LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 113

Responding Witness: Gregory J. Meiman

Q-113. Refer to the direct testimony of Gregory J. Meiman, page 6, wherein he testifies that costs to train call center reps is $16,000 per person. Provide a detailed breakdown for how this cost was derived. Include all workpapers in Excel format, with formulas intact and cells unprotected and with all columns and rows accessible.

A-113. The call center study turnover cost analysis provides a timeline of all costs of hire and training incurred when replacing call center positions attributed to turnover. The study begins with the costs associated with advertising for open positions through the total training costs associated with each new hire.

The Excel spreadsheet is being filed pursuant to a Petition for Confidential Protection.

The attachment is Confidential and provided under seal in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 114

Responding Witness: Gregory J. Meiman

Q-114. Refer to the direct testimony of Gregory J. Meiman, page 6, wherein he testifies that the three-year average turnover rate in the call center was 13.4%, excluding retirements. Mr. Meiman also testifies that the Companies determined compensation paid to those individuals was below market (page 6, line 17) and that adjusting their wages "to become market competitive . . . will reduce turnover costs and allow for uninterrupted service for our customers."

a. Explain in detail how Mr. Meiman determined that call center employees' pay was below market. Provide all supporting documentation.

b. Explain how Mr. Meiman determined that the below-market compensation was the cause of the turnover rate (e.g., exit interviews or surveys)? Any response should provide all supporting documentation.

A-114.

a. Below is the assessment of the Companies' starting pay rates:

Key	Business Information	Location	Advertised Hourly Pay Rate	Other Information
1	Global outsourcer call center	Lexington	$12.00	
2	LKE Current Offer	Lexington & Louisville	$12.00	
3	Retail & foodservice	Lexington & Louisville	$12.00	
4	Global outsourcer call center	Louisville	$13.00	
5	National utility call center	Louisville	$14.00	Free/Discounted on company provided services
6	Utility outsourcer call center	Lexington	$14.00	
7	Medical collections call center	Louisville	$15.50	bonus averaging $1,000/month and $0.50 increase every 6 months
8	Recommended LKE Salary Offer		$16.00	
9	Regional utility call center	Plainfield, IN	$16.00	
10	Large retail call center	New Albany, IN	$16.45	
11	Local utility call center	Louisville	$18.00	

Corresponding adjustments were made to maintain internal equity and assist in retention of existing employees.

b. The exit interview scores (1-5, with 5 the highest) for the Call Center area are reflected below:

	Call Center Pay	LKE Pay
2017	2.50	3.55
2016	3.17	4.23
2015	3.25	4.16

As illustrated above, satisfaction with pay decreases over the period. Additionally, the Call Center scores are lower than the rest of the company for pay.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
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Case No. 2018-00295

Question No. 115

Responding Witness: Gregory J. Meiman

Q-115. Refer to the direct testimony of Gregory J. Meiman, pages 6-7, wherein he explains the Companies' compensation philosophy. In that discussion, he states that the policy has been in effect since 1997, regularly reviewed, and used for compensation decisions, which are supported by various levels of approval. Mr. Meiman concludes that the policy results in "ensuring base salaries are competitive based on the nature and responsibilities of the employee's position and are fair relative to the pay for other similarly-situated positions within the organization."

a. If the Companies' compensation philosophy ensures competitive and fair pay as stated in testimony, provide the reason that the call center employee compensation had been below market for three years, as stated on page 6.

A-115. We consistently apply our philosophy of targeting our base compensation salary range midpoints at the 50th percentile of national market. Salary range minimums and maximums are based on 70% and 130% of the established 50th percentile midpoint.

While the compensation of the call center employees was within this competitive range, the monitoring of our recruitment and retention experiences prompted further assessment of our Call Center starting pay rates (see the response to Question No. 114a) and determined that an adjustment was appropriate.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 116

Responding Witness: Gregory J. Meiman

Q-116. Refer to the direct testimony of Gregory J. Meiman, page 7, wherein he testifies that job pay midpoints are established using external market compensation data "of the national general or utility industry."

a. What determines whether the Companies use the national general compensation data as opposed to the utility industry compensation data?

b. Specifically which positions or groups of positions use national general compensation data as opposed to utility industry compensation data?

c. Is the compensation data used to establish job pay midpoints based on a set of criteria limiting the comparison to similar utilities (e.g., within the region)? If the response is in the negative, explain.

d. If compensation data comparison is limited to similar utilities, what is the criteria for types of industries included in the national general compensation data?

e. If compensation data comparison is limited to similar utilities, what is the criteria for utility peers to be included in the utility industry compensation data?

A-116.

a. For jobs that we can recruit from any industry and don't require energy or utility specific experience, we use general industry compensation survey data. For jobs that require energy or utility specific experience and we can only recruit internally or from within the energy or utility industry, we use utility industry compensation survey data.

b. The attachment is being provided under seal pursuant to a petition for confidential protection.

c. No, job pay midpoints are established using the 50^{th} percentile of the national total sample scope regardless if we use general industry or energy services surveys.

d. Not applicable. See the response to part c.

e. Not applicable. See the response to part c.

Jobs that use national general industry compensation data:

Job Code	Job Title
[redacted]	[redacted]

Jobs that use national general industry compensation data:

Job Code	Job Title
[redacted]	

Jobs that use national general industry compensation data:

Job Code	Job Title
[redacted]	

CONFIDENTIAL INFORMATION READACTED

Jobs that use national general industry compensation data:

Job Code	Job Title
[redacted]	

CONFIDENTIAL INFORMATION READACTED

Jobs that use national general industry compensation data:

Job Code	Job Title
[redacted]	[redacted]

Jobs that use national general industry compensation data:

Job Code	Job Title
[redacted]	

CONFIDENTIAL INFORMATION READACTED

Jobs that use national general industry compensation data:

Job Code	Job Title
[redacted]	

Jobs that use national general industry compensation data:

Job Code	Job Title
[redacted]	

Jobs that use national general industry compensation data:

Job Code	Job Title
[redacted]	[redacted]

Jobs that use national general industry compensation data:

Job Code	Job Title
[redacted]	

Jobs that use national general industry compensation data:

Job Code	Job Title
[redacted]	

Jobs that use national general industry compensation data:

Job Code	Job Title
[redacted]	

CONFIDENTIAL INFORMATION READACTED

Jobs that use national general industry compensation data:

Job Code	Job Title
[redacted]	[redacted]

Jobs that use national general industry compensation data:

Job Code	Job Title
[redacted]	

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 117

Responding Witness: Gregory J. Meiman

Q-117. Refer to the direct testimony of Gregory J. Meiman, page 12, wherein he testifies that the Team Incentive Award ("TIA") Plan removed ties to financial performance, e.g., earnings per share and net income.

a. Provide examples of former incentive criteria for positions in which performance ties to financial performance existed, and also provide current adjusted incentive criteria for those same positions.

b. Provide the Individual and Team Effectiveness criteria for the TIA Plan for all Senior Managers in Electric Distribution and Energy Supply and Analysis.

c. Indicate whether any incentive awards or other compensation provided for any employees who are part of the TIA Plan receive stock-based awards. If so, indicate specific type of stock (e.g., restricted).

d. Explain whether any employees receive stock-based compensation, restricted or otherwise, in their base compensation.

