LG&E and KU
Transmission System Improvement Plan Annual Report

Filed Pursuant to Paragraph 9 of Order entered June 22, 2017
In Case No. 2016-00370 and Paragraph 8 of Order entered
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1. Executive Summary

In connection with their 2016 applications for adjustment of base rates and for issuance of certificates of public convenience and necessity, Kentucky Utilities Company ("KU") (Case No. 2016-00370) and Louisville Gas & Electric Company ("LG&E") (Case No. 2016-00371) submitted a spending plan for improvement of their combined transmission system. This plan, entitled the Transmission System Improvement Plan ("TSIP"), projected $108.3 Million in spending on reliability investments over a five year period from 2017-2021, and $430 Million in system integrity and modernization investments over the same time period.

In its orders entered on June 22, 2017, the Kentucky Public Service Commission ("PSC") approved stipulated settlements in both cases with certain modifications, resolving the applications filed by KU and LG&E (collectively, the "Companies"). The Orders approved the spending contained in the TSIP, and required that the Companies file an annual report starting June 1, 2018, detailing TSIP spending for the preceding reporting period, the criteria used to prioritize transmission projects, the impact on system reliability and other benefits to the Companies' customers resulting from the investments, and outlining proposed spending for the following year.[1]

This report is submitted pursuant to the PSC's directive. It shows that the Companies are following through on their proposed investments in the transmission system, both to increase the reliability of the system now, and to modernize the system to ensure it performs safely and resiliently for many years to come. The report further illustrates how the Companies are using inspection cycles and planned outages to maximize the efficiency of asset replacements and minimize customer impact. Improvements in reliability can already be seen for specific lines on which system infrastructure investments have been made.

The Companies anticipate that spending on certain TSIP-related programs in 2018 will continue to exceed the forecasts made when the TSIP was first created. These increases are primarily driven by the condition of assets found during inspections. The Companies are continually responding to new information and changed circumstances in determining the timing and priority of these investments into the transmission system. Through flexibility and the ability to change program priorities and investments based on inspection data, risk assessment, and scheduled outages, the Companies are best able to efficiently conduct asset replacements and carry out the objectives of the TSIP: securing the

[1] PSC Order June 22, 2017, Case No. 2016-00370, at 28-29; PSC Order June 22, 2017, Case No. 2016-00371, at 30-31, 35.

existence of a modern, reliable, safe and resilient transmission system now and in the future.

2. 2017 TSIP Spending Report

2.1 Overall Spending Comparison versus TSIP

The following table sets forth the Companies' combined actual spending for TSIP-related improvements in 2017 versus the projections in the TSIP:

Table 1: LG&E and KU Combined 2017 TSIP Projection vs. Actual ($MM)			
	TSIP 2017 Projection	**2017 Actual**	**Variance ($)**
O&M Total:	$10.2	$9.9	($0.3)
Capital Total:	$82.3	$105.0	$22.7
Total:	$92.5	$114.9	$22.4

The following tables show the same spending comparison broken down by LG&E and KU, respectively:

Table 2: LG&E 2017 TSIP Projection vs. Actual ($MM)			
	TSIP 2017 Projection	**2017 Actual**	**Variance ($)**
O&M Total:	$1.7	$1.6	($0.1)
Capital Total:	$9.3	$14.8	$5.5
Total:	$11.0	$16.4	$5.4

Table 3: KU 2017 TSIP Projection vs. Actual ($MM)			
	TSIP 2017 Projection	**2017 Actual**	**Variance ($)**
O&M Total:	$8.5	$8.3	($0.2)
Capital Total:	$73.0	$90.3	$17.3
Total:	$81.5	$98.6	$17.1

As these tables reflect, combined spending for Operations & Maintenance (O&M) programs in the TSIP was within two percent the Companies' projections, while capital spending exceeded original TSIP projections. The increase in capital spending compared to TSIP projections is primarily attributable to accelerated replacement of line equipment and substation equipment based on inspection results and the Companies' ability to take advantage of planned outages and other work to accelerate the timing of replacements of certain aging transmission infrastructure.

