakers with BCR >= 1

4.2.4.2 SF6 Circuit Breaker Results

The SF6 circuit breaker risk analysis was conducted on the fleet of 941 breakers. The results are shown in the heat map in Table 4-20 below. This heat map shows that 12 of the 941 circuit breakers (1%) have a high-risk score. Table 4-21 below is the same heat map but only includes the count of circuit breakers that produced a benefit to cost ratio equal to or greater than 1. Table 4-21 shows that 12 of the 12 SF6 circuit breakers are high risk and produce benefits that outweigh the cost to replace the breakers. These high-risk SF6 circuit breakers should be targeted for replacement in the near-term planning horizon.

Table 4-20 SF6 Circuit Breaker Heat Map

Heat Map – SF6 Circuit Breakers		PoF			
		1	2	3	4
CoF	4	417	7	4	0
	3	96	8	1	0
	2	364	8	0	0
	1	33	2	1	0
		Total SF6 Circuit Breakers			941

Table 4-21 SF6 Circuit Breaker Heat Map with BCR >= 1

Heat Map – SF6 Circuit Breakers with BCR >= 1		PoF			
		1	2	3	4
CoF	4	169	7	4	0
	3	38	8	1	0
	2	33	8	0	0
	1	4	2	1	0
		Total SF6 Circuit Breakers			275

Table 4-22 below is a summary of the benefits by category that make up the total benefits for the 12 SF6 circuit breaker with BCR >=1.

Table 4-22 SF6 Circuit Breaker Calculated Benefits by Benefit Type

Asset Class	Avoided Capital Cost ($M)	Avoided O&M Costs ($M)	Transmission Reliability Risk ($M)	Collateral Damage ($M)	Public Property Damage ($M)	Wildfire Risk ($M)	Environmental Risk ($M)
SF6 Circuit Breaker	$0.6M	$0.0M	$105.3M	$0.1M	$0.0M	$0.0M	$0.0M

Figure 4-6 below is a summary of the cost to replace high risk circuit breaker with BCR's >=1 by voltage level.

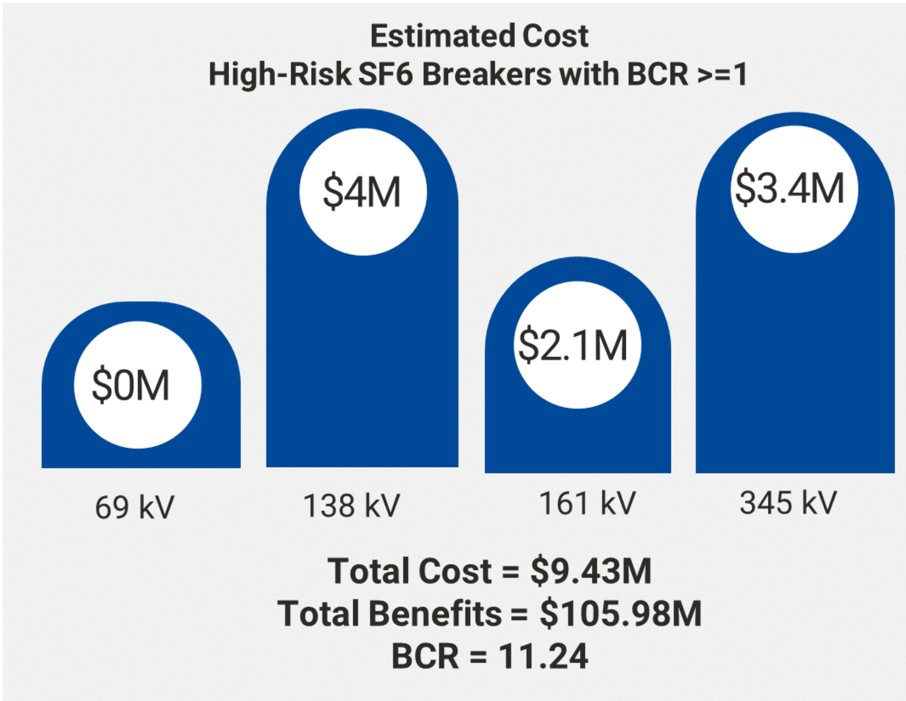

Figure 4-6 Cost Summary of High Risk SF6 Breakers with BCR >= 1 by Voltage

4.3 Resiliency Programs Results

4.3.1 Rebuild Radial Taps

The Tap Reinforcement risk analysis was conducted on 36 worst performing radial taps that LG&E/KU identified based on the length of the tap, and the customers served from the tap. These taps expose customer to extended outages when faults occur on the taps. The results are shown in the heat map in Table 4-23 below. This heat map shows that 17 of the 36 taps (47%) have a high-risk score (red zone). Table 4-24 below is the same heat map but only includes the count of taps that produced a benefit to cost ratio greater than or equal to 1. Figure 4-7 shows that all high-risk taps produced benefits that were greater than the cost to rebuild the taps. These high-risk Taps should be targeted for replacement in the near-term planning horizon.