A-117.

a. In 2016, there was incentive criteria tied to financial performance. Net income was measured as income after all expenses and all taxes have been deducted.

2016 TIA Measures and Weightings
15% – Corporate Safety 15% – Customer Satisfaction 30% – Net Income 40% – Individual/Team Effectiveness

In 2017 and 2018 the measures and weightings were as follows:

TIA Measures and Weightings
15% – Corporate Safety 15% – Customer Satisfaction 15% – Cost Control 15% – Customer Reliability 40% – Individual/Team Effectiveness

b. Measures for individual Senior Managers in Electric Distribution and Energy Supply and Analysis are established each year to ensure achievement of strategic business goals. Goals vary by individual and by department and support respective department business objectives.

c. Senior Managers participating in the TIA are eligible for restricted stock units (RSUs) which are not subject to rate recovery.

d. No employees received stock-based compensation, restricted or otherwise, in their base compensation.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 118

Responding Witness: Gregory J. Meiman

Q-118. Do the Companies or LKE have any other incentive award programs besides the TIA? If the response is in the affirmative, provide the following items:

a. Amount included in the base year and forecasted amount. If the amount is allocated, provide the allocations;

b. Copy of plan documents;

c. List of participates and awards made for 2016, 2017, and 2018 YTD; and

d. The performance objectives and actual performance results upon which the awards were based for 2016, 2017, and 2018 YTD

A-118.

a. Other than the TIA plan, the only other offering of incentive awards included in the revenue requirement is for employees working in the Customer Services Contact Center. Details of those incentive awards are set forth below.

LG&E	Base Year	Forecast Test Year
Residential Service Center (46% LG&E - 54% KU)	$78,000	$71,000
Business Offices (44% LG&E - 56% KU)	$18,000	$12,000
Business Service Center (36% LG&E - 64% KU)	$6,000	$13,000
Grand Total	**$102,000**	**$96,000**

b. See attached.

c. A total for each job family has been provided instead of a listing of participant names to protect employee privacy. There were no incentive awards made in 2016 or 2017 since the plan was implemented in 2018.

Job Family	**Total YTD (Jan-Oct) 2018 Award**
Area Retail Operations Managers	$400
Billing Analysis Associates	$1,440
Business Center Representatives	$7,675
Business Center Specialists	$1,025
CC Performance Ops Representatives (RPM)	$3,060
Customer Care Coaches	$10,724
Customer Care Representatives	$128,668
Customer Interaction Quality Analysts	$1,010
Customer Representatives	$20,500
Grand Total	**$174,502**

d. See the responses to parts b and c.

Customer Services & Marketing
Contact Center
2018 Incentive Plan

This document is a formalized incentive plan that explains the incentive programs for each contact center. Incentives may be based and awarded on team and/or individual accomplishments. While various situations are identified, flexibility is important as it is rarely pre-determined when it needs to be executed. Each instance of an incentive payout will be documented (as further defined in this document) with the following information: description of the situation, incentive to be provided, team/individuals eligible for the incentive, the period of the incentive, the eligibility for the incentive and effectiveness measurement.

Prior to the start of any incentive program, the following must be done:

- Communication provided to those individuals eligible to participate in the program. The communication will provide the individual with the following information: description of the incentive situation, period for the incentive program, incentive to be provided, eligibility for the incentive and eligibility measurement.
- Documentation of the communication will be maintained. If the communication is delivered verbally, the communication shall be documented and contain the signatures of the employees the communication was delivered to.

Upon completion of the incentive program, the following must be done:

- Employees eligible for awards will be documented in a spreadsheet. An example of an Eligible Employee spreadsheet is contained in Appendix A.
- Spreadsheet should include the effectiveness evaluation for the incentive – did it accomplish the intended goal.
- Spreadsheet will be approved by the team leader (BSC), AROM (BO), or Operation Manager (RSC) and obtain a one over approval by the appropriate department manager.

All monetary incentive awards will be reported to payroll to be included in the recipient's paycheck. All tax considerations will be addressed through the normal payroll process.

This plan will be reviewed annually in order to determine effectiveness of incentives. This review will provide insight into any necessary adjustments to the plan for the following year. The plan will be updated annually and approved by the managers and director.

Business Service Center
Budgeted Amount $43,000

Situation	Description	Frequency	Incentive	Team/Individual	Eligibility	Effectiveness Measurement
Service Level	When monthly SL goal is in jeopardy	Monthly	$25-$75 bonus on paycheck	Team (CR, Specialist and Lead)	Meeting or exceeding service level goal	SL Goal Achieved
Attendance	When call volume expected to be high or attendance low	Daily or monthly	$25-$75 bonus on paycheck	Individual or Team (CR)	All Reps that are in attendance on selected time period	Lower shrinkage than forecasted
Average Handle Time	Total call time including talk time, hold time, and ACW	Monthly or Quarterly	$25-$50 bonus on paycheck	Individual or Team (CR)	All Reps when AHT within departmental goals	AHT lower and within goal
Schedule Adherence	Improvement to schedule adherence	Monthly or Quarterly	$25-$50 bonus on paycheck	Individual (CR)	>= 95% Adherence	Enhances availability around scheduled breaks and lunches
Quality Assurance Score	Random calls selected for evaluation	Monthly	$100 bonus on paycheck	Individual (CR)	All calls for reps scored for the month receiving a 100%	Enhances consistency and accuracy
First Contact Resolution	FCR scores based on transactional surveys by third party	Monthly or Quarterly	$25-$75 bonus or logo item	Team (CR, Specialist)	Everyone based on survey results of => FCR target	FCR increases from previous month and above target
Top Rep Performance	Top rep per scorecard performance	Quarterly	$100 bonus on paycheck	Individual (CR)	One winner per site of All reps	Highest productivity compared to peers
Customer Experience Score	CE scores based on transactional surveys by third party	Monthly or Quarterly	$25-$75 bonus on paycheck or logo item	Team (CR, Specialist, Lead)	Everyone based on survey results of => CE target as reported by third party surveys	CE score increases from previous month
Customer Service Week	Celebration activities to recognize CS employees	October	Logo wear	Team (CR, Specialist, Lead)	Everyone	N/A
Other business need as appropriate	Other focus based on business need	TBD	$25-150 bonus on paycheck/ logo item	TBD	TBD	TBD

