

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,  
NATIONAL GRID USA, and THE NARRAGANSETT ELECTRIC COMPANY

Docket No. D-21-09

PPL Corporation and PPL Rhode Island Holdings, LLC's

Responses to Division's Seventh Set of Data Requests

Issued on August 31, 2021

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Division 7-45

Request:

Referencing PPL's responses to DIV 2-8 and 2-47, please provide copies of grid modernization plans developed by PPL that demonstrate PPL's overall strategic investments and roadmap. Identify:

- a. which portions of those plans have been implemented and provide the associated cost; and
- b. which portions of those plans are anticipated to be implemented in the future and provide the anticipated cost and the recovery mechanism.

Response:

Pennsylvania

PPL and PPL RI refer to PPL Electric Utilities Corporation's ("PPL Electric") Long Term Infrastructure Improvement Plan ("LTIIP"), provided as Attachment PPL-DIV 2-14-1; PPL Electric's Biennial Inspection, Maintenance, Repair and Replacement Plan, provided as Attachment PPL-DIV 2-14-2; PPL Electric's Smart Meter Technology Procurement and Installation Plan, referenced in the response to data request Division 7-49, which can be found at <https://www.puc.pa.gov/pdocs/1296056.pdf>; and PPL Electric's 2020 Annual Smart Meter Progress Report, provided as Attachment PPL\_DIV 7-45-1. PPL Electric makes smart grid investments in the normal course of business and does not have grid modernization or equivalent plans for several of the initiatives referenced in PPL-DIV 2-8 and 2-47.

PPL's prior responses at Division 2-8 and 2-47 along with the attached and referenced plans and documents provide the costs and status of the implementation of the various initiatives referenced in the responses to Division 2-8 and 2-47.

PPL Electric anticipates recovering these costs, with the exception of AMI costs, through its Pennsylvania PUC approved base distribution rates, FERC approved transmission formula rate, or under Pennsylvania Act 11 Distribution System Improvement Charge. PPL Electric recovers the costs of the deployment of AMI meters through a Pennsylvania PUC approved Advanced Metering Rider recovery mechanism.

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Kentucky

PPL and PPL RI refer to Louisville Gas & Electric Corporation ("LG&E") and Kentucky Utilities' ("KU") 2021-2025 Distribution Reliability Resiliency Plan, provided as PPL-DIV 2-14, which describes the specific strategic investments related to grid modernization.

PPL and PPL RI also refer to Attachment PPL-DIV 7-45-2, which is LG&E and KU's Distribution Automation ("DA") program included in the Certificate of Public Convenience and Necessity filing to the Kentucky Public Service Commission in 2016. This program started in 2017 and will complete by 12/31/2021. Anticipated capital expenditures for the full program are estimated to be approximately \$105 million.

PPL and PPL RI also refer to LG&E and KU's KU SCADA Expansion investment proposal, provided as Attachment PPL-DIV 7-45-3. This program started in 2018 and to date (through August 2021) approximately \$16 million has been spent with another \$5 million planned over the next five-year business plan.

PPL and PPL RI also refer to LG&E and KU's Electro-Mechanical Relay Replacement investment proposal, provided as Attachment PPL-DIV 7-45-4. This program started in 2019 and to date (through August 2021) approximately \$15.9 million has been spent with another \$10 million planned over the next five-year business plan.

PPL and PPL RI also refer to LG&E and KU's current development of their forthcoming SCADA Voltage Controller Upgrades investment proposal, which they estimate will be completed by the end of 2021.

LG&E and KU anticipate recovering the costs for these programs through retail rates approved by the Kentucky Public Service Commission.

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**E-File**

August 31, 2020

Rosemary Chiavetta, Secretary  
Pennsylvania Public Utility Commission  
Commonwealth Keystone Building  
400 North Street  
Harrisburg, Pennsylvania 17120

**RE: Petition of PPL Electric for Approval of its Smart Meter Technology  
Procurement and Installation Plan  
Docket No. M-2014-2430781**

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Dear Ms. Chiavetta:

Enclosed for filing on behalf of PPL Electric Utilities Corporation ("PPL Electric") is PPL Electric's Annual Smart Meter Progress Report. This report is being filed pursuant to the Implementation Order issued on June 24, 2019 at Docket No. M-2009-2092655.

Pursuant to 52 Pa. Code § 1.11, the enclosed document is to be deemed filed on August 31, 2020, which is the date it was filed electronically using the Commission's E-Filing System.

If you have any questions regarding the enclosed report, please call me at (610) 774-2599 or Philip S. Walnock, Director – CS Project Management for PPL Electric at (484) 634-3082.

Very truly yours,

A handwritten signature in blue ink, appearing to read "Michael J. Shafer", is written over a horizontal line.

Michael J. Shafer

Enclosures

cc: Lori Burger (via email)  
Daniel Searfoorce (via email)  
Certificate of Service

## CERTIFICATE OF SERVICE

(Docket No. M-2009-2123945 and M-2014-2430781)

I hereby certify that a true and correct copy of the foregoing has been served upon the following persons, in the manner indicated, in accordance with the requirements of § 1.54 (relating to service by a participant).

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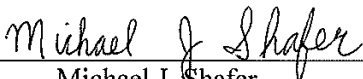
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 I.A.T.  
Michael J. Shafer

**PPL Electric Utilities Corporation**

**2020 Annual Progress Report**

**Smart Meter Implementation Plan**

**(Results to July 31, 2020)**

**Docket No. M-2014-2430781**

**August 31, 2020**

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## Introduction

On September 3, 2015, the Pennsylvania Public Utility Commission (Commission) approved PPL Electric Utilities Corporation's (PPL Electric or Company) Smart Meter Implementation Plan (SMIP) at Docket No. M-2014-2430781. Pursuant to the Implementation Order entered by the Pennsylvania Public Utility Commission (Commission) on June 24, 2009, at Docket No. M-2009-2092655, PPL Electric submits this smart meter progress report for the third period, July 31, 2019 to July 31, 2020 (Current Reporting Period).

The program is on schedule to conclude by the end of 2020; meetings objectives with planned functionality, meter installs, and cost.

PPL Electric oversees a team of program vendors to assist with the planning and implementation of all aspects of the program. Black & Veatch's role on the Project is to provide PPL Electric with program management services and system integration services. Black & Veatch replaced IBM in August 2017.

The Company's technology supplier and meter vendor is Landis + Gyr. They are providing the radio frequency network, Automated Metering Infrastructure (AMI) head end, meter data management system (MDMS), meters and installation services. They are supported by Grid One and Riggs-Distler for network installation, meter installation and meter base repairs. Tesco Services performs quality auditing of work performed.

GE-Digital is providing Mix Director, the primary software system that the Company will use to monitor the AMI network during deployment and in future operations.

Watthour Engineering Company (WECO) is providing the new meter asset management (MAM) system and test boards that is used to test and track meters and network devices.



**Black & Veatch** provided project management and end-to-end systems integration services.



**Landis + Gyr (L+G)** is our vendor for the AMI network devices, AMI meters, meter and network deployment, AMI Head End system and Meter Data Management System (MDMS).



**GE Digital** provided **Mlx Director**, the primary system that Advanced Metering Operations (AMO) will use to monitor the AMI network.



**WECO** provided the new **Meter Asset Management (MAM)** system and test boards that will be used to test and track meters and network devices.



**Riggs Distler**, an authorized sub-contractor of L+G, completed meter base repairs and installed high-end meters, and removed inactive PLC meters that do not need to be exchanged for AMI meters



**Grid One**, an authorized sub-contractor of L+G, installed the AMI meters, performed the meter inspection activities, and hosted a call center.

## Program Scope

PPL Electric's Smart Meter Implementation Plan (SMIP) was designed to meet the Act 129 requirements by first deploying the systems and infrastructure required to enable the new Automated Metering Infrastructure technology. This was then followed by the deployment of radio frequency (RF) meters replacing PPL Electric's existing 1.4 million power line carrier (PLC) meters over a four-year period.

The following items were deployed as part of the program:

- **Customer Web Portal** – The portal was updated to display the customer's interval usage
- **Electric meters** – Use two-way communication to collect electricity usage and related information from customers and to deliver information to customers
- **Local Area Network (LAN) Collectors and Routers** – Devices used to relay and collect meter data from all meters in a local area and transmit to the head end through a wide area network
- **Wide Area Network (WAN) Fiber and Cellular Backhaul** – Communications infrastructure responsible for transmitting the meter data to the head end
- **AMI Head End** – System that receives the stream of meter data from the field making the data available for other systems

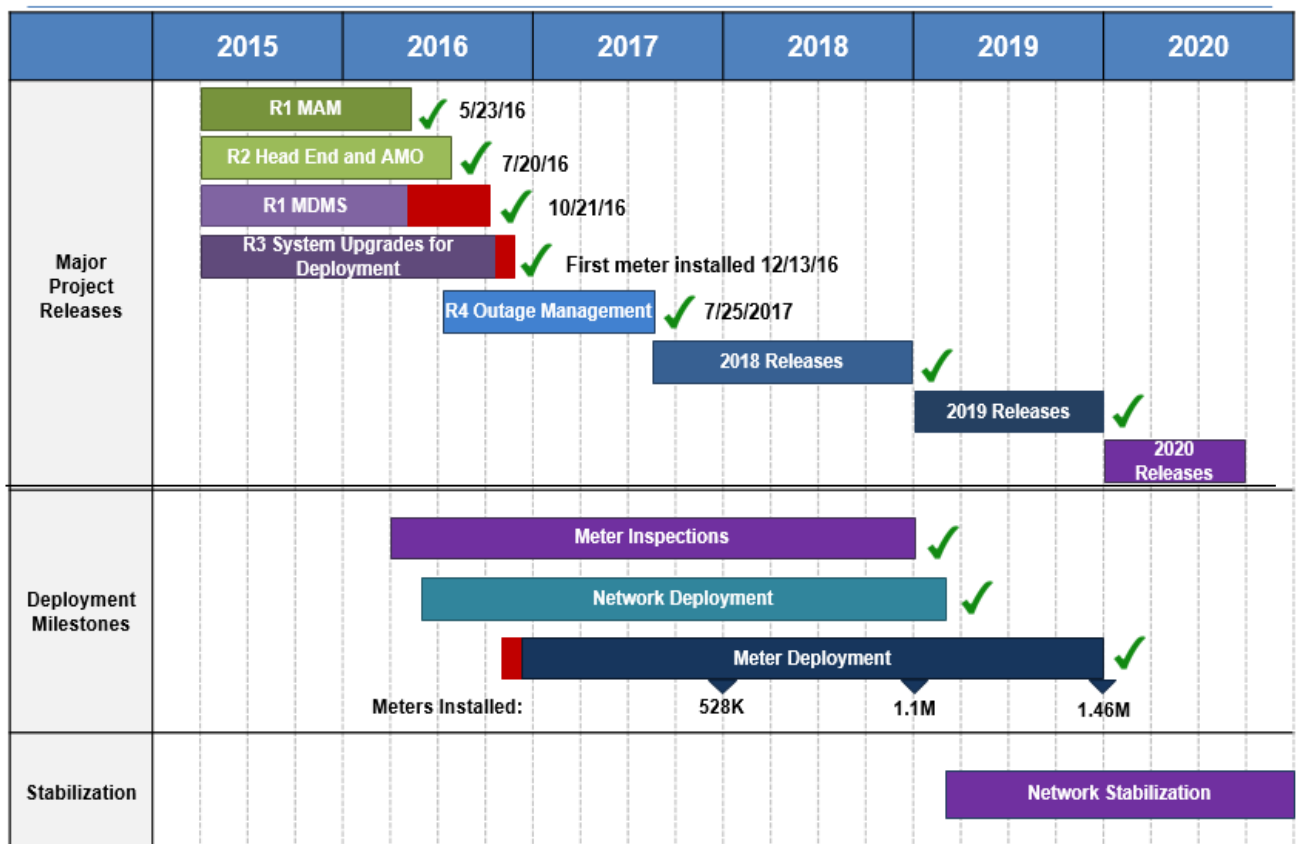


- **Meter Data Management System (MDMS)** – System that collects and stores meter data from the head end system and processes that data into information that can be used by other applications including network operations, customer information system, analytics and asset management
- **Meter Asset Management Tool** – Tool used to store the meter and network components information and manages the life cycle of the asset
- **Mix Director** – Tool used to track and perform analysis and analytics on meter and network information, along with deployment and operations
- **Home Area Network (HAN) Devices** - Customer-owned devices that connect via Zigbee to the meter and display energy usage information

## Release Schedule

All of the systems and technology previously mentioned have been deployed or will be deployed by the end of 2020. The information technology release schedule below covers the initial deployment of the systems followed by releases of additional capabilities. Releases 1 through 3, completed in 2016, were foundational to enable functionality for the deployment of the radio frequency (RF) meters. Subsequent releases enable advanced capabilities.

Below is an overview of the releases followed by a description of the enabling capabilities.



2018 Releases	2019 Releases	2020 Releases
<p><i>Support for a subset of enhanced RF functionality and operational efficiencies</i></p> <ul style="list-style-type: none"> <li>▪ AMI to OMS – Restoration (Power Up) messages for restored customers and Customer Service IVR ping capability</li> <li>▪ Command Center 7.1 MR3 – Production Upgrade</li> <li>▪ Home Area Network (HAN) Pilot</li> <li>▪ Priority Meter Alerts to Automated Filed Ticket Creation</li> <li>▪ Inventory Badge Scanning</li> <li>▪ Added Service Delivery Point (SDP) to Electric Facilities Database (EFD)</li> <li>▪ Enhance Analytics Mix Director Work Bench</li> </ul>	<p><i>Support for a subset of enhanced RF functionality and operational efficiencies</i></p> <ul style="list-style-type: none"> <li>▪ Network Model Validator – Identifying meter to transformer mismatches (AMI to OMS improvements)</li> <li>▪ Mix Director Upgrade</li> <li>▪ Polyphase Meter Diagnostic Notifications</li> <li>▪ MDMS Enhancements <ul style="list-style-type: none"> <li>- Estimates to CSS for Billing</li> </ul> </li> <li>▪ Nominal Voltage</li> <li>▪ Command Center 7.3 MR2 – Production Upgrade <ul style="list-style-type: none"> <li>Meter Asset Management updates to support Return Merchandise Authorization (RMA) process and improved inventory tracking</li> </ul> </li> <li>▪ Home Area Network Program</li> <li>▪ Begin transition of RF Network Management to PPL</li> </ul>	<p><i>Support for a subset of enhanced RF functionality and operational efficiencies</i></p> <ul style="list-style-type: none"> <li>▪ RF Network Management transition to PPL, including Field Backoffice Support</li> <li>▪ Deployment of Advanced Security Devices</li> <li>▪ Meter Asset Management updates to support Meter Failure Tracking and reporting</li> <li>▪ Revenue Protection &amp; AMI advanced analytics</li> </ul>

## Deployment

The Company's deployment plan was executed in accordance with the Smart Meter Plan. The full-scale deployment of RF meters began in December 2016 with mass deployment completed the end of 2019.

Meter deployment is broken into three distinct phases:

- Meter inspections, or pre-sweeps, were performed to identify issues or barriers to be resolved prior to physical meter deployment. An example is the identification of meter bases that need repair or replacement for a successful meter exchange.
- Network deployment is the build-out of the AMI network infrastructure of collectors and routers to transmit data and information from the meter to the AMI head-end system.
- Meter deployment is the physical replacement of the Company's existing PLC meters to new RF meters.

The first three deployment phases occurred on a regional basis sequentially through PPL Electric's six major operating regions: Harrisburg, Lancaster, Lehigh, Northeast, Central, and Susquehanna. The final phase occurred across the entire service area based on resource availability and need.

## Meter Inspections

PPL Electric precedes physical meter deployment with a meter inspection phase. This work began in October 2015 and occurred approximately six to eight months prior to meter installations in a given region. Meter inspections finished in at the end of 2018 with a total of 1.39 million inspections completed across PPL Service Territory.

These inspections identified any Rules for Electric Meter Service Installation (REMSI) violations; REMSIs are the Company's standards for meter installations. As stated earlier, PPL Electric was also able to anticipate meter base repairs that will be required in the course of meter deployment.

## Network Deployment

Deployment of the radio frequency network preceded meter installation by approximately five months. Planned RF network build out was completed in early 2019. After the initial deployment of the network components, additional work remains to optimize the network and provide support for maximum effectiveness. RF network optimization will continue through stabilization.

Collectors are being installed to form the backbone of the radio frequency network. These collectors are the "take out points" for all network data and they communicate back to the AMI Head End via cellular communications or optical fiber. As of July 31, 2020, 255 collectors have been installed with 67 collectors deployed as a part of network optimization.

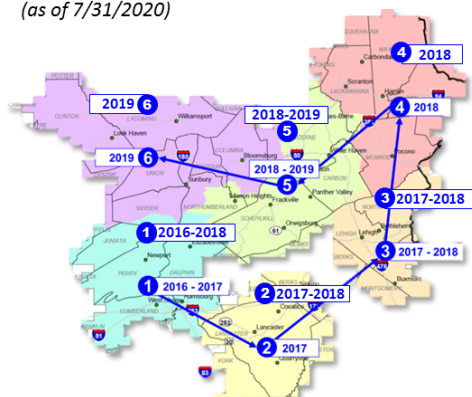
Routers will support collectors as a part of the RF Network. Routers are radio frequency devices that intercede between meters and other routers to ensure a fully formed radio mesh network allowing for a variety of communication paths from meter to collector. As of July 31, 2020, 5,077 routers have been installed with approximately 427 deployed through network optimization.

## Meter Deployment

RF meter exchanges began in the Harrisburg region in December 2016, the Lancaster region in July 2017, the Lehigh region in November 2017, the Northeast Region in May 2018, the Central Region in Oct 2018, and Susquehanna Region in March 2019.

As of July 31, 2020, 1,467,105 meter exchanges have been completed. Mass meter deployment is complete in all regions. There are 40 remaining meter endpoints that still have PLC meters on them. These locations are on hold due to PUC complaint proceedings and will be exchanged when the approval to proceed is granted.

(as of 7/31/2020)



Region	Pre-Sweep Inspections	Network Installations	Mass Meter Deployment	PPL UTC Clean Up
1. Harrisburg	Complete	Complete	Complete	100.00%
2. Lancaster	Complete	Complete	Complete	100.00%
3. Lehigh	Complete	Complete	Complete	100.00%
4. Northeast	Complete	Complete	Complete	100.00%
5. Central	Complete	Complete	Complete	100.00%
6. Susquehanna	Complete	Complete	Complete	100.00%

Note: 'End' represents mass deployment planned completion month

## Meter Base Repairs

PPL Electric is repairing meter bases in instances where the meter base conditions may not be conducive to safe meter exchanges. Approximately 10,721 meter base repairs were completed for exchange of a RF meter. Repairs to facilitate a meter exchange were conducted at a rate of approximately 0.8% of the premises where meters have been installed.