Table 4-23 Heat Map of All Taps

Heat Map – All Taps		PoF			
		1	2	3	4
CoF	4	1	1	4	3
	3	3	1	1	4
	2	0	2	4	3

Heat Map – All Taps		PoF			
		1	2	3	4
	1	2	2	4	1
				Total Taps	36

Table 4-24 Tap Reinforcements With BCR >= 1

Heat Map – Taps with BCR >= 1		PoF			
		1	2	3	4
CoF	4	1	1	4	3
	3	1	1	1	4
	2	0	2	4	3
	1	0	1	3	1
		Total Taps			30

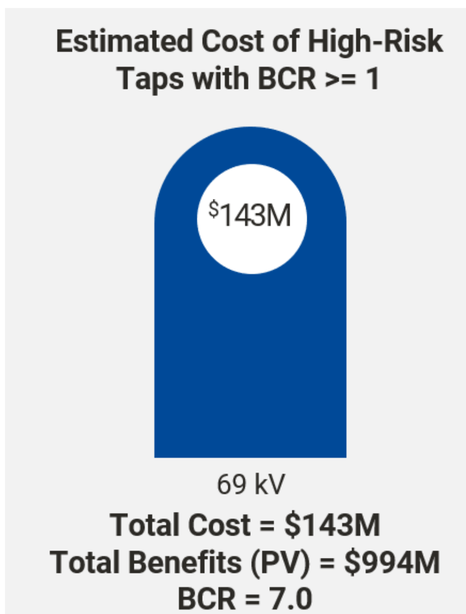

Figure 4-7 Cost Summary of Radial Taps with BCR's >= 1

Table 4-25 below is a summary of the benefits by category that make up the total benefits for the 30 Taps with BCR >=1.

Table 4-25 Taps Calculated Benefits by Benefit Type

Asset Class	Avoided Capital Cost ($M)	Avoided O&M Costs ($M)	Transmission Reliability Risk ($M)	Collateral Damage ($M)	Public Property Damage ($M)	Wildfire Risk ($M)	Environmental Risk ($M)
Taps	$2.9M	$0M	$1,060M	$30M	$30M	$0.04M	$0M

4.3.2 Automated Remote Sectionalizing (ARS)

The Automated Remote Sectionalizing (ARS) analysis was performed on 131 circuits out of a total of 471 circuits on LG&E/KU's Transmission system. The results are shown in Figure 4-8 below. The result of this investment group shows that 78 of the 131 circuits evaluated produce a benefit to cost ratio greater than one. These circuits should be targeted for rebuild in the near-term planning horizon.

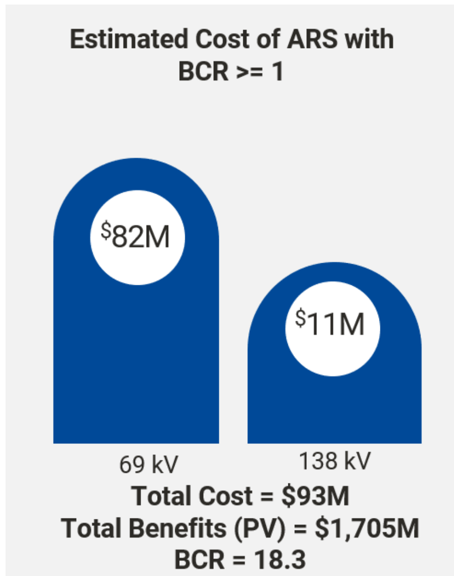

Figure 4-8 Cost Summary of ARS Additions with BCR's >= 1

Table 4-26 ARS Calculated Benefits by Benefit Type

Asset Class	Avoided Capital Cost ($M)	Avoided O&M Costs ($M)	Transmission Reliability Risk ($M)	Collateral Damage ($M)	Public Property Damage ($M)	Wildfire Risk ($M)	Environmental Risk ($M)
ARS	-	-	$1,704M	-	-	-	-

5.0 Conclusion

The risk and benefit cost analysis shows that transmission circuits pose the largest risk to reliability and resiliency to the LG&E/KU transmission system. Over 700 miles of 69kV circuit miles were ranked with the highest risk score, whilst having a benefit-cost ratio greater than or equal to 1. There are 300 miles of 138kV circuits, and over 200 miles of 161kV circuits that also met this criterion. The transmission circuits' high-risk ratings are driven primarily by the population of wood poles that are well beyond their service life. This makes transmission circuits vulnerable to widespread damage during extreme weather conditions such as tornadoes, high winds, wildfires, and ice storms. With such a high volume of transmission circuits at risk, it would take decades to fully rebuild; however, the risk analysis will be used to prioritize strategic pole replacement projects as well as opportunities to rebuild entire circuits. It will be important to prioritize high risk circuits for structure replacement or complete rebuild to effectively manage risk on the transmission system moving forward.

The population of power transformers, circuit breakers and relay panels that make up the remaining critical infrastructure of the transmission system poses less risk to the system than transmission circuits. However, there are high-risk assets among these asset classes that need replaced. Future work plans should consider high risk transformers, breakers, and relays replacements in coordination with circuit rebuilds to take advantage of outages where more than one asset replacement can be accomplished under a single outage.