Business Office
Budgeted Amount $85,000

Situation	Description	Frequency	Incentive	Team/Individual	Eligibility	Effectiveness Measurement
Attendance	Adherence to attendance policy	Quarterly	$50 Bonus on paycheck	Individual (CRs)	No more than 1 unscheduled occurrence within each quarter	Occurrence guideline
Cash Desk Outages	Cash management performance	Quarterly	$50 Bonus on paycheck	Individual (CRs)	No more than 2 cash desk outages of any dollar amount (Net zero correction does not count as additional outage)	Cash desk outages
Off in Errors (ZHONs)	CCS performance as its related to off in errors	Quarterly	$50 Bonus on paycheck	Individual (CRs)	Zero ZHONs	Zero ZHONs
Customer Experience Scores	CE scores based on transactional surveys by third party	Quarterly	$50 Bonus on paycheck	Team (CRs, Leads and AROMs)	Overall CE score of 8.8 or above each month of the quarter	Independent of each quarter
Customer Service Week	National Customer Service week. Recognition of our Customer Service Reps	October	Logo item	Team (CR's, Leads and AROMS)	Everyone	N/A
Other business need as appropriate	Other focus based on business need	TBD	$25-150 bonus on paycheck/ logo item	TBD	TBD	TBD
Other business need as appropriate	Other focus based on business need	TBD	$25-150 bonus on paycheck/ logo item	TBD	TBD	TBD

Residential Service Center
Budgeted Amount $210,000

Situation	Description	Frequency	Incentive	Team/Individual	Eligibility	Effectiveness Measurement
Service Level	Monthly SL is in jeopardy	Monthly	$75-150 bonus on paycheck/ logo item	Team (CR's, Coaches and Ops Manager)	Meet Monthly SL goal	Goal Achieved
Attendance	High Call Volume/Absenteeism expected	Daily or monthly	$50-150 bonus on paycheck/ logo item	Individual or Team (CR's and Coaches)	Work 100% of Scheduled time/No Off Duty	Amount Baseline is exceeded
Average Handle Time	Need to increase the # of calls per agent	Daily	$25-75 bonus on paycheck/ logo item	Individual (CR's)	AHT 10% below goal	Amount Baseline is exceeded
After Call Work	Increase efficiency during ACW	Daily	$25-50 bonus on paycheck/ logo item	Individual (CR's)	ACW below target	Amount Baseline is exceeded
Schedule Adherence	Higher adherence to schedules needed	Daily	$50-150 bonus on paycheck/ logo item	Individual (CR's)	Adherence > 97%	Amount Baseline is exceeded
Quality Assurance Score	New Process Introduced - Awareness of new rules needed	Monthly	$50 bonus on paycheck/ logo item	Individual or Team (CR's and Coaches)	Successful QA monitor by individual or group under new process	Increased percentage of adoption
Quarterly Performance Incentive	A quarterly performance incentive that focuses on 1 or more areas of performance	Quarterly	$150-250 bonus on paycheck/ logo item	Individual (CR's)	Meet specific performance targets	Baselined measures such as ACW, attendance or quality
Customer Experience	QA/Survey Scores declining	Monthly or Quarterly	$50-100 bonus on paycheck/ logo item	Individual or Team (CR's, Coaches and Ops Managers)	CE > 8.5 QA Average >85	Amount Baseline is exceeded
Customer Service Week	National Customer Service week. Recognition of our Customer Service Reps	October	Logo item	Team (CR's, Coaches and Ops Manager)	Everyone	N/A
Other business need as appropriate	Other focus based on business need	TBD	$25-150 bonus on paycheck/ logo item	TBD	TBD	TBD

David A. Daniel 7-10-18

David Daniel **Date**
Manager Business Service Center

Debbie Leist 7/10/18

Debbie Leist **Date**
Director Customer Service & Marketing

Lora Huff Aria 7/9/18

Lora Aria **Date**
Manager Business Offices

7/9/2018

Darius Lepp **Date**
Manager Residential Service Center

Appendix A: Example of Eligible Employee(s) Incentives Template

Paid Incentives - amounts are paid out on employee's paycheck

Employee ID (e.g. "E012345")	Name	Project	Task	Time Code (a)	Amount	Date of Incentive	Start Date (b)	End Date (b)	Comments

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 119

Responding Witness: Gregory J. Meiman

Q-119. Indicate whether any award of executive compensation (e.g., incentive pay) is in the form of stock.

a. If so, indicate the specific type of stock (e.g., restricted).

b. If so, indicate the amount (by type of stock) included in the revenue requirement.

A-119. Yes.

a. Executives are eligible to receive grants of restricted stock units and performance stock units.

b. All stock based incentives are excluded from the revenue requirement.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 120

Responding Witness: Gregory J. Meiman

Q-120. Refer to the direct testimony of Gregory J. Meiman, page 22, wherein he refers to "Mercer's comparator group." Identify those companies making up the comparator group and provide the criteria by which they are identified as peers of the Companies.

A-120. The requested entities are identified at page 10 of 13 of the study provided by Mercer which is attached as Attachment 4 to Tab 60 to the Application. These entities were selected based on their similar customer size to the Companies and/or a local presence.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
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Case No. 2018-00295

Question No. 121

Responding Witness: Gregory J. Meiman

Q-121. Provide a list of severance payments included in the base year, including the amount, reason, and position of employee involved.

A-121. The Company does not budget severance payments. As such, no severance amounts were included in the cost of service or revenue requirement.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
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Case No. 2018-00295

Question No. 122

Responding Witness: Gregory J. Meiman

Q-122. Long Term Incentive Plans ("LTIP"): Does the cost of service include any long-term incentive plan costs, either direct charged or allocated? If the response is in the affirmative, provide the following items:

a. The amount included in the base year and forecasted period. If the amount is allocated, provide the allocations.

b. A list of the officers, directors, and key employees and the amounts of LTIP awarded to each for 2016, 2017, and 2018 YTD.

c. The performance objectives and actual performance results upon which the awards were based for 2016, 2017, and 2018 YTD.

d. A copy of the LTIP plan documents and explain how the awards are made.

A-122. No, the cost of service does not include any long-term incentive plan costs, neither direct charged nor allocated.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 123

Responding Witness: Gregory J. Meiman

Q-123. Supplemental Executive Retirement Plan ("SERP"): Does the cost of service include any SERP either direct charged or allocated? If the response is in the affirmative, provide the following item:

a. The amount included in the base year and forecasted amount. If the amount is allocated, provide the allocations.