## Progress on the End-to-End Solution

PPL Electric has delivered strong meter reading performance with its legacy PLC based AMI system. Meter read performance of the new RF based system is also performing at a very high level, exceeding the industry standard read rate of 99.5%.

Metric	Target	2017 Total	2018 Total	2019 Total	2020 Total*
Interval	99.75%	99.89%	99.82%	99.86%	99.97%
Billing Register	99.75%	99.90%	99.79%	99.86%	99.87%

\* 2020 Results through July 31, 2020

## Customer Interaction

In accordance with the PPL Electric's approved Communications Plan, all customers were notified of pending meter replacements in several separate contact attempts. Each customer received a letter six weeks and three weeks prior to the meter exchange. Customers also received an automated phone call the day before their planned meter exchange. On the day of the installation, the installer knocked on the customer's door prior to the meter exchange. A door hanger was left at the premise at the conclusion of the visit.

PPL Electric has received 3,083 customer inquiries regarding the program out of 1,467,105 installations, or 0.21% of the installations. Some topics of these inquiries include:

- Questions regarding field work to be performed or completed
- Questions about scheduling an appointment for a meter exchange
- Statements regarding not wanting a new meter due to health and/or privacy concerns

There are currently zero pending customer inquiries.

## Remote Connect / Remote Disconnect

Remotely connecting or disconnecting service (RCRD) went live on April 1, 2017. The matrix below outlines transaction success rate by process and overall.

### RCRD Performance

		2017 Total	2018 Total	2019 Total	2020 Total *	Project To Date
Cut-Ins	Total Cut-Ins Attempts	8,833	33,798	39,544	1,128	83,303
	Total # of Successful Cut-Ins	8,618	33,473	39,416	1,124	82,631
	% Successful Cut-Ins	97.6%	99.0%	99.7%	99.6%	99.2%
Cut-Outs	Total Cut-Outs Attempts	11,222	43,809	53,005	1,966	110,002
	Total # of Successful Cut-Outs	11,013	43,239	52,830	1,964	109,046
	% Successful Cut-Outs	98.1%	98.7%	99.7%	99.9%	99.1%
Move-In	Total Move-In Attempts	10,475	48,725	62,834	28,346	150,380
	Total # of Successful Move-Ins	10,370	48,513	62,710	28,279	149,872
	% Successful Move-Ins	99.0%	99.6%	99.8%	99.8%	99.7%
Move-Out	Total Move-Out Attempts	8,312	38,355	48,236	24,351	119,254
	Total # of Successful Move-Outs	7,990	37,710	48,114	24,272	118,086
	% Successful Move-Outs	96.1%	98.3%	99.7%	99.7%	99.0%
Total	Total Transactions	38,842	164,687	203,619	55,791	462,939
	Total Successful Transactions	37,991	162,935	203,070	55,639	459,635
	% Successful Total Transactions	97.8%	98.9%	99.7%	99.7%	99.3%

\* 2020 Results through August 9, 2020

## Financial Analysis / Cost Recovery

The financial analysis below shows actual costs per year and split between capital and operational and maintenance costs. This view shows the actual costs since project inception along with projections for future costs.

<b>Actual Spend</b>	<b>Capital</b>	<b>Expense</b>	<b>Total</b>
12/31/2015	\$ 24,896,798	\$ 2,535,621	\$ 27,432,419
12/31/2016	\$ 70,874,632	\$ 2,426,326	\$ 73,300,958
12/31/2017	\$ 133,868,867	\$ 8,149,909	\$ 142,018,776
12/31/2018	\$ 118,216,208	\$ 8,346,431	\$ 126,562,639
12/31/2019	\$ 71,682,013	\$ 5,788,652	\$ 77,470,665
7/31/2020	\$ 19,511,026	\$ 3,760,059	\$ 23,271,085
<b>Total Project to Date</b>	<b>\$ 439,049,544</b>	<b>\$ 31,006,998</b>	<b>\$ 470,056,542</b>
<b>Projected Spend</b>			
8/1/2020-12/31/2020	\$ 4,548,974	\$ -	\$ 4,548,974
<b>Total Projected</b>	<b>\$ 4,548,974</b>	<b>\$ -</b>	<b>\$ 4,548,974</b>
<b>Total Actual + Projected</b>	<b>\$ 443,598,518</b>	<b>\$ 31,006,998</b>	<b>\$ 474,605,516</b>



## **Look Ahead**

With only 40 meter installations pending to be completed, PPL Electric is in the process of completing stabilization and looking to conclude the plan by the of this year.

## **Conclusion**

In summary, PPL Electric has followed its approved SMIP without the need for any material modifications. The RF meters installed, along with the scope, schedule, and cost of the program, are in direct alignment with the approved plan.

## Exhibit PWT-5

# LG&E and KU Electric Distribution Operations Distribution Reliability and Resiliency Improvement Program

## *Electric Distribution Operations*

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# Distribution Reliability & Resiliency Improvement Program



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**Exhibit PWT-5**  
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# 1. Executive Summary

Customer needs and expectations respective to electric service reliability, system resilience, outage response, and power quality continue to evolve and expand with advancements in grid and customer end-use technologies; electricity is increasingly entwined in nearly every aspect of their lives. Because of the broadening electrification of virtually everything, Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU), along with the rest of the electric industry, must continually monitor and assess electric delivery performance, and adjust associated electric grid investments and sustainability programs as needed to align with changing customer requirements. Inadequate service reliability or power quality, and long duration outages, are no longer tolerable due to the significance of consequences on customers.

As stewards of the electric distribution system, Electric Distribution Operations (EDO) is responsible for assuring LG&E and KU serve customers with safe, reliable, resilient, and affordable electric service. Consistent with the industry, EDO monitors and benchmarks reliability performance using standard indices defined by the Institute of Electrical and Electronics Engineers (IEEE). [REDACTED]

In the aftermath of the 2008 Hurricane Ike Wind Storm and 2009 Kentucky Ice Storm, which produced the most significant system damages and customer outages in company history, LG&E and KU electric service reliability and customer satisfaction levels declined. In response, EDO studied alternatives for enhancing electric system resiliency to guard against similar extensive and residual system damages and long duration outages for customers. As a result of these studies, EDO broadened and enhanced its portfolio of distribution system reliability and resiliency programs starting in 2010.

In total, LG&E and KU allocated more than \$192 million in Capital and \$36 million in Operations and Maintenance Expenses (OPEX) between 2010 and 2016 on incremental programs, including circuit hardening/reliability, pole inspection and treatment (PITP), aging infrastructure replacement (AIR), distribution substation transformer contingency (N1DT) and hazard tree mitigation. These programs produced significant improvements in LG&E's and KU's key reliability performance metrics (more than 22%) and contributed to improved customer satisfaction ratings (more than 16%) between 2010 and 2015.

As EDO's incremental reliability and resiliency programs have matured, step improvements in system performance and customer satisfaction levels have and will continue to become increasingly more difficult to attain. Expanded investment programs are necessary to further align system performance and service reliability with expanding customer expectations and needs.

In order to address evolving customer expectations and service challenges, EDO's 2017-2021 Business Plan allocates investment of approximately \$352 million in capital and more than \$29 million in OPEX on enhanced reliability and resiliency programs. The plan includes continued funding of EDO's existing circuit hardening (including the Circuits Identified for Improvement (CIFI) and Hazard Tree Programs), PITP, and AIR programs, as these programs continue to deliver system reliability and resiliency improvements. Substantial shifts in funding away from these programs would increase outages and decrease operational contingency. EDO's business plan also includes targeted incremental investments in the advancement of distribution automation (DA) and expansion of its distribution substation transformer contingency (N1DT) program.

## **Distribution Automation Program (DA)**

EDO's proposed Distribution Automation (DA) Program includes \$112.4M in investments between 2016 and 2022. EDO's proposed 2017 Business Plan allocates \$94.1M between the plan years 2017 through 2021 for DA. The proposed DA program will provide for acquisition and deployment of Distribution Supervisory Control and Data Acquisition (DSCADA) and a Distribution Management System (DMS), and purchase and installation of approximately 1,400 electronic SCADA connected reclosers. Approximately 360 (20%) distribution circuits and 50% of LG&E and KU customers will be targeted by the program.

The advanced technology and functionality enabled by the DA program will significantly reduce the number of customers affected by outage events, reduce restoration times for customers affected by outages, and improve operational efficiency. SAIDI and SAIFI performance is expected to improve by 12% and 19% respectively, over the next six years (2017 - 2022). The DMS will provide advanced functionality required to achieve incremental DA benefits, including Power Flow (PF); Fault Location Analysis (FLA); Suggested Switching (SS); and Fault Location, Isolation and Service Restoration (FLISR). On circuits where DA is deployed, real time data from smart reclosers will provide intelligence and remote capabilities to support switching, safety, productivity and efficiency. The technology will also enable advanced monitoring and control of the distribution system, enhance crew dispatching processes, and reduce field crew truck rolls and mileage.

## **Distribution Substation Transformer Contingency (N1DT) Program**

EDO's proposed Distribution Substation Transformer Contingency (N1DT) Program includes \$175M in investments between 2015 and 2029. EDO's proposed 2017 Business Plan allocates \$47.8M between the plan years 2017 through 2021 for this program. This funding level supports EDO's 15-year N1DT Contingency Program to further improve the integrity and recovery characteristics of LG&E and KU's distribution infrastructure and operations, through deployable or permanent "N-1" contingency design on its system. Approximately 63% of LG&E and KU's distribution power transformers do not have full contingency. If one of these substation transformers fails during high

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load or peak conditions, some customers will be without service until the transformer capacity is replaced, a process that can sometimes take multiple days. EDO's N1DT contingency program will mitigate potential high impact, long duration service interruptions which would likely result whenever a substation transformer fails, by making available either a permanent or deployable back-up source to support system and customer restoration.

The N1DT contingency program provides a three tiered approach for adding capacity in the event of a substation transformer failure: (1) the addition of permanent system capacity for full redundancy through switching. This includes substation transformer additions, circuit upgrades, and other system enhancements; (2) expanded use of mobile transformers; and (3) use of small localized spare distribution power transformers to restore service in the most efficient, and cost effective manner. Projects will be selected on a value-based approach, balancing the load density and customer impact with the cost of implementing the contingency enhancement.

EDO's investment strategies and programs referenced herein will advance grid intelligence, assure continued improvement in reliability performance and power quality, build additional contingency into critical assets, and provide for enhanced diagnostics capabilities, operational control, and system flexibility. These planned investment strategies align with industry best practices, and will modernize the grid and enable the company to satisfy expanding customer expectations.

## 2. Case for Action/Performance Objectives/Strategy

### 2.1 Background

Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU) serve nearly 1.3 million customers, and consistently rank high in customer satisfaction among utilities. LG&E serves 403,000 electric customers in Louisville and 16 surrounding counties, and KU serves 546,000 electric customers in 77 Kentucky counties and five Virginia counties.

LG&E and KU participate in multiple industry accepted customer satisfaction surveys, the most recognizable of which is administrated by J.D. Power, which evaluates several key indices. Figure 1 displays LG&E and KU's nationwide customer satisfaction rankings based on the J.D. Power 2016 Electric Utility Residential Customer Satisfaction Study published in July 2016.

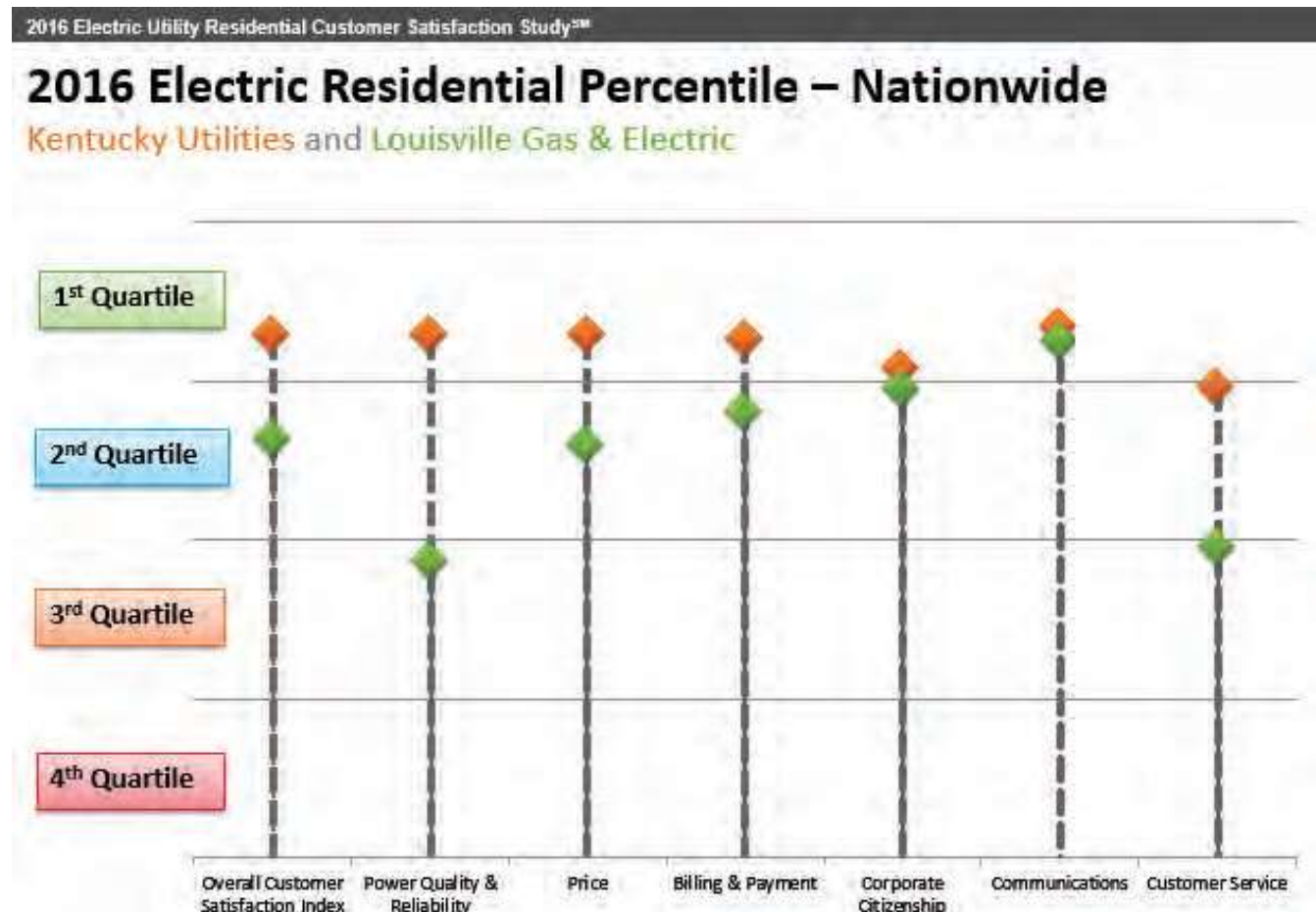


Figure 1: J.D. Power 2016 Electric Utility Customer Satisfaction Survey

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LG&E and KU customer satisfaction ratings were first or second quartile in nearly every category within the survey, including the Overall Customer Satisfaction category. Customers' perception of LG&E and KU's power quality and reliability performance ranked in the first and at the top of the third quartile respectively, nationwide.

When evaluating LG&E and KU's customer satisfaction ratings compared to the industry, it is important to note two key characteristics of the J.D. Power Study (gleaned from an article published in Public Utilities Fortnightly,<sup>1</sup> January 2013):

1. First, geography appears to have the greatest impact on relative customer satisfaction across the United States. Utilities in the Northeast and Midwest consistently have lower customer satisfaction rankings than utilities in the Southwest, Northwest, and Southeast. LG&E and KU continues to realize customer service rankings which are first or upper second quartile nationally in overall customer satisfaction, despite being located in the Midwest, a geographical area with historically lower relative customer satisfaction rankings.
2. Second, and more importantly, other than geography, reliability performance appears to have the greatest influence on the relative value of other key electric utility customer satisfaction indexes in the J.D. Power survey. LG&E and KU's high rankings in overall customer satisfaction are likely reflective of LG&E and KU's continued strong reliability performance relative to the industry.

LG&E and KU also use a third party vendor (Bellomy Research) to conduct an annual Residential Customer Satisfaction polling study among all LG&E, KU, and ODP customers (Figure 2). Overall satisfaction is measured on a 10-point scale with 10 being the most satisfied. The customer satisfaction scores in Figure 2 represent the percentage of customers rating the utility a 9 or 10 since 2006.

## Percentage of Customers Rating 9 or 10

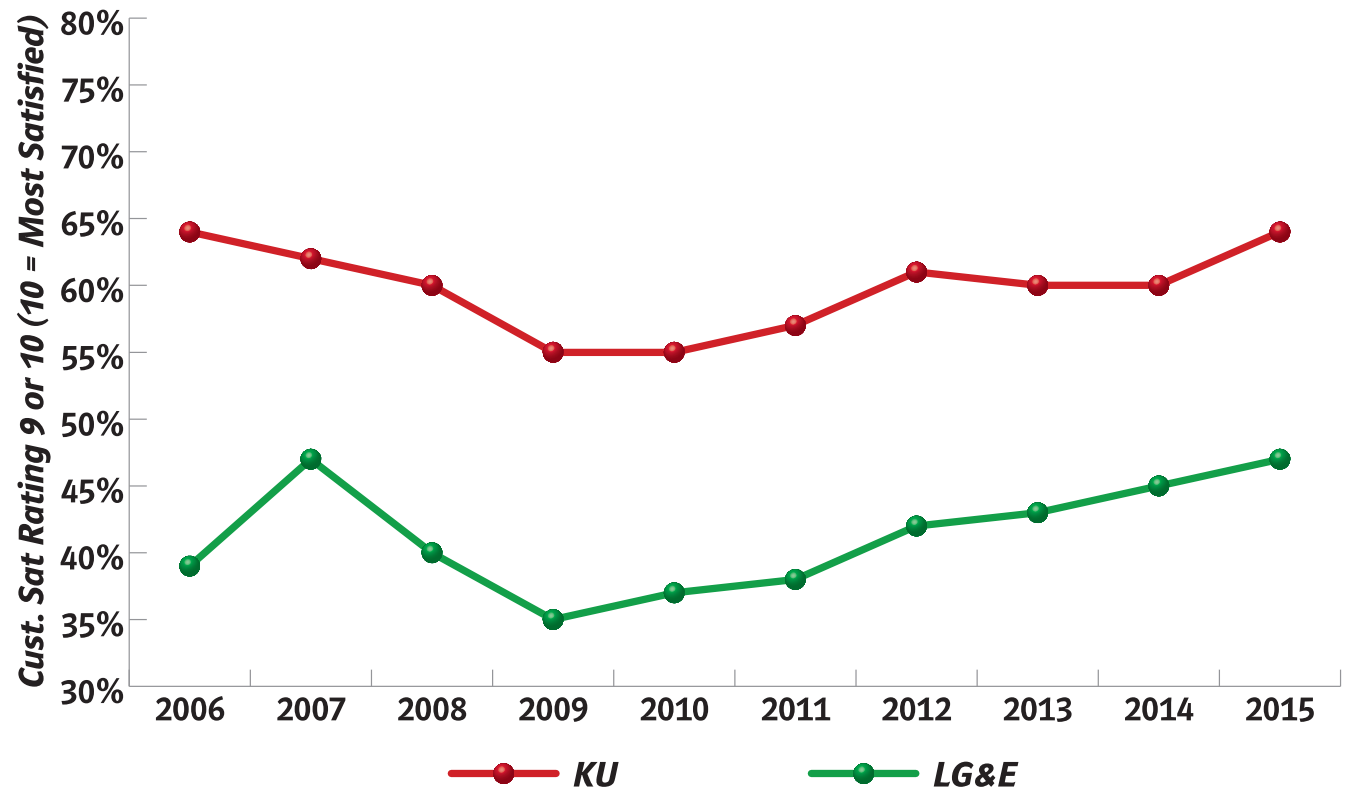


Figure 2: LG&E and KU customer satisfaction ratings.

