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
PETER W. WALDRAB
VICE PRESIDENT, ELECTRIC DISTRIBUTION
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 Peter W. Waldrab. I am Vice President for Electric Distribution for Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "Companies") and an employee of LG&E and KU Services Company, which provides services to LG&E and KU. My business address is 6900 Enterprise Drive, Louisville, Kentucky 40214. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Please describe your role with the Companies.

A. I have served in my current role since 2022. As Vice President of Electric Distribution, I oversee all electric distribution operations for LG&E and KU as well as transportation and vegetation management. I am a licensed engineer in the State of Pennsylvania and before moving to my current role, I held various roles with PPL Corporation supporting development and implementation of distribution smart grid systems, overseeing reinvestment projects for transmission systems, and supporting the digital transformation of field work.

Q. What is the purpose of your testimony?

A. I will report on the Companies' electric distribution operations and provide operational context to support the Companies' applications for an increase in their electric base rates. I will describe LG&E and KU's recent distribution performance in key operational areas and provide details on what LG&E and KU are doing to operate safely and deliver reliable power to customers in Kentucky at a reasonable cost. I will report on the results of the Companies' investments in Distribution Automation (DA) and other reliability and resiliency programs. I will report on the Companies' updated modeling for evaluation of capital expenditures outlined in the Distribution System Hardening and Resiliency Plan ("DSHARP"). I will review other capital expenditures and discuss the status of the Companies' plans for vegetation management and wildfire mitigation. I will also summarize the actions taken by the Companies to ensure the distribution system is prepared to handle emerging grid challenges, including electric vehicle charging and the increase of Distributed Energy Resources (DER) on the system. I will briefly report on the status of the Companies' AMI deployment and discuss the Companies' analysis regarding avoided distribution capacity cost arising from Rider NMS-2 net metering.

I will also provide support for two specific requests in the Companies' applications: (1) request to establish regulatory accounting treatment for storm restoration and vegetation management costs; and (2) request to deviate from the voltmeter requirements of 807 KAR 5:041, Section 7.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit PWW-1	Map of KU and LG&E Distribution Lines in Kentucky
Exhibit PWW-2	Distribution System Hardening and Resiliency Plan (DSHARP)
Exhibit PWW-3	Effects of Distributed Generation on Distribution & Transmission

DISTRIBUTION SYSTEM OVERVIEW, SAFETY AND PERFORMANCE

Q. Please describe the Companies' distribution operations in Kentucky.

A. The Companies' distribution business serves just over one million electric customers in nearly 80 Kentucky counties as well as five counties in southwestern Virginia.

The combined service area, including Kentucky and Virginia, covers approximately 7,686 noncontiguous square miles. KU's territory includes 15,700 non-contiguous miles of overhead distribution lines, many in rural and mountainous areas, and 460 distribution-level substations. LG&E's territory includes 1,700 miles of overhead distribution lines and 97 distribution-level substations. The net book value of the Companies' total distribution plant is approximately $3.4 billion as of the end of 2024, compared to a net book value of approximately $2.5 billion as of the end of 2020. A map showing the Companies' distribution lines and distribution service territory is attached to my testimony as **Exhibit PWW-1**.

Q. What are the Companies doing to promote safe work of Distribution employees and contractors?

A. The Companies have implemented a number of institutional changes and programs to promote the safety of employees, contractors, and members of the public. For example, the Companies have centralized Safety as a department with their parent company PPL, which has enabled more effective sharing and training on safety best practices and safe work across the operating companies. The Companies now have access to a dedicated Public Safety Team focused on education and public safety practices, as well as a Work Procedures team dedicated to documenting best practices for various roles within the organization. The Companies have shifted pay-for-performance metrics away from recordable incident rates and toward incentivizing safe behaviors, including training and encouragement to report safety observations and all manner of safety incidents, including positive behaviors and near misses, not just recordable injuries. The

Companies have also engaged a third-party consultant to help implement industry best-practice tools and advise them on safety programs and priorities.

Q. Are there any specific areas of safety focus for Distribution Operations?

A. While all aspects of the Companies' safety program, including those described above, are of the utmost importance, Distribution Operations has recently focused on reducing and eliminating serious injuries and fatalities (SIF). To support this effort, Distribution Operations has emphasized three core areas:

- Improving the frontline field workers' capability for identifying and mitigating jobsite hazards;
- Embedding a safety culture focused on continuous safety improvement; and
- Improving consistency of contractor oversight.

Q. Have these safety practices translated into good safety performance by the Companies' Distribution employees and contractors?

A. Yes, the Companies' distribution employees and contractors have been performing safely due to the Companies' strong emphasis on and commitment to safe work, especially in reducing serious injuries and fatalities. For the four-year period from 2021 through 2024, Distribution employees achieved an average employee days away/restricted transferred per 200,000 hours worked ("DART") rate of 0.84. For that same period, distribution contractors achieved a DART rate of 0.43, over millions of total hours worked. These numbers compare favorably to Bureau of Labor Statistics averages for Utility Electric Transmission and Distribution, which reported an average DART of 1.0 in 2023.[1]

There were also a number of safety milestones achieved by distribution employees in 2024, including 8 years with no recordable injuries in London Operations (15 years since the last lost-time injury), 5 years with no recordable injuries in Harlan Operations (16 years since the last lost-time injury), and no recordable injuries for Vegetation Management employees for the past sixteen (16) years. These milestones are a testament to the Companies' overall safety culture.

Q. How do the Companies measure their distribution reliability performance?

A. The Companies assess the reliability of their distribution system through performance metrics such as System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI"). SAIDI measures the average electric service interruption duration experienced by customers in minutes. SAIFI measures the average electric service interruption frequency experienced by customers. The Companies generally use an industry-standard IEEE 1366 '2.5 beta' method for reporting SAIDI and SAIFI. This method excludes Major Event Days (aka MEDs) to allow more consistent year-to-year comparisons. MEDs most frequently occur during severe weather events that often result in widespread service disruptions, as opposed to "blue-sky" outages, which are more indicative of how the system performs under normal operating conditions. I will report reliability numbers following this IEEE method unless otherwise noted.

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

Through targeted and carefully planned investments over the past 15 years, the Companies have achieved a reduction of the frequency and duration of disruptions on the distribution system by 47% and 39%, respectively. System-wide, the Companies' average SAIDI, excluding major-event days, was reduced from just under 95 minutes, for the four-year period from 2016 through 2019, to just under 78 minutes for the ensuing four-year period from 2020 through 2023. This resulted in a nearly 18 percent reduction in average SAIDI just between these two four-year periods. In calendar year 2024, the Companies' distribution operations continued to achieve very strong distribution system SAIDI of 82.834 minutes and a SAIFI of 0.756. The investments and enhancements the Companies have made in the distribution system to improve reliability and resiliency over the past fifteen years have resulted in the Companies achieving at or near top quartile reliability performance nationally.

Q. How have the Companies achieved greater reliability and resiliency of the distribution system in recent years?

A. As the Companies have previously reported to the Commission, we have achieved significant success in improving reliability with legacy capital improvement programs, including the Distribution Reliability and Resiliency Plan ("DRRP"). DRRP consisted of three major components: (1) Distribution Automation; (2) replacement of aging infrastructure; and (3) circuit hardening. The kinds of investments included in DRRP have a proven track record of success in improving reliability and many have been continued through today.

Q. Please summarize the Distribution Automation program and its impact on system reliability.

A. The Distribution Automation ("DA") program ran from 2017 through 2022. It involved the extension of intelligent control over electrical power grid functions to the distribution system level. DA includes the installation of Supervisory Control and Data Acquisition ("SCADA") capable electronic reclosers on the distribution grid, implementation of distributed SCADA software to monitor and communicate with the reclosers, and deployment of an Advanced Distribution Management System ("aDMS") to fully integrate and provide intelligent control over the reclosers. The additional SCADA-enabled reclosers installed under the DA program reduce the number of customers impacted by any fault, as the Companies are able to better sectionalize circuits. These intelligent reclosers then communicate with the aDMS to automatically fault-locate, isolate, sectionalize, and restore (aka FLISR) self-healing outages in minutes. The DA program now directly benefits approximately 45% of the Companies' distribution circuits and more than 80% of customers. Since implementation began in 2017, the Companies estimate that the DA program has saved more than 440,000 customers interrupted (CI) and 31.7 million customer minutes interrupted (CMI), excluding MEDs.

Q. Please summarize what the Companies have done to replace aging infrastructure and the impact on system reliability and resiliency.

A. Between 2021 and 2024, the Companies inspected 194,721 poles and proactively replaced 34,000 wood distribution poles and treated an additional 73,000 poles. Proactive replacement of wood distribution poles avoids unplanned outages and hardens the distribution system against severe weather. The Companies have also replaced nearly a quarter of its fleet of legacy oil, air-magnetic and vacuum circuit breakers since 2019. Circuit breakers automatically interrupt powerflows and protect critical infrastructure in response to faults. Proactively replacing these circuit breakers reduces the likelihood of equipment failure interrupting customers, and also provides efficiency benefits, as vacuum circuit breakers require less maintenance than legacy oil or air-magnetic circuit breakers.

From 2020 through 2024, the Companies have also replaced more than 3,000 legacy electromechanical, solid-state and microprocessor relays with new microprocessor relays, and have installed an additional 340 microprocessor relays as part of new or expanded substations or circuits. The Companies have replaced half of the relays on our system as a result of this program. Microprocessor relays offer advanced features such as fault locating, event logging and alarming, control capability, and advanced metering functionality. These advanced features provide opportunity to improve system reliability, enhance worker and public safety, and contribute to greater operational efficiencies. They also enable connectivity with the DMS and DSCADA applications deployed as part of the Distribution Automation program, providing greater centralized operability, monitoring, and control of the distribution grid.

Distribution Operations' substation transformer contingency program addresses distribution substation transformers that cannot be fully restored in the event of an outage or failure, which can lead to prolonged outages. Since inception, the number of transformers considered "at risk" has been reduced from 484 to 358 across the Companies' distribution system. This removal of 126 transformers from the "at risk" list represents a 26% reduction in the number of electric distribution substation transformers exposed to prolonged outages due to equipment failure.

Q. Please summarize the Companies' circuit hardening efforts and how they have positively impacted system reliability and resiliency.

A. Circuit hardening has been performed on certain lower-performing circuits that have a history of more frequent outages than average. Hardening investments have focused on rear-easement hardening, storm guying, use of stronger and higher-standard poles, targeted undergrounding, conductor upgrades for undersized wire, and circuit relocations where lines are in problematic areas. Over 71 miles of distribution lines have been hardened against severe weather from 2021 to 2024 through targeted reliability and resiliency programs.

Q. What trends have the Companies identified concerning distribution reliability performance?

A. As noted previously, the Companies have significantly reduced the frequency and duration of outages through the investments made. At the same time, the Companies are seeing the customer outage impact from severe weather events increase. Over the past decade, the average interruption duration inclusive of MEDS (all-in SAIDI) has increased by 200 minutes. Customers are experiencing more frequent storms, with more severe impact, especially since 2020. In early March 2023, for example, straight line wind storms with wind speeds up to 70 mph in Kentucky caused roughly 400,000 Kentuckians to lose power. In 2024, the remnants of Hurricane Helene caused more than 250,000 Kentuckians to lose power. In May 2025, a severe windstorm produced 80+ mph winds and multiple tornadoes, including an EF-4 which impacted Russell, Pulaski, and Laurel counties, and in addition to the devastating loss of life and property, collectively caused more than 120,000 Kentuckians to lose power. These severe weather events cause damage that can take days to restore, even with mutual assistance resources from neighboring states, and cause significant economic impact. This problem is not isolated to the Companies' operations and is consistent with a larger trend affecting utilities nationwide. Nationally, customers are losing power more often (+36%) and for longer (+50%) due to severe weather when comparing the five years from 2013-2017 to the five years from 2018-2022.[2]

Q. What is the disruption and economic impact of severe weather events and associated major-event days on the Companies and their customers?

A. Over the past ten years, the worst ten percent of storms cost approximately $120 million in restoration expenses and accounted for 30 percent of customer outage minutes. The remaining 90 percent cost $87 million and accounted for the remaining 70 percent of customer outage minutes. Thus, the most severe storms and widespread outages have a disproportionate impact on the overall reliability of the distribution system.

Beyond restoration costs, severe weather outages impose tremendous economic costs on customers. The Companies use a Department of Energy (DOE) Interruption Cost Estimate (ICE) calculator to estimate the cost of interruptions on customers. The calculator takes into account factors like value outage duration, power usage, and customer type. Using certain key assumptions as described in DSHARP, the total economic cost of these outages to the Companies' customers, per the ICE calculator, is estimated at more than $800 million per year.[3]

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[2] Annual Electricity Power Industry Report, EIA Form 861, detailed data workbooks.
[3] See DSHARP, Exhibit PWW-2, for an explanation of how this amount was calculated.

Q. How are the Companies addressing the threats and costs brought on by more extreme weather events?

A. In 2024 the Companies adopted more stringent design standards to ensure that new facilities are better able to withstand severe weather. Beginning in 2023, prompted by the occurrence of a number of significant severe weather events like those described above, the Companies undertook to study their design standards to determine whether those standards were appropriate. The Companies studied actual weather patterns from KY Mesonet and other data sources, and consulted with the Electric Power Research Institute (EPRI) to test the resilience of various design standards to those weather patterns. The Companies concluded that the NESC design criteria used by the Companies for electric distribution facilities for many years was no longer appropriate based on the occurrence of numerous wind and ice events that exceeded those standards. Accordingly, in 2024 the Companies changed their design standards for distribution to add compliance with NESC Rule 250C "Extreme Wind Loading". The Companies further opted to reference NESC Rule 250B heavy-loading criteria for radial ice accretion. These criteria effectively require any new facilities to be capable of withstanding a minimum of 100mph 3-second wind gusts and 0.5 inches of radial ice loading, compared with 40mph 3-second wind gusts and 0.25 inches of radial ice loading under the prior design criteria. The hardening of the system through enhanced design criteria will significantly improve the ability of the system to withstand extreme weather events occurring with increasing severity in the Companies' service territory.

The Companies have also applied new and innovative methods to assess the costs and benefits of improvements to distribution infrastructure to guide their investment strategy and improve all-in reliability. These methods resulted in the development of the DSHARP.

DISTRIBUTION SYSTEM HARDENING AND RESILIENCY PLAN

Q. Have the Companies developed a plan to address reliability improvement and harden the system against major-event day outages?

A. Yes, the Companies have recently developed a comprehensive plan to continue reliability and resiliency improvements in a manner that is cost-effective and will harden the distribution system and improve overall reliability including major-event day reliability. The plan is called Distribution System Hardening and Resiliency Plan ("DSHARP"). A copy of the DSHARP is attached to my testimony as **Exhibit PWW-2**.

Q. What is DSHARP?

A. DSHARP is a portfolio of investments in system hardening and resiliency designed to improve distribution reliability, including MEDs, by 39% over a 10-year rolling average. The investments included in the DSHARP portfolio include:

- Installing additional remotely operable distribution reclosers, expanding the Distribution Automation (DA) program to enable more targeted fault sectionalization and expand self-heal capability to more feeders;
- Building distribution circuit ties to enable self-heal capability on circuits that don't already have tie capability;
- Targeted hardening of existing overhead distribution lines, including the use of spacer cable in high-risk areas; and

- Targeted undergrounding of existing overhead distribution lines in high-risk, difficult to restore areas.

Q. What makes DSHARP different from the Companies' previous distribution reliability programs?

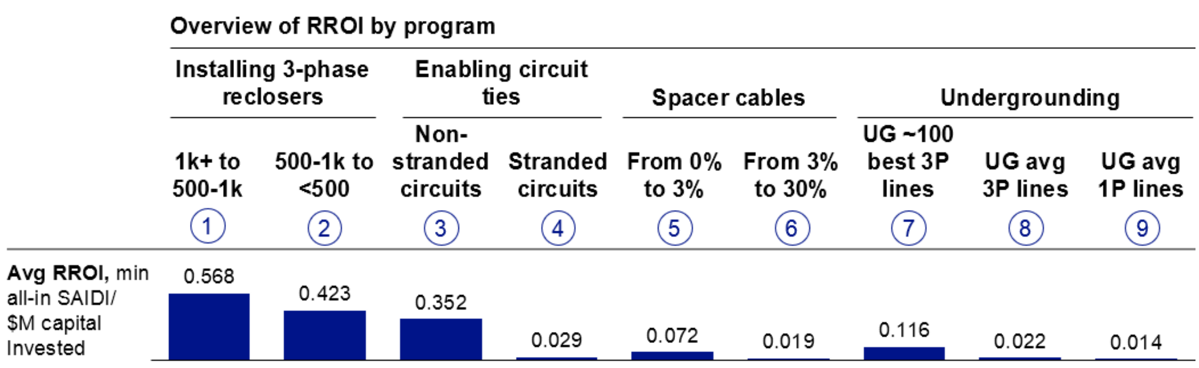
A. The Companies have previously used historical performance data to identify outage trends and prioritize reliability investments. This approach has proven to be very effective for common outage drivers that are predictable, such as routine weather, vegetation, and animal interference, and has been the basis for investment programs such as DRRP. As I discussed above, those investments have been tremendously successful in improving non-MED reliability at a reasonable cost, enabling significant improvements in outage frequency and duration. This approach is less effective, however, at prioritizing investments that mitigate low-frequency high-impact events, such as severe weather events. With DSHARP, the Companies have applied a more sophisticated modeling approach to investments focused on resiliency, i.e., improving the ability of the system to withstand storms and extreme weather events. This approach will reduce the number of customers disrupted by severe weather events and enable the Companies to restore those customers affected more quickly.

Q. What methodology did the Companies apply to select the investments included in DSHARP?

A. The Companies applied a 3-step methodology to select the investments included in DSHARP. First, the Companies set a risk baseline for performance over the past eleven years, breaking down recorded outages by location, cause, and type of equipment involved in the outage. Second, the Companies modeled the risk benefits of a specific intervention by comparing the performance of a given circuit during storm events with that intervention to one without it, based on the Companies' historical experience and data. To normalize for other factors, the Companies only compared circuits with like characteristics including geography and number of customers served by that circuit. The risk reduction benefits were then divided by the annualized cost of the intervention over its lifetime. Third, the Companies applied a "risk return on investment" number for each type of investment by circuit, using the inputs from Steps 1 and 2 and further considering the viability and cost of making the intervention on specific circuits and feeders.

Q. Please summarize the outcome of DSHARP's risk-return on investment methodology.

A. By applying the steps described above, the Companies were able to clearly calculate and prioritize the risk return on investment for each specific type of intervention. The results were as follows:



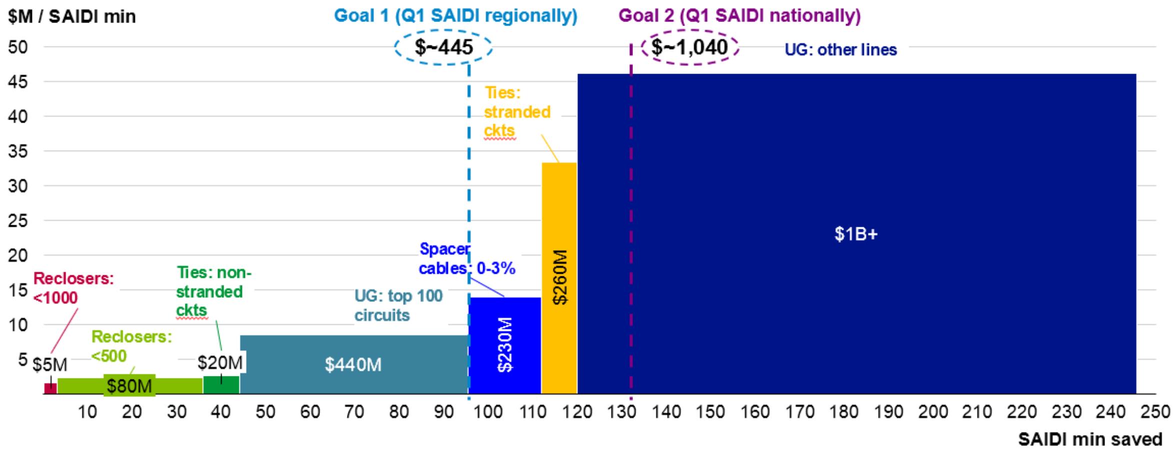
Thus, the model concluded that the greatest risk return per dollar invested can be achieved by further segmenting circuits by installing 3-phase reclosers. Reclosers have proven to be effective at improving both MED and non-MED reliability by reducing the number of customers affected by a given fault or outage. In fact, there are roughly

57% fewer customer interruptions (non-MEDs) on circuits that are fully segmented (500 or fewer customers) than on circuits that are segmented to 1,000 or more customers. Because installation of reclosers is relatively less expensive than interventions like undergrounding of circuits and because the reliability benefits of adding reclosers are high, the model prioritized these investments as having the greatest RROI.