A-123.

a. SERP expense is not included in the Company's cost of service.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 124

Responding Witness: Gregory J. Meiman

Q-124. Supplemental Executive Retirement Program (SERP).

a. Provide the comparable SERP expense for each calendar year 2015, 2016, and 2017.

b. Provide the most recent three actuarial reports for SERP.

c. Provide all actuarial studies, reports, and estimates used for SERP for the rate effective period.

d. If different for affiliated SERP costs charged or allocated to LG&E, also answer parts a-e above for each affiliate that incurred SERP costs that were charged or allocated to LG&E.

A-124.

a. SERP expense was not included in the Company's cost of service for calendar years 2015, 2016, and 2017.

b. Not applicable, as SERP expense is not included in the Company's cost of service.

c. Not applicable, as SERP expense is not included in the Company's cost of service.

d. Not applicable.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
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Case No. 2018-00295

Question No. 125

Responding Witness: Christopher M. Garrett

G. Taxes

Q-125. Refer to the direct testimony of Chris M. Garrett, pages 32-35, and Schedule E-1 sponsored by Mr. Garrett. Mr. Garrett notes that the "TCJA retains the corporate deduction for state income taxes and the interest deductibility for utilities."

a. Are these two deductions taken into account in setting the Companies' rates?

b. If the response to subpart a., above, is in the affirmative, provide a citation to the application where the deductions are evidenced.

A-125.

a. Yes, the two deductions are included.

b. The state income tax and interest expense deductions can be seen on Schedule E-1, lines 2 and 15.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
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Case No. 2018-00295

Question No. 126

Responding Witness: Christopher M. Garrett

Q-126. Refer to the direct testimony of Kent W. Blake, pages 4-5, wherein he described the Offer and Acceptance of Satisfaction as filed in Case No. 2018-00034, as "Commission-approved."

a. Is it the position of the Companies that the Commission approved the referenced Offer and Acceptance of Satisfaction? If the response is in the affirmative, provide support for same.

A-126.

a. In Case No. 2018-00034, the Commission approved, with modifications that did not impact the termination date of the TCJA Surcredit, the *Offer and Acceptance of Satisfaction* in its Order dated March 20, 2018. In the Commission's Order dated September 28, 2018, the Commission noted that the *Offer and Acceptance of Satisfaction* became non-unanimous after the AG's withdrawal, but did not alter the termination date of the TCJA Surcredit.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 127

Responding Witness: Christopher M. Garrett

Q-127. Tax Cuts and Jobs Act. Notwithstanding the regulatory treatment in Case No. 2018-00034, confirm that IRS normalization requirements for excess accumulated deferred income taxes ("ADIT") apply to only accelerated federal tax method-life depreciation, and that they do not apply to excess ADIT on other book-tax temporary differences, regardless of whether they have a basis in plant.

A-127. Confirmed. The normalization requirements apply to ADIT and excess ADIT attributable to differences in the method of computing depreciation and/or the depreciable life of an asset (method-life differences) used for federal income tax purposes versus those used for financial purposes. Federal ADIT and excess ADIT attributable to method-life differences are subject to the normalization rules and are generally referred to as "protected items." There is no prohibition against any other basis adjustments being treated in the same way (normalized) as method-life differences. The Company has, with past regulatory approval, consistently treated plant related basis adjustments arising from other than method-life differences as protected items. Furthermore, the Companies have classified net operating loss carryforward excess ADITs as "protected."

In this case customers actually benefit by including the other basis adjustments as protected items. The other basis adjustments are a net deferred income tax asset or additional "costs" to customers (rather than a deferred income tax liability that is refunded to customers) due to the income tax rate change. The customers benefit because they are "paying back" this deferred tax asset over a longer period of time as a protected item versus an unprotected item.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
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Case No. 2018-00295

Question No. 128

Responding Witness: Christopher M. Garrett

Q-128. Tax Cuts and Jobs Act. The Companies' FERC Form 1's for 2017 state the following at page 123.22:

KU
Regulatory liabilities associated with net deferred taxes represent the future revenue impact from the adjustment of deferred income taxes required primarily for excess deferred taxes and unamortized investment tax credits. At December 31, 2017, excess deferred taxes recorded as a result of the TCJA were $634 million, which includes the gross-up associated with the excess deferred taxes.

LG&E
Regulatory liabilities associated with net deferred taxes represent the future revenue impact from the adjustment of deferred income taxes required primarily for excess deferred taxes and unamortized investment tax credits. At December 31, 2017, excess deferred taxes recorded as a result of the TCJA were $532 million, which includes the gross-up associated with the excess deferred taxes.

a. Provide a reconciliation of the Companies' excess deferred tax balances, before and after the referenced gross-up.

b. What is the purpose of the gross-up and why is it necessary?

c. Considering the excess deferred taxes are amortized, how is the gross up reflected in cost of service as the excess deferred taxes is amortized?

A-128.

a. See attached.

b. The gross-up represents the future tax consequence of refunding excess deferred tax back to customers. As the Company refunds excess deferred tax back to customers in rates, the refund will result in lower future revenue (and taxable income) to the Company and therefore lower future income tax expense. This future decrease in income tax is an additional amount that is to be distributed to customers.

c. The gross-up is part of the revenue requirement calculation on Schedule A, line 7, Tab 54 of the Filing Requirements. The excess deferred tax that is amortized per Schedule E, Tab 58 of the Filing Requirement does not include the gross-up.

Kentucky Utilities Company
Louisville Gas and Electric Company
Regulatory Movement - TCJA
Balances as of 12/31/17

	KU	LG&E
Excess Deferred Taxes on Timing Differences		
Cumulative Federal Timing Differences, including NOLs	(3,497,577,603)	(2,975,451,192)
Federal Rate Change	14.00%	14.00%
Excess Deferred Tax	(489,660,864)	(416,563,167)
Cumulative State Timing Differences	(2,462,775,281)	(2,048,290,331)
Fed Benefit Rate Change	-0.84%	-0.84%
Excess Deferred Tax	20,687,312	17,205,639
Total Excess Deferred Tax before Gross-up	(468,973,552)	(399,357,528)
Gross-up Factor	1.3466	1.3466
Net Regulatory Movement	(631,529,157)	(537,782,828)
Change in Gross-up Factor on Existing Regulatory Adjustments		
Excess Deferred Tax Balance - Prior rate changes	(4,755,068)	(7,163,617)
Unamortized ITC Balance	(93,857,853)	(35,252,005)
ITC Basis Adjustments	89,034,136	21,735,503
AFUDC Equity Balance	17,870,543	-
Subtotal	8,291,758	(20,680,119)
Reduction in Gross-up Factor	(0.2900)	(0.2900)
Reduction to Existing Regulatory Adjustments	(2,404,952)	5,998,087
Total Regulatory Movement	**(633,934,109)**	**(531,784,741)**