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1. Reference: Public Utilities Fortnightly; Rates, Reliability, and Region - Customer Satisfaction and Electric Utilities; By William Zarakas, Philip Hanser, and Kent Diep; Principals and Research Analysts — The Brattle Group; January 2013.

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## REDACTED Pursuant to Third-Party Nondisclosure Agreement

LG&E and KU's SAIDI and SAIFI performance ranked REDACTED Pursuant to Third-Party Nondisclosure Agreement prior to the 2008 Hurricane Ike Wind Storm and 2009 Kentucky Ice Storm. Immediately following these storms, the most significant outage events in the combined utilities' histories,<sup>7</sup> LG&E and KU's actual and comparative reliability performance (Figures 3-6) and customer satisfaction levels (Figure 2) declined. Moreover, LG&E and KU customer satisfaction levels reached historically low levels between 2009 and 2011.

In response to the historical storms and reduced customer satisfaction levels, EDO studied alternatives for enhancing electric system resiliency<sup>8</sup> to guard against similar extensive system damages and long duration outages for customers. From this study, EDO implemented several system reliability and resiliency enhancement programs in 2010, including a Pole Inspection and Treatment Program (PITP) and Hazard Tree Program. EDO also increased investments in circuit hardening reliability programs that had proven valuable over time, namely the CIFI program. In subsequent years, EDO allocated incremental funding for Aging Infrastructure Replacement (AIR) and Distribution Substation Transformer Contingency (N1DT) programs.

Figure 7 displays EDO's electric distribution system reliability and resiliency capital investment allocations between 2006 and 2015.

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7. The 2009 Kentucky Ice Storm ranks as the largest outage event in LG&E and KU history — 654k customer outages on 8.7k outage events; Hurricane Ike ranks second — 480k customers affected, on 6.1k outage events.
8. **Definition:** Resilience, is defined as "robustness and recovery characteristics of utility infrastructure and operations, which avoid or minimize interruptions of service during an extraordinary and hazardous event."  
**Source:** National Association of Regulatory Utility Commissioners, Resilience in Regulated Utilities; Miles Keogh, Christina Cody, NARUC Grants and Research — with support from DOE; November 2013.

## Electric Distribution Operations System Reliability and Resiliency Improvement Programs

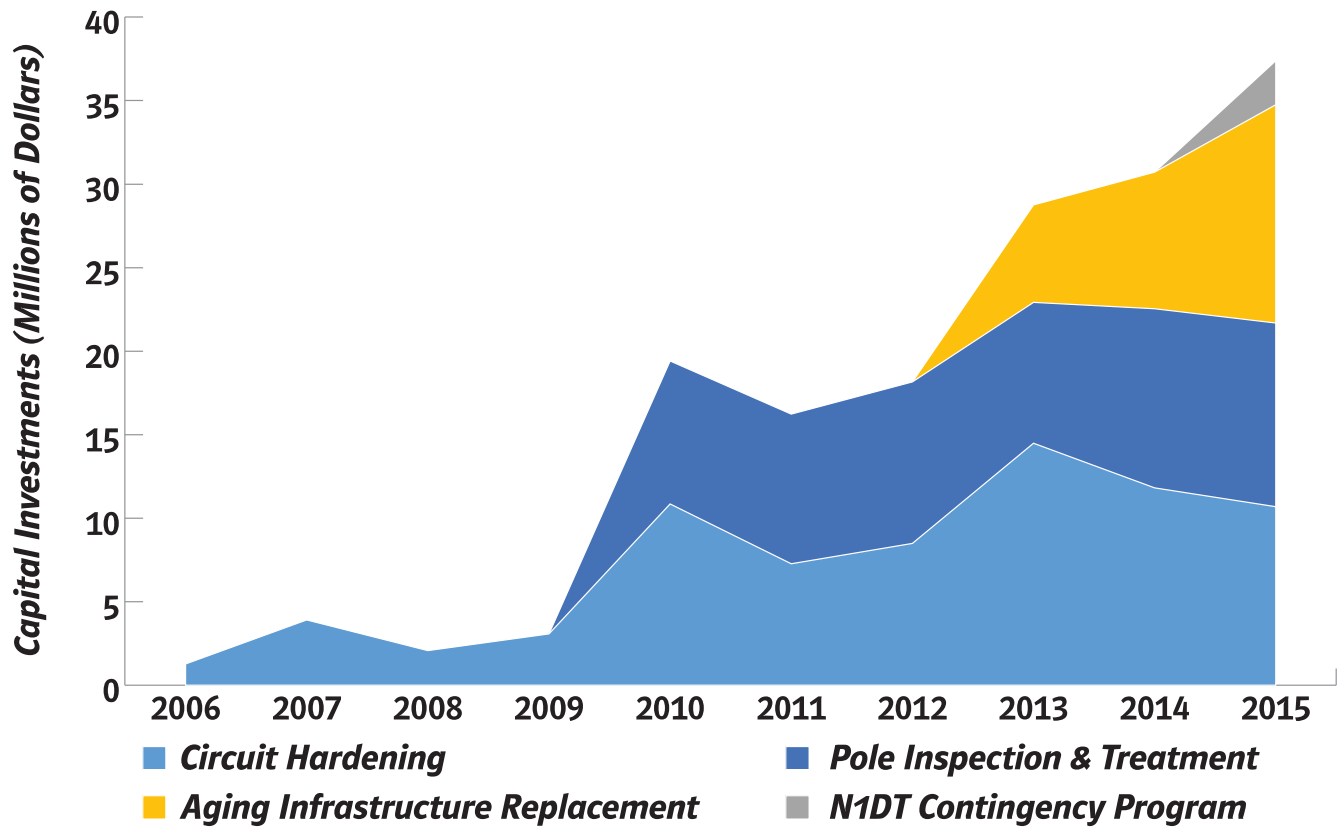


Figure 7: LG&E and KU electric distribution service reliability and system resiliency capital investment programs (2006-2015).

EDO's increased investments in reliability and resiliency produced significant improvements in LG&E and KU SAIDI (22%) and SAIFI (24%) between 2010 and 2015. Additionally, LG&E and KU's customer satisfaction ratings improved between 16 and 27 percent. EDO attributes much of its realized reliability improvements to its CIFI program. Between 2010 and 2015, EDO completed circuit hardening on 190 LG&E and KU circuits which were targeted for the CIFI program based on historical Customers Interrupted (CI). During the same period, 245 electronic reclosers were installed primarily through the CIFI program.

When the CIFI program was initiated, EDO understood that eventually, the same investment would yield progressively smaller reliability benefit per dollar invested. Figure 8 displays the average SAIFI contribution of circuits targeted for improvement since 2010. As the CIFI program has progressed, the average annual SAIFI contribution of circuits targeted for the program has steadily decreased, indicating reduced opportunity to realize further step improvements in SAIFI through the existing program. Realizing this, EDO assessed alternative investment strategies for achieving step improvements in reliability and customer satisfaction.

## Average CIFI Circuit SAIFI

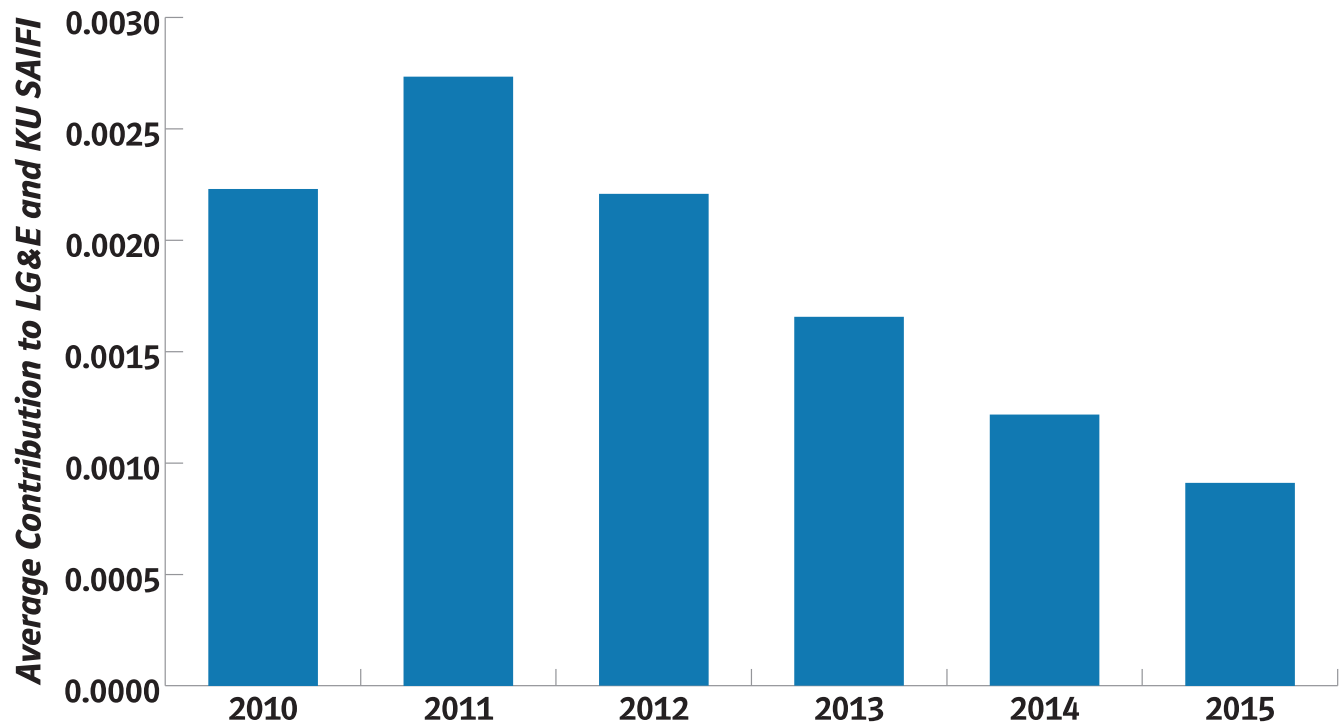


Figure 8: Average Circuit SAIFI Performance for LG&E and KU circuits selected for EDO CIFI Programs 2010–2015.

### 2.2. Industry Perspective

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converging and enhanced reliability performance characteristics are being attributed to vastly increased capital investments and modernization of electric distribution systems across the industry.

In addition to its customer service and reliability performance benchmarking studies, EDO routinely surveys the electric industry to identify emerging and advancing technologies for improving distribution resiliency and reliability. Over the past decade, most leading electric utilities have focused on improving distribution reliability by increasing capital investments in circuit hardening and critical asset contingency. More recent trends in the industry point to accelerated investment strategies in grid intelligence technologies in response to increasing customer expectations for reliable power, and the proliferation of distributed energy resources (DER).

Based on EEI's analysis, annual capital investments in U.S. investor owned electric utilities have increased 67%–96% over the last ten years, and are projected to remain above \$90 billion through 2018 (see Figure 9).

# Industry Capital Expenditures

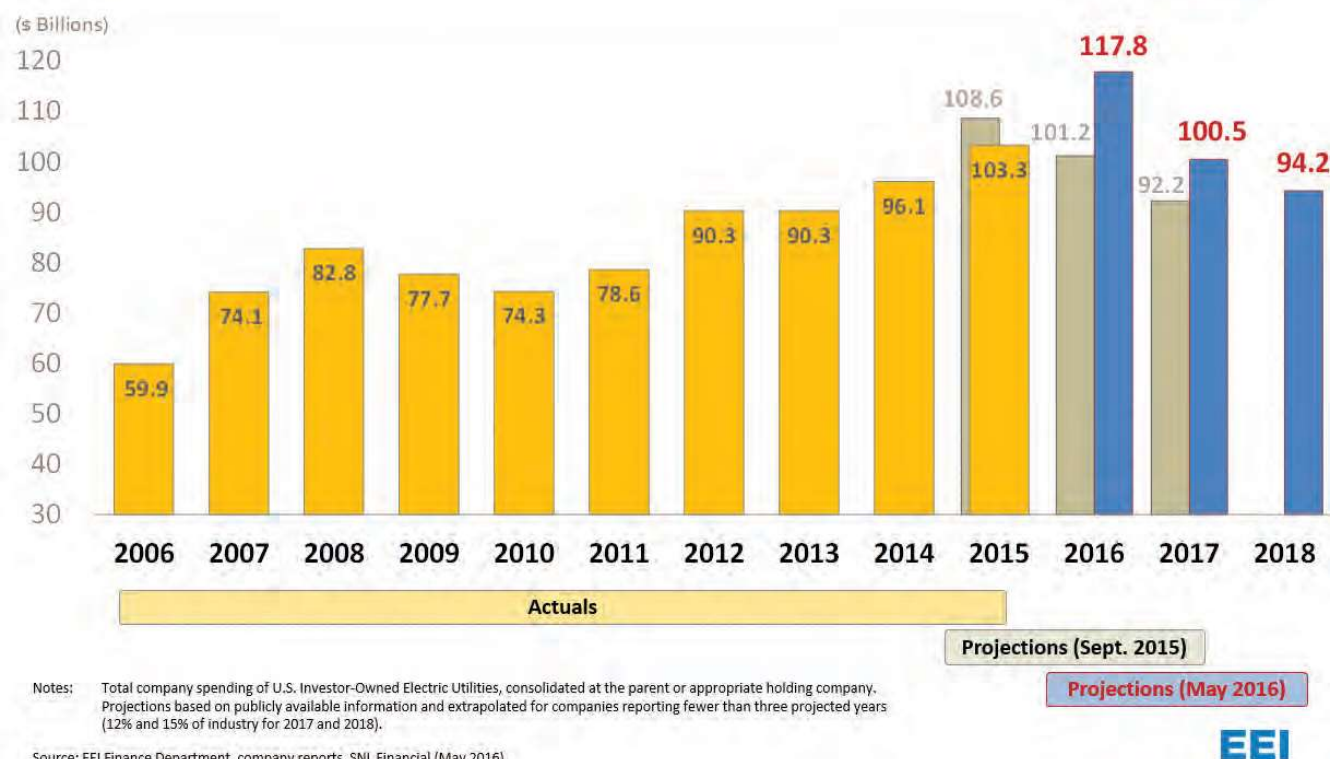


Figure 9: Annual Capital Expenditures of U.S. Investor Owned Utilities.<sup>9</sup>

It is important to note that in recent years, the capital investment across the industry is being shifted from generation to power delivery (i.e., transmission and distribution). In 2015, the percent of investor owned utility capital investments in distribution increased to 26% from 21% of total investment, when compared to 2013 capital allocations (see Figure 10).

9. Edison Electric Institute (EEI) — Electric Utility Industry Financial Data and Trend Analysis; May 2016; <http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/QtrlyFinancialUpdates/Pages/default.aspx>.

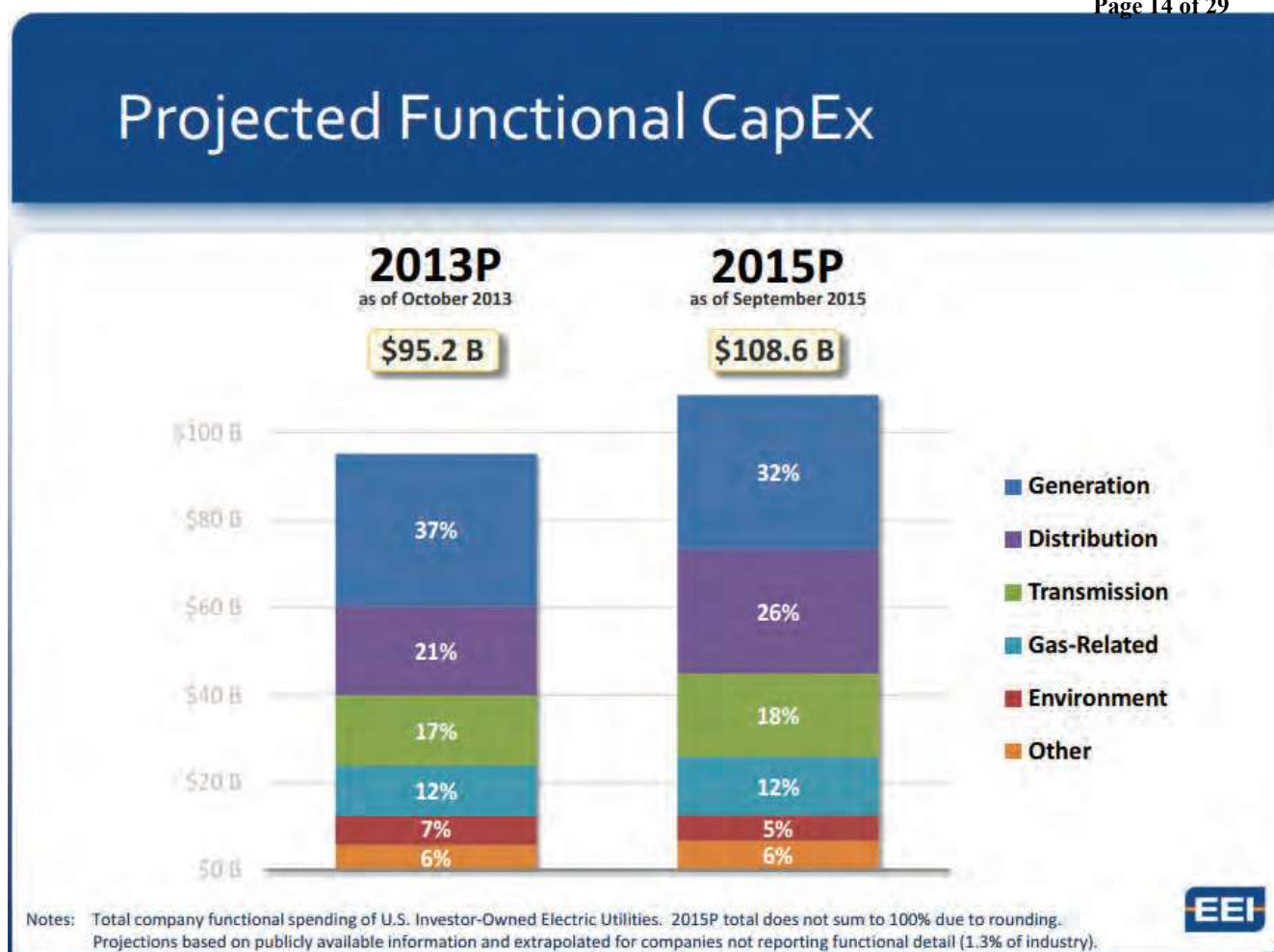


Figure 10: Projected Functional CapEx.<sup>10</sup>

The American Recovery and Reinvestment Act (ARRA) is a primary contributor and stimulant of increased investments in electric utility distribution assets since 2009. President Obama signed the ARRA into law on February 17, 2009.