As the graphic above indicates, installing circuit ties on non-stranded circuits (circuits requiring installation of only a recloser to tie to another circuit) was found to have the next most favorable RROI, followed by strategic and limited undergrounding of relatively lower-performing, mostly overhead circuits (top 100 most cost-effective projects), and spacer cable retrofits on lines with less than 30 percent spacer cable coverage. The DSHARP paper describes these results in detail.

Q. How do the Companies plan to structure their distribution investments based on the outcome of the DSHARP modeling?

A. The Companies plan to make investments identified by DSHARP's modeling by implementing the most cost-effective interventions first. The following chart summarizes the estimated cost of each intervention and its corresponding cost-effectiveness, stated in million dollar per SAIDI minute reduction achieved:



Thus, by further segmenting circuits, installing circuit ties on non-stranded circuits, and undergrounding the top 100 most cost-effective circuits, the Companies could achieve a roughly 40 percent reduction in "all-in" SAIDI including major-event days. The estimated total cost of those investments is $445 million, of which approximately $121 million is planned to be spent through the forecasted test year. However, the corresponding economic cost savings derived from that $445 million in investment according to the ICE calculator described above, would total approximately $312 million annually (39% savings from $800 million in economic impact) assuming a 96-minute reduction in "all-in" SAIDI. Should the Companies proceed with the investments to the right of blue dashed line in the chart above, a roughly 55 percent reduction in current all-in SAIDI could be achieved, consistent with first quartile performance nationally. The Companies plan to continuously evaluate the prudency and RROI of those investments as the more cost-effective investments are made first.

<u>OTHER DISTRIBUTION CAPITAL INVESTMENTS</u>

Q. Aside from the programs that are part of DSHARP, are there other significant capital investments the Companies are making in their distribution systems?

A. Yes, in addition to DSHARP, the Companies are continuing investment in proven programs that have a demonstrated and direct positive impact on reliability, including those programs I described earlier in my testimony. These include: (1) continued inspection, maintenance and, where necessary, replacement of aging infrastructure; (2) construction of new distribution infrastructure to meet customer demand; and (3) maintaining ongoing operations in the face of dramatically rising material and labor costs.

Q. Please highlight some of the Companies' ongoing aging infrastructure replacement programs.

A. ***Pole Inspection and Treatment Program***

The Companies have allocated about $10 million for the Pole Inspection and Treatment Program ("PITP") in 2025. PITP is consistent with prudent industry practice for maintaining pole assets. By intervening with inspections, treatment and, where necessary, replacement of aging wood poles, the Companies avoid costly pole failures and corresponding outages. Throughout 2025 the Companies estimate that 1,000 distribution wood poles will be replaced because of PITP. Without intervention and corrective action, those poles are projected to fail within the next two years. During a pole-failure outage, the time required to restore the outage is nearly 2.5 times that of an outage for planned pole replacement work.

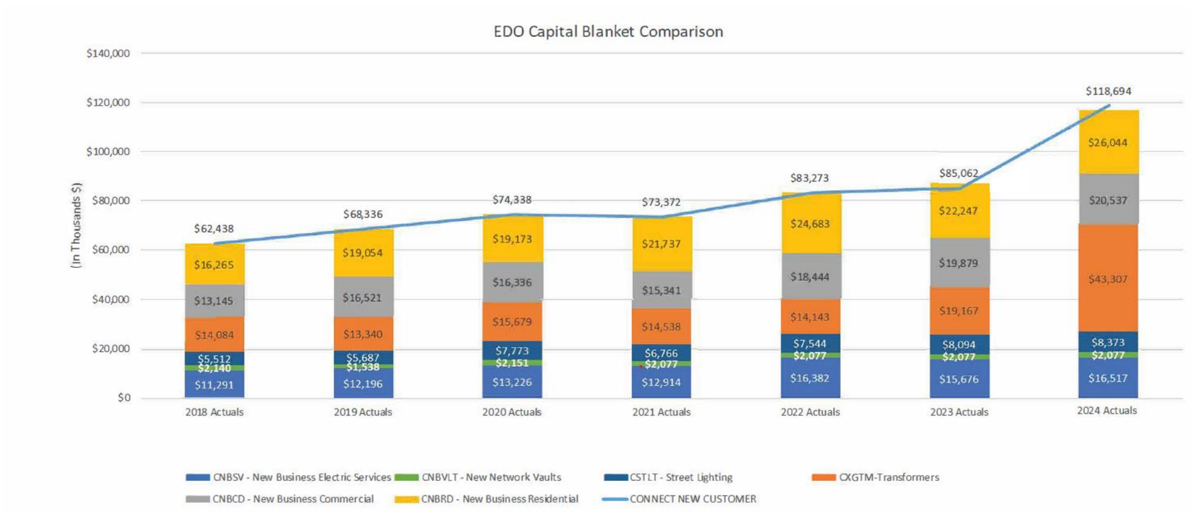
4kV Transformer Upgrade Program

The average 4kV transformer in LG&E's fleet is 63 years old, with the oldest being 95 years old. The aging 4kV system has exceeded its planned useful life and maintenance costs are expected to increase as equipment failures increase. The 4kV system is also limited insofar as much of the equipment is not SCADA-enabled and cannot interconnect with the broader 12kV network, meaning that the self-healing benefits realized on the 12kV network cannot be realized on the 4kV network. To avoid those equipment failures and associated interruptions and costs, the Companies plan to replace 24 existing 4kV substations (37 total transformers) with 3 new 12kV substations (4 new 12 kV transformers) and associated circuit work. These upgrades will allow the expansion of the Companies' smart grid programs into new areas and allow for faster responses to outages.

The Companies expect to spend $4.5 million in capital in 2025 on this project, with a time horizon to complete 12kV conversions through 2039. After the conversions are completed, customers formerly served by these 4kV circuits will be able to reap the benefits of smart grid investments being made by the Companies, including FLISR, volt-VAR optimization, and fault location analysis.

Q. Please summarize how new business growth and large projects are driving additional investment in the distribution system.

A. Distribution Operations has experienced continued escalation of new business investment over the seven-year period from 2018 through 2024:



While some of the increases are attributable to rapidly rising material costs, which I address below, there is also steady growth in customer counts for residential, commercial, and industrial customers, and the investment required to serve those new customers has increased in proportion to that growth. The increase in new business has also caused the Companies to plan additional substation and circuit work to accommodate additional load.

Q. Are the Companies also facing rising labor and material costs to support new business growth and maintain the distribution system?

A. Yes, the Companies have experienced both significant wage increases and increases in the price of materials, particularly transformers. Line technicians make up the largest portion of internal and contracted Electric Distribution Operations workforce. The labor market for these skilled positions is increasingly competitive, with contractors and other utilities offering increased wages, more benefits, and flexible work schedules that are more attractive than ever before. This is, in part, driven by the emergence of storm aggregators within the industry. These storm aggregators service the industry's need to rapidly scale line technician resources during storm events by pooling resources and deploying them nationally where needed, but at premium rates relative to local internal and contract personnel. Storm aggregators have indirectly driven up prevailing wages for line technicians. The Companies increased wages from seven to eleven percent for distribution line tech employees just since the beginning of 2023 in order to stay competitive at attracting and retaining skilled labor. Labor rates for contractors performing overhead line construction have also increased by an average of nearly 17 percent from 2020-2025.

Costs for equipment and materials have risen even more dramatically than labor costs – resulting in near-unprecedented increases over the past five years. For example, the average price of a pole mount transformer from certain suppliers has nearly doubled between 2021 and 2024, with some increases even greater than 100 percent. The average price for pad mount transformers has increased in similar fashion, with price increases upwards of 100 percent during the same period. In a single year, from 2022 to 2023, the average cost of a single-phase pad mount transformer from one vendor increased nearly 200 percent. The rising cost of doing business due to market forces is unavoidable and the Companies cannot compromise on the quality of their labor force or materials in order to continue to deliver safe and reliable power to Kentucky customers.

DISTRIBUTION CAPITAL SUMMARY

Q. Please summarize the amount of capital the Companies are investing in their distribution system.

A. For the period from January 1, 2022 to June 30, 2026, the Companies have spent or plan to invest $1.5 billion in capital in their distribution system, broken down by company in the following categories:

Category	**LG&E**	**KU**	**Total ($mm)**
Connect New Customers	$193	$373	$566
Enhance the Network	$139	$207	$346
Maintain the Network	$187	$173	$360
Repair the Network	$105	$120	$225
Miscellaneous	$6	$10	$16
Total	**$630**	**$883**	**$1,513**

<u>VEGETATION MANAGEMENT / STORM RESTORATION</u>

Q. Describe the changes to the Companies' vegetation management program since the last base rate cases.

A. Historically the Companies have managed vegetation through separate operations housed within transmission and distribution, respectively. Due to organizational changes in 2024, however, both transmission and distribution vegetation management are now under my supervision. In the past several years, the Companies have been able to achieve cost savings in distribution vegetation management through a combination of factors, including: (1) removal of hazard trees simultaneously with routine cycle maintenance work; (2) closer evaluation of "off-cycle" clearing and line maintenance work with professional arborists; (3) arborist evaluation of need for clearing secondary lines versus automatic cycled clearing of those lines; and (4) emphasis of customer maintenance and responsibility of vegetation around service wires on customer property.

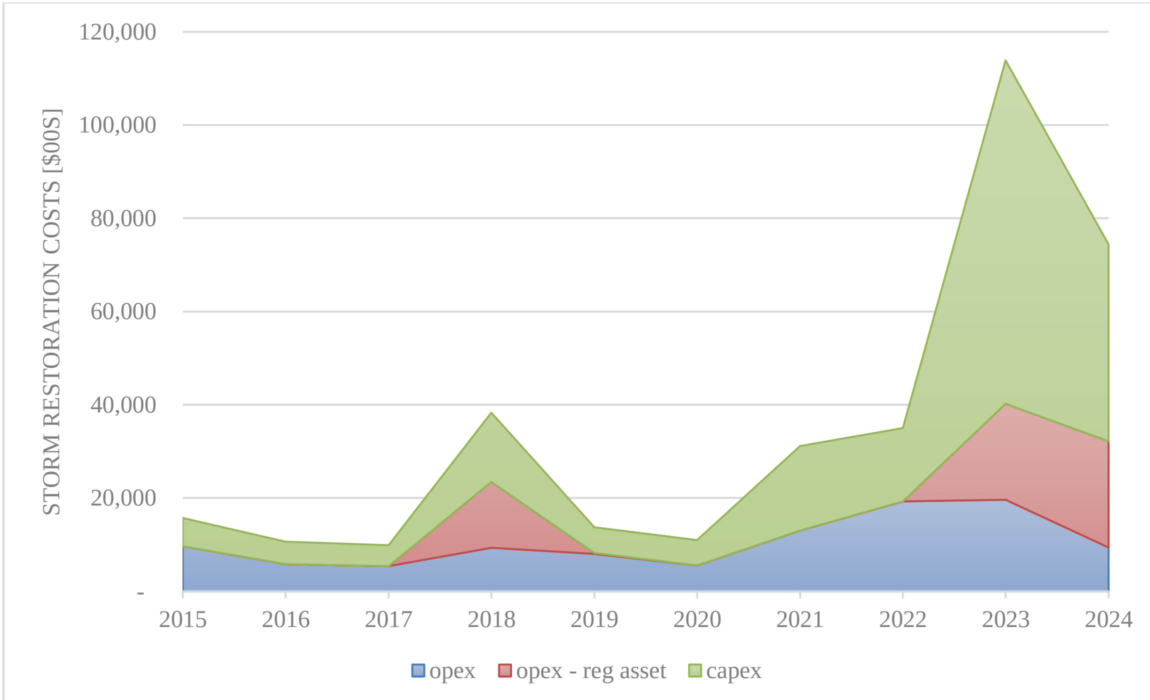
Likewise, the Companies have been able to achieve efficiencies and cost savings in transmission vegetation management in recent years because the vast majority of the right-of-way reclaim contemplated by the Transmission System Improvement Plan ("TSIP") was completed in 2022, allowing the Companies to transition from more costly "reclaim" activities to cycle-based maintenance activity in 2023 through this year. The Companies have also been able to strategically utilize more herbicide control of vegetation growth in the right of way, which reduces physical clearing expenses.

Q. Does the Companies' approach to vegetation management for transmission and distribution facilities continue to evolve?

A. Yes, the Companies strive to achieve leading industry practice for safe, reliable, and efficient maintenance of rights-of-ways. The Companies have been expanding use of herbicide where feasible to manage growth and extend the benefits of each trim cycle. The Companies have extensively explored opportunities for use of data and analytics to inform the vegetation management programs and have adjusted approaches to explore innovative technologies. Some of these efforts have proven fruitful, such as the Companies' vegetation risk model, which predicts the likelihood and consequence level of vegetation impacting overhead lines, informing the trim focus areas and targeted tree removals. Others were found to not yet be mature enough for usage, such as satellite-based imaging being used to detect individual tree species and growth rates. Following the development of the DSHARP investment plan focused on grid resilience, the Companies undertook an internal and industry benchmarking effort in late 2024 and early 2025, seeking to optimize its vegetation management programs for safety, reliability, resiliency, and efficiency. Through this effort, the Companies found that an optimal vegetation management program is one where clearance is maintained between lines and trees through cycle-based trim program, coupled with reliability enhancing efforts. These reliability enhancing efforts include targeting dead and dying trees for removal, corridor widening between the substation circuit breaker and the first downstream reclosing device, where customer impact from trees is greatest, and off-cycle targeted trimming where reliability issues are observed. The Companies have reflected this approach in a pro forma to its most recent budget, increasing expenditures in routine trim consistent with leading practices, and expanding expenditures in reliability enhancing efforts. Taken in conjunction with the infrastructure investments in storm hardening and resilience, these efforts are expected to significantly reduce the impact of severe weather to ratepayers.

Q. Are the Companies proposing regulatory deferral accounting treatment for storm damage restoration and vegetation management costs in these cases?

A. Yes. As noted in the testimony of Robert M. Conroy, the Companies are requesting deferral accounting treatment for these expenses. The costs associated with system restoration from extreme weather events has increased significantly in recent years, as shown in the Table below:



As this chart reflects, storm restoration costs were relatively stable from 2015 through 2020, with the exception of a spike in 2018. During that time period, the average annual capital the Companies spent on storm restoration was roughly $6.8 million and the average annual O&M spent on storm restoration was approximately $9.7 million. But in the past four years, 2021 through 2024, the average annual capital spent on storm restoration has increased dramatically to $37.4 million and average annual O&M has increased to $26.2 million.

These increasing storm-related expenses present challenges to the Companies' ability to predict and manage routine inspection and maintenance expenses. They also present significant administrative overhead. The Companies budget for storm restoration based on a five-year rolling average, adjusted annually. This approach is meant to level out year-to-year variations. In exceptional circumstances, including four severe storms during the period from 2023 through January 2025, the Companies have sought regulatory asset treatment for specific storm restoration costs. The testimony of Christopher M. Garrett details the status of these requests and the regulatory recovery sought and approved for each storm.

While these specific requests for regulatory asset treatment support recovery of expenses associated with the largest storm events during this period, they are not adequate to address the escalating costs of mid-sized storms, exceeding historical budgetary levels, but falling below the threshold for regulatory asset treatment. Accordingly, the Companies request the authority to net actual storm damage restoration and vegetation management costs against the respective amounts in base rates in the forecasted test period, and record a regulatory asset or liability for the difference. This approach preserves transparency of the Companies' storm recovery efforts, increases administrative efficiency, and reduces volatility in the Companies' operations and maintenance expenses. Mr. Conroy's testimony describes the Companies' proposal to regularly report to the Commission on the deferred amounts.

Q. Why are vegetation management expenses included in the Companies' request for regulatory accounting treatment of storm restoration expenses?

A. There is a relationship between storm restoration and vegetation management costs. As vegetation presents the single largest source of outages, particularly during storm events, the Companies expect that the resilience efforts being undertaken by the Companies will reduce future storm costs, thereby reducing reactive vegetation management costs.

WILDFIRE MITIGATION

Q. How are the Companies addressing wildfire risk in their service territories?

A. KU maintains approximately 144 line miles of transmission lines and 460 line miles of distribution lines in Kentucky that are within geographically-designated "high risk" zones for wildfire according to FEMA's national wildfire risk models. Mitigating wildfire risk in these areas is a high priority for the Companies, but there is no "one-size fits all" approach to managing that risk. The Companies have benchmarked extensively with industry groups such as EPRI, EEI, and AEIC on leading wildfire mitigation practices, as well as with utilities in the western United States with greater wildfire experience. There are four areas of focus to the Companies' wildfire mitigation efforts: 1) real-time risk monitoring of wildfire conditions, 2) operational procedures that define how to operate when conditions are favorable for wildfire, 3) infrastructure and maintenance practices that reduce the likelihood of an ignition event, and 4) infrastructure practices that enable the Companies' equipment to withstand wildfires.

By identifying high risk areas and taking a multi-faceted approach to wildfire mitigation in those areas, including circuit hardening, more aggressive hazard tree management, and operational controls, the Companies can help reduce the risk that their facilities are involved in the cause or spread of destructive wildfires.

Q. How are the Companies deploying operational strategies to mitigate wildfire risk?

A. The Companies have introduced an advanced analytics model that predicts the risk of a wildfire occurring based on various data sources such as humidity levels, wind speeds, and other factors. The Companies have also developed and drilled operational procedures for adjusting operational practices during times of elevated risks, such as delaying planned work or suspending reclosing on circuit breakers. The procedures are coupled with a prepared communication strategy to ensure situational awareness within the Companies and with external stakeholders, including customers, regulatory bodies, emergency management teams, and public safety resources.

Q. Please describe the infrastructure and maintenance strategies the Companies are undertaking to mitigate wildfire risk.

A. In addition to increased monitoring and improved data analytics, the Companies are also pursuing a combination of capital investments to harden the system against wildfire ignition and spread and sound vegetation management practices to prevent "fall-ins" of trees onto lines that can produce sparks and serve as ignition source.

Q. How do capital investments like those included in TSHARP and DSHARP mitigate wildfire risk?

A. Rebuilding, hardening, and undergrounding transmission and distribution circuits has risk-mitigating benefits to protect against the cause and spread of wildfires. As Ms. McFarland notes in her testimony, replacement of wood transmission poles with steel structures both reduces the likelihood that structures will fail and cause an ignition to occur, while also reducing the likelihood that utility structures will contribute to the spread of wildfires once started. The same is true for replacement of wood distribution poles with iron, where appropriate. Replacement of bare conductors on primary voltages with covered conductors makes them more resilient against arcing faults from vegetation contacts or trees falling into lines. Telemetered smart grid devices installed on distribution lines can assist with early fault detection and quicker identification of tree or other line strikes that contribute to wildfire risk. Breakaway overhead service connectors can safely de-energize overhead service drops that are brought down by falling trees or other causes. Finally, arc-less lightning arrestors suppress surges from lightning strikes without arcing like traditional lightning arrestors. Where the wildfire risk justifies it based on the location of the project, the Companies are incorporating some or all of these asset-related wildfire protections for new line construction and line rebuilds. Specifically, the Companies plan to perform asset upgrades and hardening to 162 miles of distribution lines in Kentucky in areas designated as "relatively high risk" for wildfires by FEMA. The Companies have planned for approximately $24 million in investment over the next five years to address 28 miles of distribution lines in the "relatively high risk" areas.

Q. How do vegetation management practices mitigate wildfire risk?

A. Routine, cycle-based vegetation management mitigates wildfire risk by keeping vegetation clear of energized lines, thereby reducing the risk of arcing faults. Because faults can also occur from trees falling into the lines from outside of the cleared right-of-way, the Companies are also increasing funding for hazard tree removals on transmission and distribution lines in wildfire high-risk areas. By performing concentrated hazard tree inspection and removal in high-risk areas, the Companies can further reduce the risk that a downed tree causes or contributes to causing a wildfire.

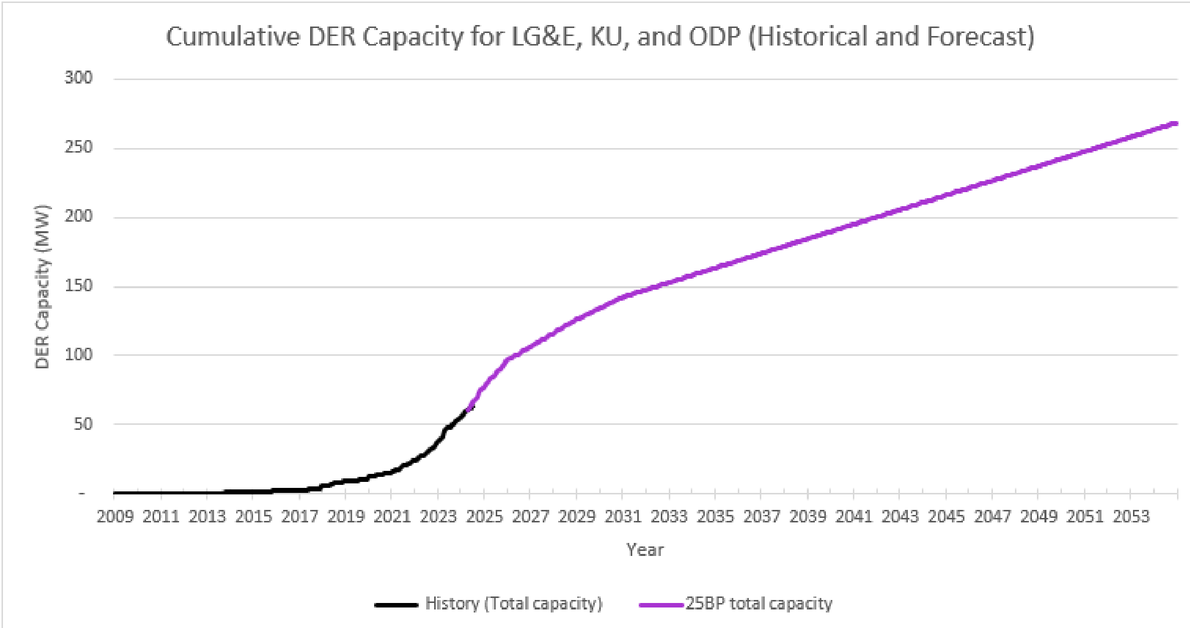
DISTRIBUTED ENERGY RESOURCES AND ELECTRIC VEHICLES

Q. What are the Companies doing to meet future challenges to the grid including vehicle electrification and growth of Distributed Energy Resource (DERs)?