The resiliency programs - Tap Reinforcements, and Automated Remote Sectionalization Deployment (ARS), both have significant benefits that are primarily focused on mitigating and offsetting sustained outages for LG&E/KU's customers. Through our Cost-Benefit Analysis, we found that these investment programs returned the greatest benefit-cost ratios amongst all investment types in our analysis and offer much more affordable solutions than undertaking complete circuit rebuilds, while offering substantial benefits to LG&E/KU's customers.

Through this analysis, high risk assets have been identified that produce benefits greater than the cost to replace the high-risk asset. Targeting high risk assets for replacement and pursuing resiliency projects that reduces customer outage frequency and duration with benefits greater than the cost of replacement will be a focus of transmission investments through the business planning horizon and beyond.

6.0 Appendix

6.1 Asset Health Scoring Methodology

6.1.1 Structures – Wood Poles

Wood poles are inspected every 6 years and given one of the following condition statuses:

- Good
- Needs Repair
- Urgent Repair
- Reject
- Critical

A "Good" structure is self-explanatory. There are no components with any identifiable issues.

A "Needs Repair" structure is one that has a minor deficiency. Once repaired, the structure will assume the status of "Good." There is not a significant sense of urgency to make the repairs, as the risk to the system and public is minimal. Some examples are missing guy guards, flashed insulators, loose bracing, or minor erosion.

An "Urgent Repair" structure has one or more significant deficiencies that need to be addressed as soon as reasonably possible. Once the issues are addressed, the structure will assume the condition status of "Good." Some examples are, loose suspension clamp pins, corroded anchor rods, broken bracing, or severe erosion.

A "Reject" structure has one or more issues that are not able to be repaired. The structure must be scheduled for replacement. Some examples for rejecting a structure include pole rot, multiple woodpecker holes (greater than softball-size), pole top deterioration, significant longitudinal cracks/checks, or minor cross-arm deterioration.

A "Critical" structure has one or more issues that need to be addressed within 6 months of the completed inspection, by replacing the structure. Some examples include significant pole rot (less than 2" of shell thickness remaining), woodpecker holes with visible daylight, nesting cavities, holes within critical connection points (high-stressed areas), or cross-arm deterioration that affects hardware support.

From LG&E/KU's inspection findings, Black & Veatch incorporated the following Asset Health Index Scores based off discussions with LG&E/KU SME's:

Table 6-1 Structures - Wood Poles - Asset Health Index Score

Health Score	Condition
4	Reject, Critical
3	Needs Repair, Urgent Repair
2	Repairs Made
1	Good, Replaced
0	Not Inspected

6.1.2 Conductors

The identified need to perform the inspections has been based upon system performance. As previously stated, circuits dating back to the 1920s are still in operation. Due to previous failures, smaller copper conductors were the most at risk. However, smaller ASCR (Aluminum Conductor Steel Reinforced) conductor, was the primary focus of the inspections. Specifically, the smaller conductors that contain only one, central, steel-core strand were most concerning.

LG&E/KU hired a contractor that specializes in non-destructive testing of overhead conductor. Figure 6-1 shows the robot used to perform the inspections. The conductor must contain ferrous material (steel) for the robot to identify deficiencies. As the robot travels along the conductor, it can measure the remaining cross-sectional area and identify flaws or broken strands. From the collected measurements, an updated remaining tensile strength of the conductor is derived.

LG&E/KU created a condition scoring matrix from the inspection data. For lines that were not inspected, a guideline was established for determining the general health of the conductor. The primary factors include the age, size, material type and stranding configuration. Table 6-2, Table 6-3, and Table 6-3-1 outline the conductor asset health index.

Figure 6-1 Non-destructive Testing of Overhead Conductor

Table 6-2 Conductor Material

Health Score	LG&E/KU Rating	Condition
4	10	AW, CU, CW
2	5	ACSR, ACSS, SSAC
0	1	ACAR, AAC, AA

Table 6-3 Conductor Core Rated Breaking Strength (RBS)

Health Score	LG&E/KU Rating	Conductor Core RBS
0	1	100%
1	4	95%
2	6	94%
3	8	89%
4	10	84%

Table 6-4-1 Entire Conductor Rated Breaking Strength (RBS)

Health Score	LG&E/KU Rating	Conductor Core RBS
0	1	100%
1	3	97%
2	7	91%
3	9	85%
4	10	84%

6.1.3 Transformers

Asset Health Index Score = Initial Health + Dynamic Health + Work Order Score

Initial Health Scoring methodology is outlined in Table 6-5. Four main factors were considered to calculate the initial health score for each transformer: Manufacturer, Dissolved Gas Analysis (DGA), Oil Quality, and DOBLE. The condition score (e.g., 1, 1.5, etc.) for each factor is converted to a numeric value and then are added together to calculate the Initial Health Score for a transformer.