The ARRA was implemented primarily to stimulate the economy, but included specific measures and funding designated to encourage private utility investment towards advancing grid intelligence and modernization. Approximately \$4.5 billion was allocated to DOE for Smart Grid Investment Grant (SGIG), Smart Grid Demonstration Program (SGDP), Energy Storage Demonstration (ESD), Smartgrid Workforce Development and other miscellaneous programs. The SGIG program was funded at \$3.4 billion. Grants under this program were awarded to approximately 99 utilities, and resulted in joint (public-private) investments of \$8 billion<sup>11</sup> for DOE approved smart grid projects.

Figure 11 displays actual and estimated smart grid investments in the United States, since the ARRA was written into law, and since SGIG grants started being distributed. Figure 12 displays geographic locations of funded smart grid projects.

10. Edison Electric Institute (EEI) — Electric Utility Industry Financial Data and Trend Analysis, May 2016, <http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/QtrlyFinancialUpdates/Pages/default.aspx>.

11. DOE, Office of Electricity Delivery and Energy Reliability; The American Recovery and Reinvestment Act Smart Grid Highlights, Jumpstarting a Modern Grid, October 2014.



## Baseline U.S. Smart Grid Spending 2008-2017 (Historical and Forecast)

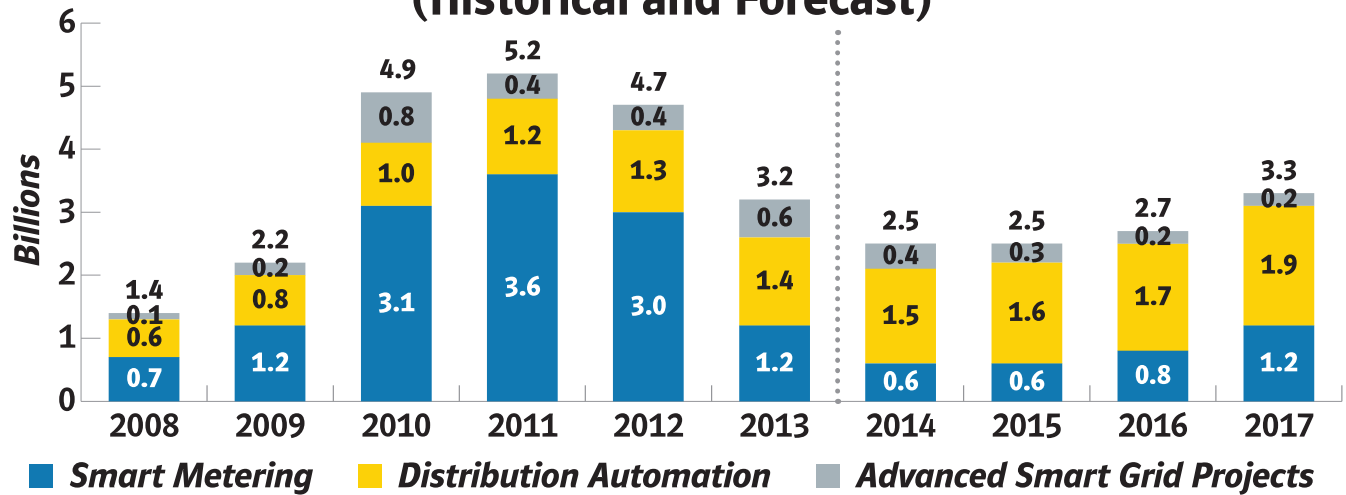


Figure 11: Baseline U.S. Smart Grid Spending 2008-2017 (Historical and Forecast).<sup>12</sup>

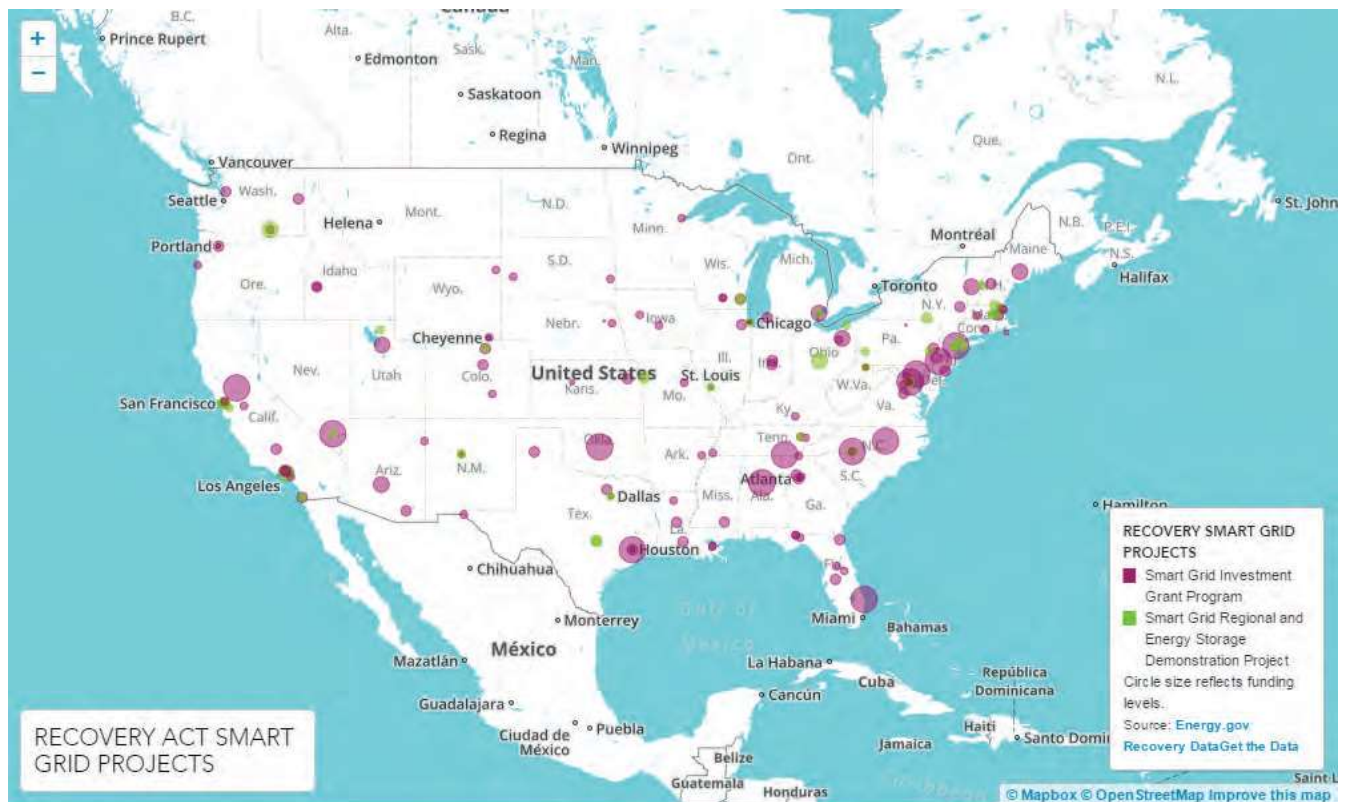


Figure 12: U.S. DOE map of American Recovery and Reinvestment Act (ARRA) Smart Grid Projects.<sup>13</sup>

Respective to smart grid deployments, utilities are generally deploying two key smart grid approaches: 1) distribution automation (DA), including automatic feeder switching (AFS) and fault location, isolation, and service restoration (FLISR), and 2) integrating advanced metering infrastructure (AMI)<sup>14</sup> capabilities with outage management systems.

12. DOE, 2014 Smart Grid System Report; August 2014, page 3.

13. DOE, Map of Recovery Act Smart Grid Projects, <http://energy.gov/maps/recovery-act-smart-grid-projects>.

14. An evaluation of LG&E and KU's Advanced Metering Infrastructure business case is currently underway and will be described in a separate report once completed.

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DA refers to technologies and equipment that automatically operate to restore or minimize outages or that allow remote operation and optimization of the distribution grid. The spectrum of DA implementation options runs from installing automated reclosers that can segment feeders to reduce the impact of an outage, to implementing “self-healing” schemes using SCADA-operated reclosers and switches that allow remote monitoring, and remote control and automation of distribution line equipment. When combined with the implementation of AMI and advanced Distribution Management Systems (DMS), more advanced DA schemes can enable integration of DER by allowing bi-directional energy flow on the distribution network.

Current industry trends respective to deployments of DA technologies are difficult to obtain due to the accelerated pace of new projects by U.S. utilities. Figure 13 provides the most recent available geographical representation of DA deployments.



*Figure 13: Distribution Automation (DA) Projects in the U.S. by utility and DA technology.<sup>15</sup>*

In order to fully support DA implementation and allow sufficient capacity to operate the distribution grid, some utilities are increasing the capacity of their power transformers and distribution lines, especially in more densely populated areas.

Respective to reliability and resiliency, many utilities have acquired mobile transformers (Figure 14) for timely deployment and service restoration in the event of catastrophic equipment failure. Since long lead times exist to manufacture and deliver substation power transformers (6 months–1 year), mobile transformers can play a vital role in timely customer restoration. They can be rapidly deployed to replace damaged substation equipment, allowing time to procure long lead-time grid components, while minimizing the service interruption. In addition to improving reliability, investments in mobile transformers address security concerns such as natural disasters, sabotage, and acts of terrorism. Furthermore, lower rated distribution substation transformers are physically small in size and can be transported with relative ease, so utilities tend to adopt spare strategies for emergency response in these instances.

15. GTM Research, Distribution Automation 2012-2016, Technologies and Strategies for a Digital Grid.

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Figure 14: Mobile Transformer owned by LG&E and KU.

### 2.3. Recent Investments into System Improvement

Following the historical storms and outage events of 2008 and 2009, EDO broadened and enhanced its portfolio of distribution system reliability and resiliency programs. These incremental investment and expense programs were designed to replace aging infrastructure, provide additional system contingency and flexibility, and harden the grid against physical exposures. Table 1 provides a summary of EDO's distribution reliability and resiliency centered programs that were expanded between 2010 and 2016.

Table 1: EDO Incremental System Reliability and Resiliency Program Funding — 2010–2016								
Program Description		2010	2011	2012	(Dollars in Thousands)		2015	2016 (Forecast)
					2013	2014		
<b>Capital</b>	Circuit Hardening/Reliability	\$ 10,856	\$ 7,273	\$ 8,486	\$ 14,484	\$ 11,826	\$ 10,692	\$ 11,798
	Pole Inspection & Treatment Program	\$ 8,568	\$ 8,965	\$ 9,680	\$ 8,436	\$ 10,723	\$ 11,000	\$ 10,902
	Aging Infrastructure Replacement				\$ 5,838	\$ 8,167	\$ 13,063	\$ 12,318
	N1DT Contingency Program						\$ 2,632	\$ 6,639
	<b>Total Capital</b>	<b>\$ 19,424</b>	<b>\$ 16,238</b>	<b>\$ 18,166</b>	<b>\$ 28,758</b>	<b>\$ 30,716</b>	<b>\$ 37,387</b>	<b>\$ 41,657</b>
<b>Expense</b>	Hazard Tree Mitigation	\$ 1,088	\$ 5,852	\$ 5,392	\$ 5,020	\$ 5,110	\$ 5,458	\$ 5,874
	Pole Inspection and Treatment	\$ 328	\$ 301	\$ 472	\$ 515	\$ 631	\$ 542	\$ 314
	<b>Total Expenses</b>	<b>\$ 1,416</b>	<b>\$ 6,153</b>	<b>\$ 5,864</b>	<b>\$ 5,535</b>	<b>\$ 5,741</b>	<b>\$ 6,000</b>	<b>\$ 6,188</b>

Table 1: EDO incremental system reliability and resiliency program funding — 2010–2016.

- **Circuit Hardening/Reliability** — system hardening investments (includes CIFI), targeted at circuits with high customer interruptions and pockets of poor performance; increased from \$2M in 2008 to nearly \$12M in 2016.
- **Pole Inspection and Treatment (PITP)** — program provides for annual inspection, treatment, reinforcement, and replacement, where necessary, of approximately 8% of LG&E and KU's wooden distribution poles. Expense allocations also provide for pole numbering, and anchor, grounding, and other ancillary maintenance.
- **Aging Infrastructure Replacement (AIR)** — programs provide for targeted replacement of critical distribution assets considered beyond their life expectancy and experiencing increasing failure or declining reliability rates. Primary assets included in this category are paper insulated lead cable, underground substation exit cables, legacy and problematic distribution circuit breakers, load tap changers, and pad mounted switchgears.



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- **Distribution Substation Transformer Contingency Program (N1DT)** — program initiated in 2015 provides added contingency for critical substation transformers, targeting power transformer additions, circuit upgrades, distribution system enhancements, and mobile or spare transformer purchases.
- **Hazard Tree Mitigation** — program targets trimming or removal of out of right-of-way trees, with noticeable decay or damaged limbs; funding levels were enhanced substantially in late 2010, with annual hazard tree expense allocations of approximately five-to-six million dollars annually since 2011.

#### 2.4. Case for Action

As stewards of the LG&E and KU electric distribution system, EDO is responsible for providing safe, reliable, resilient, high quality and valuable electric service to customers.

*"It is no secret that our society is more dependent than ever on electricity, and customers want safe, reliable, affordable, and clean energy. Tomorrow's customers will want even cleaner energy; greater grid reliability and resilience; increasingly individualized services; and the ability to connect more distributed energy resources and devices."*<sup>16</sup>

— **Lisa Wood**, Vice President, Edison Foundation

LG&E and KU's recent reliability and resiliency investment strategies and programs have resulted in steady improvements in customer satisfaction and reliability performance since 2010, but step changes are diminishing as these programs mature. Supplemental and new investment strategies are needed for the following reasons:

- Advancement of technology and the adoption of more energy-efficient end-use technologies, will continue to increase customer expectations respective to service reliability and power quality;
- Expectations for grid resiliency and outage responsiveness continue to grow in the face of increasing incidences of severe and extreme weather, and threats of cyber and physical attacks (data from the U.S. Energy Information Administration provides that weather-related outages have increased significantly since 1992, and extreme weather will continue to increase due to climate change, further stressing aging electric infrastructure<sup>17</sup>);
- Electric industry capital investments in distribution continue to accelerate in response to evolving technologies and customer expectations, resulting in improvement and compression of benchmarking reliability performance quartile thresholds; and
- Customers, community leaders, and regulations across the industry continue to push for more effectively enabling interconnection of distributed energy resources (DER), improving energy efficiency, increasing operational flexibility, and enhancing customer communications.

In their September 2015 assessment of energy technologies and research opportunities, the DOE provided, "The distribution system, from distribution substations down to customers, was originally designed to be relatively passive. Typical distribution systems deliver electricity using distribution feeders and radial lines with control equipment operated through timed set points. While this design paradigm is sufficient to provide customers with basic, reliable electrical service at affordable costs, it cannot meet today's needs for greater resilience, power quality, and consumer participation."<sup>18</sup>

In a September 2015 Quadrennial Technology Review, the DOE again highlighted that, "utilities are adopting information and communication technologies to optimize operations and support decision making to improve system performance. Coupling high-resolution data streams with computational advances will enable faster, predictive capabilities. As the distribution system becomes more complex with more points of control and load becomes less predictable, new technologies and tools will be needed to help operators interpret data, visualize information, predict conditions, and make better and faster control actions to ensure reliability and safety."<sup>19</sup>

Future system reliability and resiliency investment strategies must account for evolving and converging technologies, customer expectations, and system threats. Outages will never be completely eliminated, so consideration must be given to enhancing the ability of the LG&E and KU electric system to more effectively detect outages, isolate damaged facilities, reroute power to undamaged feeders and circuits, and limit the exposure of critical asset failures. When outages do occur, whether due to extreme weather events, equipment failure, or other reasons, adequate utility infrastructure, redundant capacity, and superior recovery operations should be in place to minimize interruption durations.

EDO must continue to build redundancy into the LG&E and KU distribution system, where value is provided to customers, and must continue to advance the intelligence of the distribution grid, to meet growing customer expectations. EDO must continue to look beyond key reliability metrics such as SAIDI and SAIFI, to adequately account for and prevent long duration, high impact (affecting a large

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16. The Edison Foundation, Institute for Electric Innovation; Key Trends Driving Change in the Electric Power Industry, Volume II, Lisa Wood, Vice President, The Edison Foundation, and Executive Director, Institute for Electric Innovation; June 2016, page 3.

17. Economic Benefits of Increasing Electric Grid Resilience to Weather Outages, Executive Office of the President, August 2013; Prepared by the President's Council of Economic Advisers and the U.S. DOE's Office of Electricity Delivery and Energy Reliability, with assistance from the White House Office of Science and Technology; page 9.

18. DOE, Quadrennial Technology Review; An Assessment of Energy Technologies and Research Opportunities, Chapter 3: Enabling Modernization of the Electric Power System; September 2015; page 63.