2.2 2017 Spending on Reliability Projects

The following table shows how the Companies allocated 2017 spending on reliability projects compared to 2017 projections in the TSIP:

Table 4: LG&E and KU Combined 2017 TSIP Reliability Project Forecast vs. Actual ($MM)			
	TSIP 2017 Projection[2]	**2017 Actual**	**Variance ($)**
O&M for TSIP Projects (Veg. Mgmt, Switch Maintenance, Corrosion Protection)[3]	$10.2	$9.9	($0.3)

[2] These projections appear in Table 5 of the TSIP Document, attached as Exhibit PWT-2 to Paul Thompson's Direct Testimony in both Case No. 2016-00370 and 2016-00371.

[3] Corrosion protection is shown as an O&M expense in Table 6 of the TSIP Document.

Line Sectionalizing (Capital):	$9.6	$8.5	($1.1)

The Companies' spending on O&M reliability projects was very close to what the Companies projected in the TSIP. Spending on line sectionalizing, a capital project to improve system reliability, was under budget primarily due to a design improvement that reduced costs compared to original estimates.

2.3 2017 Spending on System Integrity and Modernization Projects

The following table contains a breakdown of the Companies' actual 2017 spending on system integrity and modernization projects compared to the Companies' forecast in the TSIP:

Table 5: LG&E and KU Combined 2017 TSIP System Integrity Project Forecast vs. Actual ($MM)			
	TSIP 2017 Projection[4]	**2017 Actual**	**Variance ($)**
Line Equipment	$48.6[5]	$68.2	$19.6
Underground Lines	$3.2	$1.7	($1.5)
Substation Equipment	$11.4[6]	$16.8	$5.4
Substation P&C Systems	$9.5	$9.9	$0.4
Total System Integrity:	**$72.7**	**$96.6**	**$23.9**

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[4] These projections appear in Table 6 of the TSIP Document, attached as Exhibit PWT-2 to Paul Thompson's Direct Testimony in both Case No. 2016-00370 and 2016-00371.

[5] Separately shown as line equipment, line switches, and overhead lines in Table 6 of the TSIP Document.

[6] Separately shown as circuit breakers, insulators, line arresters, and coupling capacitors in Table 6 of the TSIP Document.

As summarized in this table, total 2017 spending on transmission system integrity and modernization projects under the TSIP exceeded the Companies' projections by $23.9 Million. The bulk of the additional spending is attributable to the Companies' accelerated replacement of line equipment, in particular, wood poles.

2.3.1. Line Equipment

Historically, the Companies conducted system-wide aerial inspections for damage to or deterioration of poles in the transmission system. Starting in 2013, in part in response to evolving Commission regulations regarding inspections, the Companies began performing more detailed pole inspections and initiated a cycled approach to those inspections. Wood poles are now inspected every six years and steel poles are inspected every twelve years. Pole inspections now include detailed visual observation, sounding, and, when possible, climbing of the poles to observe their condition.

The more detailed ground inspections have been successful in identifying more poles in need of replacement. The Companies budgeted for 650 pole replacements in calendar year 2017 based on historical data. However, inspections in 2017 using the methods described above yielded a higher number of poles in need of replacement. To manage the increased need for pole replacements, the Companies replaced 952 poles in 2017 versus the planned 650, contributing to additional spending toward line equipment compared to the budget projected in the TSIP.

At the end of 2017, there were roughly 2,900 poles in the transmission system slated for replacement. 2018 is the final year of the first six-year cycle for wood pole replacements. When the first cycle is completed, the Companies expect the replacement rate to stabilize as many of the more deteriorated or damaged poles will have been identified in the first cycle. In the meantime, the Companies will continue expending resources in pole replacement to manage and ultimately reduce the backlog of poles identified for replacement based on ground inspection data.

