LG&E and KU

Transmission System Improvement Plan Annual Report

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In Case No. 2016-00370 and Paragraph 8 of Order entered
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Prepared by:

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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 and 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 impacts to customers. 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 2020 will exceed the forecasts made when the TSIP was first created. The current forecasts are consistent with investment plans as filed in the 2018 LG&E and KU rate cases. These increases are primarily driven by the condition of assets found during inspections and the prioritization of investments to improve and sustain reliable performance of the transmission grid. More specifically, these assets are primarily wood structures found to be deteriorated, certain types of conductor nearing end of life and experiencing loss of strength and/or corrosion and system protection components that are at end of life and at risk of operating incorrectly. The Companies are continually responding to new information and changed circumstances in

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

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

2. 2019 Spending Report[2]

2.1 Overall Spending Comparison versus the 2019 KPSC Report

The following table sets forth the Companies' combined actual spending for TSIP-related improvements in 2019 versus the projections in the 2019 KPSC Report:

Table 1: LG&E and KU Combined 2019 KPSC Report Projection vs. Actual ($MM)

	2019 KPSC Report Projection	**2019 Actual**	**Variance ($)**
O&M Total:	$15.0	$14.9	($0.1)
Capital Total:	$130.6[3]	$136.4	$5.8
Total:	$145.6	$151.3	$5.7

[2] All tables in Section 2 show a comparison between the 2019 KPSC Report projections in Case Nos. 2016-00370 and 2016-00371 and 2019 actuals.

[3] The 2019 Projections for Capital Total were incorrectly reported on last year's report as $130.1 in Table 6. The correction to $130.6 is made in Table 1 above.

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

Table 2: LG&E 2019 KPSC Report Projection vs. Actual ($MM)			
	2019 KPSC Report Projection	**2019 Actual**	**Variance ($)**
O&M Total:	$2.5	$4.6	$2.1
Capital Total:	$27.0	$25.5	($1.5)
Total:	$29.5	$30.1	$0.6

Table 3: KU 2019 KPSC Report Projection vs. Actual ($MM)			
	2019 KPSC Report Projection	**2019 Actual**	**Variance ($)**
O&M Total:	$12.5	$10.2	($2.3)
Capital Total:	$103.6	$111.0	$7.4
Total:	$116.1	$121.2	$5.1

As these tables reflect, combined spending for Operations & Maintenance (O&M) and capital was within four percent of 2019 KPSC Report projections. The variance in the 2019 projections to actuals for O&M can mostly be attributed to Corrosion Prevention. The variance in capital spend can be attributed to Overhead Lines, Underground Lines, and Substation Equipment programs. Explanations provided in later sections.

2.2 *2019 Spending on Reliability Projects*

The following shows how the Companies allocated 2019 spending on reliability projects compared to 2019 projections in the 2019 KPSC Report:

Table 4: LG&E and KU Combined 2019 KPSC Report Reliability Projection vs. Actual ($MM)			
	2019 KPSC Report Projection	**2019 Actual**	**Variance ($)**
O&M for TSIP Projects (Veg. Mgmt, Switch Maintenance and corrosion protection)[4]	$15.0	$14.9	($0.1)
Line Sectionalizing (Capital):	$12.2[5]	$12.0	($0.2)

The Companies' spending on O&M reliability and line sectionalizing projects was in line with projections provided in the 2019 KPSC Report. Spending on O&M reliability and line sectionalizing were within two percent.

2.3 *2019 Spending on System Integrity and Modernization Projects*

The following table contains a breakdown of the Companies' actual 2019 spending on system integrity and modernization projects compared to the Companies' forecast in the 2019 KPSC Report:

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

[5] Projects were miscoded (4 total) in the 2019 KPSC Report, incorrectly reporting 2019 projections, but those have been adjusted in the tables above. The Line Sectionalizing total was reported as $11.3M (Table 4) and Substation Protection & Control (P&C) Systems was reported as $18.0M (Table 5).