Table 6-5 Transformer Initial Health Scoring Methodology

Initial Health Score					
	Condition/Score				
	1	1.5	2	2.5	3
Manufacturer					
Ranked by industry historical failure statistics: Rewinds all get condition 2	5	6	7.5	8.5	10
DGA					
TOA4 DGA Reading: 2= condition 1, 3 = condition 2, 4= condition 3 based on last results	10		20		30
Oil Quality					
TOA4 Fluid Quality: 2 = condition 1, 3= condition 2, 4= condition 3	3.33		3.83		10
DOBLE					
Inter-winding UST/Auto to ground: Stable = condition 1, increased by 50% = condition 2, doubled = condition 3	6.6		13.33		20

Dynamic Health and Work Order Scoring methodology is outlined in Table 6-6. Four main factors were considered to calculate the dynamic health score for each transformer: Oil Temperature, Dissolved Gas Analysis (DGA), Oil Quality, and DOBLE. The condition score (e.g., 2, 3, or 4) for each factor is converted to a numerical value based on the inspection results and then are added together to calculate the Initial Health Score for a transformer.

Table 6-6 Transformer Dynamic Health Scoring Methodology

Dynamic Health Score			
	Cond 2	**Cond 3**	**Cond 4**
Top Oil Temp	**10**	**20**	**200**
	>70 < 80	>80 < 90	>90
DGA	**45**	**90**	**200**
	TDCG > 692 < 1885 (IEEE code2)	ethylene >50 AND < 100 hydrogen >100 AND < 700 acetylene >2 AND < 5 methane >120 AND < 1000 ethane >65 AND < 150	ethylene >100 hydrogen >700 acetylene > 5 methane >1000 ethane >150 carbon monoxide>1400 OR (H2 >1000 AND CH4 >500 AND .1 > CH4/H2 < .5) (C2H4 >150 AND C2H6 >130 AND C2H4/C2H6 >1) (CO2 >5000 AND CO >570 AND 3 > CO2/C0 >10) (C2H2>10 AND C2H6 >130 AND C2H2/C2H6 >1) (C2H2 >30 AND C2H2/H2 >2) Leak from LTC to main tank - apply to units with LTC only
DOBLE	**10**	**20**	**200**
PF Threshold	.5 - .74 = 10	.75 -1 = 20	>1 = 200
PF Increase	>40% = 10	>60% = 20	
Cap change			±5% = 200
Oil Quality		**45**	**90**
		Cond 2	>Cond 2

The work order score is determined by the annual rate of work orders over the past decade, specifically focusing on nitrogen, pumps, and oil leaks.

Table 6-7 Transformer Work Order Scoring Methodology

Work Order Score			
	Cond 2	**Cond 3**	**Cond 4**
Work Order - Yearly Rate	**25**	**50**	**100**
	>1	>2	>4

Table 6-8 Transformer Overall Health Scoring Methodology

Health Score	Score Range	Health Score Description
4	>400	Multiple Condition 4 issues
3	150-400	Multiple contributions Cond 3, Cond 2 w/ Potential Condition 4
2	50-150	Starting to see issues
1	25-50	Minimal health contribution
0	0-25	Little to no Health Issues

6.1.4 Oil Circuit Breakers

Asset Health Index Score = Initial Health + Dynamic Health + Work Order Score

Initial Health Scoring methodology is outlined in Table 6-9. Four main factors were considered to calculate the initial health score for each oil breaker: Manufacturer's reputation, Mechanism Quality, Faults Ops/Current Interrupted, and Interview maintenance Crews. The condition score (e.g., 1, 2, etc.) for each factor is converted to a numeric value and then are added together to calculate the Initial Health Score for an oil breaker.

Table 6-9 Oil Circuit Breaker Initial Health Scoring Methodology

Initial Health Score					
	Condition Score				
	1	**1.5**	**2**	**2.5**	**3**
Manufacturer's Reputation					
No failures on this model/vintage with low maintenance costs=1, Failure of this type/vintage with average maintenance cost=2, Many failures of this type & sister types with high maintenance costs=3	4		8		20
Mechanism Quality					
Spring or similar with very low maintenance=1, Mechanisms with average maintenance and neutral effect on performance=2, hydraulic and other high maintenance performance=3	4	8	12	16	20

Initial Health Score					
	Condition Score				
	1	**1.5**	**2**	**2.5**	**3**
Fault Ops/Current Interrupted					
Available fault current < 30% of rating or averages < 10 faults cleared per year=1, between 30-60% or 10-20 faults=2, >60% and >30 faults=3	10		20		30
Interview maintenance crews					
SC&M notes few or no issues=1, some issues with failures and maintenance issues=2, major maintenance issues/unreliable=3	10		20		30

Dynamic Health Scoring methodology is outlined in Table 6-10. Five main factors were considered to calculate the dynamic health score for each oil breaker: bushings, Tank loss index, DGA, Oil quality, fault operations. The condition score (e.g., 2, 3, or 4) for each factor is converted to a numerical value based on the inspection results and then are added together to calculate the Dynamic Health Score for an oil breaker.

Table 6-10 Oil Circuit Breaker Dynamic Health Scoring Methodology

Dynamic Health Score			
	Cond 2	**Cond 3**	**Cond 4**
Bushings	**5**	**10**	**200**
PD		25% change from previous	50% change from previous
Tank Loss Index	**10**	**20.0**	**200**
TLI		Doble=B or I count >=1	
DGA/Particle	**40**	**80**	**200**
TJH2B	2	3	4
Oil Quality		**20**	
		>=2	
Fault Operations	**5**	**10**	**25**
	1-5 ops/month	5-10 ops/month	>10 ops/month or Total 20 Ops

The work order score is determined by the annual rate of work orders over the past decade.