While 2017 spending for replacement of overhead lines was below TSIP projections, the Companies were actually able to replace *more* lines than expected due to lower cost design solutions implemented during line replacement work, resulting in increased efficiencies. Specifically, the Companies were able to use more guyed structures instead of self-supporting structures in line replacements. KU achieved further efficiencies by replacing static wire on the Rosine – Leitchfield line while crews were replacing poles on that line.

2.3.2. Underground Lines

The Companies' actual spending for replacement of undergrounds lines in 2017 was roughly half of TSIP projections. Conflicts with other underground utilities during installation of transmission conduit contributed to delays and deferred some of this planned spending to 2018.

2.3.3. Substation Equipment

Spending on replacement of substation equipment, including circuit breakers, insulators, line arresters, and coupling capacitors exceeded TSIP projections by $5.3 Million in 2017. Due to lower spending in Transmission in programs outside of the TSIP, the Companies took advantage of an opportunity to focus more resources on replacing substation equipment as part of previously-scheduled work. For example, the Companies replaced a total of 61 circuit breakers in 2017 compared to planned replacement of 37 breakers, largely during planned outages. Effective use of planned outages lowers the overall risk to the system and lowers overall costs to replace equipment.

3. Criteria Used to Prioritize Projects

There is not a "one size fits all" approach to prioritizing reliability or system integrity projects contained in the TSIP. The Companies must be nimble and adapt their approach to asset replacement to respond to changed circumstances. For example, planned substation outages allow the Companies to accelerate replacement of equipment at that substation without causing additional impact to customers. Furthermore, overall system resiliency is best achieved when certain related equipment (such as breakers, insulators, and line arrestors) are replaced simultaneously. The Companies can maximize efficiency in asset replacement when they have flexibility to determine how such replacements are prioritized and when they occur.

Prioritization within each program or asset class depends on the impact of failure on the Companies' customers, the type of asset, the age and condition of the asset, past performance and maintenance history, or some combination of these factors. This section describes the various projects contained in the TSIP and the general criteria used to prioritize those projects.

3.1 Reliability Programs

3.1.1. Prioritizing Vegetation Management Activity

As the Companies reported in testimony and related materials filed in the 2016 rate cases, in 2016 the Companies began transitioning their line clearing and vegetation management programs on 345kV and higher lines from a just-in-time approach to a 5-year cycled approach. Starting in mid-2017, the Companies began the first cycle for lines operating below 345kV. Because the complete cycle will take five years to implement, the Companies have continued with aerial inspections to identify potential line interference and hazard trees, and those inspections are still the primary method of prioritizing vegetation management activities. Potential customer impact and the occurrence of other work, such as pole and conductor replacements, is also a factor.

Once the first five year cycle is complete, prioritization of line clearing will be based primarily on the established cycle, while off-cycle work will continue to be prioritized through inspection programs.

3.1.2. Prioritizing Line Switch Maintenance

As part of the TSIP, the Companies have established a detailed annual inspection cycle for all automated and motor operated line switches. All remaining manual switches will be inspected every other year. The results of these inspections allow the Companies to repair switches as necessary or to prioritize switches for replacement. The cycles for the inspections themselves were established based on experience and typical industry practices.

3.1.3. Prioritizing Line Sectionalizing

Line sectionalizing involves installation of in-line breakers or switches to decrease customer exposure to outages on long transmission lines with multiple load taps. Priority for lines to receive this new equipment is based on the length of the line, the total customer impact in the event of an outage, and past performance of the line in terms of outage frequency and duration.

3.2 System Integrity Programs

3.2.1. Prioritizing Line Equipment Projects

Prioritization of line equipment (including poles), line switches, and overhead lines is based primarily upon analysis of field inspection data and the condition of the asset. For example, inspection data for poles reflects the overall condition of the poles, and those showing a greater degree of damage or deterioration are prioritized for replacement sooner than poles in better condition. Other factors that can influence the priority of replacement of line equipment, line switches, and overhead lines are field-notes captured during inspection, past performance of the circuit on which the equipment operates, extent of customer impact in the event of equipment or line failure, and other work planned on the circuit which may allow the Companies the opportunity to replace line equipment without further service interruption.