Table 5: LG&E and KU Combined 2019 KPSC Report System Integrity Project Forecast vs. Actual ($MM)			
	2019 KPSC Report Projection	**2019 Actual**	**Variance ($)**
Line Equipment	$83.7[6]	$91.2	$7.5
Underground Lines	$3.6	$4.6	$1.0
Substation Equipment	$14.0[7]	$12.4	($1.6)
Substation Protection & Control (P&C) Systems	$17.1[5]	$16.2	($0.9)
Total System Integrity:	**$118.4**	**$124.4**	**$6.0**

As summarized in this table, total 2019 spending on transmission system integrity and modernization projects under the 2019 KPSC Report was within five percent of the Companies' projections from the prior year's report submitted in June of 2019. The additional spend allocated to Line Equipment was due to favorable weather conditions that provided opportunities for further overhead line replacements. The additional spend for Underground Lines can be attributed to unforeseen challenges identified during construction that required extra resources to resolve, resulting in additional spend. Unlike the favorability in weather for Line Equipment, the installation of Substation Equipment was negatively impacted by the warmer weather. Their variances were largely due to warmer weather conditions, impacting outage availability, that resulted in fewer assets replaced for both substation equipment and P&C equipment.

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

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

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

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 include detailed visual observation, sounding, and, when possible, climbing of the poles to observe their condition.

The more detailed ground-based inspections have been successful in identifying poles in need of replacement and the Companies continue to focus on addressing replacements in the pole backlog. The Companies budgeted and executed the replacement of 907 poles in calendar year 2019.

At the end of 2019, there were approximately 4,300 poles in the transmission system slated for replacement. 2018 was the final year of the first six-year cycle for wood pole replacements. Early in this second cycle of detailed pole inspections, the reject rate for inspected wood structures has remained higher than originally anticipated. Quality control checks have confirmed the inspections produce consistent results. As such the Companies will continue to need to spend more on wood structure replacement than originally anticipated.

The Companies 2019 spend for overhead lines replacement was above 2019 KPSC Report projections due primarily to favorable working conditions in the second half of 2019. With less rain than normal for this time of year, these favorable conditions resulted in completion of additional overhead line replacements.

2.3.2. Underground Lines

The Companies' actual spending for replacement of undergrounds lines in 2019 was more than 2019 KPSC Report projections. During installation of the underground duct bank in downtown Lexington, the Companies' encountered more rock than anticipated and additional unmapped underground utility lines. The Companies completed their planned underground transmission replacement in Lexington in April 2020.

2.3.3. Substation Equipment

Spending on replacement of substation equipment, including circuit breakers, insulators, line arresters, and coupling capacitors was less than 2019 KPSC Report projections by $1.5 Million in 2019. As previously noted, the variance was due to warmer than expected weather conditions, which inhibited the ability to schedule outages needed to replace substation 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 industry best practices and the likelihood of failures for different types of equipment.

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, if inspection data reveals that certain poles are in need of replacement sooner than others, those poles are targeted for replacement earlier. . 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. The Companies are further integrating these factors into line replacement prioritization to allow more impactful equipment to be replaced sooner.

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. Replacements are prioritized using a number of factors, including past maintenance history, environmental risks (risk of oil release), age, 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

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.