	Old Tax Rates	New Tax Rates	Change in Rates
Federal	35.00%	21.00%	-14.00%
State	6.00%	6.00%	0.00%
Fed Benefit	-2.10%	-1.26%	0.84%
Composite	38.90%	25.74%	-13.16%
Gross-up Factor (1/(1 - tax rate))	1.6367	1.3466	-0.2900

Note: Tax Rates are based on enacted tax law as of 12/31/17. The reduction to the Kentucky state tax rate was enacted per HB 487 in April 2018 and is not reflected in the balances above.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 129

Responding Witness: Christopher M. Garrett

Q-129. State Tax Reform. Refer to the direct testimony of Chris M. Garrett, page 35, wherein he states, "Prior to the implementation of H.B. 487, the Companies paid a state corporate income tax rate of 6%. For taxable years beginning on or after January 1, 2018, the state corporate income tax will be imposed at a 5% tax rate."

a. What are the estimated savings from the corporate rate reduction and estimated increases in sales tax resulting from state tax reform for the period between January 1, 2018, and April 30, 2019?

A-129.

a. See Exhibit 2 from Case No. 2018-00304 which provides an annual estimate for income tax savings, excess ADIT amortization, and offsets for the loss of the Kentucky domestic production activities deduction and the increase in sales tax attributable to the total Company (including rate mechanisms).

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 130

Responding Witness: Christopher M. Garrett

Q-130. State Tax Reform. Refer to the direct testimony of Chris M. Garrett, page 35, wherein he states, "In a separate filing earlier this month, the Companies requested permission to establish regulatory liabilities by the end of the year for the excess ADIT created by the reduction in the state corporate income tax rate."

a. How are the regulatory liabilities reflected in the base and forecasted test years?

A-130.

a. The Company has assumed that the regulatory liability treatment will be granted and has included the Kentucky excess ADIT regulatory liability in rate base in both the base and forecasted test period. See the response to Question No. 131 for the associated Kentucky excess ADIT amortization on Schedule E.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 131

Responding Witness: Christopher M. Garrett

Q-131. State Tax Reform. Refer to the direct testimony of Chris M. Garrett, page 38, wherein he states, "Included in the forecasted test year is approximately $1.0 million for KU, $0.5 million for LG&E Electric, and $0.1 million for LG&E Gas of additional excess ADIT amortization associated with Kentucky state tax reform."

a. Reconcile the referenced amortizations to the excess ADIT adjustments in the Companies' respective Schedule Es.

A-131.

a. See reconciliations below:

LG&E Electric Forecasted Test Year	
Schedule E-1, Line 105 – Excess Deferreds – Protected	$(826,671)
Schedule E-1, Line 106 – Excess Deferreds – Unprotected	(94,601)
Total state excess ADIT amortization - forecasted test year	(921,272)
Less state excess ADIT amortization - prior rate changes	(321,667)
Excess ADIT amortization - Kentucky state tax reform	$(599,605)
Net of federal tax offset [$599,605 * (1 - .21%)]	$(473,687)

LG&E Gas Forecasted Test Year	
Schedule E-1, Line 97 – Excess Deferreds – Protected	$(212,028)
Schedule E-1, Line 98 – Excess Deferreds – Unprotected	(12,053)
Total state excess ADIT amortization - forecasted test year	(224,081)
Less state excess ADIT amortization - prior rate changes	(48,333)
Excess ADIT amortization - Kentucky state tax reform	$(175,748)
Net of federal tax offset [$175,748 * (1 - .21%)]	$(138,841)

For KU's reconciliation, refer to Case No. 2018-00294 response to AG 1-131.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 132

Responding Witness: Christopher M. Garrett

Q-132. State Tax Reform. Refer to the direct testimony of Chris M. Garrett, page 35, wherein he states, "Like the Companies' treatment of the TCJA, KU and LG&E will account for the state corporate tax rate reduction by amortizing all protected excess ADIT using the Average Rate Assumption Method ("ARAM") and amortizing all unprotected excess ADIT over a 15-year amortization period. The Companies will continue to treat all property-related excess ADIT as protected."

a. Cite the Kentucky law or tax code that defines "protected" excess ADIT.

b. Cite the Kentucky law or tax code that requires using ARAM to amortize "protected" excess ADIT consistent with IRS requirements for electing federal accelerated depreciation.

A-132.

a. Effective for tax years beginning on or after January 1, 2018, House Bill 366 section 53(14) amends Kentucky's income tax provisions for conformity to the Internal Revenue Code that was in effect on December 31, 2017 (includes Tax Cuts and Jobs Act and normalization section). However, Kentucky will continue to decouple from the full expensing deduction allowed for federal purposes under Internal Revenue Code Section 168(k). House Bill 366 was adopted in its entirety into House Bill 487.

b. See the response to part a.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 133

Responding Witness: Christopher M. Garrett

Q-133. State Tax Reform. Refer to the direct testimony of Chris M. Garrett, page 35, wherein he states, "The amortization of the unprotected excess ADIT will begin when new base rates go into effect."

a. Discuss when the "protected" excess ADIT amortizations under the ARAM method begin.

b. If they do not begin when new base rates go into effect, will the benefit of the "protected" excess ADIT amortizations from January 1, 2018, through April 30, 2019, ever accrue to customers?

A-133.

a. The Company began amortizing its Kentucky "protected" excess ADIT under the ARAM effective January 1, 2018. This approach is consistent with the approach taken in the previous two Kentucky state tax reform cases, Case No. 2005-00180 and Case No. 2006-00457.

b. Unlike with the much larger federal Tax Cuts and Jobs Act, no separate cases were initiated nor Orders issued to address state tax reform from its inception. The base rates set forth in this proceeding, however, do provide customers the benefit of the forecast test year amortization of the "protected" excess ADIT on an ongoing basis. Whether benefits embedded in the calculation of base rates will ultimately be greater or less than the cumulative excess ADIT amortization will depend on the timing of rate cases during the life of the underlying assets giving rise to the excess ADIT balances.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 134

Responding Witness: Christopher M. Garrett

Q-134. State Tax Reform. The Kentucky corporate income tax rate was previously reduced from 7 percent to 6 percent, effective in 2008, and from 8.25 percent to 7 percent, effective in 2006.

a. Were the excess ADIT's in connection with the previous tax rate reductions amortized consistently with the Companies' proposed ratemaking treatment in the instant case? If the response is in the negative, explain the differences.

b. Do the Companies have remaining excess ADIT balances on their books from the previous tax rate reductions? If the response is in the affirmative, provide the forecasted balances as of December 31, 2018, and April 30, 2019.