3.2.2. Prioritizing Substation Equipment Projects

Circuit breakers are mechanical switching devices subject to mechanical failure and are sometimes difficult to keep in adjustment. The TSIP targets replacement of 12 345kV breakers, 40 138kV or 161kV breakers, and 125 69kV breakers over the five year period. Replacements are prioritized using a number of factors, including past maintenance history, environmental risks (risk of oil release), age, availability of replacement parts, results of diagnostic test results, and potential customer impact of breaker failure.

Substation insulators are used to isolate energized conductors and switching equipment from ground. Replacement of substation insulators contemplated by the TSIP targets both cap and pin and hollow post insulators. Cap and pin insulators typically fail when their cement joints deteriorate and allow separation of components. Most hollow post insulator failures are attributable to water ingress to the hollow portion of the insulator. Replacements are prioritized by the timing of scheduled work on related breakers, potential customer impact of failure, and in some cases, visual inspection.

Line arresters protect transmission equipment by limiting transient overvoltage typically caused by lightning strikes or switching. Porcelain or silicon carbide components on older line arresters are prone to failure and resulting outages. Replacement of line arresters is performed in connection with replacement of other substation assets and is not individually prioritized.

Coupling capacitors couple a signal from a power line carrier to the transmission line. Their failure is difficult to predict. Replacements are prioritized based primarily on customer impact of failure, age and type of equipment.

3.2.3. Prioritizing Substation Protection and Control Systems

Protection and Control (P&C) Systems refer to a class of equipment used to identify power system disturbances, stop system degradation, restore the system to a normal state, and minimize the impact of disturbance. P&C equipment is typically contained inside a substation control house and includes relay panels, remote terminal units (RTUs), power line carriers, digital fault recorders, and batteries.

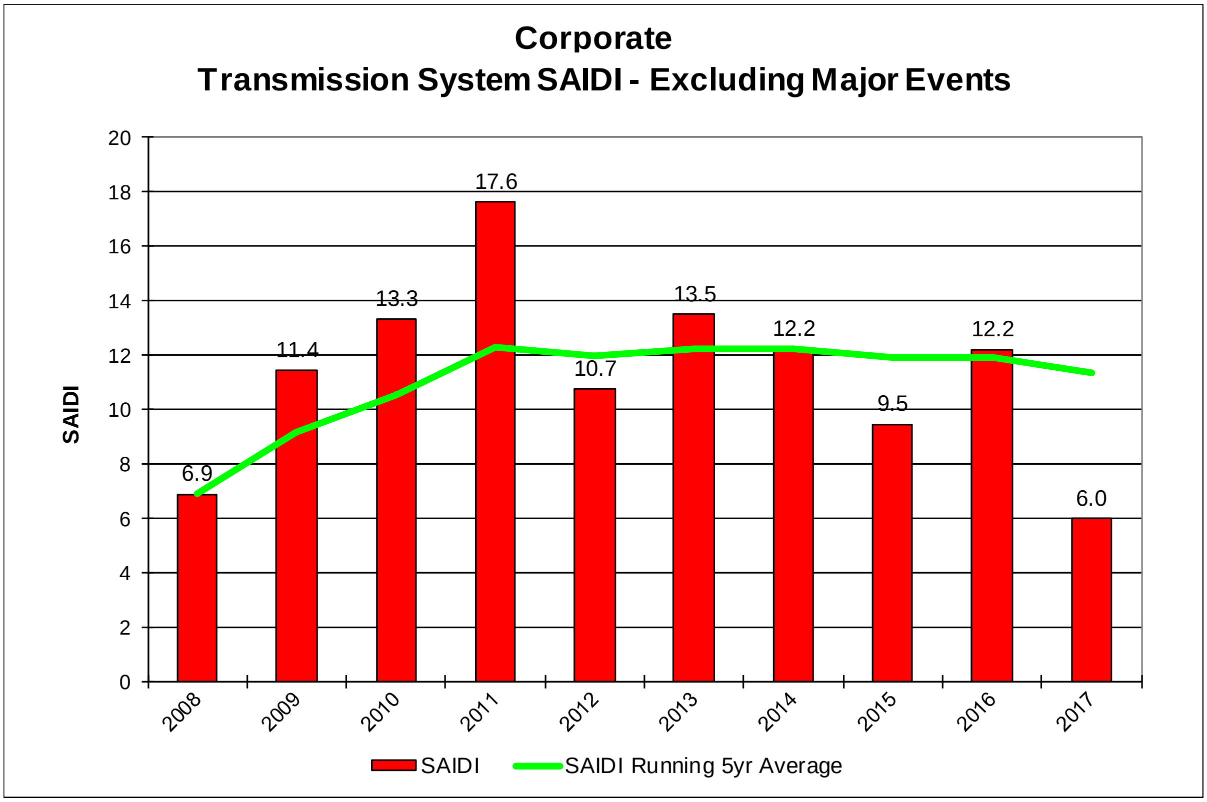
Replacement of the control house itself is prioritized based on the overall condition of the control house and the equipment inside. Replacement of relays and RTUs are prioritized primarily based on past performance and obsolescence. Power line carriers and digital fault recorders are replaced based on past maintenance history, and new digital fault recorders are added based on the need to improve data on a particular circuit. Batteries are replaced based upon their age and/or condition.