A. In order to support more dynamic resources, such as DERs and electric vehicles (EVs), the grid needs to be smarter. These resources are frequently bi-directional, acting as both sources and loads, where traditional grid assets are designed for single-directional flow. These resources are also difficult to model using classic load modeling techniques. The Companies are participating in industry peer groups—EPRI, EEI, AEIC, SEE, etc—to stay abreast of leading practices. We're adjusting engineering standards where appropriate to better support interconnection of these resources. We're using data from the smart equipment that the Companies are deploying—AMI meters, SCADA-enabled reclosers, microprocessor relays—to provide grid operators and planners with greater visibility into the size and type of resources that are connected, informing grid planning.

Q. Describe the current status of DERs on the distribution system and the expected growth of DERs.

A. The Companies currently serve approximately 69 MW of distributed generation capacity from more than 5,900 unique customers. The Companies process on average between 100 and 250 individual DER interconnection applications per month. Connection of DERs is expected to continue to grow steadily over the next 30 years, as projected in the following chart:



Q. How are the Companies handling customer demand for interconnection of more DERs?

A. The Companies quickly act on new DER interconnection applications, often providing engineering approval in less than two weeks from receipt of an application. Details regarding the DER interconnection process, application forms, frequently asked questions, interconnection rules and standards, and interconnection queues are publicly available on our company website. The Companies continue to assess and adopt leading industry practices around DER interconnection. In an attempt to further streamline the interconnection process, the Companies and their sister utilities in Pennsylvania and Rhode Island are currently researching available options for an online interconnection portal to more efficiently manage and track interconnection applications.

Q. Can DERs provide grid-enhancing benefits?

A. DERs can generally be configured to provide grid services beyond strictly operating as a load or a source. Solar inverters, for example, can be programmed to output at a specific power factor to improve line efficiencies when connected to the grid, allowing more customers to be served before a circuit needs to be upgraded. Behind-the-meter storage can help to time-shift peak loads, improving grid capacity during peak periods, potentially deferring the need for costly capital upgrades to serve load growth. Electric vehicles plugged into chargers can act as both a scalable load and battery storage if configured for vehicle-to-grid services. All of these example use-cases rely on DERs to be dispatchable, however, in order to provide broader grid benefit. The benefit must be timed with the need. Without dispatchability, grid operators must assume worst-case scenarios. The Companies' sister utility, PPL Electric Utilities, are currently conducting a multi-year DER Management System (DERMS) pilot for a subset of its customers in Pennsylvania. This pilot program has customers install utility-provided SCADA modems on DER equipment, enabling the utility's aDMS the ability to perform specific dispatching functions. PPL Electric Utilities have saved customers approximately $20 million in capital and O&M on a $6.5 million investment in capital and O&M through the first two years of the program. The Companies are currently exploring the merits of introducing similar capabilities.

Q. How does Electric Vehicle ("EV") adoption affect the Companies' grid operations?

A. The primary impact from EV charging is at the electric distribution service transformer level, where home-charging can overload service transformers sized for household appliances and heating/cooling loads. The Companies routinely monitor load levels on feeders and feeder components from EVs and other load sources. With new AMI capabilities, the Companies are developing analytics tools to help planners identify from load profiles the size and location of behind-the-meter charging infrastructure, and where upgrades are required to prevent overloads.

Furthermore, in response to the Commission's Order in their 2020 rate cases, in 2022 the Companies submitted to the Commission a whitepaper studying where the Companies could support DC fast charging infrastructure with existing 3-phase electric distribution service.[4] That study concluded that the Companies could host up to 600MW of EV charging load, assuming it was equally distributed. As of March 2025, Kentucky has over 350 public charging stations including 274 Level 2 and 77 DC Fast stations. There are 983 public EV charging ports, 17 Tesla Supercharger stations and 178 Tesla Supercharger ports in Kentucky[5]. The Companies serve electricity to a majority of those publicly available stations. The Companies have also partnered with Edison Electric Institute (EEI) to implement best utility practices for EV adoption, which has resulted in changes to technical standards for sizing of primary and secondary service to better accommodate EV charging infrastructure.

Q. Are the Companies running their own EV charging stations?

A. Yes, LG&E operates ten Level 2 charging stations in its territory and KU operates ten Level 2 charging stations in its territory. In 2024 the Companies installed Level 3 fast

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[4] *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; *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 Meter Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00350, EV Charging Station Location Study, filed June 17, 2022 (Post Case Filings).

[5] Source: Kentucky EV Incentives, Tax Credits and EV Rebates (https://qmerit.com/location/kentucky/).

charging stations in Russell Springs, Kentucky at the Lake Cumberland Tourist Commission and in Louisville at the Norton Healthcare Sports and Learning Center. The Companies also recently installed six Level 3 DC Fast chargers and 52 Level 2 EV chargers at 5 different company facilities to be used by company-owned fleet electric vehicles. The Companies' fleet of electric and hybrid plug-in vehicles now includes 139 fully electric or plug-in hybrid vehicles. This number includes 33 fully electric passenger vehicles and pickup trucks, 1 fully electric bucket truck, and 105 plug-in hybrid pickup trucks and SUVs.

AMI IMPLEMENTATION UPDATE

Q. What is the status of the AMI rollout approved in connection with the Companies' last base rate cases?

A. As the Companies reported in their last quarterly AMI report to the Commission,[6] the timeline for full rollout of AMI meters and associated network equipment to support AMI remains on schedule for the end of 2025. As of March 31, 2025, nearly 1.3 million AMI meters and modules have been installed and 98 percent of planned network deployments have been installed. The first phase of the new aDMS was deployed in March 2025. The second phase of ADMS is expected to be deployed in the fourth quarter of 2025, which will include the Outage Management System (OMS) and other DMS functionality.

[6] *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; *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 Meter Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00350, AMI Quarterly Implementation and Deployment Status Report, filed April 30, 2025 (Post Case Filings).

Q. Please summarize the grid-enhancing benefits of AMI during the rollout and once fully deployed.

A. Fully integrated AMI provides a powerful telemetry tool for monitoring the state of the grid. Data from AMI meters can be used to improve outage detection, grid control, and network planning. Improved outage prediction, management and response is expected to accompany the initial rollout of ADMS and should become measurable after the second phase rollout. The first phase of ADMS rollout also enables conservation voltage reduction (CVR), an optimization tool which manages voltage to improve energy efficiency for residential customers with heavy resistive loads. The second phase of ADMS will introduce 'last-gasp' outage messaging from AMI. This will enable the Companies to identify power outages and predict fault device without relying on customers notifying the Companies of a power outage. Further data use-cases include using AMI data to more accurately model peak circuit loading, point-of-delivery voltages, DER and EV usage patterns, as well as predicting equipment overloads and failures. These capabilities are being introduced through planning models in calendar year 2025.

Q. Please summarize the Companies' request for deviation from compliance with 807 KAR 5:041, Section 7.

A. This regulation requires each electric utility to maintain portable and recording voltmeters and to perform voltage surveys sufficient to indicate the service furnished from each center of distribution, and to maintain at least three (3) years of records for such surveys. The regulation further requires at least one recording voltmeter to be in continuous service at a representative point in the system. The Companies currently comply with this regulation by maintaining 160 recording voltmeters that are utilized at representative points in the system. The annual cost to perform these voltage surveys is estimated to be $100,000. The AMI meters deployed by the Companies are capable of capturing and transmitting voltage data that satisfies the surveying requirements of the regulation. The AMI meters record voltage for every customer every 15 minutes. Meters comply with requirements for 0.2 accuracy class set forth in ANSI C12.20 and readings are retained for 5 years. Further, designated "bellwether" meters used for voltage optimization record voltage every 5 minutes and those records are also retained for 5 years. In essence, the voltmeters required by 807 KAR 5:041, Section 7 are redundant of AMI and add cost. Accordingly, the Companies request a deviation from the requirements of that regulation to allow them to use AMI voltage data to satisfy its requirements, including maintenance of at least three (3) years of voltage records as required by the regulation.

NEW PROGRAMS AND OPERATIONAL EFFICIENCIES

Q. Please describe the planned expansion of the Companies' 811 "Call Before you Dig" Membership.

A. The Companies are currently members of the 811 "Call Before you Dig" program for counties in which they maintain a significant number of underground facilities. Beginning in 2026, the Companies will become 811 members for all of the counties in their service territories. While the Companies have not in the past been able to cost-justify 811 membership in counties where there are not a significant number of underground facilities with low dig-in rates, they recently studied this again and concluded that there is sufficient benefit to justify 811 membership in all counties. The principal benefit of expanding the Companies' 811 membership will be clarifying and streamlining public safety messaging, specifically concerning safe-dig campaigns and providing clearer guidance to customers.

Q. What programs have the Companies implemented to make Distribution Operations more efficient?

A. The Companies have recently implemented an "Edge of Grid Optimization" program, which targets fuses protecting overhead distribution transformers to drive cost efficiencies, improve reliability, and boost customer satisfaction. This program replaces traditional fuses with VacuFuse self-resetting interrupters to bring fault testing technology closer to the grid edge than previously possible. VacuFuse self-resets to avoid the expense of a truck roll and keep the lights on for customers. Much of the savings attributable to the VacuFuse devices will be realized through rural operation centers which are not staffed for 24/7 trouble response, thereby avoiding lengthy after-hours trouble calls. The Companies plan to roll out 2,700 VacuFuse devices annually, resulting in $500,000 in O&M efficiencies each year.

The Companies are also focused on targeted equipment replacement vs. repair as part of field operations when equipment is identified as in need of replacement. Proactive replacement can reduce truck rolls for assets that are frequently in need of maintenance or repair, resulting in long-term efficiencies over the life the asset. Also, as referenced earlier, AMI technology allows operators in the Companies' Distribution Control Center (DCC) to ping meters to determine voltage at the meter and inform the operator if a truck roll is necessary to respond. In some instances, a truck roll can be saved based on the data provide by the AMI infrastructure.

By leveraging efficiency programs like these, the Companies' Distribution Operations have achieved a net savings of operations and maintenance expense of approximately sixteen percent (16%) when comparing 2024 to 2021. The Companies have achieved this net reduction in O&M expense even in the face of steadily rising labor costs for both employees and contractors during this time period.

NMS-2 AVOIDED DISTRIBUTION COST

Q. The Companies provided testimony concerning Rider NMS-2 avoided distribution capacity cost in the Companies' 2020 rate cases,[7] including concerning an appropriate conceptual framework for determining avoided distribution capacity cost arising from net metering.[8] Do you have any fundamental changes to make to that framework?

A. No. The conceptual framework articulated in the 2020 rate cases remains sound with only one minor revision and to clarify that this framework is intended to address avoided distribution capacity cost arising from Rider NMS-2 customers only, not all distributed generation. This clarification is important because the purpose is to formulate an appropriate avoided distribution capacity cost component for Rider NMS-2, not other rate schedules.

With those points in mind, an appropriate conceptual framework for determining avoided distribution capacity cost arising from Rider NMS-2 net metering must account for the following:

[7] Case Nos. 2020-00349 and 2020-00350, Supplemental Direct Testimony of John K. Wolfe (July 13, 2021); Case Nos. 2020-00349 and 2020-00350, Supplemental Rebuttal Testimony of John K. Wolfe (Aug. 5, 2021).
[8] Case Nos. 2020-00349 and 2020-00350, Supplemental Direct Testimony of John K. Wolfe at 1-3 (July 13, 2021).

1. Distribution capacity costs, if any, avoided by Rider NMS-2 customers can include only capacity-related distribution investments made since Rider NMS-2 service began on September 24, 2021, as well as future capacity-related distribution investments. By definition, Rider NMS-2 customers cannot have avoided any embedded distribution cost prior to September 24, 2021; net metering customers taking service prior to that date take service under Rider NMS-1.
2. Distribution components are sized to serve anticipated peak loads and power flows, which can occur at different seasons and times of day for different systems. Therefore, when net metering customers' generation can produce net energy onto the Companies' systems is highly relevant, and particularly whether that net production regularly coincides with the distribution system components' peak loads.
3. The location of energy exports that affect distribution system components affects either the cost or benefit of those exports.
4. Distribution components must perform reliably across a wide range of operating conditions every hour of the year, not just when the sun is shining on a hot day. This includes a broad array of environmental conditions and system contingencies—including the contingency that customers' generating sources might not perform as expected. Therefore, any framework must account for the dispatchability, intermittency, and reliability of Rider NMS-2 net metering customers' generators.
5. Net metering generating facilities are necessarily distributed rather than concentrated due to customer choice and the requirements of the Commission's Net

Metering Interconnection Guidelines.[9] For example, the Guidelines state, "For interconnection to a radial distribution circuit, the aggregated generation on the circuit, including the proposed generating facility, will not exceed 15% of the Line Section's most recent annual one hour peak load."[10] This approach limits (or ideally eliminates) cost incurrence related to net metering, but it also limits (and likely eliminates) savings creation.

6. It must account for the portion of the distribution system that does not vary with demand or does not vary with small changes in demand associated with net exports from net metering customers. And it is important to note that the portion of net metering output that is relevant here is net exports, not the gross output or capacity of net metering systems; Rider NMS-2 customers are already fully compensated for energy they consume by avoiding the retail rate they would otherwise pay to consume that energy from the Companies. Thus, the only question to address here is how much distribution capacity cost, if any, can net exports from net metering customers avoid.

Q. Has anything occurred since the Companies' testimony in 2021 that affects your analysis of avoided distribution capacity cost arising from Rider NMS-2 net metering?

A. Yes. Unlike the 2020 rate cases, at which time there were no Rider NMS-2 customers—all net metering customers were served under Rider NMS (now Rider

[9] *See, e.g., Development of Guidelines for Interconnection and Net Metering for Certain Generators with Capacity up to Thirty Kilowatts,* Case No. 2008-00169, Order Appx. A at 3 (Ky. PSC Jan. 8, 2009).
[10] *Id.*

NMS-1)—the Companies can now know with a much higher degree of certainty three key data points:

1. The *location* of NMS-2 customers. Whereas the location of Rider NMS-2 customers was entirely unknown when the Companies filed their 2020 rate cases, because this class of customers could soon close and no new customers will be served under Rider NMS-2 thereafter, the Companies can now say with greater certainty where Rider NMS-2 customers are and will be as long as they remain on service.
2. The *magnitude* of NMS-2 generation. As of January 1, 2025, KU has 26 MW of net metering capacity, of which 17.5 MW is Rider NMS-2 capacity, and LG&E has 24 MW of net metering capacity, of which 17 MW is Rider NMS-2 capacity. The Companies' 2025 Load Forecast presented by Charles R. Schram projects Rider NMS-2 capacity values will grow to 35.5 MW for KU and 26 MW for LG&E by early 2026.
3. The *type* of Rider NMS-2 generation. Rider NMS-2 customers have exclusively installed solar generation, which affects the timing and conditions under which they can generate.

Q. Informed by the conceptual framework you articulated and the data available to you and your team, have the Companies performed an analysis to the appropriate avoided distribution capacity cost component for Rider NMS-2?

A. Yes. The Companies' analysis in **Exhibit PWW-3** shows the appropriate avoided distribution capacity cost component for Rider NMS-2 is zero because Rider NMS-2 have allowed the Companies to avoid and are not projected to allow the Companies to avoid any distribution capacity costs.

Q. Could distributed energy resources like Rider NMS-2 generation result in avoided distribution capacity costs under the right conditions?

A. Yes, it is certainly possible they could. Other utilities, including the Companies' affiliate utility in Pennsylvania, PPL Electric Utilities, have demonstrated that distributed energy resources can enable avoidance of distribution capacity cost when (1) distributed energy resource penetration is significant and (2) the serving utility can control and dispatch distributed energy resource functions. When distributed energy resources are dispatchable, the serving utility can use them, for example, to time-shift peak demand on circuits nearing capacity to offset the need for capacity upgrades. Dispatchable distributed energy resources can also be used to manage reactive power, reducing the need for investment in voltage regulation and improving circuit capacity.

The Companies do not currently have the capability to dispatch distributed energy resources, but they are exploring these capabilities with industry peers and research groups.

Importantly, though, even if the Companies gain this ability in the future, the appropriate means to compensate participating customers would be through whatever program the Companies offer to incentivize customers, including Rider NMS-2 customers, to participate. Again, the Companies' analysis shows there is no avoided distribution capacity cost resulting from Rider NMS-2 customers' uncontrolled, un-dispatched distributed generation.

CONCLUSION

Q. Do you have any recommendations for the Commission?

A. Yes, I recommend that the Commission approve the Companies' request to establish regulatory accounting treatment for the Companies' storm restoration and vegetation management costs. I further recommend that the Commission grant the Companies' request for a deviation from the requirements of 807 KAR 5:041, Section 7, for the reasons stated in my testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Peter W. Waldrab**, being duly sworn, deposes and says that he is Vice President, Electric Distribution, for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, that he has personal knowledge of the matters set forth in the forgoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Pete W G
Peter W. Waldrab

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of May 2025.

Caroline J. Davison
Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

CAROLINE J. DAVISON
COMM EXPIRES 01/22/2027
NOTARY
PUBLIC
ID #KYNP63286
STATE AT LARGE, KENTUCKY

APPENDIX A

Peter W. Waldrab, PE

Vice President, Electric Distribution
Louisville Gas and Electric Company
Kentucky Utilities Company
6900 Enterprise Drive
Louisville, Kentucky 40214

<u>Education</u>

Bachelor of Science, Electrical Engineering
Penn State University, Aug 2004
Master of Science, Electrical Engineering
Drexel University, May 2013
GE Six Sigma Green Belt: 2007
Tosan Achieving Excellence Program: 2013
PA engineering licensure: 2014
PPL Lean / Six Sigma Black Belt: 2014
PPL Managing People and Processes Program: 2012
PPL Leading People and Processes Program: 2015

<u>Professional Experience</u>

Louisville Gas and Electric Company
Kentucky Utilities Company

Vice President, Electric Distribution Operations	June 2022 - Present

PPL Corporation

Director, Strategic Projects	July 2021 – June 2022

PPL Electric Utilities

Director, Engineering and Project Delivery	May 2015 – July 2021
Regional Engineering Manager	Feb. 2013 – May 2015
Distribution Design Supervisor	Jan. 2010 – Feb. 2013

Alcan Cable

Process Development Engineer	Aug. 2007 – Jan. 2010

General Electric

Process Development Engineer	Sept. 2005 – July 2007

DuPont

Research Engineer	Aug 2004 – Sept 2005

Professional Memberships

Institute of Electrical and Electronics Engineers (IEEE) – 2006 - present
- Power Engineering Society (PES)

Substation Design Solutions (SDS) Industry Consortium – 2016-present
Electric Power Research Institute (EPRI) – 2022-present
- Distribution Sector Council

Southeast Electric Exchange – 2023-present
- Board of Director
- Engineering and Operations Committee

Association of Edison Illuminating Companies (AEIC) – 2024-present
- Power Delivery Committee

Edison Electric Institute (EEI) – 2023-present
- National Response Executive Committee

Civic Activities

United Way – 2014-present
- Greater Lehigh Valley United Way donor and Tocqueville Society member
- Metro United Way Tocqueville Society donor and Tocqueville Society member

Penn State University mentor – 2011-2014
Habitat for Humanity volunteer – 2015-2020
American Red Cross – 2022-present
- KY Region Board of Directors; executive committee vice-chair
- Louisville Area Chapter Disaster Services Committee
- Disaster Action Team volunteer

USA Cycling Member – 2022-present
Trees Louisville Board of Directors – 2025 - present

LG&E KU

PPL companies

PPL companies

Distribution System Hardening and Resiliency Plan (DSHARP)

White Paper on Risk Return on Investment

Contents

1. Executive Summary

In 2008 and 2009, the Hurricane Ike Windstorm and the Kentucky Ice Storm caused the most significant system damage in history for LG&E and KU customers. The impacts of these storms and the recognition that weather-related hazards were growing in scale and frequency prompted LG&E and KU to make targeted investments to improve system resiliency and reliability. Over succeeding years, LG&E and KU expanded existing programs and incorporated best practices from utility peers. These investments evolved into the Distribution Reliability & Resilience Program (DRRP), launched in 2010, the Transmission System Improvement Plan (TSIP), launched in 2017, and Distribution Automation (DA) project, launched in 2017, all targeted toward a comprehensive resilience approach. Combined, these programs have resulted in $1.4 billion in investment over 14 years, reducing the frequency and duration of disruptions on the distribution system by 47% and 39%, respectively, during that time period. These improvements have contributed to LG&E and KU being named at or near the top of its peers in the region for customer satisfaction and among the top quartile of utilities nationally for reliability.