19. DOE, Quadrennial Technology Review; An Assessment of Energy Technologies and Research Opportunities, Chapter 3: Enabling Modernization of the Electric Power System, September 2015; page 63.

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number of customers or key customers) outages, such as those caused by substation power transformer failures. Substation transformer outages typically affect a large number of customers, are long in duration, and garner extreme customer scrutiny due to their community impact. Costs from a utility perspective range from \$1,000/MWh for residential customers to more than \$10,000/MWh for commercial and industrial customers.<sup>20</sup>

Further support for advancement of grid intelligence, specifically distribution automation, can be tied to documented industry results for distribution automation projects funded by the ARRA, under the DOE's SGIG program. "Utilities who have been awarded grants and executed smart grid projects have reported SAIFI improvements of 11-49 percent."<sup>21</sup> Furthermore, PPL Electric Utilities has reported SAIDI and SAIFI improvements of 21% and 31%, respectively, on circuits where DA has been deployed.

In addition to these stated reliability improvements, utilities have achieved operational and cost benefits, such as reduced restoration costs, truck rolls, and outage durations, and more efficient crew utilization. Financial impacts of outages on customers have also been reduced, due to reduced outages and outage durations, which improves public safety, reduces lost production, product losses, and other disruptions to businesses. For example, grid automation provides the ability to remotely de-energize a downed circuit, enhancing public safety.

## 2.5. Strategy

Utility industry customer satisfaction surveys consistently reveal that reliable service is a fundamental customer expectation that must be met before additional initiatives and service options can result in improved customer satisfaction ratings. As reliance on electricity increases, customer expectations respective to service reliability and power quality will continue to expand. Accordingly, EDO's 2017-2021 Business Plan includes the following high-level investment strategies for system reliability and resiliency:

- Advance automation on the distribution system;
- Accelerate funding for the distribution substation transformer contingency program;
- Continue existing reliability improvement programs; and
- Continue existing aging infrastructure replacement programs.

These investment strategies will advance grid intelligence, provide for increased operational control and flexibility, assure continued improvement in reliability performance and power quality, and build additional contingency into critical assets. These strategies also align with industry best practices and are comprehensive, continual, and flexible.

### Reliability and Resiliency Programs

Table 2 provides a summary of EDO's strategic 2017-2021 reliability and resiliency capital and expense programs.

Table 2: EDO Primary Incremental System Reliability and Resiliency Improvement Programs						
Program Description		2017	2018	(Dollars in Thousands)		
				2019	2020	2021
<b>Capital</b>	Distribution Automation	\$ 10,420	\$ 25,250	\$ 22,000	\$ 18,203	\$ 18,203
	Circuit Hardening/Reliability	\$ 14,614	\$ 13,235	\$ 13,687	\$ 14,666	\$ 15,019
	Pole Inspection & Treatment Program	\$ 11,573	\$ 11,920	\$ 12,278	\$ 12,646	\$ 13,026
	Aging Infrastructure Replacement	\$ 15,577	\$ 15,923	\$ 16,286	\$ 14,620	\$ 15,003
	N1DT Contingency Program	\$ 7,245	\$ 7,506	\$ 10,000	\$ 10,000	\$ 13,000
	<b>Total Capital</b>	<b>\$ 59,429</b>	<b>\$ 73,834</b>	<b>\$ 74,251</b>	<b>\$ 70,135</b>	<b>\$ 74,251</b>
<b>Expense</b>	Hazard Tree Mitigation	\$ 5,021	\$ 4,303	\$ 5,285	\$ 5,719	\$ 5,969
	Pole Inspection and Treatment	\$ 579	\$ 609	\$ 625	\$ 631	\$ 638
	<b>Total Expenses</b>	<b>\$ 5,600</b>	<b>\$ 4,912</b>	<b>\$ 5,910</b>	<b>\$ 6,350</b>	<b>\$ 6,607</b>

Table 2: EDO 2017-2021 Reliability and Resiliency Improvement Programs.

EDO's proposed investment strategy provides for continued funding of the existing circuit hardening (including CIFI and the Hazard Tree Program), PITP, and AIR programs. These existing programs continue to deliver system reliability and resiliency improvements. Any substantial shifts in funding away from them would increase outages, and decrease operational contingency. Program continuation is necessary to deliver maintenance, replacement, or upgrade on LG&E and KU system components not yet addressed and circuits not well suited for distribution automation (due to limited circuit ties, etc.). For example, the CIFI program has addressed only 190 of LG&E and KU's 1600 circuits. Over time, remaining circuits will ultimately require circuit hardening and aging infrastructure replacement to maintain and/or improve reliability performance. Likewise, the PITP has addressed only 366,925 of 663,173 (55%) LG&E and KU distribution poles. More than 14,000 poles have been replaced under this program, and the contribution of pole related outages to SAIDI has dropped by

20. Typically, reliability metrics alone "1) undervalue the impact of large-scale outage events and focus on normal operating conditions, and 2) price lost load at a flat rate, when in fact the value of lost load compounds the longer it's lost." Source: The Regulatory Assistance project and Synapse Energy Economics, Workshop on Risk in the Electricity Industry, a training provided to the Mid-Atlantic Conference of Public Utility Commissioners in Hershey, PA on June 14, 2013.

21. DOE QER Report: Energy Transmission, Storage, and Distribution Infrastructure, April 2015, Appendix C — Electricity, page 37.

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approximately 40% on completed circuits. The remaining LG&E and KU distribution poles also need to be addressed under the program, and subsequent inspection cycles will be needed as the poles continue to age.

**Distribution Automation (DA)**

EDO's proposed Distribution Automation (DA) Program includes \$112.4M in investments between 2016 and 2022. EDO's proposed 2017 Business Plan allocates \$94.1M between the plan years 2017 through 2021 for DA. The proposed DA program will yield step-improvement in reliability performance and customer satisfaction, through enablement of remote monitoring and control, circuit segmentation, and "self-healing" of select electric distribution system circuits. More specifically, DA will provide for acquisition and deployment of a Distribution Supervisory Control and Data Acquisition (DSCADA) and Distribution Management System (DMS), and purchase and installation of approximately 1,400 electronic SCADA connected reclosers. Approximately 360 (20%) distribution circuits, and 50% of LG&E and KU customers, will be targeted by the proposed program. The DMS will provide advanced functionality required to achieve incremental DA benefits, such as Power Flow (PF), Fault Location Analysis (FLA); Suggested Switching (SS), and Fault Location, Isolation and Service Restoration (FLISR). The DMS will also be equipped with the functionality to support a potential future Volt Var Optimization (VVO) program. VVO involves a real-time system monitoring and dynamic control, and provides for increased system efficiency, improved power quality and reduced energy consumption. LG&E and KU is currently implementing a VVO pilot program at one substation in the LG&E territory and the results of this pilot will be used to determine the specific scope of a future VVO initiative.

From a grid modernization perspective, DA will provide the ability to monitor grid voltage and currents that have not been accessible in real time in the past. This window of awareness will not only support reliability, power quality, and efficiency initiatives, but will ultimately be required to support increased penetration of distributed generation in LG&E and KU service areas. (Sections 4 and 5 of this report provide additional detail on the DA strategy.)

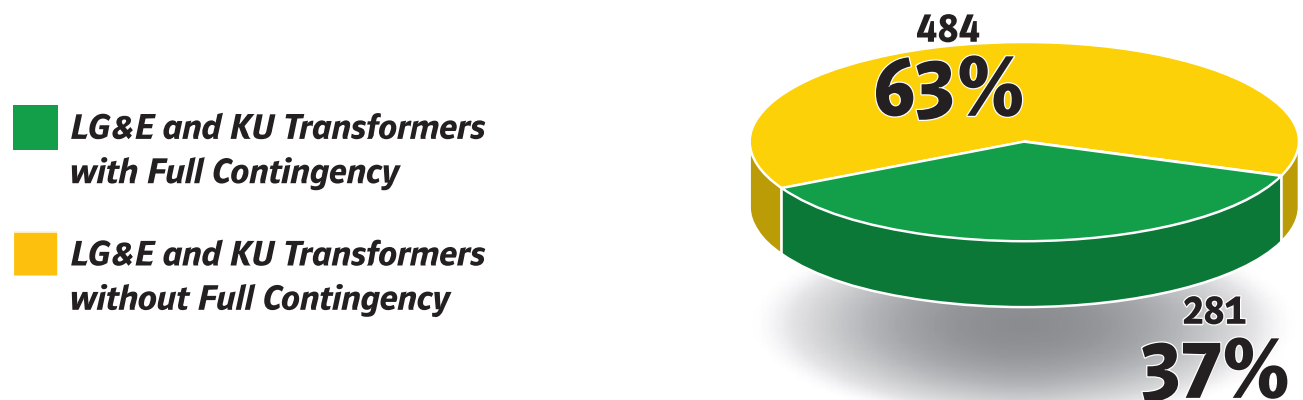
**Distribution Substation Transformer Contingency Program (N1DT)**

EDO's proposed Distribution Substation Transformer Contingency (N1DT) Program includes \$175M in investments between 2015 and 2029. EDO's proposed 2017 Business Plan allocates \$47.8M between the plan years 2017 through 2021 for the N1DT Contingency Program.

The typical "N-1" industry design concept is that a single component failure will not affect electricity supply. The term "N-1" used here is relaxed in the sense that a distribution substation transformer failure will still cause an outage, but interruption of service can be minimized through adoption of different supply security (contingency) plans based on transformer size and number of customers impacted.

Approximately 63% of LG&E and KU's distribution power transformers do not have full contingency (See Figure 15). If one of these substation transformers fails during high load or peak conditions, some customers will be without service until the faulty transformer is replaced, a process that can sometimes take multiple days.

## LG&E and KU Combined Transformers (765 Total)



*Figure 15: Transformer Contingency — as of June 2016.*

EDO's planned N1DT Contingency Program will mitigate potential high impact, long duration service interruptions which would likely result whenever a transformer (without contingency) fails, by making available either a permanent or deployable back-up source to support system and customer restoration. Mitigation solutions for these transformers include substation/circuit upgrades, capacity additions, improved spare and mobile transformer strategies, and other distribution substation enhancements. EDO's proposed improvements will provide for N-1 contingency of larger substation transformer failures, and reduced outage durations on smaller substation transformers where providing full redundancy is not cost effective.

Large-scale power transformers are custom-made, require many months of lead time, and are not typically available locally. Strategic investment in permanent or deployable contingency will provide for increased system flexibility when high impact trouble strikes.

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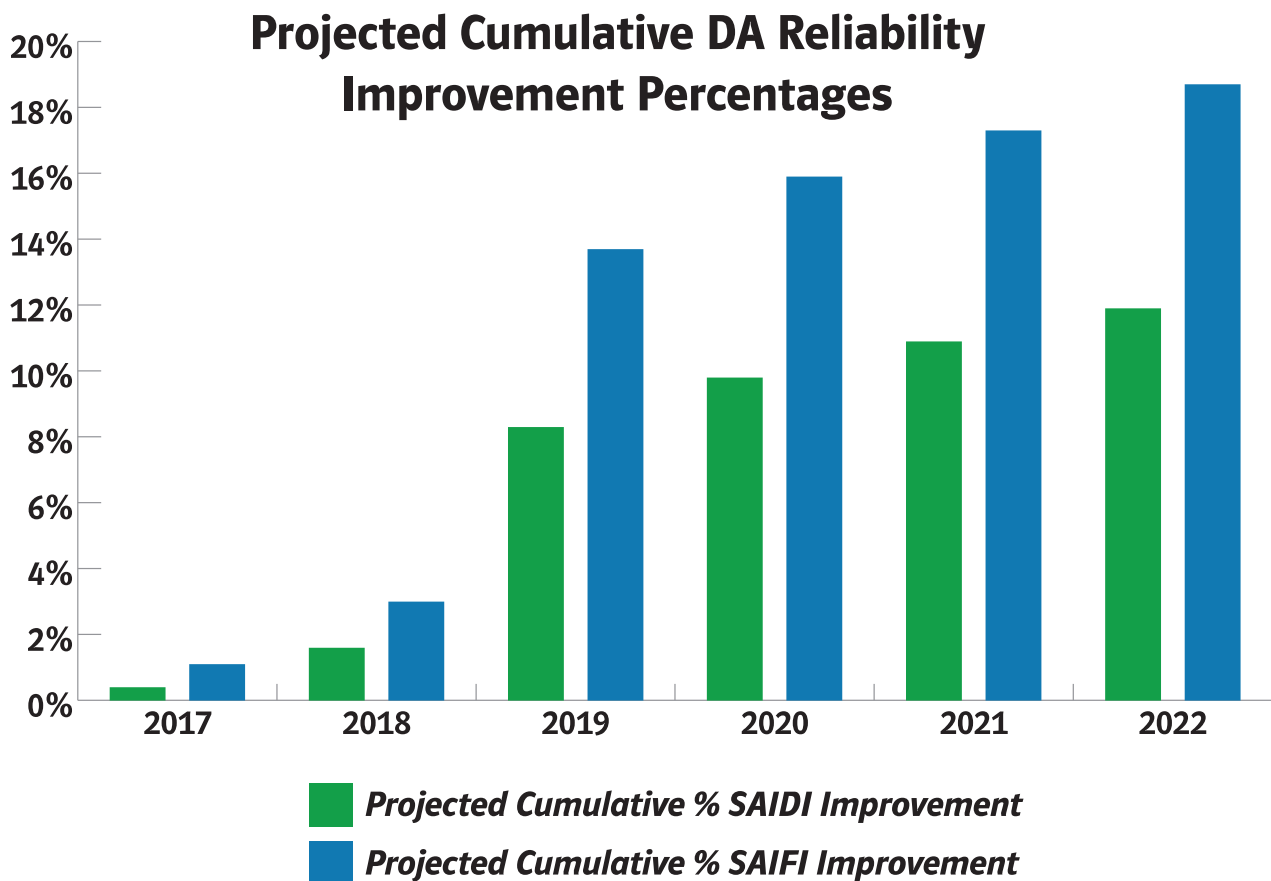
**2.6. Performance Objectives**

EDO's proposed capital investment strategies are designed to improve electric distribution system reliability and resiliency to meet expanding customer expectations respective to service quality and align with industry best practices.

Investments in traditional reliability programs will be maintained at current levels to sustain the improvements that have been achieved and to continue to improve reliability in areas that are not well suited for distribution automation.

As a result of its new DA program, LG&E and KU is projecting to improve its SAIDI performance by 12% over the next six years and SAIFI by 19% over the same period (2017-2022). Figure 16 shows the projected SAIDI/SAIFI improvement. In addition to reliability and power quality performance improvement, the implementation of DA will provide flexible monitoring and control of the distribution system and is expected to create future operating efficiencies in field crew dispatch, and reducing truck rolls and crew miles. Similarly, in areas where DA is implemented, real time data from smart reclosers will provide intelligence and remote capabilities to support switching, further supporting safety, productivity and efficiency.

Based on a cost/benefit analysis, EDO believes a strategic investment in DA will significantly reduce the number of customers affected by outage events and reduce restoration times for customers affected by outages. This strategic shift will enable the company to satisfy growing customer expectations respective to system reliability and resiliency, power quality, operational flexibility, and grid intelligence.



*Figure 16: Projected Cumulative DA Reliability Improvement Percentages.*

The company also expects the N1DT contingency program to minimize the impact of long duration service interruptions by providing either permanent or temporary contingency capacity into the system, rapidly restoring electric service to areas subjected to blackouts as a result of equipment failure, natural disaster, acts of terrorism, sabotage, or vandalism.

In critical high load density applications, where the distribution substation transformers are typically larger, this program aims to provide full back-up capacity (N-1 contingency) to roughly 60% of power transformers base 12MVA or larger that are currently "at-risk" (at-risk meaning that if the substation transformer were to fail, the company cannot restore service to all customers without installing additional capacity in the form of a replacement transformer or a mobile transformer).

Installation of permanent contingency into the system could reduce a multi-day outage event down to minutes with fast transfer to a redundant transformer within a SCADA equipped substation, or less than four hours if the contingency capacity requires manual switching to another alternate substation source.

In substations serving low load density areas there is typically not sufficient contingency to overcome the loss of a distribution substation

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transformer. Often the grid in these areas is topologically in a radial arrangement without circuit ties, and it is not cost effective to provide contingency. In these areas, the N1DT contingency program will enhance and expand the existing spare and mobile transformer strategy to provide accelerated restoration of electric service for less dense load centers. Utilizing localized mobile transformers and small spare units, multi-day outages will be reduced to between 12-24 hours in most cases. Although this approach provides a longer restoration than a permanent redundancy option (which is cost prohibitive), the disruption would be much longer if spares and mobiles were not available (e.g., estimated to be up to five days at some substations). Spare and mobile strategies in the case of equipment failure, natural disaster, sabotage or some other destructive event, play a critical role in reestablishing the connection to the grid.

A report completed by the DOE in 2005<sup>22</sup> detailing the benefits of mobile transformers supports the notion that in most high-load-density areas, which are indicative of urban areas, substation transformers are installed within the network in a manner that provides redundancy either within the substation or from a nearby substation (alternate source). The report refers to this redundancy as “modern utility practice in urban environments.” In addition, the report references the fact that there are often spare power transformers stored in convenient central locations ready for transport. Furthermore, the report describes that in less customer dense rural areas, a substation may only have one transformer, and essentially no contingency, which means that the load served is at risk of long-term outage if the substation is damaged beyond repair.

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22. DOE Report to US Congress Pursuant to Section 1816 of the Energy Policy Act of 2005: Benefits of Using Mobile Transformers and Mobile Substations for Rapidly Restoring Electric Service, August 2006.



### 3. Investment Selection Methodology

In 2011, EDO started using an Asset Investment Strategy (AIS) decision-support model and supporting business processes to help evaluate and prioritize distribution investment programs. The model and processes enable EDO to evaluate and prioritize proposed investments based on 1) a set of custom benefit criteria defined by EDO subject matter experts; and 2) estimated costs of proposed projects. The AIS prioritization algorithm sorts proposed investments based on a benefit/cost ratio, which in turn allows EDO to determine the best allocation of spending. EDO's management team then applies other criteria, such as resource availability and seasonality of work, to determine the ultimate set of investment projects to include in EDO's Business Plan.

As part of its annual business plan development, EDO has used the AIS approach to evaluate traditional reliability and asset replacement investment programs. During the 2016 business planning process, EDO utilized AIS and available industry data to assess DA against its existing portfolio of system reliability and resiliency capital programs, and concluded that DA provides LG&E and KU the best option for making step improvements in reliability performance, and maintaining or improving upon its relative peer group standing in reliability benchmarks. Figure 17 displays the EDO's past and projected reliability improvements per dollar invested for CIFI and DA.