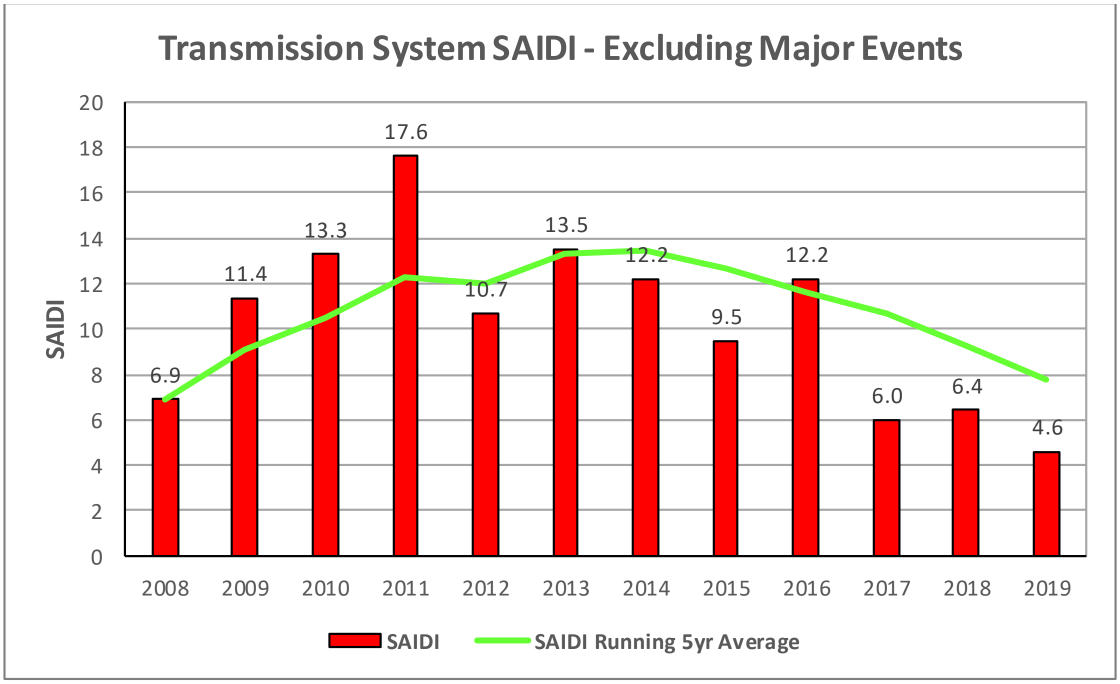
Replacement of the control house itself is prioritized based on the overall condition of the control house and the equipment inside. Replacement of relays and RTUs are prioritized primarily based on past performance. Power line carriers and digital fault recorders are replaced based on past maintenance 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 condition.

4. Impact on System Reliability and Other Benefits

4.1 System-Wide Reliability Performance

Transmission System Average Interruption Duration Index ("SAIDI") has been a traditional metric to track transmission reliability. SAIDI measures the average electric service interruption duration in minutes per customer for the specified period and system. Typically, major event days such as a severe windstorm are excluded from this metric. The following graphic shows the Companies' combined transmission system SAIDI for the past eleven years:

Figure 1: Combined Transmission SAIDI 2008-2019



As this figure demonstrates, the Companies' combined 2019 transmission reliability performance was favorable compared to recent years as measured by SAIDI, resulting in just 4.6 minutes of average service interruption per customer. This data shows a continued 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 2015, the Companies have implemented and completed 95 reliability projects. These include installing 12 new breakers and a total of 71 switches to improve the system's reliability by reducing overall customer exposure to outages and reducing the restoration time when an outage occurs. Out of the 71 switches, 49 are motor operated switches and 32 have Automatic Reclosing Scheme ("ARS") to further speed customer restoration. The Companies are continuing to invest in these types of projects in order to enhance system performance and maintain a high level of system reliability. The Companies have noted immediate and significant improvements in reliability resulting from TSIP investments on certain lines as described in the examples below.

4.2.1 Beattyville to West Irvine

KU added a motor operated switch in 2016 and implemented auto-reclosing scheme in 2017 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 six (6) sustained events, but collectively those events accounted for only 0.2 minutes of SAIDI impact for an average SAIDI of 0.03 minutes per event. Additionally, the combination of the auto-reclosing scheme with the motor operated switches on the line prevented a potential 2 minutes of SAIDI.

4.2.2 Lexington Plant to Pisgah

The Lexington Plant to Pisgah line was previously KU's worst performing transmission line in terms of system outages and duration. In 2016, KU completed a project that 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 also replaced and rebuilt. From 2012 until the time this project was completed, the line experienced eleven (11) sustained events and contributed 8.6 minutes of SAIDI. Since the completion of these improvements, there have been six (6) sustained outages. Only one of those outages caused a SAIDI impact on a major event day of 0.079 minutes.