In recent years, Kentucky has been impacted by an escalating number of extreme weather events. The number of "Billion-Dollar Weather and Climate Disasters" in Kentucky has increased from less than one event per year in the 1980s to five in 2022 alone, according to the National Oceanic and Atmospheric Administration (NOAA). Floods, thunderstorms, tornadoes, ice storms, and winter storms are some of the most prevalent extreme weather events. While such events caused nearly $790 million in damage from 2009 to 2019, major disasters have generated an additional $469 million in damage within the last two years alone. Over the past decade, the severity and frequency of major disasters[1] have resulted in more than 400 Federal Emergency Management Agency (FEMA) disaster declarations for Kentucky, the eighth most declarations of any state in the country.

The reliability metrics against which LG&E and KU have traditionally been benchmarked against their peers follow the industry-standard IEEE 1366 "2.5 Beta" methodology, which exclude Major Event Days (MEDs) from the reporting. When MEDs are excluded from reliability reporting, LG&E and KU's reliability performance since 2010 has shown steady improvement. However, over the past decade, all-in SAIDI (which includes MEDs) has increased by 200 minutes. There has been an especially sharp increase in the frequency and duration of outages associated with major events since 2020, as well as an above-average number of MEDs.

All of this indicates that while investments made in the distribution system over the past fifteen (15) years have achieved significant improvement in reliability, i.e. the ability to withstand routine disruptions, there is increasing resilience risk associated with exposure to extreme weather events. This trend of increasing extreme weather events is consistent with a larger national trend. Customers are losing power more often (+36%) and for longer (+50%) due to severe weather across the United States when comparing the 5-year period from 2013-2017 to the 5-year period from 2018-2022.

The costs of restoring customer outages caused by extreme weather are typically greater than blue-sky[2] outage restoration due to their widespread nature and extended duration.

[1] Storms and hurricane natural disasters as declared by FEMA.

[2] 'Blue sky' refers to normal, day-to-day operations without adverse weather conditions

Emergency response efforts, including rapidly mobilizing contractors and mutual aid resources, which are more expensive than day-to-day repairs and planned maintenance work, impose direct costs. There are also indirect costs driven by the loss of power to businesses and residences (e.g., spoiled food, lost economic output and wages).

In planning future investments on the distribution system, LG&E and KU have historically used an asset investment modeling approach which trends historical outages by type and location to score investments on their efficacy in reducing future interruptions. This approach has enabled LG&E and KU to ensure that reliability-focused investments are cost-effective and are appropriate for common interruption mechanisms. This historically-driven statistical approach does not, however, value the exposure of the grid to infrequent extreme weather events, including tornadoes, ice storms, hurricanes, and severe windstorms.

To address the increasing trend of extreme weather events, LG&E and KU have developed a prioritization model for grid investments which analyzes the interruption risk from extreme weather at a distribution feeder level. It further values the efficacy of various hardening techniques to mitigate interruption from extreme weather. Taken together, this enables LG&E and KU to model various hardening investment scenarios and analyze the corresponding benefit to customers as measured by interruption duration during major event conditions.

Using the model, LG&E and KU have developed the Distribution System Hardening and Resiliency Plan ('DSHARP'). DSHARP is an investment portfolio that is designed to improve all-in SAIDI (inclusive of MEDs as defined earlier in this paper) by 39% through a series of resilience-focused hardening programs. All-in SAIDI is used here as a 10yr rolling average, to capture trends but normalize year-to-year variation. These investments include:

- Installing additional remotely operable distribution reclosers, expanding the Distribution Automation (DA) program to enable more targeted fault sectionalization and expand self-heal capability to more feeders
- Building additional distribution circuit ties to circuits that don't already have tie capability to expand self-heal capability to more feeders
- Targeted hardening of existing overhead distribution lines, including the use of spacer cable in high-risk areas
- Targeted undergrounding of existing overhead distribution lines in high-risk, difficult to restore areas

The analysis that is presented in this white paper suggests that LG&E and KU could achieve average customer outage minutes per year on a rolling average, including major weather events (i.e., all-in SAIDI) of

- 148 minutes for approximately $450 million of capital investment, vs. a 2013-2023 average of 244 minutes; and
- 113 minutes for approximately $1,100 million of capital investment

According to the ICE calculator, which estimates the cost of unserved load due to sustained outages, the average annual cost of these outages is more than $800 million. LG&E and KU can reduce this by more than half with these investments.

2. The Reliability and Resiliency Context Facing Utilities

2.1 Common Industry Definitions and Measures for Reliability and Resiliency

In the utility sector, reliability and resiliency are two fundamental metrics that gauge the effectiveness and robustness of power distribution systems.

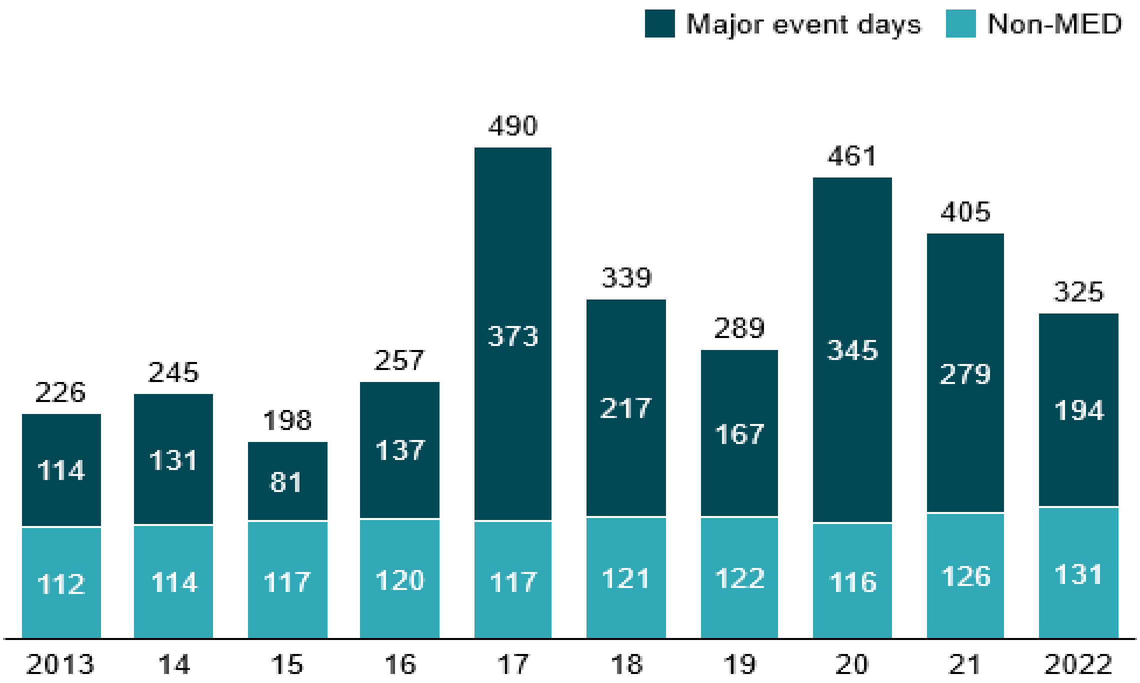
- **Reliability** refers to the ability of the electrical grid to deliver uninterrupted power to customers. It is often measured using indices such as System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). SAIDI quantifies the average duration of interruptions per customer over a specific period, while SAIFI measures the average number of interruptions per customer. SAIDI and SAIFI are IEEE metrics that measure blue sky day performance byexcluding Major Event Days.
- **Resiliency** is the grid's capacity to anticipate, absorb, adapt to, and rapidly recover from disruptive events, including natural disasters, cyber-attacks, and other emergencies. In practice, Resiliency performance is often evaluated through selective reliability metrics which measure a system's ability to absorb, adapt and recover from a major event. Example metrics include--
    - Average customer interruptions per major event, which measures how well the system can avoid widespread customer outages when exposed to hazards;
    - 90^{th} percentile customer outage duration, which measures how long it takes to restore 90% of customers in a major event
    - All-in SAIDI (inclusive of MEDs), which measures the average time per year a customer is without power (which combines both frequency of an outage event and the restoration time for said event)

2.2 National Trends in Reliability and Resiliency Performance Over the Last 15 Years

Over the past decade and a half, the landscape of utility performance has been shaped by significant technological advancements, regulatory changes, and environmental challenges. Analyzing these trends provides insight into the evolving nature of reliability and resiliency in the industry.

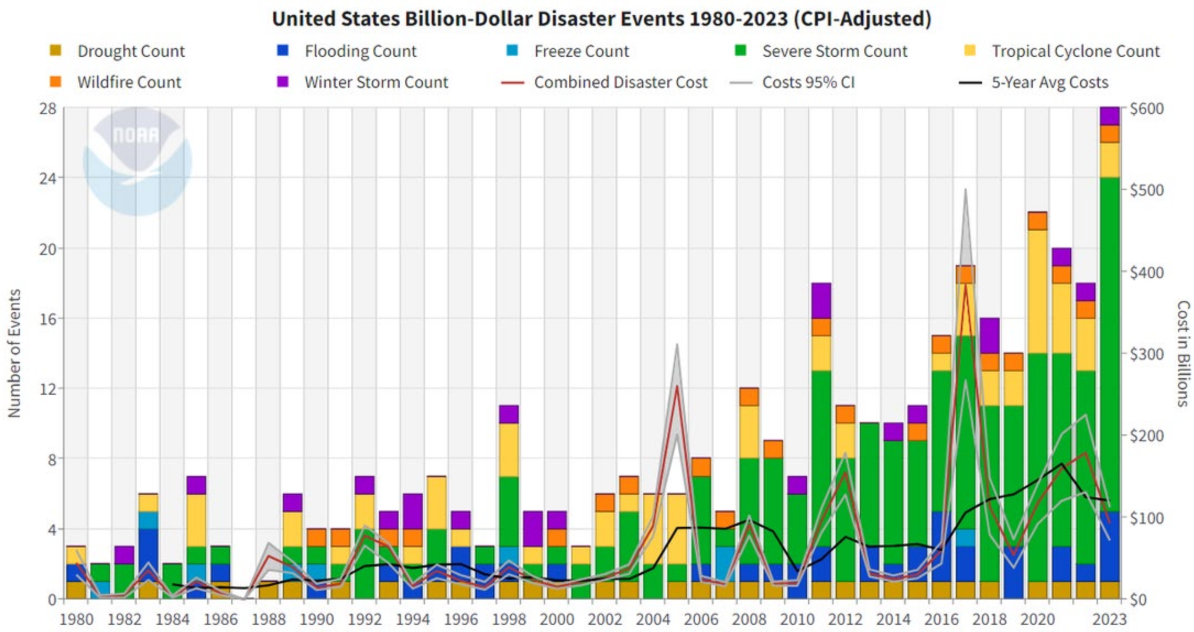
As shown in Figure 2-1 below, across the U.S., non-MED SAIDI has remained relatively stable over the past decade, ranging between 112-131 minutes. However, the MED contribution to SAIDI has been higher in the last 5-6 years. This data is consistent with Figure 2-2, which shows that the average number of extreme weather events has been increasing over the past couple of decades, with their intensity also rising based on annualized costs.

Figure 2-1: US average annual power outage per customer including major event days, 2013-2022, IEEE SAIDI minutes[3]



[3] **Source:** Annual Electricity Power Industry Report, EIA Form 861 detailed data workbooks.

Figure 2-2[4]: Number of extreme weather events annually and the dollars spent[5]



These trends underscore the growing impact of extreme weather on utility resiliency. As extreme weather events become more frequent and severe, utilities will face greater challenges in maintaining consistent service levels. The national trend of decreased resiliency using objective metrics highlights the critical need for enhanced infrastructure and proactive measures to mitigate the effects of such events.

Utilities must prioritize investments in robust infrastructure and advanced technologies to better withstand and recover from extreme weather conditions. This will ensure more resilient and reliable power for customers in the face of extreme weather.

2.3 Overall, Customers are Losing Power for Longer and More Often

The data over the last decade reveal a dual narrative: while non-MED reliability has shown marked improvements, resiliency has faced mounting challenges.

1. **Reliability Performance Has Broadly Improved Over Time**

   Utilities, including LG&E and KU, have made considerable strides in enhancing the reliability of their power distribution systems. Investment in grid modernization, such as the deployment of smart grid technologies, advanced metering infrastructure

[4] **Source:** https://www.climate.gov/news-features/blogs/beyond-data/2023-historic-year-us-billion-dollar-weather-and-climate-disasters

[5] **Source:** https://www.climate.gov/news-features/blogs/beyond-data/2023-historic-year-us-billion-dollar-weather-and-climate-disasters

(AMI), and automated distribution systems, has played a pivotal role in reducing the frequency and duration of power outages.

- **Smart Grid Technologies**: The adoption of smart grid technologies such as Advanced Distribution Management System (ADMS) has enabled utilities to better monitor and manage the grid in real-time, allowing for quicker identification and resolution of issues before they escalate into full-blown outages.
- **Advanced Metering Infrastructure (AMI)**: AMI systems provide utilities with detailed usage data and improved fault detection capabilities, leading to faster response times and more targeted maintenance efforts.
- **Fault Location, Isolation and Service Restoration (FLISR) Systems**: Automation in distribution networks has facilitated more efficient rerouting of power and isolation of faults, minimizing the impact of outages on customers.

2. Resiliency Performance, However, Has Become Increasingly Challenged as Utilities Experience More Severe Weather Events

Despite advancements in reliability, the resiliency of utility systems has been increasingly tested by a rise in the frequency and severity of extreme weather events. Hurricanes, wildfires, floods, and other natural disasters have strained the capacity of utilities to maintain continuous service and recover swiftly from disruptions. Select examples of these events in recent years include:

- **Hurricane Helene (2024):** Category 4 storm that caused significant inland damage including in Kentucky – where wind speeds of 65 miles per hour left more than 250,000 homes in LGE/KU's territory without power
- **Hurricane Beryl (2024):** Hurricane Beryl caused up to 2.6 million customer outages in Houston
- **Kentucky Wind Storm (2023)**: Causing wind speeds of more than 70 miles per hour, the March 3 wind storm left roughly 400,000 Kentucky residents in LGE/KU's territory without power.
- **Hurricane Ida (2021):** Hurricane Ida caused up to 1 million customers in Louisiana, and 200,000 elsewhere, to lose power, and damaged 30,000+ utility lines for Entergy alone
- **Winter Storm Uri (2021):** 4.5 million homes without power during winter Storm Uri in Texas
- **Midwest Storms (2021):** Greater than 700,000 customers in Michigan lost power due to storms
- **Hurricane Irma (2017):** 4th largest blackout in US history from Hurricane Irma in Florida

In conclusion, while the utility industry has made notable progress in improving reliability through technological advancements and strategic investments, the challenge of maintaining and enhancing resiliency in the face of escalating environmental and extreme weather events remains a critical area of focus. Addressing these challenges requires a holistic approach that integrates advanced technology, robust infrastructure, and comprehensive operational strategies.

3. Overview of LG&E and KU's Distribution System

The LG&E and KU electric distribution systems collectively serve more than 1,030,000 customers in Kentucky and Virginia. LG&E serves more than 445,000 customers in Louisville and 17 surrounding counties. KU serves 587,000 electric customers in 77 Kentucky counties and five Virginia counties.

A summary of the key attributes of the LG&E and KU systems follows in Figure 3-1.

Figure 3-1: Descriptive Attributes of the LG&E-KU distribution network, by Operating Company

	KU	LG&E	ODP	Total
Electric Customers ('000s)	557K	446K	30K	1,033K
Counties Served	77	17	5	99
Square Miles	6,475	700	511	7,686
Circuit Miles	15.7K	1.7K	1.2K	23.6K
% Circuit Miles Overhead	83%	58%	96%	76%
No. Substations	434	96	46	576
Poles	353K	138K	29K	520K

4. The LG&E and KU context

To evaluate the trends impacting LG&E and KU's service territory specifically, an extended timeframe was used in an attempt to minimize year-to-year randomness in major event exposures. LG&E and KU's detailed outage data goes back 11 years, until 2013, and as such was selected as the baseline for this analysis.

Over this 11-year time frame, LG&E and KU has made significant strides in improving reliability performance for its customers, in large part due to the success of programs like the Distribution Reliability and Resiliency Plan (DRRP). Non-MED SAIDI has fallen from approximately 93 minutes in 2013 to approximately 74 minutes in 2023 – an improvement of nearly 20 minutes per customer. These improvements have been achieved through a series of programmatic investments to increase reliability and address aging infrastructure.

Overview of the DRRP

Key investments included in the DRRP are:

1. **Distribution Automation.** Since 2017, LG&E and KU has systematically deployed monitoring and control hardware and software on the distribution system. These investments build the company's capability to automatically identify and isolate faults on the grid, while restoring power to many customers in the process. These investments include supervisory control and data acquisition-enabled ('SCADA') reclosers, which can both monitor grid condition and operate to disconnect or reconnect power on a given circuit; a distribution SCADA (DSCADA) platform to monitor and control those devices; and a distribution management system (DMS) software that enables intelligent control over the recloser devices. Through the DRPP program, approximately 45% of LG&E and KU's distribution circuits now have these capabilities improving reliability for over 80% of customers.

2. **Aging Infrastructure Improvements.** LG&E and KU uses a variety of techniques to monitor and evaluate the health of its distribution assets, including but not limited to internal inspections, infrared scans, dissolved gas analysis, and power factor testing. These techniques are applied across a range of asset classes to ensure that assets with higher probabilities of failure (and associated consequence of failure on customer outages) are prioritized for replacement. Some of the key asset improvements covered in DRPP include:

    a. **Poles.** The company owns and manages over 500,000 wood poles with average estimated age of 30 years. Many are much older. From 2021-2024, LG&E and KU managed wood poles through routine bi-annual inspections and the cycle-based Pole Inspection and Treatment Program leading to the proactive replacement of 34,000 poles, reinforcement of 1,000 poles, and treatment of 73,000 poles.

    b. **Substation Circuit Breakers.** The company has approximately 2,200 substation circuit breakers, which are operational devices that can automatically interrupt powerflows and protect critical infrastructure. Through 2024, 487 legacy oil, air-magnetic, and vacuum circuit breakers have been replaced. An additional 148 vacuum circuit breakers have been installed as a part of new or expanded substations and circuits.

    c. **Legacy Relays.** The company owns and manages 4,000+ relays, which control circuit operations through electrical signals. Many of these devices are beyond their useful lives and lack intelligent control capabilities (vs. microprocessor-based relays). Through 2024, 3,011 legacy electromechanical, solid-state, and microprocessor relays have been replaced. An additional 340 microprocessor relays have been installed as a part of new or expanded substations and circuits.

    d. **Underground Residential Distribution Cable.** Many customer premises are served through direct buried cables, which have a 30-year asset life (for accounting purposes). Since 2021, over 80 miles of URD, direct-buried cable has been replaced.

    e. **Paper Insulated Lead Covered (PILC) Cable.** Beginning in 2013, Louisville Operations initiated a program to accelerate replacement of bare (unjacketed), paper insulated, lead covered low voltage secondary and medium voltage primary cables. Since 2021, 11 miles of non-network PILC cable has been replaced along with 6 miles of underground substation exit cable.

f. **KU SCADA Expansion.** Beginning in 2018, EDO elected to accelerate expansion of SCADA capabilities to KU substations. At that time, only approximately 20% of circuits in the KU service territory were equipped with SCADA connectivity - accounting for approximately 30% of KU customers (including ODP). Lack of SCADA capabilities to monitor and control substation facilities prevents remote and central monitoring, control, and operations of line equipment, adding time to circuit restoration following an outage event. The expansion of SCADA capabilities in KU substations allows distribution system operations to have the necessary information to identify outages and take remedial measures in those substations in real time. Through 2024, Distribution Substations added 375 distribution circuits and low-side voltage transformer breakers now have SCADA-connectivity.

g. **Substation Wildlife Protection.** Since 2012, wildlife has been the single largest contributor to distribution substation level outages at KU. Wildlife protection is included in the design and construction of new and expanded distribution substations. However, EDO's current design practice was only formalized as of 2012, and numerous previously constructed KU distribution substations continue to utilize legacy standards that are sometimes less than adequate in providing the highest level of station protection. Primary wildlife threats to these stations include raccoons, squirrels, birds and snakes. Through 2024, enhanced wildlife protection has been added to 107 substations.

h. **Substation Transformer Contingency.** EDO's substation transformer contingency program addresses distribution substation transformers that cannot be fully restored in the event of an outage or failure. During associated outages, some customers could experience service interruption periods greater than 24 hours until failed equipment can be replaced or until a portable transformer can be installed. Since inception, the number of transformers considered "at risk" has been reduced from 484 to 358 across KU and LG&E. This reduction of 126 transformers results in a 26% outage exposure reduction to electric distribution substation transformers.

i. **Volt/VAR Optimization (VVO).** Volt/VAR Optimization technologies and business processes enable greater capabilities to manage system-wide voltage levels and reactive power flow on the electric distribution grid. An effective VVO solution enables distribution system operators to reduce system losses, peak demand or energy consumption using Conservation Voltage Reduction techniques. VVO control is an advanced system operations function that determines the best set of control actions for voltage regulating devices and VAR control devices on the electric distribution grid to achieve a one or more specified operating objectives without violating any fundamental operating constraints (high/low voltage limits, load limits, etc.). Associated functionality and capabilities are partially enabled by ongoing technology advancements on the distribution grid and will be needed with greater proliferation of distributed energy interconnections on the distribution system. As of March 2025, 189 Capacitors have been installed across 19 buses impacting nearly 170,000 customers as part of the VVO program.