Table 6-11 Oil Circuit Breakers Work Order Scoring Methodology

Work Order Score			
	Cond 2	**Cond 3**	**Cond 4**
Work Order - Yearly Rate	**10**	**50**	**100**
	>=0.3	>=0.5	>=1

Table 6-12 Oil Circuit Breakers Overall Health Scoring Methodology

Health Score	Score Range	Health Score Description
4	>260	One or more Condition 4 issues
3	80-260	Multiple contributions with DGA, bushings, work orders, internal contributions to poor oil quality. Potential condition 4
2	50-80	Starting to see issues
1	25-50	Minimal health contribution
0	0-25	little to no health issues

6.1.5 SF6 Circuit Breakers

Asset Health Index Score = Initial Health + Dynamic Health + Leak Rate Score + Work Order Score

Initial Health Scoring methodology is outlined in the Table 6-13. Four main factors were considered to calculate the initial health score for each SF6 breaker: Manufacturer's reputation, Mechanism Quality, Faults Ops/Current Interrupted, and Interview maintenance Crews. The condition score (e.g., 1, 2, etc.) for each factor is converted to a numeric value and then are added together to calculate the Initial Health Score for an SF6 breaker.

Table 6-13 SF6 Circuit Breakers Initial Health Scoring Methodology

Initial Health Score					
	Condition Score				
	1	**1.5**	**2**	**2.5**	**3**
Manufacturer's Reputation					
No failures on this model/vintage with low maintenance costs=1, Failure of this type/vintage with average maintenance cost=2, Many failures of this type & sister types with high maintenance costs=3	4		8		20
Mechanism Quality					
Spring or similar with very low maintenance=1, Mechanisms with average maintenance and neutral effect on performance=2, hydraulic and other high maintenance performance=3	4	8	12	16	20

Initial Health Score					
	Condition Score				
	1	1.5	2	2.5	3
Fault Ops/Current Interrupted					
Available fault current < 30% of rating or averages < 10 faults cleared per year=1, between 30-60% or 10-20 faults=2, >60% and >30 faults=3	10		20		30
Interview Maintenance Crews					
SC&M notes few or no issues=1, some issues with failures and maintenance issues=2, major maintenance issues/unreliable=3	10		20		30

Dynamic Health Scoring is outlined in the Table 6-14. Four main factors were considered to calculate the dynamic health score for each SF6 Breaker: SF6 Gas Moisture, SF6 Gas Purity, SF6 Gas SO2, and fault operations. The condition score (e.g., 2, 3, or 4) for each factor is converted to a numerical value based on the inspection results and then are added together to calculate the Dynamic Health Score for an SF6 breaker.

Table 6-14 SF6 Circuit Breakers Dynamic Health Scoring Methodology

Dynamic Health Score			
	Cond 2	Cond 3	Cond 4
SF6 Gas Moisture	**20**	**40**	
	>=51 <75	>=75 < 150	
SF6 Gas Purity	**15**	**30**	
	<98.9 >=98.5	<98.5 >=97.9	
SF6 Gas SO2	**30**	**60**	
	>=51 <100	>=100 <150	
Fault Operations	**5**	**10**	**25**
	1-5 ops/month	5-10 ops/month	>10 ops/month or Total 20 Ops

The SF6 Leak Rate score is based on the rate of emissions of SF6 gas over the past 5 years.

Table 6-15 SF6 Circuit Breakers Leak Rate Scoring Methodology

Leak Rate Score			
	Cond 2	Cond 3	Cond 4
SF6 Leak Rate- Year Rate	**20**	**40**	**200**
	>=1 lbs.	>=3 lbs.	>=6 lbs.

The work order score is based on the rate of work order over the past 10 years.

Table 6-16 SF6 Circuit Breakers Work Order Rate Scoring Methodology

Work Order Score			
	Cond 2	**Cond 3**	**Cond 4**
Work Order - Yearly Rate	**10**	**25**	**100**
	>=0.3	>=0.5	>=1

Table 6-17 SF6 Circuit Breakers Overall Health Scoring Methodology

Health Score	Score Range	Health Score Description
4	>230	Multiple condition issues with/or severe leaking
3	150-230	Multiple contributions with leaking, work orders, internal conditions
2	50-150	Starting to see issues
1	25-50	Minimal health contribution
0	0-25	Little to no health issues

6.1.6 Relay Panels

The objective of this approach is to provide a comprehensive and data-driven method to evaluate the condition of electromechanical and Microprocessor relays and prioritize panel replacements. This is achieved by using **As Found (AF)** and **As Left (AL)** test results, along with field performance data such as **known mis-operation** rates. By systematically weighing these factors, we can effectively identify high-risk panels and take preventive actions to maintain operational reliability and prevent mis-operations in the power grid.

As-Found Testing: This process checks if the relay is operating within the designed engineering parameters. It provides a baseline to understand the current state of the relay and identify any deviations from the expected performance.

As-Left Testing: As-Left testing ensures that the relay can be adjusted back to the designed parameters. This step confirms that the relay is functioning correctly and meets the required specifications.