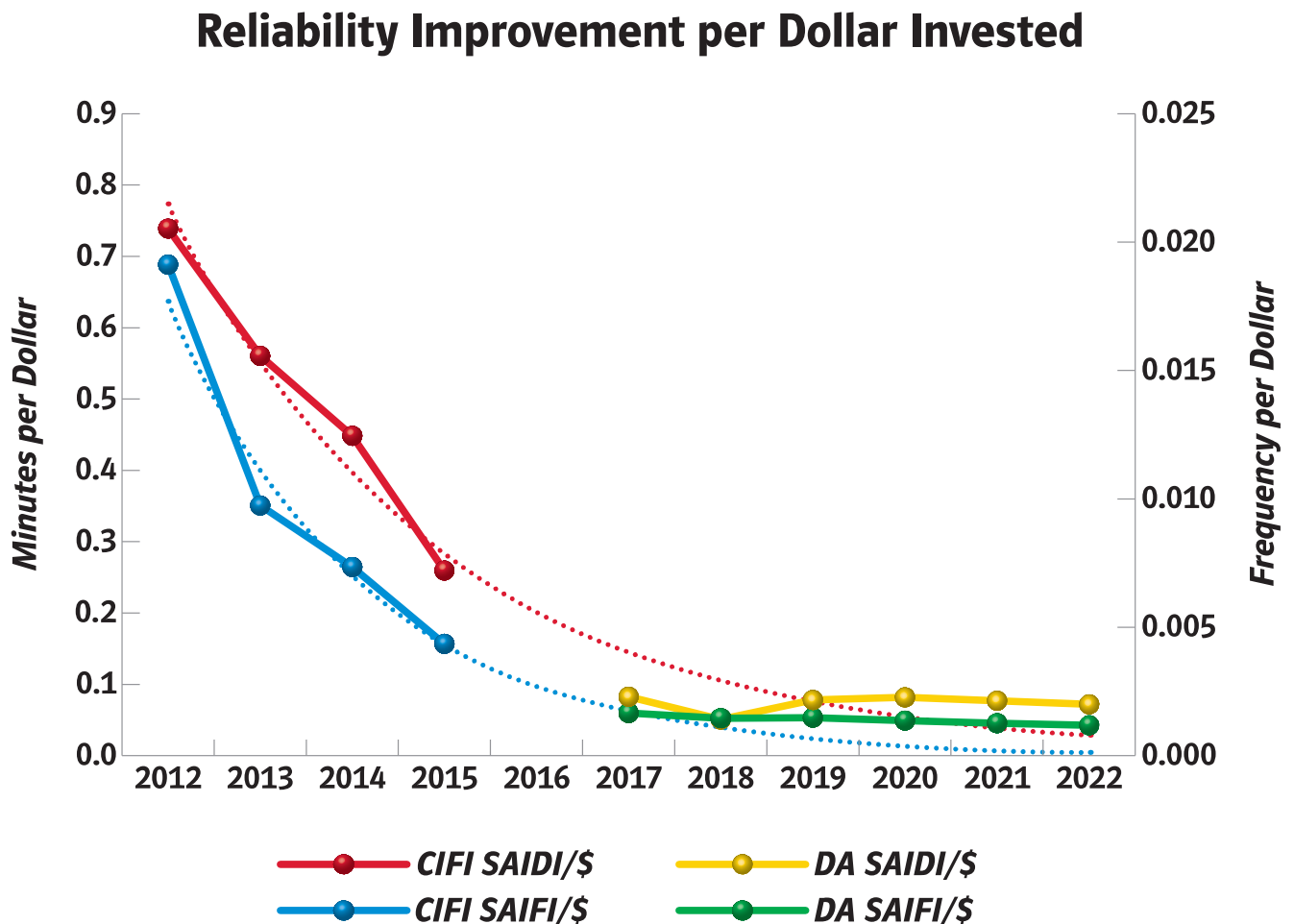


Figure 17: Reliability Improvement per Dollar Invested.

In order to get the most value for the investment in the N1DT contingency program, LG&E and KU expanded the AIS evaluation framework to include at-risk power transformers based on benefit/cost, which also identified the most vulnerable transformers that need to be addressed. Considerations include: the number of customers affected by a transformer failure, the amount of load at risk, the length of time to replace the capacity, the amount of time during the year the load is at risk, the age and health of the transformer, and the impact a long term outage may have on the surrounding community and critical infrastructure. Scaling factors were applied to the inputs to calculate the total benefit. This benefit was then divided by total project cost to determine the benefit/cost ratio.

## 4. Overview of Proposed Projects

### 4.1. Background

LG&E and KU has gained the expected reliability improvements on the distribution system from its existing reliability programs. Even considering these improvements, peer group reliability as observed through benchmarking continues to improve at an increasing pace, customer expectations on availability of service continue to increase, power transformers continue to age, and contingency margins continue to be reduced. The expectations of grid resilience and responsiveness continue to grow in the face of extreme weather, equipment failure, and potential high impact events such as sabotage and terrorism. The penetration of advanced technologies such as distributed generation will continue to demand reliability, power quality, and operational flexibility from the grid. Given the company's strong commitment to maximizing the customer experience, the company has made the decision to leverage the best practices in the industry to improve reliability, expand resiliency efforts, and prepare for the grid of the future. Substantial distribution infrastructure investments in both Distribution Automation and the Distribution Substation Transformer Contingency Program will be added to an already extensive portfolio of capital investments to meet these objectives.

### 4.2. Distribution Automation

The deployment of Distribution Automation (DA) involves the extension of intelligent control over electrical power grid functions to the distribution system level. The intelligent control of distribution equipment can provide real-time information and allow for the remote monitoring, remote control, and automation of distribution line equipment. This project is intended to leverage distribution automation technologies to improve the customer experience through enhanced reliability performance. The DA program will install electronic SCADA (Supervisory Control and Data Acquisition) capable reclosers enabling segmentation of feeders, and "self-healing" of the distribution system. This will result in fewer outages and faster restoration times for customers.

### 4.3. Distribution Substation Transformer Contingency Program (N1DT)

The purpose of the N1DT Contingency Program is to enhance the LG&E and KU customer experience through improved reliability and reduced exposure to low probability, high consequence, long duration service interruptions due to failure of a substation power transformer. There are a significant number of power transformers in the LG&E and KU system, 484 of 765 (63%), where service cannot be fully restored in the event of a transformer failure during heavy load periods without direct transformer replacement or the installation of a mobile transformer. This program is designed as a multi-tiered approach for adding contingency based on the anticipated value added in terms of customers impacted and load density versus the cost to implement the change. The tiered approach consists of three methodologies: 1) the build-out of permanent system capacity providing full redundancy through switching, 2) the expanded use of mobile transformers across the service territory, and 3) the use of small localized spare distribution power transformers to restore service in the most efficient, and cost effective manner.

The installation of additional substation and circuit capacity throughout the system will help facilitate the use of Distribution Automation and will support the implementation of a "self-healing" or smart grid system, year round. Investments for the N1DT Contingency Program will be coordinated with the DA Program where the programs intersect.

## 5. Analysis of Proposed Projects

### 5.1. Distribution Automation

At this time, approximately 25% of the LG&E and KU substations are connected to the Distribution SCADA System. From a load perspective, approximately 37% (i.e., 1294 MW) is SCADA connected on the KU system, with a higher concentration in the more metropolitan portions of the service territory. On the LG&E system, approximately 95% (i.e., 2498 MW) of system load is SCADA connected. Existing Distribution SCADA, which currently resides in the EMS (Energy Management System), will be migrated to a new, dedicated Distribution SCADA System. This will allow for a single interface to operate and control distribution equipment.

To date, 300 electronic reclosers have been installed on the LG&E and KU distribution system as part of existing reliability programs and projects, all of which will be connected to the new Distribution SCADA System. In addition to these existing devices, approximately 1,400 new electronic reclosers will be installed as a part of the proposed program.

A total of 360 circuits have been targeted for DA, representing approximately 20% of LG&E and KU circuits, 40% of LG&E and KU circuit miles, and 50% of LG&E and KU customers. Recloser installations are targeted for approximately one device for every 500 customers.

#### 5.1.1. Benefits

DA is expected to result in fewer outages and faster restoration times for customers. The estimated benefits are a 12% improvement in SAIDI and a 19% improvement in SAIFI at the end of the 7-year period of the planned implementation. The program will also provide the potential for enhanced operational capabilities and efficiencies as a result of remote monitoring and resulting situational awareness.

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### 5.1.2. Expected Cost

The prioritization of DA opportunities within the program is based on avoided customer outages as well as cost. Total estimated costs for the 2016-2022 period are provided in Table 3.

Table 3: Breakdown of Investments within DA Plan — 2016–2022								
DA Plan Detail	2016	2017	2018	(All Dollars in Thousands)		2021	2022	Total Spend
				2019	2020			
Reclosers		\$ 7,120	\$ 21,672	\$ 20,675	\$ 17,608	\$ 17,608	\$ 17,617	\$ 102,300
DMS/DSCADA		\$ 2,500	\$ 2,922	\$ 700				\$ 6,122
Communication	\$ 80	\$ 800	\$ 656	\$ 625	\$ 595	\$ 595	\$ 584	\$ 3,935
<b>Total</b>	<b>\$ 80</b>	<b>\$ 10,420</b>	<b>\$ 25,250</b>	<b>\$ 22,000</b>	<b>\$ 18,203</b>	<b>\$ 18,203</b>	<b>\$ 18,201</b>	<b>\$ 112,357</b>
SAIFI Reduction	0.0%	1.0%	1.9%	10.7%	2.2%	1.4%	1.4%	18.7%
SAIDI Reduction	0.0%	0.4%	1.2%	6.7%	1.5%	1.1%	1.0%	11.9%

*Table 3: Breakdown of the Investments within the DA Plan (2016–2022).*

### 5.1.3. Progress to Date

- An engagement with a telecommunications consultant began in 2016 to determine the optimal method to communicate with distribution equipment. Results from the telecommunications study are reflected in Table 3, above.
- Requirements for a DSCADA (Distribution Supervisory Control and Data Acquisition) system and a DMS (Distribution Management System) have been defined, and an RFP has been issued.

### 5.1.4. Timing of the Program

Distribution Automation is a seven-year program proposed to continue through 2022. DMS and DSCADA vendor evaluations were conducted during the first three quarters of 2016. Purchase and deployment of selected DMS and DSCADA systems will begin during the third quarter of 2017; deployment will continue into 2019. Electronic field devices (reclosers) will be installed between July 2017 and 2022.

### 5.1.5. Summary of Justification

Because of broadening electrification and advances in end-use technology, electric utility customer needs and expectations respective to service reliability, system resiliency, outage response, and power quality continue to evolve. As part of its routine review of system investment strategies, EDO assessed its system reliability and resiliency investment programs to identify opportunities for improving and aligning system performance with changing customer requirements. EDO added DA to its portfolio of programs for system reliability and resiliency because it is projected to provide SAIDI and SAIFI performance improvements of 12% and 19% respectively by the end of the planned seven year program. As indicated in section 2.4, the DOE has reported that DA has provided reliability performance improvements of 11-49 percent on deployments across the industry. Also, PPL has reported reliability performance improvements greater than 21%. In addition to these stated reliability improvements, utilities have reported DA associated operational and cost benefits, such as reduced restoration costs, truck rolls, and outage durations, and more efficient crew utilization. DA will facilitate similar opportunities for LG&E and KU, and was evaluated to be the most cost effective alternative for achieving step improvements in reliability performance over the planned program period.

### 5.2. Distribution Substation Transformer Contingency Program (N1DT)

The purpose of the N1DT Contingency Program is to enhance the LG&E and KU customer experience through improved reliability and reduced exposure to low probability, high consequence, long duration service interruptions due to failure of a substation power transformer. While the vast majority of power outages are due to power line related failures, the grid is highly vulnerable to substation failures, where multiple transmission and distribution lines intersect. A single failure inside an electric substation typically interrupts service to a large number of customers and typically takes a long time to restore.

Depending on the loading at the time of a substation transformer failure, there are 484 (out of the 765) distribution substation transformers operating on the LG&E and KU system that are considered “at-risk”, meaning if they were to fail, the company cannot restore service to all customers without installing additional capacity. Among the large transformers (loads of base 12MVA or larger), 114 (out of 271) are considered at-risk.

The LG&E and KU distribution system is designed and operated as a radial system with open tie points between substations for load transfer in more urban parts of the service territory. Capacity and infrastructure, and thus tie points are limited or are non-existent in the more rural service areas making load transfer more difficult or impossible (181 of the 484 N1DT transformers have no ties).

In more urban areas of the LG&E and KU distribution system, with multiple transformers and/or circuit ties, some or most of the customers can be restored through switching. While some transformers may be at risk year round due to minimal or no circuit ties, many are only in this situation at peak load times, which is when customers typically need power the most (extreme heat and cold), and outages have the most community and corporate impact.

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LG&E and KU is proposing to use three different contingency plans depending on the size of the substation transformers. Class I contingency plan will be used for power transformers sized at or below base 3750kVA, typically serving 300 customers or less. With Class I contingency, if a fault occurs on the substation transformer leading to failure, some or all customers will be without service until the failed transformer is replaced. The N1DT contingency program will increase the number of spare transformers as well as redistribute all spares throughout the state to reduce transportation and replacement time. As this size transformer typically serves less than 300 customers, buildout of additional infrastructure for contingency is not considered economically viable. Transformers sized at or below 3750kVA, typically, can be replaced as fast as or faster than a mobile transformer can be deployed and installed. There are 164 transformers rated 3750kVA or less in the LG&E and KU service territory, and 130 are considered at-risk.

Class II contingency will be used for power transformers at or between base 5MVA and 10MVA, typically serving less than 1000 customers. With Class II contingency, if a fault occurs on the power transformer leading to failure, some or all customers could be without service until the failed transformer is replaced or a mobile transformer is installed. The N1DT contingency program will provide for additional spare transformers of this size as well as a mobile transformer for the local area, which will be ready for transport. Since this size transformer typically serves less than 1,000 customers, build out of infrastructure for contingency is not considered economically viable. The station layout, seasonal loading considerations, and ease of access will determine whether the installation of a spare transformer or a mobile transformer will restore customers faster. If the restoration of the two options are comparable, the spare transformer installation will be chosen to avoid double installation costs. There are 330 transformers rated between base 5MVA and 10MVA in the LG&E and KU service territory, and 240 are considered at-risk.

Class III contingency will be used for power transformers base 12MVA and larger, on average serving 2,500 customers or more. With Class III contingency, if a fault occurs on the power transformer leading to failure, the corresponding customers will typically be without service between five minutes to less than 4 hours (some exceptions will apply) until the corresponding switching to the alternative source is completed. The N1DT contingency program will provide for an alternative source via normally open tie points to other substation transformers by investment in circuit upgrades, capacity additions, or other system enhancements. As transport of this size transformer involves transformer dress/undress and oil removal and processing, some customer outages can extend well beyond the 24-hour mark. There are 271 transformers rated base 12MVA or larger in the LG&E and KU service territory, and 114 are considered at-risk. Until Class III contingency is implemented in a targeted substation, the mobile/spare transformer strategy will be utilized. Which strategy will be applied is dependent on the system conditions and load at risk when the failure occurs.

Table 4 provides the number of transformers that are considered at-risk (N1DT) which are part of the N1DT contingency program.

Table 4: LG&E and KU Substation Transformer Counts and N1DT Detail					
		Class I	Class II	Class III	Total
LG&E and KU Substation Transformer Count	KU Only	141	302	137	580
	LG&E Only	23	28	134	185
	Total	164	330	271	765
N1DT Transformer Count	KU Only	123	232	69	424
	LG&E Only	7	8	45	60
	Total	130	240	114	484
% N1DT	KU Only	87%	77%	50%	73%
	LG&E Only	30%	29%	34%	32%
	Total	79%	73%	42%	63%

**Table 4: LG&E and KU Substation Transformer Counts and N1DT Detail.**

In addition to the proposed tiered solutions, LG&E and KU considered other alternatives to address the potential gap in system flexibility and contingency, including:

- Mobile generation; and
- Operating equipment past current emergency ratings.

Mobile generation was ruled out as both insufficient and impractical. The largest mobile generation that can be practically mobilized is in the 2MVA range while LG&E's largest standard transformer is 44.8MVA. Also, other significant challenges associated with mobile generation are interconnection delays, air quality permitting, and objectionable noise in public areas near substations. Operating equipment beyond current emergency rating is considered an unacceptable practice as it reduces transformer life and causes equipment stress potentially resulting in additional outages. As a result, these alternatives were deemed not viable.

### 5.2.1. Benefits

Substation transformer failures and outages are not a significant contributor to SAIDI (less than 4%) or SAIFI (less than 6%). Eliminating or minimizing customer's exposure to long term outages greater than 24 hours due to substation transformer failures is the primary benefit of the program. Some improvement in SAIDI may be realized due to faster restoration times in areas where capacity is added.

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Likewise, some improvement in SAIFI may be realized due to fewer customers being affected by a substation transformer failure.

The benefit of the tiered N1DT contingency program described above is the ability to minimize long duration service interruptions by providing either permanent or temporary contingency capacity into the system, more rapidly restoring electric service to areas subjected to blackouts as a result of equipment failure, natural disaster, acts of terrorism, sabotage, or vandalism. These benefits are especially evident in reducing the impact of larger power transformers failure, because their replacement requires complex transport, heavy lifting capabilities, detailed un-assembly/re-assembly, oil handling, drying, and filtering - a process that can take many days to accomplish.

Installation of permanent contingency into the system could reduce a multi-day outage event down to minutes with fast transfer to a redundant transformer within the substation through a remote SCADA controlled bus tie breaker, or less than four hours if the contingency capacity requires switching to another alternate substation source.

Since 2005, LG&E and KU has had 96 contingency outage events that resulted in long duration loss of a substation transformer. Causes ranged from winding or core failure of the transformer that led to replacement of the equipment, which historically has taken six months to a year, to load tap changer or bushing failures that were repaired in a few hours or days. On average, there are 1-2 power transformer failures per year in the LG&E system which has 185 transformers, and 5-6 power transformer failures per year in the KU system which has 580 transformers. In total, LG&E and KU expects failures on 1% of distribution substation transformers per year, which represents relatively low probability, but can have a significant impact on the customer and communities that the company serves.

Of the 185 LG&E transformers, 60 (or 32%) do not have sufficient capacity to support contingency transfers, and of the 580 KU transformers, 424 (or 73%) do not have sufficient capacity to support contingency transfers at some time during the year (see Figure 18 and Figure 19).