3. **Circuit Hardening.** LG&E and KU has multiple investment programs to upgrade circuits to ensure they will perform well during periods of grid stress. There are a range of specific interventions in these programs, including storm guying, stronger and/or higher-standard poles, targeted undergrounding, replacement of aging assets, and relocation of assets to less problematic areas. A portion of these investments are specifically targeted towards low-performing circuits based on five years of customer outage frequency (SAIFI) for a given circuit. Over 71 miles have been hardened from 2021-2024 through targeted reliability investments

These investments enhance reliability and resiliency by reducing outage minutes and improving restoration times. This proactive approach aligns with industry trends and positions LG&E and KU to better meet customer expectations for dependable service.

While these programs have driven significant improvements in day-to-day system reliability, major weather events – and the associated outage minutes attributable to them – have increased for LG&E and KU since 2013 as they have nationally. These types of weather events have long been a challenge in the LG&E and KU service territory (dating back to the 2009 ice storm) due to its large, diffuse system serving many rural counties with difficult topographies. At the same time, these events appear to be increasing over time over the last 11 years, in line with the broader industry trend. The frequency of customer outages (SAIFI) and the average number of customer outage minutes (SAIDI) caused by major events have risen by 40% and 200%, respectively, during this time period. Historical analysis of these trends is summarized in Figures 4-1 and 4-2.

Figure 4-1: Average SAIFI customers experience per year from major events (MED SAIFI)

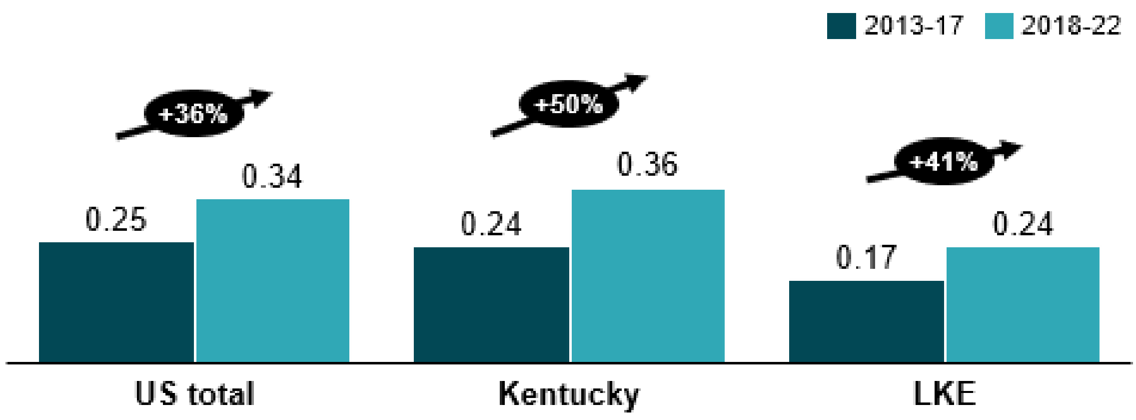


Figure 4-2: Average minutes per year a customer is without power from major event (MED SAIDI)

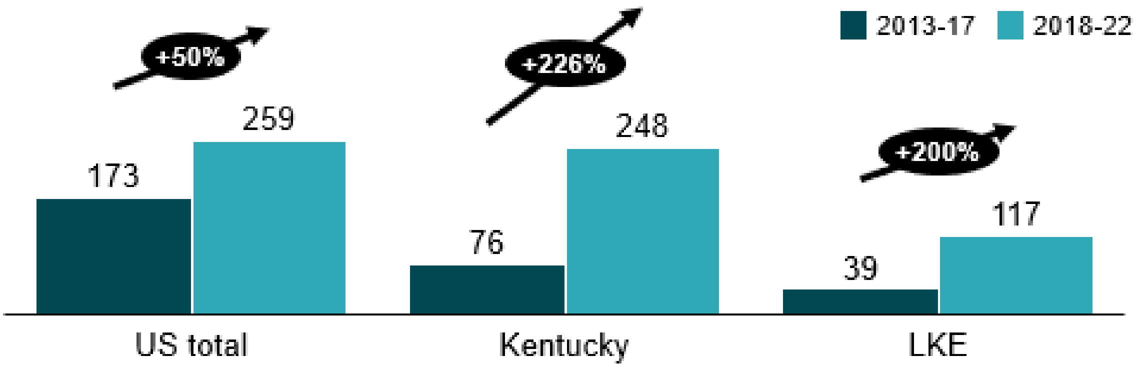


Figure 4-3: LG&E and KU's year-over-year SAIDI

SAIDI, minutes	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
MED	39	87	33	11	25	341	35	21	97	92	925
Non-MED	95	97	92	102	81	99	97	75	83	79	74

Over the past 10 years, blue sky day-to-day outages (i.e., non-MED) have declined, supported by investment programs like DRRP. While there is significant variance year-to-year, the overall trend in outage minutes from major weather events (i.e., MED) is increasing. In 4 of the last 6 years, outage minutes from major events have exceeded non-MED outage minutes.

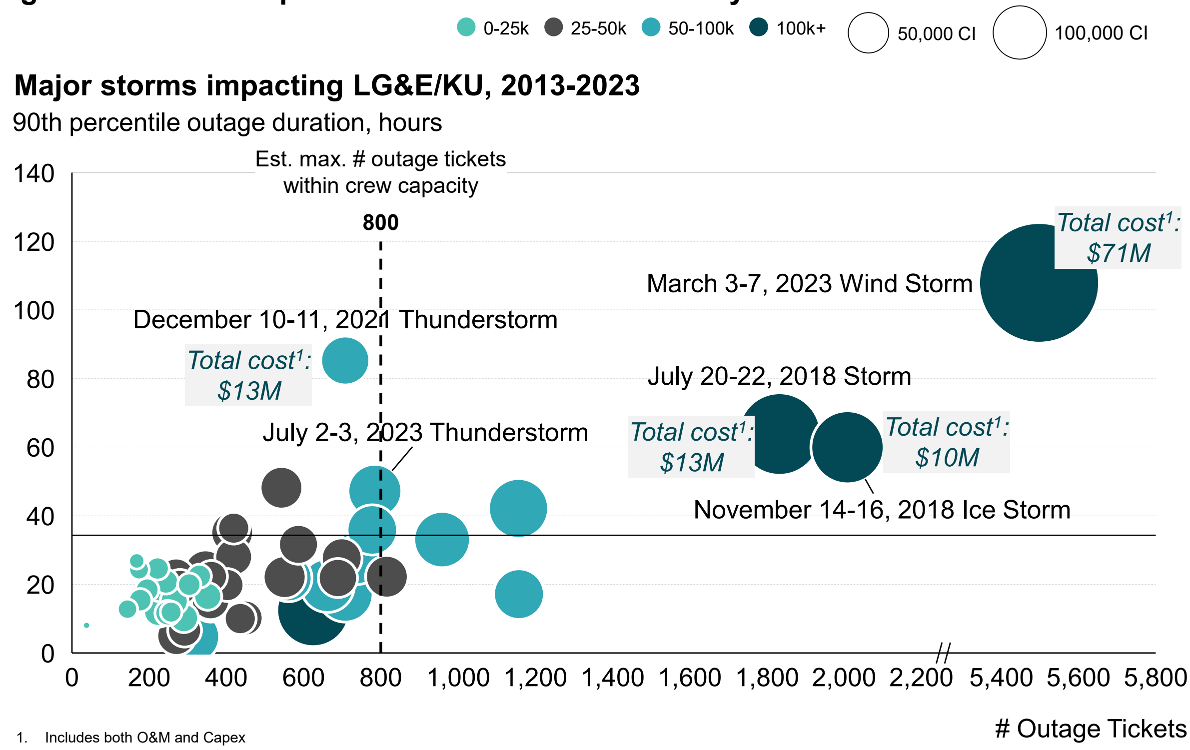
Major weather events account for a disproportionate amount of customer outage minutes. In 2023, for example, the top 1% of events accounted for nearly 50% of all customer outage minutes. These events also tend to cause longer outage durations and account for a greater share of cost. The larger the storm, the more damage to the grid, and the greater strain that is placed on restoration resources. For very significant storms, LG&E and KU will go beyond its internal workforce and on-site contractors to engage off-system resources to speed restoration.

During the same 11-year period:

- The 5 most catastrophic events in LG&E and KU's service territory had customer outage durations of up to 73 hours – which is 3x the average of other storms
- The worst 10% of events cost approximately $120M in emergency restoration costs

Figure 4-4 summarizes the impacts of these storms on LG&E and KU's service territory, and maps the relationship between the number of outage tickets (how much damage occurred in the territory) and the duration of the 90th percentile customer outage (how long it took to restore 90% of customers).

Figure 4-4: Storm Impacts on LG&E and KU's territory



1. Includes both O&M and Capex

The data above suggest delivering better resiliency performance is a function of outage prevention, as with very large numbers of outage tickets, the outage duration tends to increase significantly. In the 5 most catastrophic storms, 90th percentile outage duration[6] averaged at 73 hours, approximately 3 times the average during other major storms. This suggests that outage prevention must be a core focus of DSHARP. Additionally, over the last 10 years, the worst 10% of storms cost approximately$120M and accounted for 30% of customer outage minutes. The remaining 90% cost $87M and accounted for remaining 70% of customer outage minutes.

Beyond restoration costs, we must consider the economic impact of storm outages to customers. The Interruption Cost Estimate (ICE) calculator is a public tool for valuing the cost of outages and takes into account factors like value outage duration, power usage, and customer type. Key assumptions underpinning the ICE calculator's valuation of lost load include values of $2, $97, and $20 per unserved kWh. Assuming average all-in SAIDI of 244 minutes (i.e., the average annual outage minutes a customer has experienced due to severe events over the last 10 years), the total economic cost of these outages per year to LG&E and KU customers, per the ICE calculator, is estimated at more than $800 million.[7] This figure does not include the restoration costs for these storms.

[6] Defined as the time it takes to restore 90% of customers

[7] Based on an average of ~244 outage minutes per customer and a system interruption frequency index of 1.13 (i.e., ~1.13 interruptions per customer per year). Values from the ICE calculator are in 2016 dollars, and were thus inflated to 2023 dollars using changes in the CPI from 2016 to 2023, which is estimated to be ~27% gross.

Overall, based on analysis of recent historical performance data, these major events account for an outsize share of customer outage minutes, extended outage durations, and cost. To deliver the level of service reliability that our customers demand, it is becoming increasingly important for LG&E and KU – like other utilities – to examine 'all-in' performance metrics and plan to minimize disruptions caused by MEDs.

5. Overview of LG&E and KU's methodology to arrive at the optimized investment plan

To develop an investment portfolio that can most cost-effectively mitigate resiliency risk, LG&E and KU followed a 3-step approach: (1) established a resiliency risk baseline; (2) modeled cost-effectiveness of particular investments to address risk; and (3) used return-on-investment to evaluate investment portfolios to meet a specified level of performance.

Step 1: Establish LG&E and KU's resiliency risk baseline over time

The first step was to establish a baseline of annual grid faults and associated customer outages, as a proxy for risk within the system. The same 11-year time period (from 2013-2023) was used to establish the baseline. The baseline was then separated into 'blue sky' (i.e., non-MED outages) and 'grey sky' (i.e., outages from MED events) outages. Outages were then further broken down by a number of factors including:

- **Grid location** – which grid network suffered the damage and resulting grid outages;
- **Outage cause** – what was the root cause driver of the damage and outage (e.g., lightning, vegetation, equipment failures);
- **Affected equipment** – which piece of grid equipment failed and resulted in the outages (e.g., conductor, pole)

This data is recorded within LG&E and KU's Outage Management System ('OMS'). When crews track their work to repair the grid, they capture this information.

Step 2: Model the cost-effectiveness of a grid investment at reducing the probability and impact of an outage caused by a major event

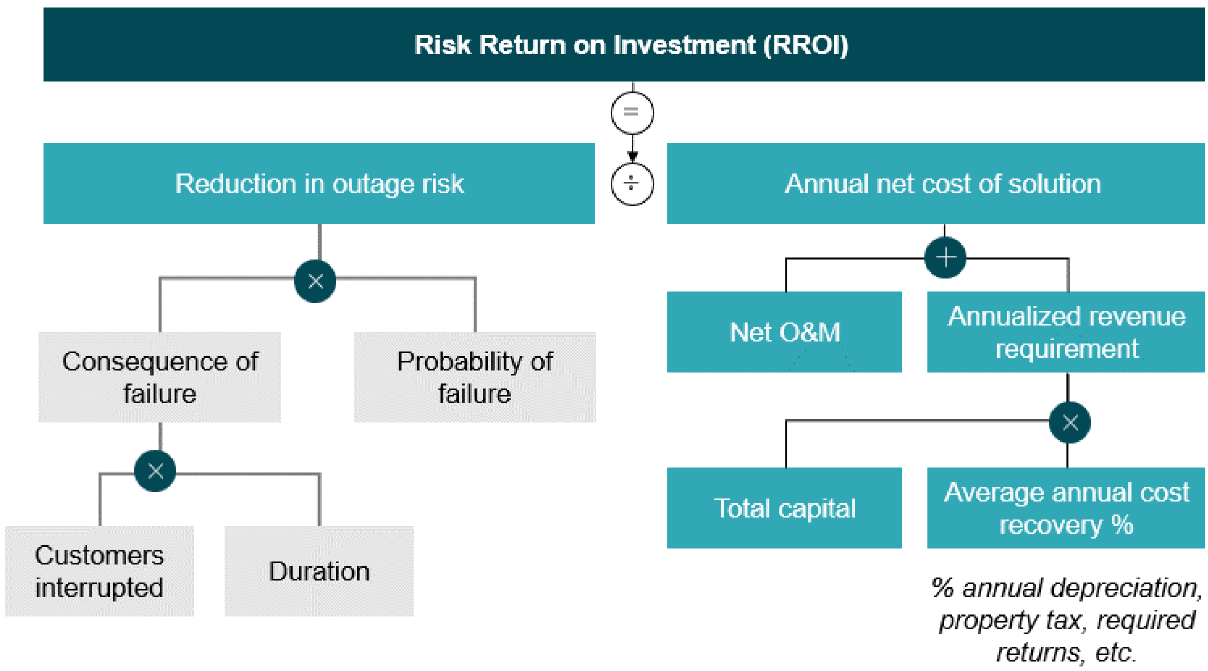
The reduction in expected SAIDI from a MED event can be estimated from an individual intervention by comparing the performance of a circuit with that intervention vs. one without it. These comparisons rely on hundreds of data points to generate a directional estimate of the risk reduction value for that particular investment program, which can then be used in go-forward investment portfolio modeling.

To normalize these comparisons as much as possible, circuits are compared with circuits in a similar region or geography. For example, circuits in the Lexington service area are compared with other Lexington circuits. Further normalization is achieved by accounting for the number of customers on a given circuit. Circuits with more customers are by definition more likely to account for a greater number of customer minutes interrupted. Therefore, by normalizing for CMI as well, a directional valuation of the risk reduction potential of an investment can be inferred.

The expected risk reduction from a grid investment is then divided by the annualized lifetime cost of that investment. This includes the annualized depreciation of an investment, as well as the ongoing maintenance expenses and potential for avoided costs.

An important benefit of this approach is that the risk reduction per dollar of investment can be compared ‘like-for-like’ across different investment types. For instance, undergrounding a line may require a greater upfront capital investment, but it has a longer useful life and will require less ongoing vegetation spend than a comparable overhead circuit hardening project. These nuances are incorporated into the methodology as shown in Figure 5-1.

Figure 5-1: Assessing the Risk Return on Investment



To calculate RROI as described in this paper, we applied A/B testing of real, historical performance in LG&E and KU’s service territory for the last 11 years. These calculations compare the resiliency performance of a circuit that benefitted from a specific intervention (e.g., undergrounding or distribution automation) vs. comparable circuits that did not. Cost is then estimated by type of intervention (e.g., $/mile undergrounded).

These calculations can then be tailored to individual circuits and feeders, described in the next step.

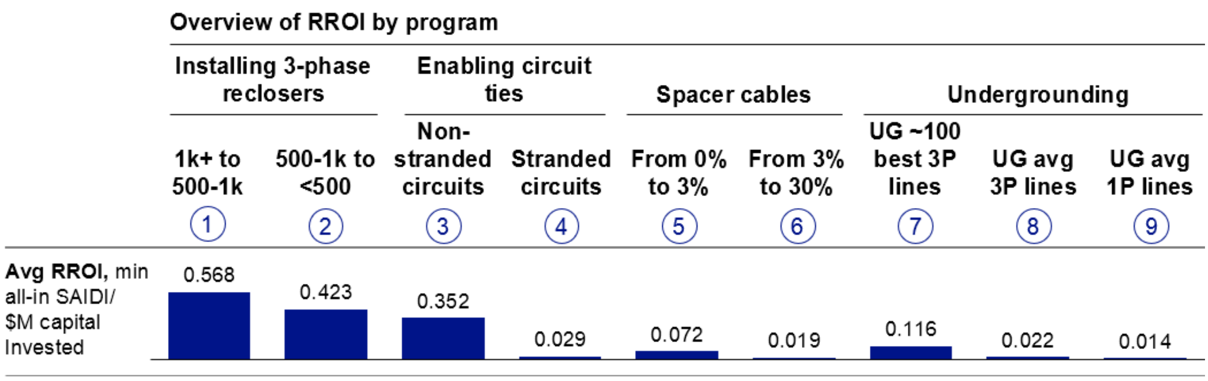
Step 3: Use ‘Risk Return on Investment’ to model strategic investment portfolios to meet a given level of performance.

The RROI of an intervention can be modelled at a feeder and circuit level. Performing these calculations generates an estimate of the ‘total potential’ risk reduction from a given intervention (e.g., how many weather-induced outage minutes could be avoided from 100% penetration of distribution automation and reclosers). These calculations rely on three types of inputs, including the outputs from Steps 1 and 2:

- The intrinsic resiliency risk on a given feeder or circuit, as determined by the frequency of grid outages (SAIFI) and duration (SAIDI) in terms of customer minutes interrupted. The risk of these circuits is assumed to be consistent with the 10-year, historical baseline computed in Step 1 (i.e., on average, circuits will experience the same frequency and severity of weather stresses over the next 10 years as well)
- The reduction of risk from an investment if applied to that circuit (i.e., its efficacy), as determined by actual performance of similar circuits that do have that investment, which was calculated in Step 2. (For example, reduction in outage minutes for an undergrounded line relative to an overhead line with similar characteristics)
- Circuit-specific parameters, including:
    - o The viability of applying an investment to a given circuit (e.g., some circuits may not be undergrounded due to technical considerations)
    - o The estimated cost to make that investment on a specific feeder (e.g., longer circuits will require more undergrounding cost)

With these inputs, we developed an estimate of the RROI of each intervention for a given circuit. Because RROI is comparable across intervention types, we can develop a prioritized view of the most effective interventions to apply on circuits with the most risk. Figure 5-2 shows the results of some of these calculations at a program level.

Figure 5-2: RROI by program



By using RROI to prioritize investments, we ensure we are delivering the greatest benefit to our customers for a given level of investment. Developing the overall portfolio is then a function of how much risk to reduce. Mitigating 100 minutes of all-in SAIDI will require more capital than 50 minutes, but in both cases, we can develop a cost-effective, strategic portfolio.

These portfolios are top-down and not project specific. They help identify the high-priority circuits and candidates for investment, but additional engineering and design analysis was then required to develop specific, individual projects with accurate cost estimates (e.g., elevated costs in areas with difficult terrains that make construction more expensive). Nonetheless, the analysis results in a prioritized view of which feeders and investment programs to pursue first, which can then be refined over time.

The next section explores in further detail the resiliency hardening toolkit that LG&E and KU assessed to develop these portfolios, while the appendix contains further details on the calculations described in this section.