The scoring model is designed to bubble up panels with multiple problematic relays, ensuring we can prioritize replacements effectively. The formula is as follows:

- As Found Results: Sum Panel AF Results x 120 points
- As Left Results: Sum AL Results x 20 points
- Known Mis-operations: Mis-operations Ratio x 60 points.

AF/AL Score: If a panel contains five relays with corresponding AF test results of 0.23, 0.31, 0.15, 0.1, and 0.27, the total AF results would sum to 1.06. The panel score = 120 x 1.06 = 127.2.

Mis-operations Score: Relay models with the highest number of mis-operations receive 60 points, with a linear reduction applied to the remaining models associated to mis-operations.

The following table outlines the asset health scoring methodology for Relay Panels.

Table 6-18 Relay Panel Overall Health Scoring Methodology

Asset Factors	Min Score	Max Score	Asset Health Score
(AF Results *120) + (AL Results *20) + (Mis-operations Ratio * 60)	201	>201	4
(AF Results *120) + (AL Results *20) + (Mis-operations Ratio *60)	101	200	3
(AF Results *120) + (AL Results *20) + (Mis-operations Ratio *60)	21	100	2
(AF Results *120) + (AL Results *20) + (Mis-operations Ratio *60)	6	20	1
(AF Results *120) + (AL Results *20) + (Mis-operations Ratio *60)	0	5	0

6.2 Logic Based Consequence of Failure

Table 6-19 summarizes the logic-based methodology used to score the consequence of failure for each asset class:

Table 6-19 Substation Transformer Consequence of Failure Scoring Methodology

Substation/Line	Asset Class	Environmental Impact Risk	Collateral Damage	Public Property Damage
Substation	Transformer*	Proximity to waterway Volume of oil Oil containment (yes/no)	Minor consequence for transformers in urban areas Low Consequence for transformers in rural areas Generation transformer = zero Public Property Risk	Is xfmr protected with high side breaker? (yes/no) **If yes:** If xfmr primary voltage = 500kV then consequence = moderate If xfmr primary voltage = 345kV then consequence = moderate If primary voltage = 161kV then consequence = moderate If xfmr primary voltage = 138kV then consequence = moderate If xfmr primary voltage = 69kV then consequence = minor **If no:** For all xfmr primary voltages - consequence = minor
Substation	Circuit Breaker**	Oil Breaker Proximity to waterway Volume of oil Oil containment (yes/no) SF6 Breaker Convert SF6 Capacity to metric tons of CO2 All SF6 is released upon failure $/CO2 per metric ton X CO2 metric tons	Urban Oil Brkrs = Minor Rural Oil Brkrs = Low SF6 Brkrs = N/A Vacuum Brkrs = N/A Any breaker at a generating plant = N/A	Is breaker protecting a xfmr? (yes/no) **If yes:** If breaker voltage = 500kV then consequence = significant If breaker voltage = 345kV then consequence = significant If breaker voltage = 161kV then consequence = moderate If breaker voltage = 138kV then consequence = moderate If breaker voltage = 69kV then consequence = moderate **If no:** Oil CB Consequence = minor SF6 CB Consequence = low Vacuum CB Consequence = low
Substation	Relay	Logic on scoring methodology: A fault occurs on the system. The relay fails to clear the fault. (Relay PoF) Fault current stays on system longer. The second/third zone of protection operates as designed clearing the fault The extended fault current time causes an eventful	Logic on scoring methodology: A fault occurs on the system. The relay fails to clear the fault (Relay PoF) Fault current stays on system longer. The second/third zone of protection operates as designed clearing the fault The extended fault	Logic on scoring methodology: A fault occurs on the system. The relay fails to clear the fault (Relay PoF) Fault current stays on system longer. The second/third zone of protection operates as designed clearing the fault The extended fault current time causes an eventful failure of the asset. The eventful failure cause LG&E/KU collateral damage

Substation/Line	Asset Class	Environmental Impact Risk	Collateral Damage	Public Property Damage
		failure of the asset the relay is protecting. The eventful failure of the asset the relay is protecting cause an environmental event (PoF of Relay) X (Probability of extended fault current time causing an eventful failure of the asset the relay is protecting) X (Probability of an eventful failure causing an environmental event) If voltage = 500kV then consequence = moderate If voltage = 345kV then consequence = moderate If voltage = 161kV then consequence = moderate If voltage = 138kV then consequence = moderate If voltage = 69kV then consequence = minor	current time causes an eventful failure of the asset. The eventful failure cause public property damage Rural (PoF of Relay) X (Probability of extended fault current time causing an eventful failure) X (Probability of eventful failure causing a public property consequence) = Minor Urban (PoF of Relay) X (Probability of extended fault current time causing an eventful failure) X (Probability of eventful failure causing a public property consequence) = Moderate	(PoF of Relay) X (Probability of extended fault current time causing an eventful failure of the asset the relay protects) X (Probability of eventful failure causing collateral damage) If voltage = 500kV then consequence = moderate If voltage = 345kV then consequence = moderate If voltage = 161kV then consequence = moderate If voltage = 138kV then consequence = moderate If voltage = 69kV then consequence = minor
Line	Overhead Conductor	N/A	Minor consequence for all overhead conductors	Minor consequence for all overhead conductors
Line	Underground Cable	N/A	N/A	Minor consequence for all underground cables
Line	Structures	N/A	Significant consequence for all structures	Maximum consequence value used after scoring the following variables: Structure In city limits = Minor Structure Out of city limits = Low Structure near waterway = Moderate Structure within 500' of highway crossing = Significant

Table 6-20 summarizes the matrix used to score the Environmental Impact Scores for Transformers.