A-134.

a. The protected excess deferred income tax was amortized consistent with the approach in Case No. 2005-00180 and Case No. 2006-00457. For the unprotected excess deferred tax in both of the previous cases the Company immediately reduced income tax expense in the year of the tax rate reduction due to the de minimis amount of the adjustment ($25,000 in 2005 and $106,000 in 2006).

b. Yes. The Company does have "protected" ADIT balances from the previous tax rate reductions that continue to amortize. The forecasted balances as of December 31, 2018, and April 30, 2019 are $9.1 million and $9.0 million, respectfully.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 135

Responding Witness: Christopher M. Garrett

Q-135. Property Tax. Refer to Filing Requirement 807 KAR 5:001 Section 16(7)(c), Item A, wherein the Companies describe the financial planning modeling process. Page 13 of 19 states the following:

Property taxes are estimated annually based on net book asset values, including CWIP, as of December 31 of the previous year and include several current asset balances such as; fuel inventory and materials and supplies. The expense accrual is spread evenly over twelve months while cash payments are based on historic trends, which normally result in large cash payments during the fourth quarter of a calendar year.

The primary source of data used to calculate the estimates is within the UI report labeled "KY Plant Account". The plant account assignment determines the property classification (real estate, manufacturing machinery, other tangible) and then the appropriate tax rates are applied to those balances. State and local tax rates are based on prior year settlements with an assumed increase to local tax rates of two percent per year.

a. Provide the computation supporting monthly property tax expense for 2019 and 2020. The computation should reflect:

   i. Net book asset values, including CWIP, as of December 31 of the previous year and current asset balances such as; fuel inventory and materials and supplies.

   ii. Rates applied to those balances.

b. Reconcile the state and local tax rates based on prior year settlements with the assumed increase to local tax rates of two percent per year going back to 2017.

A-135.

a. See the attachment to the response to KIUC 1-47.

b. The Kentucky Department of Revenue releases an "Average Local Property Tax Rates" schedule each year which supports the assumed increase to local tax rates of two percent. State tax rates remain unchanged. See attached.

TABLE II
AVERAGE LOCAL PROPERTY TAX RATES

Tax rates are expressed in cents per $100 of assessed value.

TYPE OF DISTRICT CLASS OF PROPERTY	TAX RATE *	NO. DISTRICTS REPORTING	% Increase
COUNTIES			
Average Real Estate Rate	33.0544	120	3%
Average Tangible Rate	39.4471	120	2%
Average Motor Vehicle Rate	25.0962	120	1%
CITIES			
Average Real Estate Rate(Zero Rates Excluded)	22.5847	403	0%
Average Real Estate Rate(Zero Rates Included)	22.4179	406	1%
Average Tangible Rate(Zero Rates Excluded)	29.1876	298	3%
Average Tangible Rate(Zero Rates Included)	21.4234	406	4%
Average Motor Vehicle Rate(Zero Rates Excluded)	24.9731	273	0%
Average Motor Vehicle Rate(Zero Rates Included)	16.7922	406	1%
SCHOOL DISTRICTS			
Average Real Estate Rate	64.8006	178	3%
Average Tangible Rate	64.8927	178	3%
Average Motor Vehicle Rate	56.1073	178	0%
SPECIAL TAX DISTRICTS			
Average Real Estate Rate(Zero Rates Excluded)	10.415	243	1%
Average Real Estate Rate(Zero Rates Included)	10.33	245	1%
Average Tangible Rate(Zero Rates Excluded)	10.6932	158	1%
Average Tangible Rate(Zero Rates Included)	6.896	245	2%
Average Motor Vehicle Rate(Zero Rates Excluded)	10.1796	152	1%
Average Motor Vehicle Rate(Zero Rates Included)	6.3155	245	1%

2017 Property Tax Rate Book

TABLE II

AVERAGE LOCAL PROPERTY TAX RATES

Tax rates are expressed in cents per $100 of assessed value.

TYPE OF DISTRICT CLASS OF PROPERTY	TAX RATE *	NO. DISTRICTS REPORTING
COUNTIES		
Average Real Estate Rate	31.9487	120
Average Tangible Rate	38.5832	120
Average Motor Vehicle Rate	24.9274	120
CITIES		
Average Real Estate Rate(Zero Rates Excluded)	22.5454	403
Average Real Estate Rate(Zero Rates Included)	22.1605	410
Average Tangible Rate(Zero Rates Excluded)	28.4638	298
Average Tangible Rate(Zero Rates Included)	20.6883	410
Average Motor Vehicle Rate(Zero Rates Excluded)	24.9011	274
Average Motor Vehicle Rate(Zero Rates Included)	16.6412	410
SCHOOL DISTRICTS		
Average Real Estate Rate	63.0714	178
Average Tangible Rate	63.2248	178
Average Motor Vehicle Rate	56.0843	178
SPECIAL TAX DISTRICTS		
Average Real Estate Rate(Zero Rates Excluded)	10.3065	243
Average Real Estate Rate(Zero Rates Included)	10.2224	245
Average Tangible Rate(Zero Rates Excluded)	10.558	157
Average Tangible Rate(Zero Rates Included)	6.7657	245
Average Motor Vehicle Rate(Zero Rates Excluded)	10.0983	151
Average Motor Vehicle Rate(Zero Rates Included)	6.2239	245

2016 Property Tax Rate Book

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 136

Responding Witness: Christopher M. Garrett

Q-136. Tax Depreciation. Refer to the Companies' response to PSC Data Request No. 1-65.

a. Provide the tax depreciation rates for each line item in Att_LGE_PSC_1-65_Depreciation_Exp_Wkpr_Electric&Att_LGE_PSC_1-65_Depreciation_Exp_Wkpr_Gas.

b. Reconcile the book-tax timing difference to accumulated deferred income taxes in rate base for the forecast period.

A-136.

a. See attached.

b. See the response to PSC 2-62(c).