6. The resiliency and hardening toolkit

To complete a thorough analysis of potential investments, LG&E and KU evaluated four key programs using the 'Risk Return on Investment' (RROI) model. These programs demonstrated significantly higher RROI and opportunity size compared to others like pole upgrades and batteries/storage:

1. **Installing Reclosers** – further segment circuits with large number of downstream customers to a higher segmented configuration
2. **Enabling Circuit Ties** – build circuit ties to create redundancy in power sources (i.e., alternative sources of power that can sustain service to customers)
3. **Targeted Undergrounding –** underground single-phase or 3-phase sections of mostly overhead circuits in urban areas
4. **Installing Spacer Cables** – add or expand spacer cable coverage in overhead powerlines with high customer counts

LG&E and KU considered additional investment programs as well, including enhanced feeder designs, line relocations, and batteries and storage. These solutions, however, were deprioritized due to limited operational evidence in LG&E and KU's service territory and less favorable RROIs.

Figure 6-1: Overview of resiliency programs considered

	Midline reclosers	Circuit ties	Spacer cables	Under-grounding	Enhanced Dx feeder design std.	Batteries / storage	Line relocation
Description	Add reclosers to sectionalize lines and reduce the # of customers impacted by a grid fault	Add reclosers at circuit ties to by enable back-feeding (i.e., re-route power) from other substations	Install spacer cable on targeted line segments to enhance their ability to withstand tree damage	Convert existing overhead lines to underground	Systematically improve line resiliency with pole upgrades, storm guying, intermediary poles, etc.	Adopt storage solutions to provide power supply in case of an outage	Relocate lines to lower-risk areas
Actions considered in modelling	Segment lines to (a) <1000 or (b) <500 customers per segment	Enable 2 ties for (a) non-stranded and (b) stranded circuits	Install spacer cables on (a) up to 3% of OH miles or (b) up to 30% of OH miles	Underground (a) 3-phase or (b) 1-phase overhead lines	N/A	N/A	N/A
Relevant LKE projects *(non-exhaustive)*	CIFI Legacy recloser replacement	DA Enhance circuit ties	CEMI	Richmond strategic UG pilot	PITP	N/A	System hardening
	Solutions selected for further portfolio analysis				*Solutions not included in final portfolio due to lack of proof points in LKE's service territory and/or more challenged business cases*		

Installing Additional Reclosers

Segmentation is done by installing reclosers strategically on a segment to divide customer counts and reduce exposure to outages. Around 65% of LG&E and KU's circuits are already at the most segmented configuration, so the analysis focuses on the remaining 35%. These circuits are further categorized into segments with 1,000+ customers and those with 500-1,000 customers. The analysis compares segmenting 1,000+ customer segments down to 500-1,000 customers, and 500-1,000 customer segments down to 0-500 customers with the former having a higher RROI. Segmenting 1,000+ customer segments to 0-500 customers offers diminishing returns due to the high cost of adding multiple reclosers.

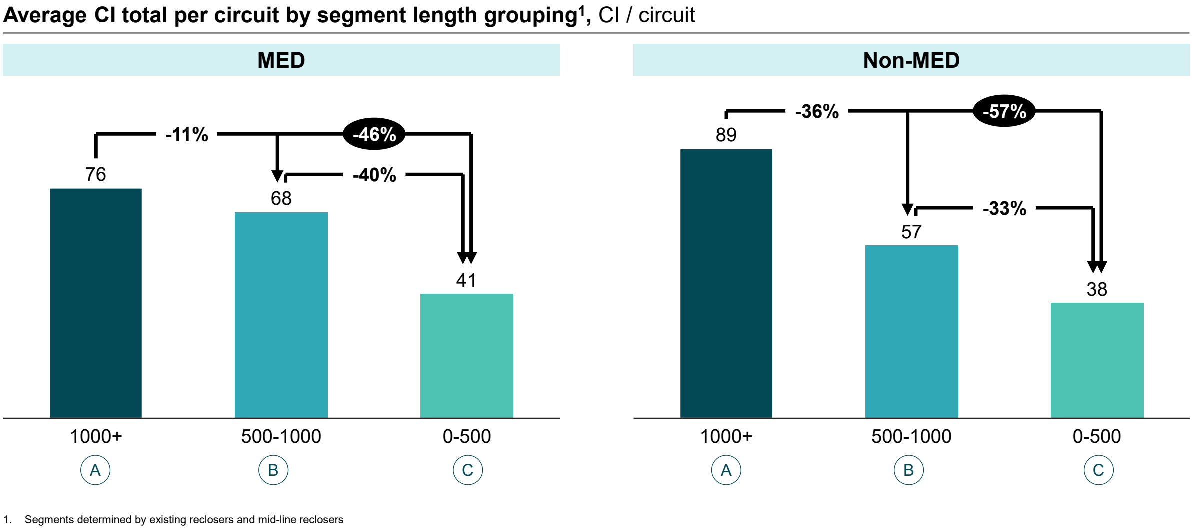
Figure 6-2: Segmenting 1000+ customer/segment circuits into 500-1000 bucket with the highest RROI

	SAIDI savings			÷ Cost		= RROI
	Remaining circuits to be further segmented	**Avg SAIDI per circuit,** min	**SAIDI that could be saved,** min	**Add'l reclosers added**	**Total cost to install reclosers,** $M	**RROI,** SAIDI/$M
1000+ to 500-1000	56	0.055	3.05	~70	5.38	0.568
500-1,000 to 0-500[1]	304	0.072	33.66	~1000	77.17	0.423

1. Considers the opportunity to further segment circuits, consecutive and incrementally to first segmentation (1000+ to 500-1000). These two opportunities are mutually exclusive.

Reclosers have proven to be an effective tool at providing day-to-day system reliability, and as such were deployed as part of the DRRP program (and specifically the distribution automation investment program). These assets have also been shown to be effective at reducing outages caused by major weather events, as shown in Figure 6-3 below.

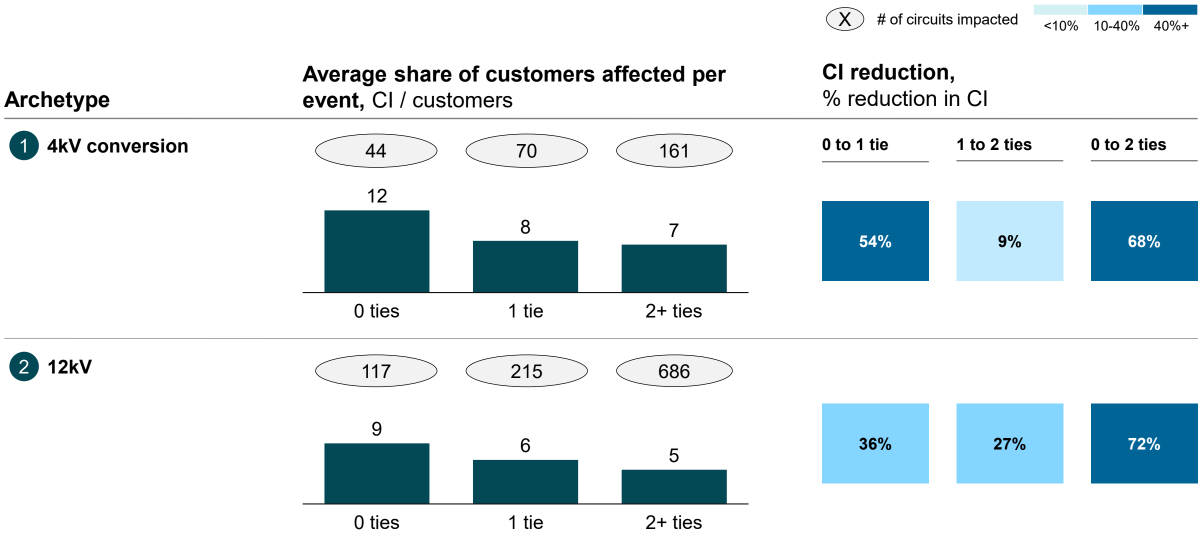
Figure 6-3: Circuits with higher segmentation experience up to 58% fewer customer interruptions



Enabling Circuit Ties

Circuits considered candidates for circuit tie installations are 4kV and 12kV circuits with either no ties to other circuits or only 1 tie to another circuit. Adding ties can create redundancy and provide alternate paths to powering customers. Adding a tie provides the most CI reduction for 4kV circuits with no ties. Whether a circuit is ‘stranded’ or not affects the RROI of the investment. Stranded circuits require additional investment in the form of additional conduit and circuit infrastructure, whereas non-stranded circuits only need a recloser to tie to another nearby circuit. Thus, adding ties to non-stranded circuits generally has a more favorable RROI.

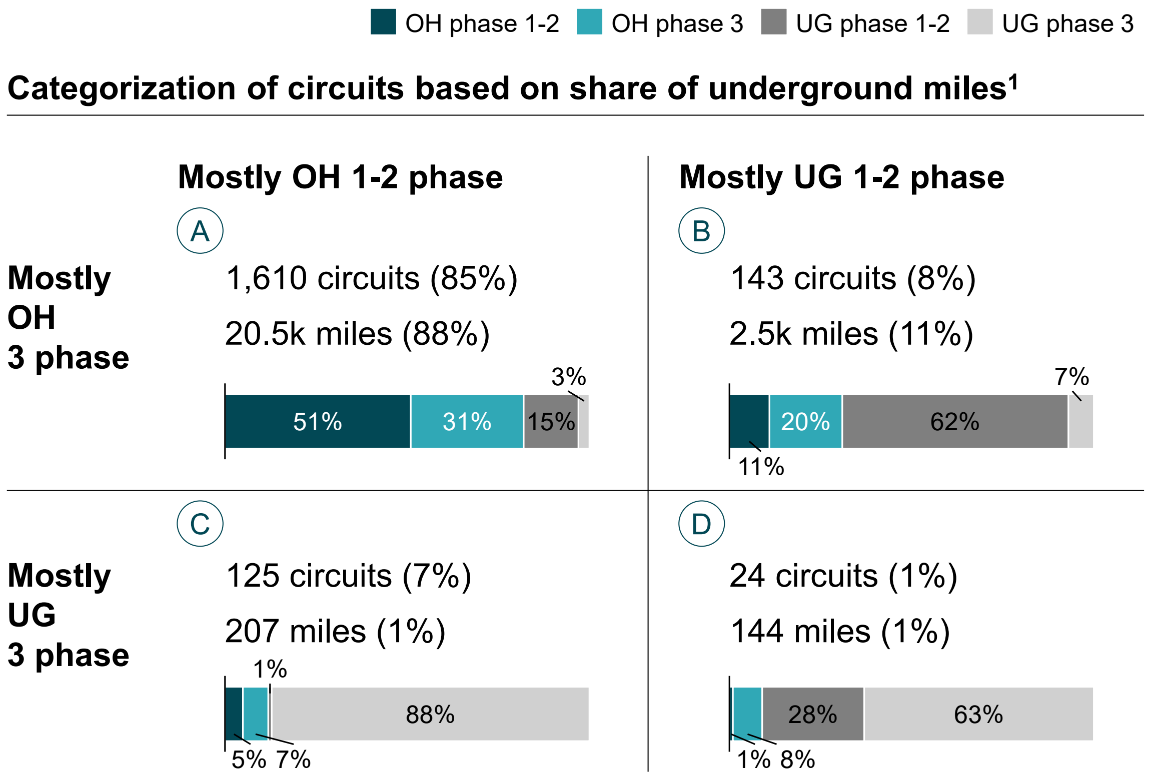
Figure 6-4: 12kV circuits can provide 15 min of SAIDI reduction at an RROI of 0.029-0.352



Targeted Undergrounding

Approximately 85% of LG&E and KU's circuits are mostly overhead (OH), 1% are mostly underground (UG), and 14% are a mix of OH and UG, as shown in Figure 6-5. Due to limited data on mostly UG circuits, targeted undergrounding was focused on assessing the RROI for undergrounding either the single-phase or three-phase portions of mostly OH circuits. The cost of undergrounding varies by area, with urban areas being more expensive than rural ones (e.g., more difficult dig areas, need for traffic controls and flagging crews, permitting complexities). The three urban operating centers which cover Louisville (AOC, EOC) and Lexington (LEXOC)- offer the greatest opportunities for SAIDI reduction but also have the highest cost per foot for undergrounding, as shown in Figure 6-6 below.

Figure 6-5



1. A circuit is considered underground if at least 70% of its 1-2 phase or 3-phase miles (or both) are underground

Figure 6-6

	SAIDI savings				÷ Cost				= RROI, SAIDI / $M	
	(A) OH circuits	Avg SAIDI from A[1]	(B) SAIDI saved if B[2]	(C) SAIDI saved if C[3]	OH 1 phase mi	(B) Total cost to UG, $M	OH 3 phase mi	(C) Total cost to UG, $M	(B) UG 1P, SAIDI / $M	(C) UG 3P, SAIDI / $M
AOC	284	26.1	~12	~26	875	852	891	1,424	0.014	0.018
EOC	116	30.9	~14	~31	919	896	556	1,151	0.016	0.027
LEXOC	184	40.0	~18	~39	1,675	1,629	904	1,579	0.011	0.025
All other OCs	806	24.7	~11	~24	7,013	2,435	3,952	2,090	0.005	0.012
Overall	1,390	121.6	~55	~120	10,483	5,811	6,303	6,244	0.010	0.019

1. Using 2013-2023 outage data, including only MED outages from all outage causes
2. Applying weighted average SAIDI savings from undergrounding 1-phase lines – 45%
3. Applying weighted average SAIDI savings from undergrounding 3-phase lines – 99%

Installing Spacer Cables

Most circuits at LG&E and KU have no spacer cables. Among those that do, over half have fewer than 10% coverage in OH miles. The analysis categorizes circuits into three groups: no spacer cables, less than 10% coverage, and more than 10% coverage. Circuits with substantial spacer cable installation experience fewer outages, although the magnitude varies by region. Lexington Operations Center (LEXOC) and EOC see the greatest reduction in SAIDI. There are diminishing returns when expanding coverage to other circuits, especially in rural areas and AOC.

Figure 6-7

0-10k 10k-100k 100k+

<0% <0-25% -25-50% -50%+

	Number of customers, '000			# of outages / customer[2]					SAIDI / '000 customers[2]				
	A No spacer cable	B ~3% spacer cable[1]	C ~30% spacer cable[1]	A No spacer cable	B ~3% spacer cable	Δ from A to B, %	C ~30% spacer cable	Δ from A&B to C, %	A No spacer cable	B ~3% spacer cable	Δ from A to B, %	C ~30% spacer cable	Δ from A&B to C, %
AOC	52	133	65	0.20	0.21	+4%	0.19	-9%	1.62	2.25	39%	2.02	-2%
EOC	6	87	126	0.35	0.26	-25%	0.23	-13%	3.98	3.43	-14%	2.79	-19%
LEXOC	77	91	48	0.28	0.21	-24%	0.11	-55%	3.94	3.67	-7%	1.72	-55%
All other OCs	314	56	8	0.39	0.32	-17%	0.21	-45%	1.94	1.43	-26%	0.81	-56%
Total	450 (42%)	367 (35%)	246 (23%)	**Weighted avg. by customers**		-16%		**-35%**	**Weighted avg. by customers**		-15%		**-39%**

1.Based on the number of miles
2.Using 2013-2023 outage data, including all (MED and non-MED) outages from all outage causes

7. Results and conclusions

Key takeaways on the effectiveness of LG&E and KU investment measures

LG&E and KU's investigation into the most cost-effective measures for improving resiliency yielded the following takeaways based on the analysis performed:

1. **Installing three-phase reclosers is the most cost-effective solution for reducing outages on the system**. 3-phase reclosers are estimated to offer the highest RROI (0.4-0.6 minutes of SAIDI per $1M of investment), but their total impact is limited as the grid already incorporates significant segmentation. In total, 3-phase reclosers would require ~$100M in investment for a reduction of approximately 40 min of all-in SAIDI.

2. **Enabling circuit ties for non-stranded circuits can act as a step beyond installing reclosers**. While installing circuit ties for stranded circuits does not tend to be cost efficient (given meaningful construction costs for additional conduit), installing

a single recloser to tie circuits close to each other can offer additional redundancy for a much more limited cost

3. **Undergrounded lines perform exceedingly well, but are significantly more expensive – lowering RROI**. Undergrounded 3-phase lines experience, on average, 90% lower SAIDI per customer – the highest impact of any intervention. The average RROI, however, is lower than other interventions due to the significant cost of undergrounding.

    - Undergrounding also tends to perform better when considering **grey-sky SAIDI** (vs blue-sky SAIDI), likely due to the significant reduction of outages caused by vegetation and tree falls during major weather events

    - Certain circuits – which have experienced a higher share of outages in the past – may be candidates for **targeted undergrounding**. The estimated RROI for undergrounding the top 100 most cost-effective circuits is approximately 5x higher than RROI for the average circuit.

4. **Spacer cable installations are a *moderately* cost-effective solution to lower SAIDI**. Circuits with 30%+ of miles covered by spacer cables show, on average, approximately 40% lower SAIDI than circuits with no spacer cables. The data, however, is not definitive given wide range of spacer cable length and non-random placement.

It is important to note that these conclusions are oriented towards mitigating the risk from major events specifically, and do not necessarily reflect the effectiveness of existing LG&E and KU investment programs, which have been focused on maintaining day-to-day reliability.

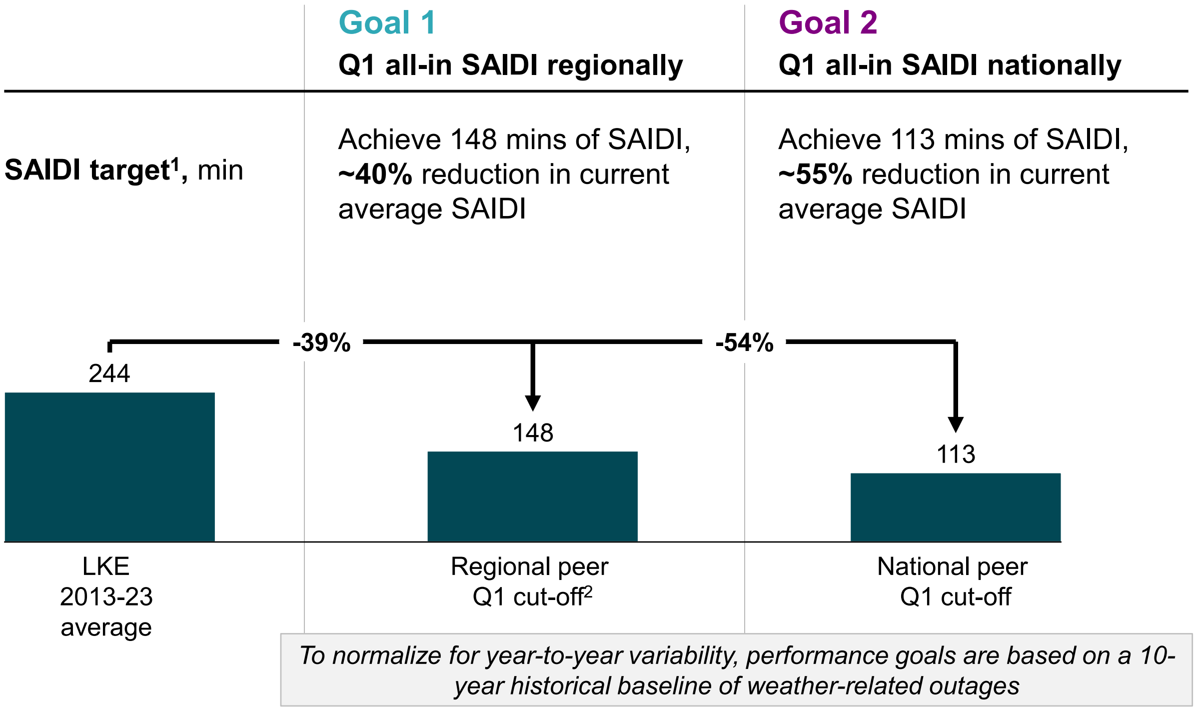
LG&E and KU's performance goals – achieve Q1 performance – and implied investment needs

Having assessed the RROI of different types of investments and the total opportunity on the system, LG&E and KU can then estimate the capital required to mitigate varying levels of risk from major events. LG&E and KU considered three hypothetical resiliency performance outcomes:

- **Goal 1: Achieve Q1 all-in SAIDI, including MEDs, regionally**.
- **Goal 2: Achieve Q1 all-in SAIDI, including MEDs, nationally**

Both of these hypothetical performance goals require reducing outages caused by major events relative to current performance. The following figure provides an overview of the number of SAIDI minutes that would need to be eliminated to reach these goals. A 10-year baseline was used to minimize year-to-year variance in the number of storms.