Table 6-20 Environmental Impact Scores for Transformers

	Minor	Moderate	Minor	Significant	Moderate	Significant	Moderate	Significant
Close to water - No	X	X	X	X				
Close to water - Yes					X	X	X	X
Below 10,000 gallons of oil	X	X			X	X		
Above 10,000 gallons of oil			X	X			X	X
Oil Containment - Yes	X		X		X		X	

	Minor	Moderate	Minor	Significant	Moderate	Significant	Moderate	Significant
Oil Containment - No		X		X		X		X

Table 6-21 summarizes the matrix used to score the Environmental Impact Scores for Transformers.

Table 6-21 Environmental Impact Scores for Oil Breakers

	Minor	Moderate	Minor	Significant	Moderate	Significant	Moderate	Significant
Close to water - No	X	X	X	X				
Close to water - Yes					X	X	X	X
Below 10,000 gallons of oil	X	X			X	X		
Above 10,000 gallons of oil			X	X			X	X
Oil Containment - Yes	X		X		X		X	
Oil Containment - No		X		X		X		X

6.3 Value of Redundant Transmission Capacity

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[10] *See* http://icecalculator.com/home The Interruption Cost Estimate (ICE) Calculator is a tool designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements.

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PPL companies

Expected NM DER Impact on the Transmission System

May 22, 2025

Table of Contents

Executive Summary

The purpose of this study was to estimate any potential cost savings on the LG&E/KU transmission system due to Net Metering (NM) customers' operation of Distributed Energy Resources (DERs) located across the LG&E/KU service territory by identifying if there are any avoided transmission infrastructure upgrades due to the NM DER generation.

To make the determination of any avoided transmission system upgrade projects, two sets of models were created, one that included NM DER generation, and another that did not and thus had higher summer peak load levels. P0, P1, and P3 analyses were then conducted on each set of the models to determine if the lack of NM DER generation had a significant impact in creating any MVA flow or voltage violations.

The NM DER generation had no significant impact on the avoidance of transmission system upgrade projects. Therefore, the overall estimated savings due to the NM DER generation was determined to be $0.

Introduction

The purpose of this study was to estimate any potential cost savings on the LG&E/KU transmission system due to Distributed Energy Resources (DERs) located across the LG&E/KU service territory by identifying if there are any avoided transmission infrastructure upgrades due to NM DER generation. By analyzing the expected operating conditions of DERs at various seasonal peak scenarios, the study estimates the extent to which DERs can defer or eliminate the need for new transmission upgrade projects.

The first step in determining the expected impact on the Transmission System was collecting the necessary data to model the increased load on the LG&E/KU transmission system as if the DERs did not exist. To do this, a list of all delivery points to the transmission system where DER generation is forecasted to be greater than 1 MW was collected. These forecasts include all customers in the NMS-1, NMS-2, and QF retail tariffs. The table below provides the location and amount of DER generation that was removed from the model, as if it did not exist:

Delivery Point	Company	2027 DER (MW)	2030 DER (MW)	2035 DER (MW)
ALEXANDER 12KV	KU	0.929	1.152	1.152
DELAPLAIN 12KV	KU	0.913	1.017	1.017
GREENVILLE NORTH 12KV	KU	1.389	1.544	1.544
HAMBLIN	KU	0.955	1.050	1.050
LANSDOWNE 1 12KV	KU	1.425	1.770	1.770
LANSDOWNE 2 12KV	KU	0.701	0.878	0.878
MIDWAY 12KV	KU	1.265	1.426	1.426
REYNOLDS 12KV 1	KU	0.685	0.848	0.848
STONEWALL 12KV2	KU	0.799	1.009	1.009
WILDWNG 2 12KV	KU	0.890	1.140	1.140
WINCHESTER IND 12KV	KU	0.997	1.083	1.083
ASHBY 1	LG&E	0.648	0.648	0.648
DAHLIA 1	LG&E	1.285	1.285	1.285
DAHLIA 2	LG&E	0.797	0.797	0.797
FAIRMOUNT 1	LG&E	0.839	0.839	0.839
FARNSLEY 2	LG&E	0.716	0.716	0.716
HIGHLAND 2	LG&E	1.432	1.432	1.432
HILLCREST 2	LG&E	1.050	1.050	1.050
KENWOOD 1	LG&E	0.934	0.934	0.934
LOCUST 2	LG&E	0.645	0.645	0.645
MUD LANE 6	LG&E	1.147	1.147	1.147
OKOLONA 1	LG&E	0.698	0.698	0.698
OXMOOR 1	LG&E	1.088	1.088	1.088
SEMINOLE 4	LG&E	0.656	0.656	0.656
SMYRNA 1	LG&E	0.764	0.764	0.764
WATTERSON 4	LG&E	1.195	1.195	1.195
WATTERSON 5	LG&E	0.626	0.626	0.626
	Total (MW):	25.466	27.435	27.435

This study assumed Net Metering would be available to eligible customer-generators on a first-come, first-served basis up to a cumulative capacity of 1% of the utility's single hour peak load in Kentucky during the previous year. It is expected that LG&E NM DER generation will reach this peak by 2027, therefore the NM DER generation for LG&E included in the models is held constant starting in 2027. KU NM DER generation is expected to reach this peak by 2030, therefore the NM DER generation for KU included in the models is held constant starting in 2030.