4.2.3 Rogersville to Vine Grove

The Rogersville to Vine Grove line was previously KU's third worst performing transmission line in terms of SAIDI. In 2017, KU added a motor operated switch with auto reclosing scheme at the Radcliff station. From 2012 until the time the switch was installed, the line experienced ten (10) sustained events and contributed 4.04 minutes of SAIDI for an average of 0.4 minutes per event. Since the completion of these improvements, there has only been one sustained outage in 2018 with a SAIDI impact of 0.12 minutes. The auto reclosing scheme prevented over 4,300 customers from experiencing the sustained outage.

4.2.4 Harlan Y to Evarts to Pocket

KU added a motor operated switch and implemented auto-reclosing scheme in 2017 at the Harlan 557 station on this line. From 2012 until the time this switch was installed, this circuit experienced nine (9) sustained events and accounted for 1.17 minutes of SAIDI. After this project was completed, this circuit experienced two (2) sustained events with a SAIDI impact of 0.14 minutes.

4.2.5 Boyle County to Lancaster

In 2017, KU installed a breaker at Stanford. Prior to this project the circuit experienced two (2) sustained outages contributing 1.48 minutes of SAIDI. Since the project was completed there have been two (2) events as well; however, they total only 0.37 minutes of SAIDI.

4.2.6 Farley to Sweet Hollow 69 kV line

KU added a motor operated switch in 2017 at the Corbin Steel tap on this line. From 2012 until the time this switch was installed, this circuit experienced three (3) sustained events and accounted for 0.91 minutes of SAIDI for an average SAIDI of 0.30 minutes per event. After this project was completed, this circuit experienced one (1) sustained events with no SAIDI impact. The motor operated switch at Corbin steel was used to sectionalize the line and restore the customers in less than 5 minutes.

4.2.7 Millersburg (604) to Paris (634) 69 kV

KU added a motor operated switch and implemented auto-reclosing scheme in 2017 at the Paris tap on this line. From 2012 until the time this switch was installed, this circuit experienced seven (7) sustained events and accounted for 1.17 minutes of SAIDI for an average SAIDI of 0.17 minutes per event. After these projects were completed, this circuit experienced one (1) sustained events with no SAIDI impact. The auto-reclosing scheme at the Paris tap operated to sectionalize the line and restore the customers with no interruptions.

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 extra high voltage lines (345kV and 500kV) first and is now being performed on lower voltage lines (161kV, 138kV, and 69kV) as described in the TSIP. 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 through uniform maintenance of established transmission corridors.

In 2019, the Companies also completed hazard tree patrols on over 750 transmission miles across the transmission system. These patrols identified roughly 300 ash trees and roughly 500 total hazard trees for removal. The Companies removed roughly 1,000 ash trees and roughly 1,800 total hazard trees in 2019. 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. The assets being replaced under the TSIP are nearing end of life and/or obsolete. Replacement parts for many of 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 resilience, public and employee safety, and operational efficiency in addition to improving overall system reliability.

5. 2020 Projected KPSC Spending

The following table shows the Companies' combined projected spend in 2020 related to programs outlined in the TSIP:

Table 6: LG&E and KU Combined KPSC Projections for 2020 ($MM)	
	Current 2020 Forecast[8]
O&M Total:	**$ 14.4**
Capital Total:	**$ 137.5**
Total:	**$ 151.9**

The Companies intend to continue their strategy for proactive replacements to sustain the integrity of the system and want to build on the current progress made to improve reliability through additional line sectionalizing. As noted previously, LG&E and KU continues to see a growing pole replacement backlog and intends to continue their focus on reducing the backlog. Other areas that are being targeted for proactive replacements in the Lines program are aging conductors and switches, with the Substation program targeting proactive replacement of breakers, switches, and relays. The focus of the reliability program is geared toward adding motors and breakers to the system.

[8] Forecast includes actual spending through April, 2020 and projected spend for the remainder of the year.