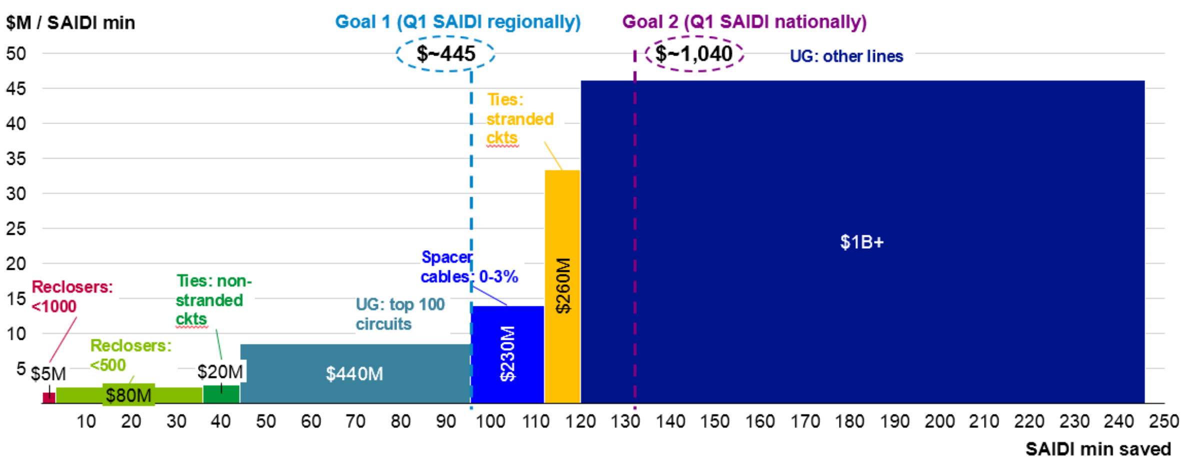
Figure 7-1: LG&E and KU's resiliency targets



1. All-in SAIDI, including MED events as defined by IEEE
2. 10-year average (2013-2022) of the Q1 cut-off

To achieve these goals as cost-effectively as possible, LG&E and KU should prioritize interventions with the highest RROI. The analysis performed shows that the cost of reducing the next outage minute increases non-linearly, as the most cost-effective solutions are exhausted first. Figure 7-2 summarizes this trend below, which shows the cost of mitigating an incremental SAIDI minute by intervention. Mitigating an incremental SAIDI minutes (i.e., reduce average customer outage minutes) requires incremental investment.

Figure 7-2: Required capital investments to reduce a minute of SAIDI



The cost of achieving these goals ranges from approximately $450M-$1,100M in resiliency-focused capital. These investments would likely require an expansion in operational capabilities as well. Undergrounding today is limited in scope, largely focused on pilots. Undergrounding the 100 highest-risk circuits (~360 miles) would require significant growth in capabilities, potentially on top of the incremental capital investment necessary to implement each initiative.

There is a clear value case to LG&E and KU's customers to pursue these investment portfolios, which represent the most cost-effective portfolio for addressing major weather event outages. LG&E and KU can reduce average SAIDI by 40-55% (approximately 95 minutes to 130 minutes) with a capital investment portfolio of approximately $450-1,100M. The annualized economic cost of these outages greatly exceeds the capital portfolio requirements, as shown in Figure 7-3 .

Figure 7-3

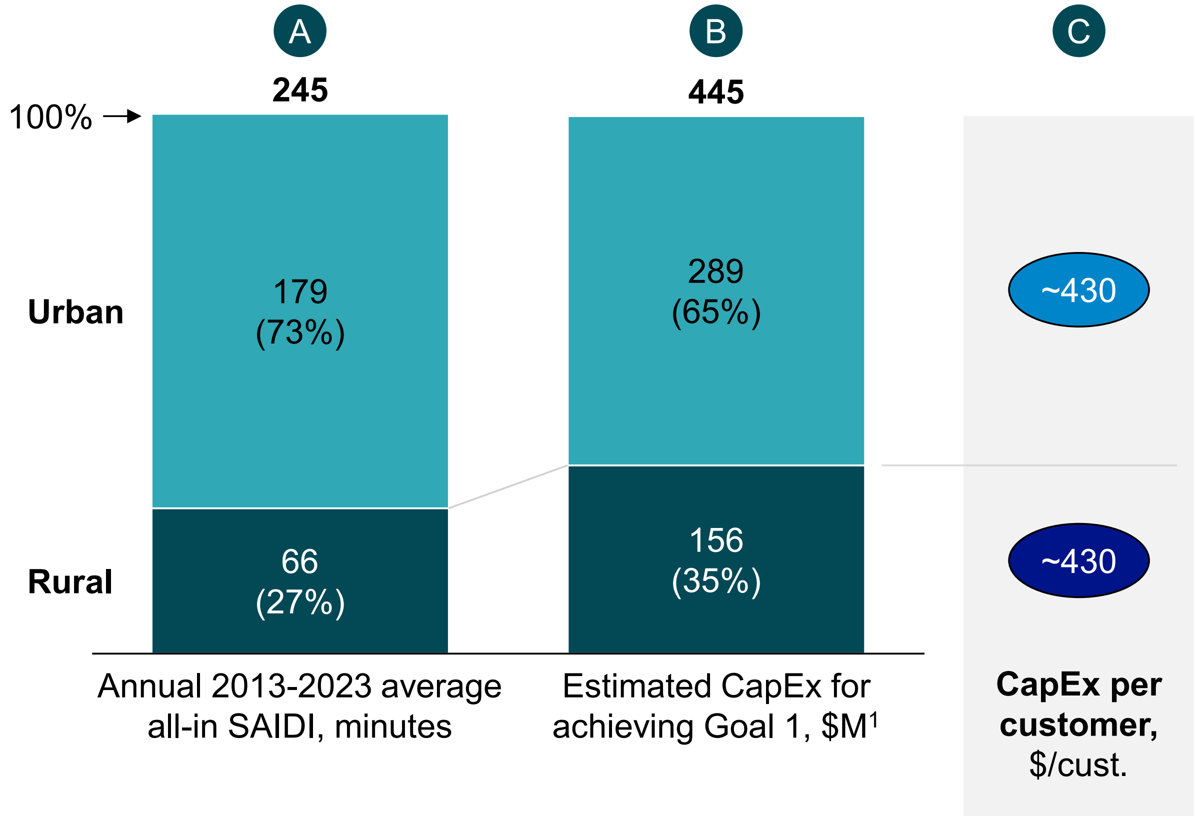
Target resiliency grid performance outcomes	**Goal 1: Q1 all-in SAIDI regionally**	**Goal 2: Q1 all-in SAIDI nationally**
% reduction in all-in SAIDI	**~40%**	**~55%**
All-in SAIDI saved, mins/yr	**~96**	**~131**
MED SAIDI saved, mins/yr	**~69**	**~90**
Estimated capex, $M over 10 years	**~$445M**	**~$1,040M**
Estimated economic cost of addressed outage minutes over 10 years, $M	**~$3,275M**	**~$4,470M**

Other key conclusions

Beyond the cost-effectiveness of the investments, LG&E and KU also took into account several other considerations for these investment plans.

Distribution of benefits. LG&E and KU also considered where these benefits would be realized in LG&E and KU's service territory to ensure equity across urban and rural customers. While modeling identified greater need for investment in more densely populated areas in LG&E and KU's service territory, given that SAIDI impact is concentrated in those areas, the per customer investment need is roughly similar between urban and rural areas. In total ~65% of capital would need to be invested in urban areas such as Louisville and Lexington, addressing ~73% of the SAIDI minutes; the average per customer capital spending, however, is equivalent, as shown in Figure 7-4.

Figure 7-4



Overall –

- A: 73% of historical all-in SAIDI minutes are concentrated in urban areas, such as AOC, EOC, and LEXOC.
- B: 65% CapEx for achieving Goal 1 is projected to be spent in urban areas, proportional to the SAIDI distribution.
- C: However, investment per customer is similar across both urban and rural areas

Operational capabilities. Scaling these capital programs will require additional materials and capabilities, beyond LG&E and KU's historical pace of deploying capital. For example, LG&E and KU has historically deployed approximately100 midline reclosers per year; for LG&E and KU to capture the full resiliency opportunity, it will need an additional 1,000, which could take 10 years if LG&E and KU does not accelerate its deployment. This a key consideration for the company as it considers the pace at which these projects can be executed in the coming years. Figure 7-5 shows the historical pace of these investments and the number of years it would take to complete them given that pace.

Figure 7-5: Overview of investments required to achieve this portfolio

Years to achieve Goal 1 | Add'l years to achieve Goal 2

Investment program	Avg historical execution	Total units in strategic portfolio		Years to achieve goals based on historical execution
Reclosers	100 midline reclosers per year (~1k from 2013 to today)	**1000 to 500**	~60 circuits; ~70 reclosers	<1
		500 to <500	~300 circuits; ~1,000 reclosers	10
Circuit ties	~80 reclosers per year (~580 reclosers from 2017 to today)	**Non-stranded**	~200 circuits; ~235 reclosers	3
		Stranded	~130 circuits; ~360 reclosers[1]	5
Undergrounding	4 miles of UG lines per year (Richmond pilot, started 2023)	**Top 100 ckts**	~100 circuits; ~360 OH miles	>20
		Other ckts	*Not needed to achieve goals*	
Spacer cables	~15-20 miles of spacer cables per year (~500 miles from 1995 to today)	**0 to 3%**	~1,082 spacer cables; ~350 OH miles	18

1. + ~150 miles reconductored, ~200 add'l line miles

Measuring and tracking benefits. Finally, the company has considered how it will track the benefits of these investments over time. The value of resiliency investments is tied to the occurrence of more severe storms, which by nature are more sporadic and difficult to predict. Severe events are low probability, high impact events that account for a growing, outsize proportion of customer outage minutes. Thus, a rolling 10-year all-in SAIDI performance will be the most effective measure for tracking whether these investments are delivering the intended value. LG&E and KU expects to see a clear improvement in storm outage performance over time assuming the same overall level of frequency and severity of storms as the 10-years of historical data used in this analysis.

Appendix A – Risk Return on Investment Modeling Calculations

Resiliency interventions, such as reclosers or undergrounding, are not randomly assigned to specific circuits and are not well-suited for "treatment" versus "control" analysis. However, given sufficient historical outage data, we can make reasonable inferences about the *typical* performance of "treated" circuits (i.e., circuits that were exposed to a specific intervention, such as undergrounding) in relation to "control" circuits (those that were not). This approach is the basis for much of the SAIDI reduction estimates.

The following section will outline how SAIDI calculations were performed for one intervention – undergrounding. A similar process was performed for other initiatives, though some – such as enabling circuit ties – required more tailored analysis.

Step 1: Identifying treatment and control categories

Circuit-level data was used to create four categories of circuits:

a) Mostly overhead: if a circuit's 1- , 2- and 3-phase sections were all >30% overhead. Most circuits fell in this category, which accounted for 85% of circuits and 88% of total circuit mileage.

b) Underground 1-2, overhead 3-phase: This accounted for 143 circuits, equal to 8% of the total circuits and 11% of total miles.

c) Overhead 1-2-, underground 3-phase: This group account for 125 circuits and made up 7% of all circuits but only 1% of total miles.

d) Mostly underground: 1-, 2- and 3-phase sections were all at least 70% underground. This was the smallest group, with only 24 circuits (1% of circuits and miles).

Given the scarcity of data in groups (d), the analysis focused mostly on the overhead circuits in group (a) – used as "controls" – and the partly-underground circuits in groups (b) and (c).

Step 2: Calculating SAIDI performance differences

Within each category, we calculated the average SAIDI performance, scaled by the number of customers served by each circuit. (Circuits with more customers will necessarily have a higher SAIDI in the event of an outage.)

On average, circuits where the single-phase is mostly underground (group B) had a 44% lower SAIDI/customer than mostly overhead circuits (group A). Circuits where the 3-phase lines were mostly underground (group C) performed even better on average, with a 96% lower SAIDI/customer.

The analysis also considered regional differences. This was broadly limited because of data scarcity, and results from a region were not considered if there were fewer than 10 circuits from a given category in that region.

Figure A-1

0-10 | 11-50 | 51-100 | 100+

Results may be skewed by low sample size (N<10)

<-30% | -30-40% | -40-60% | -60%+

Number of circuits[1]

	A Mostly OH	B UG 1-phase	C UG 3-phase	D Mostly UG
AOC	284	23	25	2
EOC	116	61	6	12
LEXOC	184	45	10	6
All other OCs	806	13	6	1
Overall	1,390	142	47	21

SAIDI / '000 customers[2]

	A Mostly OH	B UG 1-phase	A to B Δ, %	C UG 3-phase	A to C Δ, %	D Mostly UG	A to D Δ, %
AOC	1.94	1.43	-26%	0.07	-96%	/	/
EOC	3.60	2.00	-44%	/	/	0.46	-87%
LEXOC	3.52	1.87	-47%	0.09	-97%	/	/
All other OCs	1.47	0.43	-71%	/	/	/	/
Overall	Weighted avg. by customers		-44%		-96%		/

1. Excluding circuits with fewer than 3 customers
2. Using 2013-2023 outage data, including outages from all outage causes

ppl

Step 3: Calculating RROI from undergrounding

In the previous step, the analysis determined an average SAIDI "savings" of 44% and 96% from circuits with underground single-phase and 3-phase lines, respectively. This step uses those SAIDI "savings", alongside the projected cost, to estimate the RROI from each intervention.

The resiliency-ROI (RROI) is, conceptually, an estimate of the minutes of outages avoided per dollar of investment. As such, the numerator is SAIDI "savings" and the denominator is total cost.

To calculate the RROI numerator, the analysis started with the average historical SAIDI for each circuit category (using all outage data from 2013-2023; the analysis can be replicated using only non-MED or only-MED outages). It indicated that an average of ~80 (or ~180) minutes of SAIDI may have been avoided if *all* circuits had mostly underground 1-phase or 3-phase lines, respectively.

The RROI denominator is calculated by multiplying the remaining mileage of 1-phase and 3-phase lines by an estimated cost to underground. This leads to an estimate of ~$5.8B to underground every mile of overhead 1-phase line, and $6.2B to underground every mile of overhead 3-phase line.

The RROI, captured in Figure A-2, is then calculated by dividing the SAIDI savings by cost. It indicates that 3-phase undergrounding is most cost-effective, likely driven by the ~2x higher SAIDI savings based on historical performance.

Figure A-2

	SAIDI savings				÷ Cost				= RROI, SAIDI / $M	
	(A) OH circuits	Avg SAIDI from A[1]	(B) SAIDI saved if B[2]	(C) SAIDI saved if C[3]	OH 1 phase mi	(B) Total cost to UG, $M	OH 3 phase mi	(C) Total cost to UG, $M	(B) UG 1P, SAIDI / $M	(C) UG 3P, SAIDI / $M
AOC	284	38.9	~17	~37	875	852	891	1,424	0.020	0.026
EOC	116	43.4	~19	~42	919	896	556	1,151	0.021	0.036
LEXOC	184	51.8	~23	~50	1,675	1,629	904	1,579	0.014	0.032
All other OCs	806	50.0	~22	~48	7,013	2,435	3,952	2,090	0.009	0.023
Overall	1,390	184.1	~80	~177	10,483	5,811	6,303	6,244	0.014	0.028

1. Using 2013-2023 outage data, including all (MED and non-MED) outages from all outage causes
2. Applying weighted average SAIDI savings from undergrounding 1-phase lines – 44%
3. Applying weighted average SAIDI savings from undergrounding 3-phase lines – 96%

Assumptions

Costs to underground:
3-phase
- **$249/ft** in metro area
  $100/ft in rural area

1-phase
- **$184/ft** in metro area
  $66/ft in rural area

2013-2023 average SAIDI will stay the same in the future (i.e., savings are applied to historical SAIDI, without consideration of how SAIDI may change going forward)

ppl

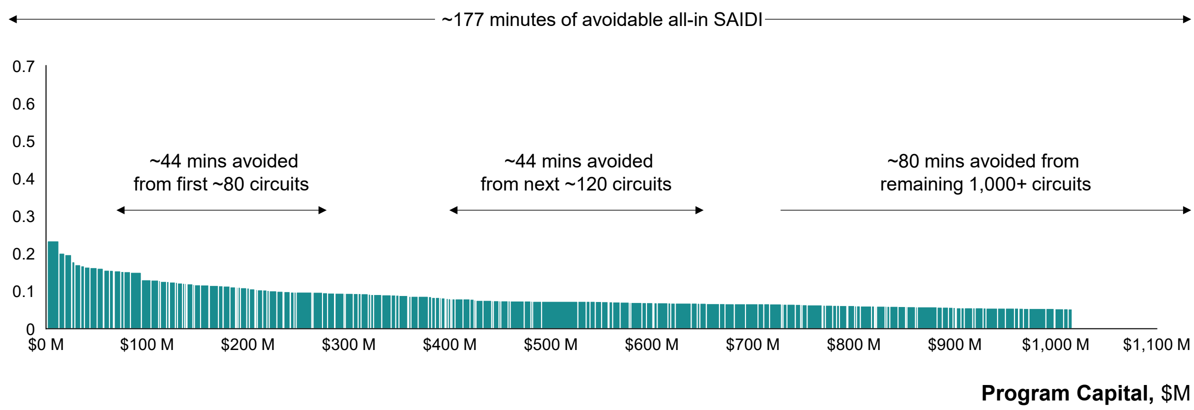
Step 4: Prioritizing individual circuits

The analysis in steps 1-3 is indicative of the system-level SAIDI savings potential from undergrounding. While it can be replicated on a circuit level. The natural limitation to circuit-level analysis is that a specific circuit may not experience the same SAIDI in the future that is has experienced, on average, in the 2013-2023 period. However, circuit-level analysis can still provide a directional estimate of (a) the estimated SAIDI savings from a subset of highest-risk circuits, and (b) the list of circuits that may be prioritized.

To do so, we perform a similar analysis (dividing "savings" by the cost to underground the leftover mileage on each circuit) and rank the circuits by RROI. Figure A-3 demonstrates the skewed nature of RROI results, where <100 circuits – given historical performance – are estimated to account for ~25% of SAIDI savings.

Figure A-3

Risk Return on Investment (RROI), mins SAIDI / $M capex



Appendix B – Portfolio Composition

B.1 Brief overview of RROI calculations for other interventions

The approach to calculating RROI for each intervention was conceptually similar:

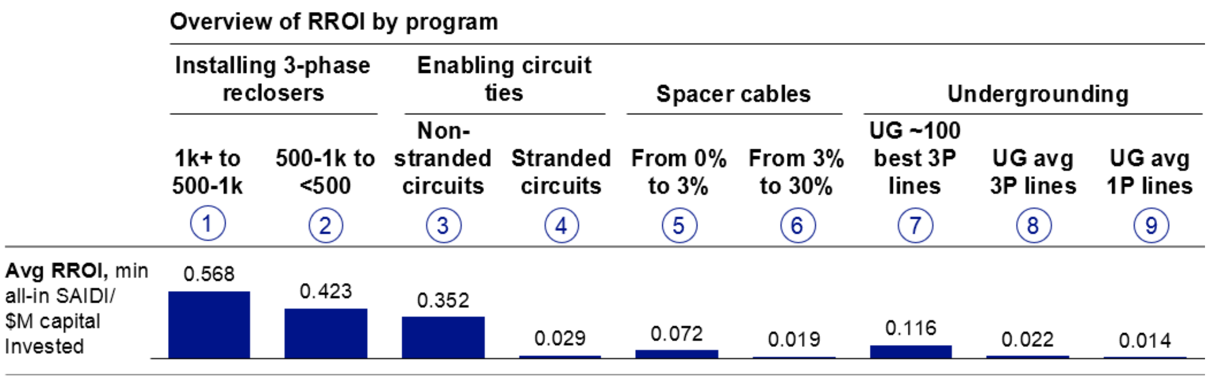
- Circuits were categorized based on whether (or the extent to which) they had undergone a specific intervention
- Historical average SAIDI performance (normalized for customer count) was assessed for each category to estimate the directional impact of the intervention
- Estimated SAIDI "savings" were applied to the historical SAIDI performance for circuits that had not undergone the intervention, which resulted in a rough estimate of future SAIDI savings
- SAIDI savings were divided by the estimated cost of implementing the intervention to come up with RROI

In particular, the categories considered for each intervention were:

- Reclosers: Based on the number of reclosers already present and the number of customers served by a circuit, the categories were circuits with (a) 0-500 customers per segment, (b) 501-1,000 customers per segment, or (c) 1,000+ customers per segment.
- Circuit ties: 4kV and 12kV circuits were separately categorized as having (a) no ties with other circuits, (b) one tie or (c) two or more ties
- Spacer cables: as the spacer cable intervention is not discrete (i.e., spacer cable can cover a continuous range of 0% to 100% of the circuit's mileage), we categorized circuits based on the share of current mileage already covered by spacer cables. The categories of comparison were (a) no spacer cable installed, (b) spacer cable installed on less than 10% of mileage (the in-group average was 3%), and (c) spacer cable installed on more than 10% of mileage (in-group average of 30%).

The end-result of the analysis was a comparison of RROI across interventions, as shown on Figure B-1.