### LG&E Transformers (185 Total)

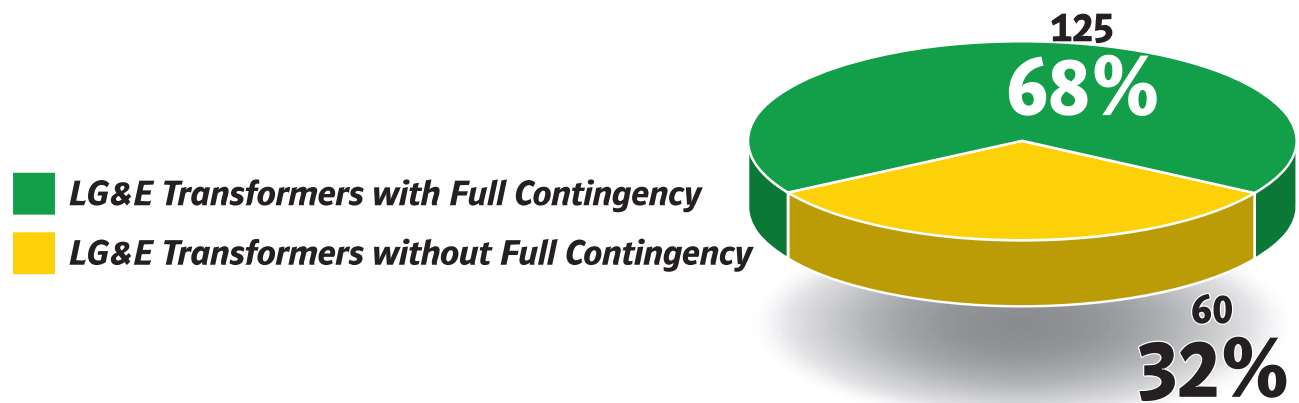


Figure 18: Portion of LG&E transformers without full contingency.

### KU Transformers (580 Total)

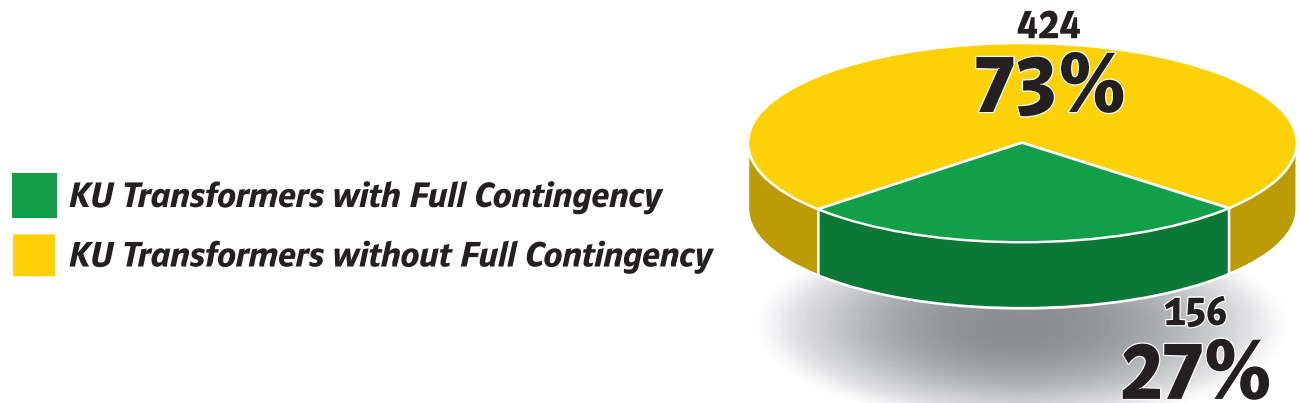


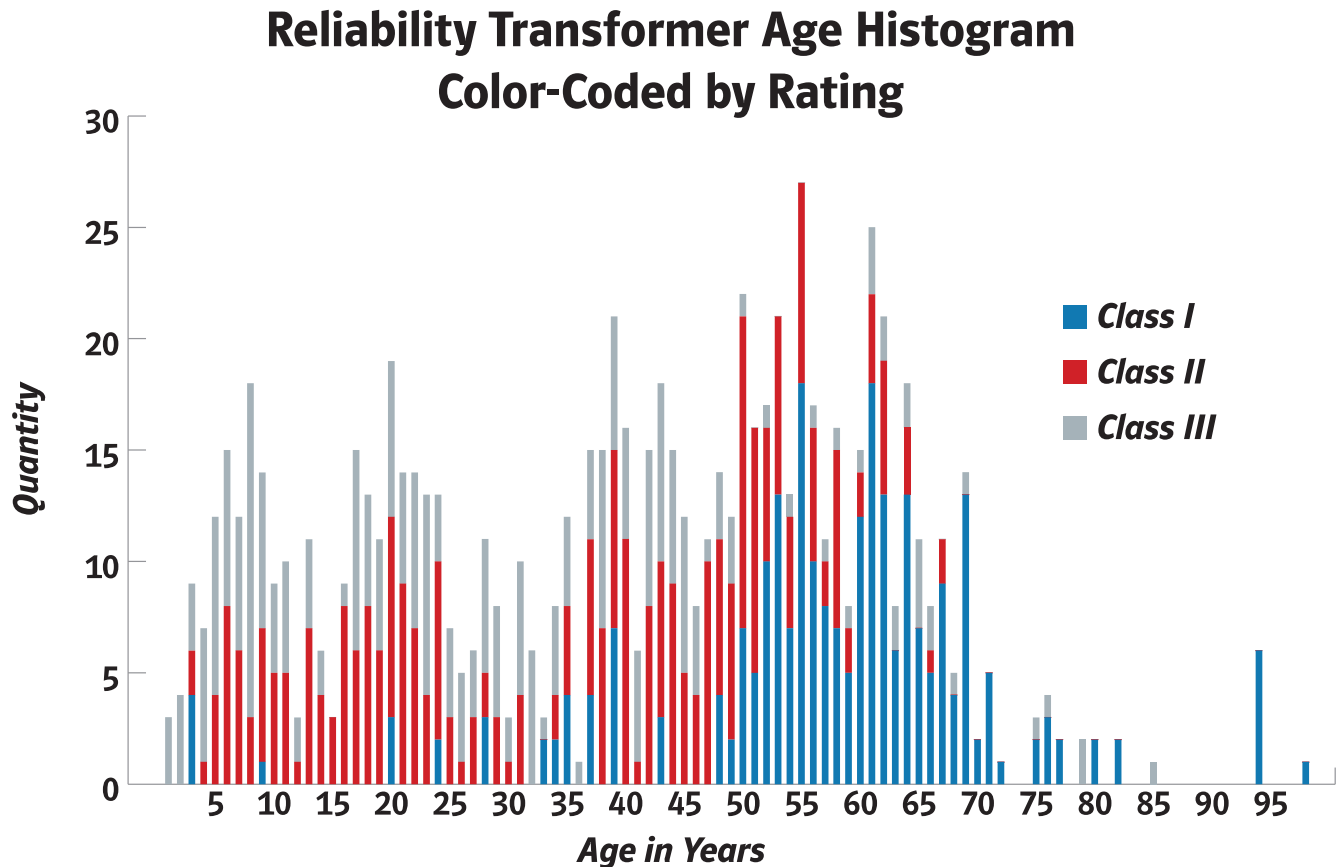
Figure 19: Portion of KU transformers without full contingency.

Investment in substation/distribution equipment is expected to have a 30-year life span and in most cases much longer. As transformers age, an increasing percentage of them face increased probability of failure. LG&E and KU monitors transformer conditions

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through routine diagnostic testing including dissolved gas analysis (DGA) to predict impending failure, but due to a number of factors, such as lightning exposure and through fault current, unexpected failures still occur. Decreasing the amount of load on transformers year-round and reducing the exposure to faults with shorter circuits will increase the life of the substation transformer assets whose average age is approaching 40 years old. Figure 20 shows the age distribution of transformers by class currently operating on the LG&E and KU system.



*Figure 20: Age Distribution of Substation Transformers by Class Size.*

Enhancing and expanding the existing spare and mobile transformer strategy will provide accelerated restoration of electric service for less dense load centers. Utilizing localized mobile transformers and small spare units, multi-day outages will be reduced, in most cases to between 12-24 hours for Class I and II Contingency transformers.

For the Class III Contingency transformers, the N1DT contingency program will eliminate long duration outages on the largest (by load) and most customer dense substations. While rare in occurrence, a long term loss of power to critical infrastructure, such as hospitals, schools, pumping stations, airports, communications, and traffic control, will negatively affect the community and interrupt local events. A long duration outage can also impact the reputation of the area and its ability to host events of regional or national significance.

The N1DT Contingency Program will also provide improved switching flexibility between substations in areas where capacity contingency is installed. The improved switching will also enable maintenance, planned and unplanned, of substation transformers and breakers. Eliminating the need to install a mobile or spare transformer under emergency conditions or scheduled maintenance will result in reduced operating costs. The current process requires many substation planned outages to be limited to off-peak times or weekends resulting in overtime expenses or requires the costly temporary installation of a mobile transformer. In contrast, in areas where permanent capacity contingency is not practical due to lack of circuit ties, mobile transformers will provide options beyond planned outages that leave customers in the dark and contribute to reliability metrics.

Installing enough substation and circuit capacity throughout the system will also help facilitate the use of Distribution Automation and is a critical component in being able to implement a "self-healing" system, year round.

#### 5.2.2. Expected Costs

Program funding was originally approved in the 2014 Business Plan beginning in 2015 at \$2.5M per year, escalating 2.5% annually. Additional funding was approved in the 2016 Business Plan to accelerate the program and fund on the schedule provided in Table 5.



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EDO's proposed funding for its planned 15-year N1DT program is estimated at \$175M. The 2017 Business Plan includes \$47.8M funding for the next five years (2017-2021). \$6.1M of the five-year investment is allocated to support the spare and mobile transformer strategy which includes two mobile transformers for the eastern and western service territory, two small spare power transformers, capital refurbishment of several existing spares, and construction of basic storage facilities to store the spare and mobile equipment closer to the substations that they are intended to back up.

Table 5: Business-Plan-Approved N1DT Spending													
15-Year Program	(All Dollars in Thousands)												
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026-2029	Total Spend
Program Cost	\$ 2,600	\$ 6,700	\$ 7,200	\$ 7,500	\$ 10,000	\$ 10,000	\$ 13,000	\$ 13,000	\$ 15,000	\$ 15,000	\$ 15,000	\$ 60,000	\$ 175,000

*Table 5: 2017 Business Plan Approved N1DT Spending.*

### 5.2.3. Progress to Date

The N1DT contingency program began in 2015 with two substations, Lakeshore and Innovation Drive. The stations are in the Lexington Operations Center area and were initially identified as "high impact" targets that would require minimal investment. These projects include the removal of two large transformers from the N1DT list, eliminating the long term outage exposure to over 9,000 customers by the end of 2016. Also in 2015, funding was approved to address N1DT contingency while completing a load driven capacity upgrade for the Central City Substation in the Earlington Operation Center. The incremental cost to obtain N1DT benefit was funded through the N1DT contingency program. This project removed two transformers from the N1DT list, and benefit for nearly 3,000 customers was demonstrated. A similar process was followed to fund incremental N1DT improvements for the load driven capacity enhancement project at West Hickman Wastewater Treatment in 2016.

### 5.2.4. Timing of the Program

The N1DT Contingency Program is a 15-year program that began in 2015 and will continue to be implemented through 2029. The proposed timeline enables integration with other projects and programs.

### 5.2.5. Summary of Justification

When outages do occur, utility infrastructure and recovery operations should be in place to minimize interruptions as much as possible. "Bounce back", or resiliency strategies will strengthen both reliability and customer satisfaction. The Distribution Substation Transformer Contingency Program supports this mission through the mitigation of high-impact, long-duration service interruptions caused by substation power transformer failures. The program achieves this by making available either a permanent or deployable backup source to support customer restoration, thus minimizing the scale and duration of the outage in the most cost-effective manner. It also continues to improve the resiliency and recovery characteristics of LG&E and KU's distribution infrastructure in response to extreme weather, equipment failure and other potential high-impact events such as sabotage or terrorism, while supporting the mission of providing safe, reliable, resilient, high-quality energy at a reasonable cost to our customers.

Investment Proposal for Investment Committee Meeting on: October 25, 2017

Project Name: KU SCADA Expansion Project

Total Expenditures: \$16,989k (including contingency of \$1,544k)

Project Number(s): 155975

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Tony Durbin/Ray Connolly/Dan Hawk

### **Executive Summary**

Electric Distribution Operations (EDO) seeks funding authority of \$16,989k over the next four years to expand Supervisory Control and Data Acquisition (SCADA) capability in the Kentucky Utilities and Old Dominion Power service territories through upgrading, retrofitting and replacing distribution substation assets. Benefits of this program include:

- Expected System Average Interruption Duration Index (SAIDI) improvement of 3.43 minutes.
- Increased functionality and situational awareness for Distribution Control Center (DCC).
- Leveraging DMS fault locating capability resulting in faster response times and improved utilization of Company resources.
- Immediate system operator response to 911, public safety, fire and police emergencies.
- Enhanced safety functionality for Company and contract personnel performing live line maintenance.
- Real-time capabilities for data collection of substation loading to be used in real-time operations and long-term system planning.
- Up to an estimated \$50k/yr. avoided annual costs.

This project's main focus is to bring SCADA capabilities to distribution substations. This will be accomplished primarily through the replacement of 170 power circuit breakers and 160 electromechanical relay packages and the retrofit of 100 circuits with communications equipment. Legacy electromechanical relays lack features enabling alarming, fault data, diagnostics, supervisory control, and as a mechanical device, require routine periodic on-going maintenance. The relay upgrade will include a pre-configured "Relay in a Box" solution which will reduce periodic maintenance requirements, enable system operations with SCADA, and provide the necessary fault data to achieve pinpointed and timely service restoration.

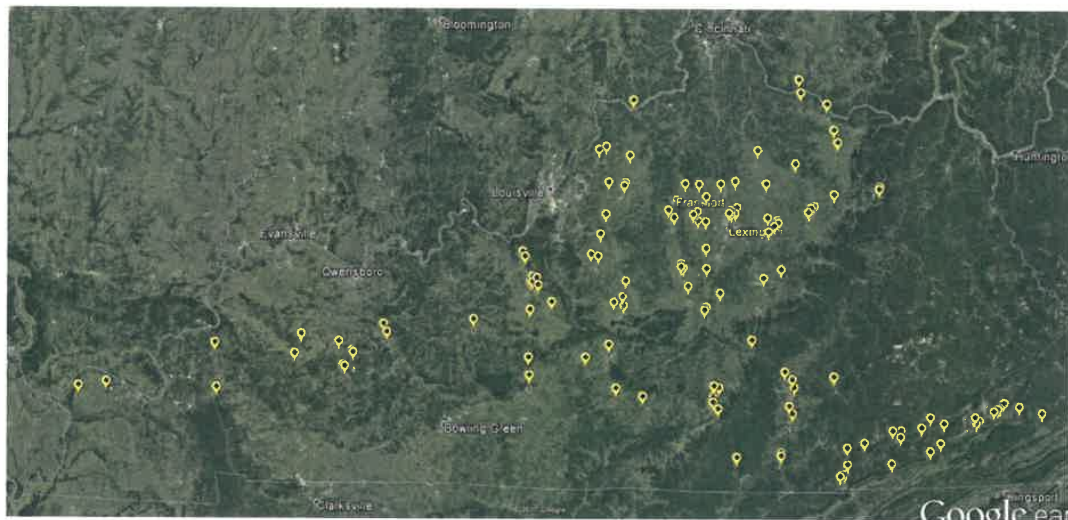
It is considered "good utility practice" for electrical system operators to deploy SCADA technology to manage the electrical infrastructure, protect the public, and to minimize customer exposure to outages. The KU service territory is significantly lacking such operational capabilities.

The proposed 2018 Business Plan (BP) includes \$17,063k for this project.



## Background

For comparison, LG&E has a total of 538 feeders, with 454 having SCADA capability while KU and ODP have a total of 1,108 feeders, with 215 having SCADA capability. These KU and ODP circuits, spread across 73 substations, currently account for approximately 175,000 customers or 30% of the customer base. This program aims to add SCADA capabilities to 129 additional substations, resulting in 260,000 additional customers. At the end of this program, 75% of KU and ODP customers are expected to be connected to the Distribution Management System (DMS) via substation SCADA. Criteria was developed to rank and prioritize stations based on customers connected and loading of the station. Since the intent of the project is to reach as many customers as possible, stations with <500 customers were removed from the scope of this project. A map of the proposed locations is shown below.



SCADA functionality and visibility brings an array of operational, reliability, and safety capabilities. This includes better situational awareness by the Distribution Control Center (DCC) operators, more efficient use of company resources in day-to-day operations, and increased reliability through quicker fault locating and restoration time. This project will involve many departments and organizations, as well as deliver many benefits across the Company. Benefits include:

- *Efficient Operations:* Expanded SCADA functionality in KU substations provides DCC and field resources with the ability to know the status of station breakers quickly during an emergency, after an interruption, and during normal operations. The microprocessor relays that will be installed in substations will allow control center operators to identify possible fault locations through the use of the Distribution Management System (DMS). Field personnel will then be directly dispatched to the trouble area identified, leading to faster restoration times and more efficient use of field resources. These efficiencies are estimated to reduce entire circuit outages by 30 minutes on average. DCC operators will also be able to control breakers and components like reclosers from the control center, reducing the need for crews to visit the substation before and after performing live line work. Additionally, the feature rich microprocessor relaying will provide alarming and

diagnostics data to system operations. Of significance is battery monitoring and alarming, which today is unavailable and places stations at significant risk for breaker failure operation and total loss of a station.

- *Emergency Response:* With the ability to remotely control substation assets, system operators will be able to quickly respond in times of emergency (e.g. 911 calls) and coordination during the restoration of a Transmission outage – providing for better public safety and equipment protection. This is a very valuable benefit, as today’s response to such events is time consuming and requires dispatching a person physically to the substation(s) to de-energize equipment.
- *Enhanced Safety:* The upgraded relays also bring a unique feature that enhances the safety for Company and contract crews performing live line maintenance. These advanced relays offer a “Hot Line Tag” (HLT) feature that goes above and beyond our current practices for protecting line crews at the circuit breaker. The HLT option, when enabled, makes the device more sensitive to faults such that clearing times are faster to potentially reduce impacts of arc flash situations.
- *System Data:* Capturing data will enhance Distribution’s and Transmission’s abilities to analyze real-time situations and have the best information to make decisions. For Distribution, circuit loading data will provide the operator information to know if an overload is occurring and/or other circuit’s conditions in the area if action is required. Transmission Operations will benefit from additional system data to further improve State Estimator and Power Flow results – two analyses that drive operator action on the transmission system. System data will also be extremely beneficial for Distribution Planning to compare and optimize planning models with the real circuit data, aiding in capital project prioritization.