4. Impact on System Reliability and Other Benefits

4.1 System-Wide Reliability Performance

Transmission System Average Interruption Duration Index ("SAIDI") is used as a metric to track transmission reliability impact on customers. SAIDI measures the average electric service interruption duration in minutes per customer for the specified period and system. Based on industry standard, major event days such as a severe wind storm are excluded from this metric. SAIDI can be influenced by a number of factors, including weather events which do not meet the "major events" threshold for exclusion and the number and duration of planned outages. The following graphic shows the Companies' combined transmission system SAIDI for the past ten years:

Figure 1: Combined Transmission SAIDI 2008-2017



As this figure demonstrates, the Companies' combined 2017 transmission reliability performance was favorable compared to recent years as measured by SAIDI, resulting in just 6.0 minutes of average service interruption per customer. Combined transmission SAIDI for calendar year 2018 through May is 1.44 minutes, more than one minute lower than the same period in 2017. These data show a positive trend in improvement of transmission system reliability, and the Companies expect that the upgrades and improvements included in the TSIP are contributing to and will continue to contribute to that positive trend.

4.2 Reliability Benefits on Specific Lines

Since the implementation of the TSIP, the Companies have made TSIP-related upgrades to a total of 26 circuits. While there is not enough history for most of these circuits to determine impact on overall reliability, the Companies have noted immediate and significant improvements in reliability resulting from TSIP investments on certain lines.

4.2.1 Beattyville to West Irvine

In 2016, KU added a motor operated switch and in 2017 added automation at the Irvine tap point for this line. From 2012 until the time this switch was installed, this circuit experienced fourteen (14) sustained events and accounted for 2.7 minutes of SAIDI for an average SAIDI of 0.19 minutes per event. After these projects were completed, this circuit experienced four (4) sustained events, but collectively those events accounted for only 0.03 minutes of SAIDI impact for an average SAIDI of 0.008 minutes per event.

4.2.2 Lexington to Pisgah

The Lexington to Pisgah line was previously KU's worst performing transmission line in terms of system outages and duration. The line experienced eleven (11) sustained events and contributed 8.6 minutes of SAIDI since 2012. In 2016, KU added two circuit breakers at the Parker's Mill station and motor operated switches at the Parker's Mill tap point. Several miles of the line were replaced and rebuilt. Since the completion of these improvements, there have been no outage events on the line.