System Models

The most current (revised March 26th, 2025) 2026 Transmission Expansion Plan ("TEP") models (WITH-DER) were selected to perform this study. Winter peak models were not analyzed due to the expectation that DER generation output would be 0% during this time.

- **2027 summer peak (50/50) –** two-year model; peak demand scenario represents 50% probability of load being higher than forecast and 50% probability of load being fewer than forecast.

- **2027 summer peak (90/10) –** two-year model; peak demand scenario represents 10% probability of load being higher than forecast and 90% probability of load being lower than forecast.

- **2030 summer peak (50/50) –** five-year model; peak demand scenario represents 50% probability of load being higher than forecast and 50% probability of load being fewer than forecast.

- **2030 summer peak (90/10) –** five-year model; peak demand scenario represents 10% probability of load being higher than forecast and 90% probability of load being lower than forecast.

- **2035 summer peak (50/50) –** ten-year model; peak demand scenario represents 50% probability of load being higher than forecast and 50% probability of load being fewer than forecast.

- **2035 summer peak (90/10) –** ten-year model; peak demand scenario represents 10% probability of load being higher than forecast and 90% probability of load being lower than forecast.

The first step in the study process was to modify the models above to represent the described scenarios as if NM DERs did not exist (W/O-DER). This included increasing the load by the NM DER generation amount for each for the 27 delivery points with 1 MW or more of NM DER generation.

Study Analysis

Once the "W/O-DER" models were created to include the increased load forecast due to no NM DERs P0, P1, and P3 analyses were conducted on each of the models. These select analyses were chosen because the vast majority of LG&E/KU TEP Projects are a result of these analyses.

P0 is a simulation of the normal operating system with no contingencies.

P1 is a simulation of a normal operating system with a single contingency including loss of a generator, transmission circuit, transformer, or shunt device.

P3 is a simulation of the loss of a single generator unit, followed by system adjustments. Once the generator outage is simulated followed by system adjustments, all P1 contingencies were simulated. This includes a second generator, transmission circuit, transformer, and shunt devices on bulk electrical system contingencies.

This study included all contingencies and monitored elements that are consistent with the LG&E/KU TEP and Transmission Service Request (TSR) studies. The objective of the contingency analysis is to identify any overloads or voltage violations on all monitored elements which have been significantly impacted.

A thermal loading impact is considered a significant impact, per the LG&E/KU TSR Study Criteria, when both of the following are true:

- 5% or more of the subject TSR is found to detrimentally impact an overloaded facility under system intact conditions or if 3% or more of the subject TSR is found to detrimentally impact an overloaded facility under contingency conditions.
- If the total impact on a facility due to the TSR(s) under study is more than or equal to 2 MW.

A voltage impact is considered a significant impact, per the LG&E/KU TSR Study Criteria, if the impact is 1.0% or more and the bus voltage is found to be outside of acceptable voltage guidelines.

Study Results

The P0 and P1 simulations showed no MVA flow or voltage violations without the NM DERs.

The P3 simulation showed no MVA flow or voltage violations without the NM DERs in the Summer 50/50 model.

The P3 simulation showed the potential for an MVA flow and voltage violation in the Summer 90/10 model in 2030 and 2035 without the NM DERs. However, neither was significant and would not be attributed to the absence of NM DER generation.

The MVA flow violation in the table below would not be considered a significant impact caused by the NM DER generation due to the MW impact on the transmission line being less than 2 MW.

Facility	Worst Contingency	Worst Dispatch	Rating (MVA)	WITH DER - 2030		W/O DER - 2030		MW Impact	WITH DER - 2035		W/O DER - 2035		MW Impact
				Flow (MVA)	% of Rating	Flow (MVA)	% of Rating		Flow (MVA)	% of Rating	Flow (MVA)	% of Rating	
Ghent to Owen County Tap 138kV	None	None	208	208.37	100.2%	208.6	100.3%	0.23	207.71	99.9%	208.3	100.1%	0.59

The voltage violation in the table below would not be considered a significant impact caused by the NM DER generation due to the voltage impact on the transmission bus being less than 1%.

Facility	Worst Contingency	Worst Dispatch	WITH DER - 2030	W/O DER - 2030	Voltage Impact - 2030	WITH DER - 2035	W/O DER - 2035	Voltage Impact - 2035
Magazine 138kV	Magazine to Waterside	Outage of Cane Run 7	90.04%	89.96%	-0.08%	91.36%	91.33%	-0.03%

Based on the results above, the expected savings on the transmission system upgrade projects due to NM DER generation is $0.