In addition to the benefits listed above, the advancement of SCADA capabilities into the KU and ODP service territories is a major step to advancing the distribution system in terms of technology and preparing for future changes. Many utilities all across the country are facing challenges with distributed resources and grid modernization efforts. While these challenges are not impacting Kentucky today, SCADA expansion will better prepare the companies to handle these issues as they arise.

The proposed program will have a monthly telecommunications cost. The project is expected to cost \$22k per year once fully implemented. This cost is the data usage for the devices to communicate information with the DSCADA system. Alternatives were considered to aggregate information at the substation and bring back fewer communications channels, however, current technology options eliminated this option and increased security risks through local wireless connections.

The majority of the circuits that will be retrofitted for SCADA capability currently utilize legacy electromechanical relays and breakers. These assets cannot provide the desired capabilities and require additional maintenance compared to newer relays and breakers. EDO has evaluated assets associated with the targeted circuits for SCADA expansion. This evaluation drove a three tier approach to the program implementation:

1. For an identified circuit that is protected by a circuit breaker that was manufactured prior to 1980, it was determined any capital improvement of this device was unjustified. These assets are near end of life and would be better suited for complete replacement with upgraded relays. Replacing these breakers is also estimated to avoid periodic maintenance costs of \$75k over the next ten years. 170 circuits were identified as part of the program that meet this criteria.
2. A key driver to this program is to implement microprocessor relays in order to obtain full SCADA capabilities. Replacing electromechanical relays, along with breaker upgrades, will avoid overall relay maintenance expenses by an estimated \$37k per year once the program is fully implemented. In 2006, the Distribution Substation specification for substation circuit breakers was revised to standardize on microprocessor relays. Due to this change, circuits with breakers that were manufactured between 1980 and 2006 are determined to still have substantial useful life and a relay upgrade would be all that is needed to implement SCADA. The "Relay in a Box" solution was determined to be the least cost solution. 160 circuits were identified as part of the program that meet this criteria.
3. Lastly, breakers installed after 2006 contain the desired microprocessor relays to meet the objectives and deliver the benefits of this program. These breakers will be retrofitted with Calamp radios to deliver SCADA capabilities. 100 circuits were identified as part of the program that meet this criteria.

#### **Alternatives Considered**

1. Recommended option: NPVRR (\$000s): \$19,000  
Implement the KU SCADA Expansion program.
2. Alternative #1: Current Replacement Plan NPVRR (\$000s): \$24,412  
The choice to not implement the recommended KU SCADA program results in a continued capital spend requirement of \$10M+ over the next 20 years under current proactive replacement strategies. KU and ODP have over 250 breakers in service today that are between 40 and 70 years old and nearing end of life. Under the current replacement strategies, these breakers will be prioritized and replaced over the next 20 years. The Company cannot expect significant improvement in outage restoration times on non-SCADA equipped stations without these expanded capabilities, resulting in an expected decline in customer satisfaction and an estimated cost of unserved energy of \$1.2M/yr once fully implemented (escalated each year). On-going relay and breaker maintenance costs will also be required to address aged assets until they are replaced in later years under current programs. This alternative does not align with EDO's strategy to address aged assets, nor promote reliability improvements through advanced grid intelligence and system controls.

## **Project Description**

- **Project Scope and Timeline**

2017/18	Preliminary engineering and detailed scope development.
2018	Select EPCM contractor and secure material contracts.
2018	Complete SCADA installations at 6 substations
2019	Complete SCADA installations at 26 substations
2020	Complete SCADA installations at 47 substations
2021	Complete SCADA installations at 50 substations

- **Project Cost**

The total estimated cost of the program is \$16,989k. The costs used in the estimates are consistent with actual average costs for proactive breaker replacement in 2017 as well as PPL's actual costs to implement the "Relay in a Box" solution with adjustments to account for construction differences. A 10% contingency is incorporated into the project cost estimates.

## **Economic Analysis and Risks**

- **Bid Summary**

- For material, a new Sole Source Agreement with Schweitzer Engineering Laboratories (SEL) is being submitted for Investment Committee approval for the "Relay in a Box" solution. Other material will be purchased utilizing existing purchase agreements that will be amended to account for this program.
- For installation labor, the plan is to utilize the existing Substation Construction Contracts (recently rebid and approved by the IC in August 2017 for \$28M over 5 years). The contracts in this award include: Davis H. Elliot, G&G Utility, and Chu-Con, William E. Groves, CE Power, R&K Contracting, Doss and Horky, Bray Electric, and M. Bowling. After the first year, we may take a look at rebidding the work to the most productive contractors based on a unit cost pricing model.
- For engineering, the plan is to utilize the existing EPCM (Engineering, Procurement, and Construction Management) contracts for distribution (awarded in February 2017 for \$9.4M over 5 years) which include the following: B&M, S&L, Mesa, UCS, and Primera. We may also look at utilizing some other regional Engineering firms on a limited basis to minimize travel/site surveying costs.

### Budget Comparison and Financial Summary

The 2018 BP contains funding to meet the level of this project. The \$46k variance from the BP in 2018 will be reallocated from the 2018 Danville Legacy Breaker project that is within EDO's BP. The incremental telecommunications costs in O&M were not included in the 2018 BP and will be covered through the EDO RAC process.

Financial Detail by Year (\$000s)	2018	2019	2020	2021	Total
1. Capital Investment Proposed	893	3,325	5,031	5,100	14,349
2. Cost of Removal Proposed	168	616	928	928	2,640
3. Total Capital and Removal Proposed (1+2)	1,061	3,941	5,959	6,028	16,989
4. Capital Investment 2018 BP	1,015	4,045	6,003	6,000	17,063
5. Cost of Removal 2018 BP	-	-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	1,015	4,045	6,003	6,000	17,063
7. Capital Investment variance to BP (4-1)	122	720	972	900	2,714
8. Cost of Removal variance to BP (5-2)	(168)	(616)	(928)	(928)	(2,640)
9. Total Capital and Removal variance to BP (6-3)	(46)	104	44	(28)	74

Financial Detail by Year - O&M (\$000s)	2018	2019	2020	2021	Total
1. Project O&M Proposed	1	4	9	17	31
2. Project O&M 2018 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	(1)	(4)	(9)	(17)	(31)

#### Financial Summary (\$000s):

Discount Rate: 6.32%

#### Capital Breakdown:

Labor: \$ 704  
Contract Labor: \$ 5,629  
Materials: \$ 6,272  
Transportation: \$ 8  
Local Engineering: \$ 1,514  
Burdens: \$ 1,318  
Contingency: \$ 1,544  
Reimbursements: (\$ 0)  
Net Capital Expenditure: \$16,989

#### • Assumptions

- Estimates are based on bids received from EPCM contractors in 2017.
- EPCM contractors will be utilized to complete the entire project scope.
- EPCM will coordinate design and build, requiring minimal company resources.

- **Environmental**

This project will include replacement of select oil filled circuit breakers, reducing future environmental risk related to spills and contamination. It is likely these oil filled circuit breakers contain PCB levels above acceptable levels and will require special disposal.

**Risks**

- The estimates are based on engineering and installation averages of breaker replacement projects during 2017, PPL's actual costs to implement the "Relay in a Box" solution, and good engineering judgement. There is a cost risk since each substation is unique to some degree, driving construction and engineering costs to vary from site to site. This risk will be mitigated by detailed and accurate scope documents and continued review and revision (as needed) of the program cost expenditures.
- There is a potential risk in the wireless communication costs associated with each breaker. This project assumes a \$4/month charge per circuit. An increase in this price will drive annual operating costs to increase. This risk can be mitigated through a reduction in data usage from each device. While not optimal, reducing polling frequencies and data transmitted can reduce costs while maintaining most functionality.
- This project modifies existing circuits, and there is always a risk of inadvertent outages for the customers served. This risk can be mitigated using good engineering and commissioning practices, detailed functional testing, and good project management.
- There is a possible schedule risk due to the number of circuits that need to be modified, installed, and tested. Depending on loading, the DCC could stagger the outages in such a way that seamless transition between substations will not occur. This risk can be mitigated by securing outages early in the year and involving the DCC earlier in the scheduling.

**Conclusions and Recommendation**

EDO recommends that the Investment Committee approve the KU SCADA Expansion program for \$16,989k in order to improve efficiency and productivity, and continue to provide safe and reliable electric service to our distribution customers.

**Approval Confirmation for Capital Projects Greater Than or Equal to \$2 million:**

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.



Kent W. Blake  
Chief Financial Officer



Paul W. Thompson  
President and Chief Operating Officer

Investment Proposal for Investment Committee Meeting on: November 28, 2018

Project Name: Electromechanical Relay Replacement

Total Expenditures: \$26,000k (includes no contingency)

Project Number(s): 157578 (LGE), 157579 (KU)

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Tony Durbin

## **Executive Summary**

Electric Distribution Operations (EDO) seeks funding authority of \$26,000k over the next five years to replace targeted traditional electromechanical relays with modern microprocessor-based relays. This proposed program supports EDO's continuing strategy to improve safety, reliability, and operational efficiency.

The LG&E and KU electric distribution system is comprised of nearly 6,000 electromechanical relays. These devices are designed to protect the electric grid through detection and reaction to abnormal operating conditions.

Microprocessor-based relays emulate the system detection and operational functionality of electromechanical relays, but also 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.

- Fault location functionality will reduce outage durations through reduction of field patrol durations on permanently faulted lines.
- Delayed circuit breaker trip and close functionality and hot line tag front panel features will advance engineering safety controls for field personnel.
- Advanced station feeder "arc sense" technology will enable System Operators to detect downed energized wires remotely, thereby providing opportunity for improved public and worker safety.
- Fault recording functionality will provide protection engineers invaluable historical information for analyzing abnormal power system operations and relay performance.

This project anticipates replacing 1,735 electromechanical relays, providing the above mentioned benefits to 495 distribution feeders.

EDO allocated the requested funding for this program in its 2019-2023 Business Plan.



## Background

The LG&E and KU distribution system is comprised of 900 distribution power transformers and 2,100 distribution circuits. Roughly 88% of the transformers and 76% of the circuits are currently protected from faults by electromechanical relays. The average age of electromechanical relays in service on the LG&E and KU distribution system is greater than forty-years old. Electromechanical relays are an obsolete technology that are limited in production, availability, and spare parts, and whose utilization and practice in the utility sector has been exclusively replaced by microprocessor technology.

Starting in the 2000s, the Company standardized on microprocessor based relays for new protection relay installations. Microprocessor based relays feature advanced programmable functions which maximize flexibility and monitoring capabilities. They typically require substantially less electronic circuitry required of traditional relay installations, and enable integration of advanced protection functions, fault location, event recording, control and monitoring, alarm and annunciation, metering and communication into a single relay device. These standard features enable microprocessor relays to implement more complex protection and control functions, have increased accuracy, and be more immune to environmental effects. Additionally, the configuration of microprocessor relays enables them to perform/replace the functionality of multiple traditional electromechanical relays in a substation.

EDO Substation and Asset Management leadership identified the need and opportunity to accelerate replacement of targeted electromechanical protection relays with new standard microprocessor based relays. EDO's current year funding level for targeted electromechanical relay replacement is only approximately \$200k per year. EDO allocated \$26M in its 2019 Business Plan for replacement of 1,735 electromechanical relays between 2019 and 2023. The planned program aligns with EDO's overall strategy to improve safety, reliability, and operational efficiency by leveraging asset management evaluations in determining accelerated replacement of aging infrastructure.

### 1. Safety

- a. *"Hot Line Tag" (HLT) Functionality* will advance engineering controls for protecting line crews at the substation circuit breaker level. When enabled, this functionality makes the protective relay more sensitive to faults (such that clearing times are faster), inhibits automatic reclosing, and reduces potential impacts of arc flash events.
- b. *Delayed Circuit Breaker Trip/Close Pushbuttons* will enable field technicians to temporarily delay breaker operation until physically clear of equipment.
- c. *Arc Sense Technology* contains a special algorithm which detects downed conductors that are still energized, provides System Operators greater situational awareness, and enables manual or automatic opening of the associated substation breaker to protect the public, and police/fire/utility first responders.

### 2. Reliability

- a. *Microprocessor Based Technology* further enables Distribution Management System (DMS) fault location, fault isolation, and service restoration functionality on Distribution Automation (DA) and non DA circuits. System Operators will be able to leverage this information to direct field resources to calculated fault locations, versus having them patrol lines from the predicted outage device, and enables quicker fault isolation and service restoration. Calculated SAIDI benefits at the conclusion of the

replacement program are roughly 0.33 minutes annually and \$300k in annual savings (escalated each year) of Cost of Unserved Energy.

- b. Reduction of electromechanical relay failures and malfunctions is expected to reduce SAIDI by 0.26 minutes annually, at the conclusion of the program and generate approximately \$232k in annual savings (escalated each year) of Cost of Unserved Energy.

### 3. Operational Efficiency

- a. *SCADA Compatibility* enables remote monitoring and control of relays, and provides opportunity to eliminate truck rolls of field personnel to perform reclosing, ground relaying, or hot line tagging operations; reducing associated operations expenses by \$450 per year.
- b. *Self-Test Functionality* eliminates the need for manual field testing of relays in the field, reducing SC&M maintenance expenses by \$20k per year.
- c. *Data Capturing Functionality* enhances Distribution's and Transmission's abilities to analyze real-time situations and have the best information to make real-time operational or future system planning decisions.

## Alternatives Considered

1. Recommended option: NPVRR (\$000s): \$17,675  
 Implement proposed Electromechanical Relay Replacement program. Leverage industry best practice of utilizing microprocessor relay technology to replace obsolete electromechanical relaying. This recommendation results in multiple benefits including increased employee and public safety, reliability through maximization of distribution management system (DMS) functions, and reductions in operations and maintenance costs.
  
2. Alternative #1: Current Replacement Plan NPVRR (\$000s): N/A  
 This alternative does not offer a timely implementation to leverage the multiple benefits offered by microprocessor relays (safety, reliability, lower operating costs). This strategy does not address obsolescence, nor provide the strategic value of maximizing the investment in our advanced DMS and vision of a centralized grid operations model. EDO's current electromechanical replacement funding levels provide for approximately eight upgrades a year. As mentioned above, the average age of these 6,000+ relays on the system today is 40+ years, which is well beyond their expected life. It is anticipated that due to this age, failure rates of these relays will increase over time – driving down reliability and increasing operational costs. Additionally, parts and replacements for these relays are becoming harder to obtain as almost all manufacturers have stopped making and supporting these devices. This option assumes that upgrades to microprocessor relays are completed upon failure of the electromechanical relays, however, this will be at the cost of reduced reliability and operational impacts. This alternative also delays taking full opportunity of EDO's recently deployed DMS and SCADA capabilities, thereby limiting opportunities to further improve safety, and operational efficiencies. EDO believes this alternative is unacceptable in order to maintain customer reliability and advance operational excellence.

## Project Description

- **Project Scope and Timeline**

Dec 2018	Preliminary scope development, bidding engineering and construction to contract partners.
2019 -2023	Select EPC contractor and secure material contracts. Complete design and construction for the targeted electromechanical relay upgrades.

- **Project Cost**

The total estimated cost of the program is \$26,000k. Costs used to develop the program estimate are consistent with actual average costs for proactive relay replacements in 2018, and unit pricing negotiated in the associated EPC contract.

## Economic Analysis and Risks

- **Bid Summary**

- A new Design/Build contract was sent out to seven (7) Engineering, Procurement and Construction (EPC) firms during 2018: Pike Engineering, LLC; Dashiell Corporation; Burns & McDonnell; Sargent & Lundy, LLC; SEL Engineering Services; Primera Engineers, LTD; William E. Groves Construction, Inc. The contract for the recommended EPC vendor, SEL Engineering Services, will be presented to the Investment Committee during November.
- Design engineering and project management will be provided by the recommended EPC.
- Materials, such as relay panels, will be procured by the successful bidder.
- Installation labor is part of the bid and will be provided by contract firms that are aligned with the recommended EPC firm.

## Budget Comparison and Financial Summary

Financial Detail by Year - Capital (\$000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	5,956	4,958	4,958	9,918	25,790
2. Cost of Removal Proposed	44	42	42	82	210
3. Total Capital and Removal Proposed (1+2)	6,000	5,000	5,000	10,000	26,000
4. Capital Investment 2019 BP	6,000	5,000	5,000	10,000	26,000
5. Cost of Removal 2019 BP					-
6. Total Capital and Removal 2019 BP (4+5)	6,000	5,000	5,000	10,000	26,000
7. Capital Investment variance to BP (4-1)	44	42	42	82	210
8. Cost of Removal variance to BP (5-2)	(44)	(42)	(42)	(82)	(210)
9. Total Capital and Removal variance to BP (6-3)	-	-	-	-	-

Financial Detail by Year - O&M (\$000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed					-
2. Project O&M 2019 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

### Financial Summary (\$000s):

Discount Rate: 6.59%

#### Capital Breakdown:

Labor:	\$ 626
Contract Labor:	\$ 12,296
Materials:	\$ 10,387
Transportation:	\$ 0
Local Engineering:	\$ 1,954
Burdens:	\$ 737
Contingency:	\$ 0
Reimbursements:	(\$ 0)
Net Capital Expenditure:	\$ 26,000

### Assumptions

- Estimates are based on bids received from EPC contractors in October, 2018.
- EPC contractors will be utilized to complete the entire project scope, including construction.
- EPC will coordinate design and build, requiring minimal company resources.
- Environmental**  
This project will include replacement of select electromechanical relays. There is the possibility of encountering some asbestos wiring that has to be removed.

## **Risks**

- Program estimates are based on engineering and installation averages of relay replacement projects in 2018. There is a cost risk since each substation is unique to some degree, driving construction and engineering costs to vary from site to site. This risk will be mitigated by detailed and accurate scope documents and continued review and revision (as needed) of the program cost expenditures.
- This project modifies existing circuits, and there is always a risk of unintended outages for the customers served. This risk can be mitigated using good engineering and commissioning practices, detailed functional testing, and good project management.
- There is a possible schedule risk due to the number of circuits that need to be modified, installed, and tested. Depending on loading, the DCC could stagger the outages in such a way that seamless transition between substations will not occur. This risk can be mitigated by securing outages early in the year and involving the DCC earlier in the scheduling.