Louisville Gas & Electric
Depreciation Calculation - Electric

Description	Current Rate	Proposed Rate eff. May-2019	Tax Depr Rate
LGE-130100-Elect. Intagible Plant -	0.00%	0.00%	LGE ELECTRIC MISC INTANGIBLE PLT SLT 5
LGE-130200-Franchises and Consents	0.00%	0.00%	LGE ELECTRIC MISC INTANGIBLE PLT SLT 5
LGE-130300-Misc Intang Plant-Softwa	21.72%	21.72%	LGE ELECTRIC MISC INTANGIBLE PLT SLT 5
LGE-131020-Steam-Land	0.00%	0.00%	NA
LGE-131020-Steam-MC 4 Land ECR 2016	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131020-Steam-TC 2 Land ECR 2009	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131025-Steam-Land ECR 2005	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131026-Steam-Land ECR 2011	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131027-Steam-Land Future Use	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-Cane Run Unit 1 Structur	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-Cane Run Unit 2 Structur	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-Cane Run Unit 3 Structur	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-Cane Run Unit 4 SO2-Stru	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-Cane Run Unit 4 Structur	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-Cane Run Unit 5 SO2-Stru	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-Cane Run Unit 5 Structur	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-Cane Run Unit 6 SO2-Stru	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-CR 6 Struc ECR 2009	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-CR Unit 6 Struc	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-CR Unit 6 Struc ECR 2005	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-Distribution Dr ECR 2011	1.84%	2.66%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-Distribution Drive	1.84%	2.66%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-MC Unit 1 Struc ECR 2011	1.08%	1.76%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-MC Unit 2 SO2 ECR 2011	0.00%	5.61%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-MC Unit 2 Struc ECR 2011	1.10%	2.31%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-MC Unit 4 Struc	1.84%	2.21%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-MC Unit 4 Struc ECR 2005	0.00%	2.21%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-MC Unit 4 Struc ECR 2011	1.84%	2.21%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-Mill Creek 3 ECR 2011	1.06%	1.83%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-Mill Creek Unit 1 SO2-St	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-Mill Creek Unit 1 Struct	1.08%	1.76%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-Mill Creek Unit 2 SO2-St	0.00%	5.61%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-Mill Creek Unit 2 Struct	1.10%	2.31%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-Mill Creek Unit 3 SO2-St	0.00%	5.26%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-Mill Creek Unit 3 Struct	1.06%	1.83%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-Mill Creek Unit 4 SO2-St	0.56%	2.80%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-Mill Creek3 SO2 ECR 2011	1.06%	5.26%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-Mill Creek4 SO2 ECR 2011	0.56%	2.80%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-TC 1 Future Use - 105	1.77%	1.77%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-TC Unit 1 Struc	1.77%	1.68%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-TC Unit 1 Struc ECR 2006	1.77%	1.68%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-TC Unit 2 Struc	2.34%	2.16%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-TC Unit 2 Struc ECR 2006	0.00%	2.16%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-TC Unit 2 Struc ECR 2009	2.34%	2.16%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-Trimble Unit 1 SO2-Struc	1.13%	3.57%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131100-Trimble Unit 2 FGD-Struc	2.34%	2.25%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131101-AROP CR 1 Struct & Impr	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131101-AROP CR 6 Struc ECR 2005	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131101-AROP CR 6 Struct & Impr	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131101-AROP MC 1 Struct & Impr	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131101-AROP MC 3 Struct & Impr	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131101-AROP MC 4 Struct & Impr	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131101-AROP TC 1 Struct & Impr	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20

Louisville Gas & Electric
Depreciation Calculation - Electric

Description	Current Rate	Proposed Rate eff. May-2019	Tax Depr Rate
LGE-131101-AROP TC 2 Struc ECR 2009	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131110-CR 6 Capital Leased Equi	6.99%	6.99%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131110-MC 4 Capital Leased Equi	1.65%	1.65%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200 CR ECR Future Plan	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-Cane Run Rail Cars - Boi	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-Cane Run Unit 1 Boiler P	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-Cane Run Unit 2 Boiler P	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-Cane Run Unit 3 Boiler P	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-Cane Run Unit 4 SO2 Boil	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-Cane Run Unit 5 SO2 Boil	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-CR Unit 4 Boil	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-CR Unit 4 Boil ECR 2006	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-CR Unit 5 Boil	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-CR Unit 5 Boil ECR 2006	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-CR Unit 6 Boil	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-CR Unit 6 Boil ECR 2006	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-CR Unit 6 ECR 2009	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-CR6 SO2 Boil	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-CR6 SO2 Boil ECR 2005	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC ECR 2018 Plan	2.83%	3.61%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC ECR Future Plant	2.83%	3.61%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC Offsite Rail Cars	0.36%	0.36%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC Unit 1 Boil	2.82%	6.15%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC Unit 1 Boil ECR 2006	2.82%	6.15%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC Unit 1 Boil ECR 2011	2.82%	6.15%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC Unit 1 Boil-Ash Pond	0.00%	10.94%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC Unit 2 Boil	3.16%	6.27%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC Unit 2 Boil ECR 2006	3.16%	6.27%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC Unit 2 Boil ECR 2011	3.16%	6.27%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC Unit 2 Boil ECR 2016	3.16%	6.27%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC Unit 2 SO2 ECR 2011	1.56%	6.27%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC Unit 2 SO2 ECR 2016	1.56%	6.27%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC Unit 3 Boil	2.94%	4.47%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC Unit 3 Boil ECR 2006	2.94%	4.47%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC Unit 3 Boil ECR 2011	2.94%	4.47%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC Unit 3 Boil ECR 2016	2.94%	4.47%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC Unit 3 Boil-Ash Pond	0.00%	21.94%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC Unit 3 SO2 ECR 2011	2.42%	4.47%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC Unit 3 SO2 ECR 2016	2.42%	4.47%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC Unit 4 Boil	2.83%	3.61%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC Unit 4 Boil ECR 2005	2.83%	3.61%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC Unit 4 Boil ECR 2006	2.83%	3.61%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC Unit 4 Boil ECR 2011	2.83%	3.61%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC Unit 4 Boil ECR 2016	2.83%	3.61%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC3 SO2 Boil ECR 2011	0.00%	5.54%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC4 SO2 Boil	1.74%	4.47%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC4 SO2 Boil ECR 2005	1.74%	4.47%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC4 SO2 Boil ECR 2009	1.74%	4.47%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC4 SO2 Boil ECR 2011	1.74%	4.47%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-MC4 SO2 Boil ECR 2016	1.74%	4.47%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-Mill Creek Rail Cars Boi	0.36%	0.36%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-Mill Creek Unit 1 SO2 Bo	1.96%	3.67%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-Mill Creek Unit 2 SO2 Bo	1.56%	6.78%	LGE ELECTRIC STEAM PROD MACRS 20