4.2.3 Carrollton to Owen County

The Carrollton to Owen County line was historically a poor SAIDI performer. This line experienced eight (8) sustained events and contributed 2.66 minutes of SAIDI since 2012 for an average SAIDI of 0.53 minutes per event. At the end of 2015, KU added a breaker to sectionalize this line into two segments. Since that time, there has only been one (1) event resulting in 0.39 minutes of SAIDI for an average SAIDI of 0.39 minutes per event. The SAIDI impact of this single event would have been much more severe without the additional breaker.

4.3 Reliability Benefits of Cycled Vegetation Management and Hazard Tree Removal

As set forth above, the Companies are in the midst of implementing a 5-year line clearing cycle for transmission lines. Cycled line clearing began on high voltage lines (345kV and 500kV) in 2016 and is now being performed on lower voltage lines (161kV, 138kV, and 69kV). Inspections of lines which have already been cleared under the cycle reveal more uniform line clearance as compared to the previous just-in-time approach, in which significant variations in vegetation encroachment on a single line were sometimes observed. As completion of the first five-year cycle progresses, the Companies expect to see improved reliability, particularly during severe weather events, through uniform maintenance of established transmission corridors.

In 2017 the Companies also completed hazard tree patrols on over 1,000 transmission miles across the transmission system. These patrols identified roughly 1,800 ash trees scheduled for removal. Hazard trees pose a risk of line interference and resulting service disruption. Early identification and removal of hazard trees improves the overall reliability of the transmission system and mitigates the risk of tree-related outages.

4.4 Other Benefits of TSIP Projects

Replacement of aging transmission assets not only contributes to system reliability now, but also improves the resiliency and reliability of the transmission system long into the future. Many of the assets being replaced under the TSIP were past their useful life and obsolete. Replacement parts for these aging assets are costly and difficult to obtain, and do not necessarily extend the life of the assets. Replacement assets installed under the programs outlined in the TSIP employ modern technology which enhances the overall safety and resiliency of the system. For example, replacement relays installed in the Companies' substations contain microprocessors which capture valuable data used in fault analysis and outage prevention. This equipment enables the Companies to more accurately identify a fault location and reduce the number of faults where an initiating cause cannot be identified.

Furthermore, many of the lines being improved were previously designed for medium loading under the National Electrical Safety Code ("NESC"). New equipment installed on these lines is designed for heavy loading under the NESC, improving the ability of the line to withstand weather events such as wind and ice. For example, while most of the poles being replaced on the transmission system are wood, most of the replacement poles are steel. Steel poles have a longer expected life than wood poles, are more resilient to hazards and severe weather events, and do not deteriorate like wood poles. This approach is typical in the industry for transmission structures, particularly in areas where woodpeckers are common.

Replacement of aging infrastructure also reduces the risk and potential impact of environmental contamination. Circuit breakers containing oil are being replaced with modern equipment that does not contain oil, reducing the amount of oil in the transmission system and thus reducing environmental risks posed thereby.

In summary, the investments being made consistent with the TSIP provide long lasting benefits to system resiliency, public and employee safety, and operational efficiency in addition to improving overall system reliability.

5. 2018 Projected TSIP Spending

The following table shows the Companies' combined projected 2018 spending on projects included in the TSIP:

Table 6: LG&E and KU Combined TSIP Projections vs. 2018 Forecast ($MM)			
	TSIP Projection for 2018	**Current 2018 Forecast[7]**	**Variance ($)**
O&M Total:	$14.3	$14.3	$0.0
Capital Total:	$88.4	$108.5	$20.1
Total:	$102.7	$122.8	$20.1

As with 2017, 2018 projected spending for O&M projects is expected to track near the Companies' projections in the TSIP. Also like 2017, the forecast for 2018 spending on system integrity and modernization projects (capital projects) is expected to exceed the Companies' initial projections. The primary drivers for the projected variance are the same as those applicable to 2017 spending: increased need to replace aging or deteriorated line equipment identified through inspections and other risk analysis, and increased ability to take advantage of planned outages on certain lines and substation equipment.

[7] Forecast includes actual spending through April 2018.