Figure B-1



B.2 Crafting a capital portfolio based on RROI estimates

Capital investment portfolios were designed based on:

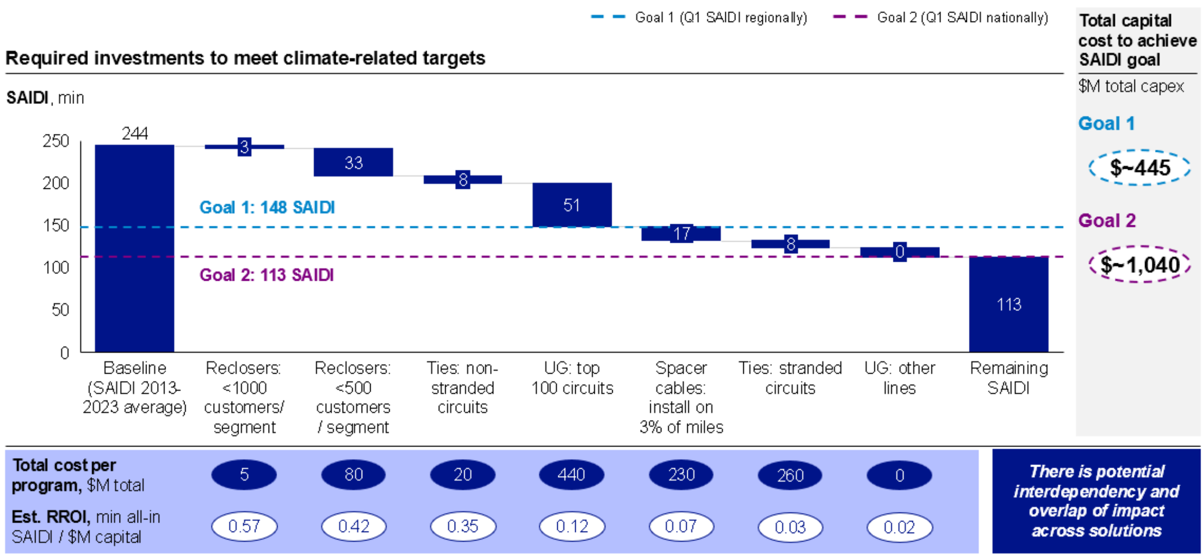
(1) The estimated RROI of each intervention, which determined the *order* in which interventions were selected

(2) The estimated SAIDI savings from each intervention, which determined how far down the list the portfolio needed to go to reach each SAIDI target

(3) The estimated per-unit spend for each intervention, which determined the total capital needed to reach the goal

The waterfall chart in Figure B-2 lays out the portfolio approach. In it, the left-most bar represents the baseline SAIDI, calculated based on the average across the 2013-2023 period. Each following bar is an intervention. Item (1) above determined the order of bars. Item (2) determined the height of each bar. Item (3) determined the total capital needed from each bar once the waterfall reached each goal.

Figure B-2



The logic underlying this analysis is in line with the logic outlined in Section 6 of the main document: the most cost-effective interventions, such as further segmenting the grid, tend to have a limited total impact on SAIDI because they have largely already been implemented. In contrast, the SAIDI savings from undergrounding every circuit would be massive – with a limitation that the cost-effectiveness of each minute of SAIDI savings is significantly lower.

By going down the steps of the waterfall until each goal is reached, the analysis can illustrate a potential investment portfolio, with spend on each program determined by the estimated per-unit cost. For the highest-RROI programs, the total projected spend equals the total possible spend, as LG&E and KU runs out of e.g., circuits to segment. Farther to the right of the chart, there is a choice of how much to spend on lower-RROI programs, such as ties for stranded circuits. The analysis is flexible based on (a) the choice of SAIDI target and (b) assumption on cost for each program.

Appendix C – Considerations on Vegetation Management

LG&E and KU historical data shows that 69% of the total vegetation-driven outages are caused by just 26% of all circuits, highlighting the opportunity to perform targeted vegetation management work to improve grid resiliency.

Targeted vegetation management work includes accelerated trimming on a shorter cycle, and/or targeted canopy and hazard tree removals. The effectiveness of each method depends on the RROI associated with each activity, the calculation of which requires remote sensing and activity-level cost analysis.

□ □ □

EFFECTS OF DISTRIBUTED GENERATION ON DISTRIBUTION & TRANSMISSION

PROBLEM STATEMENT

LG&E and KU (Companies) wish to determine the effects that Distributed Generation (DG) has when designing distribution and transmission infrastructure for new construction. The Companies would like to know if cost savings are possible during engineering and construction if it is known that DG is installed on 20% of the new customers up front during the design process.

APPROACH

Two neighborhoods were chosen for the study due to the likelihood of installing DG. These include the Norton Commons community in Louisville (LG&E) and the Rocky Creek Reserve community in Lexington (KU). Modeling was performed to show the effects of DG on net load for an average customer in each of the two areas, a customer with natural gas service in the LG&E service area and a customer without gas service in the KU service area. These results were used to determine if any design or construction changes would be necessary knowing that a subset of homes would have DG. Additionally, the results from the distribution study were then modeled for a new 500 home development/expansion to determine any impacts on the transmission system. Finally, the Companies gathered costs for typical new neighborhood construction or expansion using traditional design practices. Using the results from the modeling exercise, The Companies predicted any changes in construction costs resulting from DG installation.

DG MODELING EFFORT

15-minute interval load data was collected from customers participating in the AMI smart meter opt-in program over a 2-year span in 2019 and 2020. For the LG&E case, meter data was collected from 47 residential meters on the WO1184 circuit, which feeds the Norton Commons community. Similarly, for the KU case, meter data was collected from 21 residential meters on the 777-0431 circuit, which feeds the Rocky Creek Reserve community. This data was then combined to determine average seasonal load profiles for a typical customer in each of the Companies' service areas.

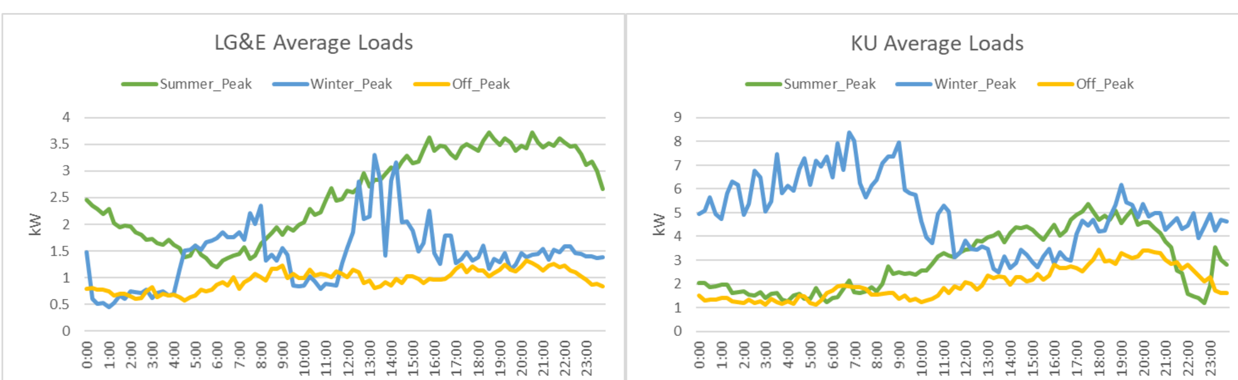


Figure 1 – (Left) Average load profiles calculated from AMI opt-in data on WO1184 in the LG&E service area without DG. (Right) Average load profiles calculated from AMI opt-in data on 777-0431 in the KU service area without DG.

Next, solar production data was gathered from the Companies' Simpsonville Solar Share facility for various seasons (summer, winter, and off-peak; see Figure 2 below). Multiple seasons were chosen due to the variation in solar production throughout the year. Additionally, production profiles favorable to solar were chosen (e.g., essentially no cloud cover was assumed in the summer and winter profiles). This production was scaled to various size arrays (5 kW, 10 kW, and 15 kW) to represent the typical array sizes seen on residential customer interconnections. An example of the 10 kW array production data is shown in the following figure. Analysis was performed using NREL's PVWatts calculator to determine the average annual energy production from various sized arrays.[1] Using this analysis, it was determined that a 10 kW solar array would produce enough energy annually for the average customer in LG&E to consume net zero energy. Similarly, a 16 kW array would result in net zero energy for a KU customer.

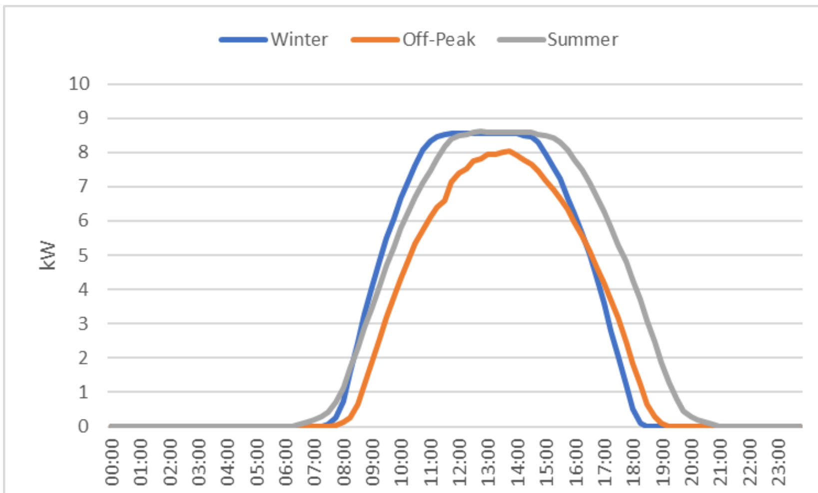


Figure 2 - Solar production profiles used during the analysis. All data was captured from the LG&E and KU Simpsonville Solar Share facility.[2] Note that only the 10 kW array size profiles are shown here and a 1.2 DC to AC ratio was assumed.

The solar profiles in Figure 2 were added to the average customer load shapes in Figure 1 to determine the net load on a typical distribution service transformer serving a single customer. The results of this analysis are shown in Figure 3. Note that without solar, the service transformer would be sized to serve approximately 5 kVA of peak load for an LG&E customer and approximately 10 kVA of peak load for a KU customer. Once the solar array is added to the net load shape, the service transformer must now be upsized to handle increased power flows in cases where the excess solar generation exceeds the average peak load. This could result in increased costs during design and construction of the utility service.

In typical designs, a service transformer serves multiple customers under the assumption that secondary length does not create negative impacts to voltage loss. In instances where multiple customers are served from a single service transformer, it is of importance to note that transformer upsizing would only be required when multiple customers on that transformer install solar PV. In cases where only a single customer on a given service transformer installs solar PV, the excess energy would most likely be

[1] https://pvwatts.nrel.gov/pvwatts.php
[2] https://lge-ku.com/solar-share

consumed by the coincident loads from other customers. Therefore, the locational analysis of solar PV is critical to ensure that service transformers are not overloaded.

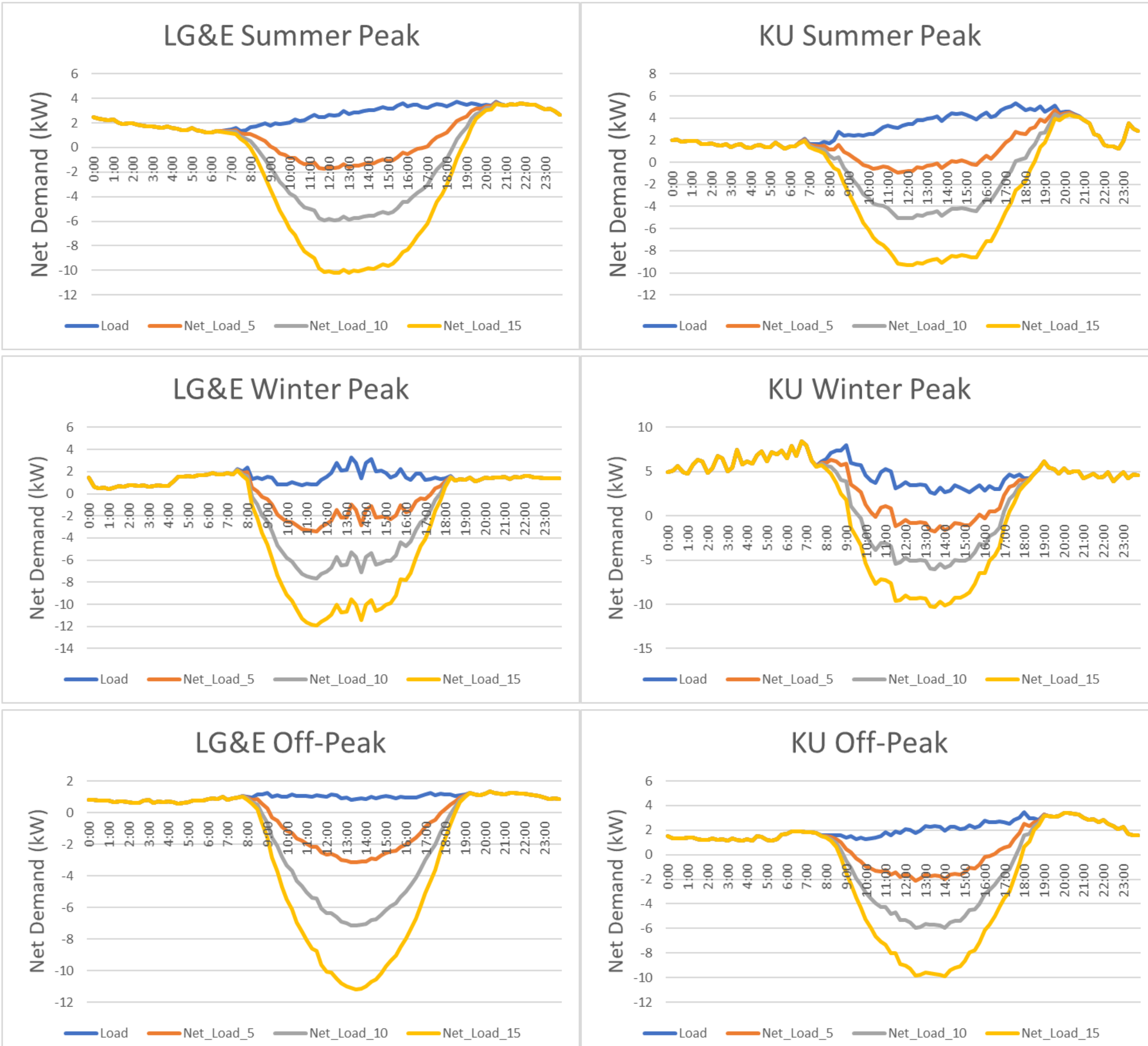


Figure 3 - (Left) Summer, Winter, and Off-peak load profiles with solar for an average LG&E residential customer. (Right) Summer, Winter, and Off-peak load profiles with solar for an average KU residential customer.

Additional modeling was performed at the substation level to determine any resultant effects on the transmission system. Two cases were studied: a 500-home development with no solar added, and a 500-home development with 20% of those new homes (100) having 10 kW rooftop solar arrays. Note that this assumption of nearly 1 MW of DG interconnection in a concentrated area is highly favorable to net metering solar deployment. Especially when considering the 15% capacity limit outlined in the Kentucky

Public Service Commission's current Net Metering Interconnection Guidelines for level 1 installations[3]. If each hypothetical 500-residence development were treated as a standalone line section, due to the need for a sectionalizing recloser, the LG&E development would have a net metering capacity of 45% or more of the hypothetical annual peak load, and the KU development would have a net metering capacity of 20% or more of the hypothetical annual peak load on each respective line section. Both would be well in excess of the 15% limit for level 1 interconnections. Additionally, the highest concentration of net metering generation behind a single substation transformer as of May 1, 2025, is only 508 kW for LG&E and 280 kW for KU, both of which are significantly less than 1 MW.

In LG&E the net impact of the 500-home development at the Worthington substation was modeled, and for KU the net impact at the Newtown substation (777) was modeled. The resultant net loads at each transformer, for each case and season, are shown in the following figure. The addition of solar does reduce the summer peak slightly but has little to no effect on the non-summer peaks, which typically occur outside of the hours that solar produces.

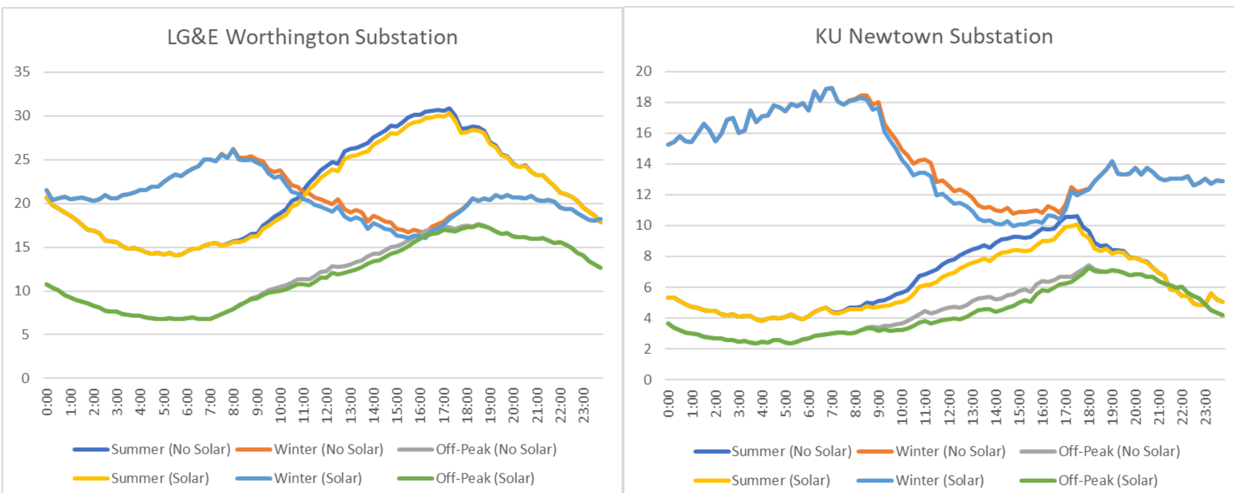


Figure 4 - Impact of 500 home development at distribution substation. (Left) LG&E (Right) KU

The peak load savings from distributed generation for each seasonal profile were then calculated and are summarized in Table 1. Since the net effects of solar generation on system peak are less than 1 MW for LG&E (summer) and 0 MW for KU (winter), the MW savings would be rounded to 0 MW for planning purposes. Therefore, distribution's input in modeling data provided to the Transmission Planning Assessment would be a 0 MW reduction as a result of DG. This is due primarily to the non-coincidence of solar production with the actual load peaks on LG&E and KU circuits.

[3] Under the Kentucky Public Service Commission's current Net Metering Interconnection Guidelines, "For interconnection to a radial distribution circuit, the aggregated generation on the circuit, including the proposed generating facility, will not exceed 15% of the Line Section's most recent annual one hour peak load. A line section is the smallest part of the primary distribution system the generating facility could remain connected to after operation of any sectionalizing devices."

Table 1 - Seasonal load savings at peak resulting from the addition of DG.

	Load Savings w/Solar (MW)		
	Summer	Winter	Off-Peak
LG&E	0.582301	0	0
KU	0.529001	0	0.184921

CONSTRUCTION COST ANALYSIS

Costs were estimated for a typical home development using joint-trench design being added to an existing substation and distribution circuit. These costs were then extrapolated to a 500 home development and are summarized in Table 2. Note that KU does not show any gas costs. Distribution Engineering predicts that the only cost changes due to the addition of solar would be an increase in service transformer costs. This increase is due to the larger transformers needed to support DG injection when multiple homes with solar are connected to a single service transformer. It is estimated that this cost increase would be minimal, around $10k-$11k in total, and is a fraction of the total cost shown in Table 2.

Table 2 - Summary of costs for a 500-home development being added to an existing circuit. The addition of DER is not assumed in this estimate.

Table 3 - Summary of costs for a 500-home development being added to an existing circuit. The addition of DER is not assumed in this estimate.

Line Item	LG&E				KU			
	Material	Labor	Overhead	Total	Material	Labor	Overhead	Total
Gas Pipeline	$121,000	$162,500	$50,068	$333,568	N/A	N/A	N/A	N/A
Wire and Cable	$202,330	$191,682	$70,000	$464,011	$202,330	$191,682	$70,000	$464,011
Transformers	$954,932	$30,591	$12,557	$998,080	$954,932	$30,591	$12,557	$998,080
Conduit/Misc.	$282,955	$405,409	$123,886	$812,250	$282,955	$405,409	$123,886	$812,250
Sectinalzing Recloser	$53,096	$2,607	$9,706	$65,409	$53,096	$2,607	$9,706	$65,409
Total:				$2,673,318				$2,339,750

CONCLUSIONS

In conclusion, the Companies performed modeling using AMI data from two representative circuits. This data, combined with solar production data, was used to determine the net impact on the distribution and transmission systems. Distribution impacts are limited to the possibility of needing larger service transformers to handle excess solar generation. No savings are possible on the distribution system due to adequate capacity already being present. Distribution services provided by the DG are possible, but this is not feasible until a DERMS is implemented, and independent production meters are installed to monitor asset performance. Also, any benefits from distribution services would be localized near the DG interconnection and would provide minimal impact at the distribution substation. Additionally, since 20% penetration of solar PV on a new 500 home development would have little impact on the peak demand for each circuit studied, due to non-coincidence between solar production and load, the net impact on the transmission system would be negligible. Therefore, transmission cannot account for and benefit from the DG when planning or operating the transmission system.