Louisville Gas & Electric
Depreciation Calculation - Electric

Description	Current Rate	Proposed Rate eff. May-2019	Tax Depr Rate
LGE-131200-Mill Creek Unit 3 SO2 Bo	2.42%	5.54%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-TC 1 Future Use - 105	2.83%	2.83%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-TC 2 FGD Boil	2.75%	2.33%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-TC 2 FGD Boil ECR 2006	2.75%	2.33%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-TC ECR 2018 Plan	2.74%	2.39%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-TC ECR Future Plan	2.74%	2.39%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-TC Unit 1 Boil	2.83%	3.02%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-TC Unit 1 Boil ECR 2006	2.83%	3.02%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-TC Unit 1 Boil ECR 2009	2.83%	3.02%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-TC Unit 1 Boil ECR 2011	2.83%	3.02%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-TC Unit 1 Boil-Ash Pond	0.00%	10.30%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-TC Unit 2 Boil	2.74%	2.39%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-TC Unit 2 Boil ECR 2006	2.74%	2.39%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-TC Unit 2 Boil ECR 2009	2.74%	2.39%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-TC Unit 2 Boil ECR 2016	2.74%	2.39%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-TC1 SO2 Boil	1.39%	2.31%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-TC1 SO2 Boil ECR 2005	1.39%	2.31%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-TC1 SO2 Boil ECR 2016	1.39%	2.31%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131200-TC2 Boil ECR 2009-Ash Po	0.00%	21.96%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131201-AROP MC3 Boiler Plt Equp	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131201-AROP MC4 SO2 Boiler Plt	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131400-Cane Run Unit 1 Turbogen	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131400-Cane Run Unit 2 Turbogen	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131400-Cane Run Unit 3 Turbogen	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131400-Cane Run Unit 4 Turbogen	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131400-Cane Run Unit 5 SO2 Turb	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131400-Cane Run Unit 5 Turbogen	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131400-Cane Run Unit 6 SO2 Turb	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131400-Cane Run Unit 6 Turbogen	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131400-Mill Creek Unit 1Turboge	1.15%	4.76%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131400-Mill Creek Unit 2 Turbog	1.66%	4.22%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131400-Mill Creek Unit 3 Turbog	2.13%	2.63%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131400-Mill Creek Unit 4 Turbog	1.75%	2.88%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131400-TC 1 Future Use - 105	2.43%	2.43%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131400-Trimble Unit 1 Turbogene	2.43%	2.17%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131400-Trimble Unit 2 Turbogene	2.35%	2.21%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-Cane Run Unit 1 Accessor	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-Cane Run Unit 2 Accessor	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-Cane Run Unit 3 Acessory	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-Cane Run Unit 4 Accessor	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-Cane Run Unit 4 SO2 Acce	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-Cane Run Unit 5 Acccesso	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-Cane Run Unit 5 SO2 Acce	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-Cane Run Unit 6 Accessor	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-Cane Run Unit 6 SO2 Acce	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-MC Unit 1 Acc ECR 2011	3.06%	3.31%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-MC Unit 2 Acc ECR 2011	1.98%	3.77%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-MC Unit 2 SO2 ECR 2011	0.00%	4.97%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-MC Unit 3 Acc ECR 2011	1.02%	2.89%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-Mill Creek 4 ECR 2011	1.66%	2.16%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-Mill Creek Unit 1 Access	3.06%	3.31%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-Mill Creek Unit 1 SO2 Ac	0.00%	0.07%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-Mill Creek Unit 2 Access	1.98%	3.77%	LGE ELECTRIC STEAM PROD MACRS 20

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LGE-131500-Mill Creek Unit 2 SO2 Ac	0.00%	4.97%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-Mill Creek Unit 3 Access	1.02%	2.89%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-Mill Creek Unit 3 SO2 Ac	0.00%	4.75%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-Mill Creek Unit 4 Access	1.66%	2.16%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-Mill Creek Unit 4 SO2 Ac	0.42%	3.15%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-Mill Crk #3 SO2 ECR 2011	0.00%	4.75%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-Mill Crk #4 SO2 ECR 2011	0.42%	3.15%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-TC 1 Future Use - 105	2.55%	2.55%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-TC Unit 2 Acce	2.55%	2.21%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-TC Unit 2 Acce ECR 2006	2.55%	2.21%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-TC Unit 2 Acce ECR 2009	2.55%	2.21%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-Trimble 1 Acc ECR 2011	2.23%	2.26%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-Trimble Unit 1 Accessory	2.23%	2.26%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-Trimble Unit 1 SO2 Acces	0.98%	0.92%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131500-Trimble Unit 2 FGD Acces	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131501-AROP Cane Run 4 Acc	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131501-AROP Cane Run 5 Acc	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131501-AROP Cane Run 6 Acc	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131501-AROP Mill Creek 1 Acc	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131501-AROP Mill Creek 2 Acc	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131501-AROP Mill Creek 3 Acc	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131501-AROP Mill Creek 4 Acc	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131501-AROP Trimble Unit 1 Acc	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131600-Cane Run Unit 1 Misc. Po	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131600-Cane Run Unit 3 Misc. Po	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131600-Cane Run Unit 4 Misc. Po	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131600-Cane Run Unit 4 SO2 Misc	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131600-Cane Run Unit 5 Misc. Po	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131600-Cane Run Unit 5 SO2 Misc	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131600-Cane Run Unit 6 Misc. Po	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131600-Cane Run Unit 6 SO2 Misc	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131600-Distribution Dr ECR 2011	3.02%	2.42%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131600-Distribution Drive	3.02%	2.42%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131600-MC Unit 1 Misc ECR 2011	2.80%	4.23%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131600-MC Unit 2 Misc ECR 2011	1.96%	3.18%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131600-Mill Creek #4 ECR 2009	3.02%	3.47%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131600-Mill Creek #4 ECR 2011	3.02%	3.47%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131600-Mill Creek Unit 1 Misc P	2.80%	4.23%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131600-Mill Creek Unit 2 Misc.	1.96%	3.18%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131600-Mill Creek Unit 3 Misc.	1.36%	0.77%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131600-Mill Creek Unit 4 Misc.	3.02%	3.47%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131600-Mill Creek Unit 4 SO2 Mi	2.28%	0.04%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131600-Trimble Unit 1 Misc. Pow	2.75%	2.59%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-131600-Trimble Unit 2 Misc. Pow	2.83%	2.69%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-133020-Ohio Falls Non-Project	0.00%	0.00%	NA
LGE-133020-Ohio Falls Project 289	0.00%	0.00%	NA
LGE-133100-Ohio Falls Non-Project	1.43%	1.43%	LGE ELECTRIC HYDRO PROD MACRS 20
LGE-133100-Ohio Falls Project 289	1.59%	1.59%	LGE ELECTRIC HYDRO PROD MACRS 20
LGE-133200-Ohio Falls Project 289	0.91%	0.91%	LGE ELECTRIC HYDRO PROD MACRS 20
LGE-133300-Ohio Falls Project 289	3.24%	3.24%	LGE ELECTRIC HYDRO PROD MACRS 20
LGE-133400-Ohio Falls Project 289	2.39%	2.39%	LGE ELECTRIC HYDRO PROD MACRS 20
LGE-133500-Ohio Falls Non-Project	2.77%	2.77%	LGE ELECTRIC HYDRO PROD MACRS 20
LGE-133500-Ohio Falls Project 289	3.10%	3.10%	LGE ELECTRIC HYDRO PROD MACRS 20

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LGE-133600-Ohio Falls Non-Project	0.00%	0.00%	LGE ELECTRIC HYDRO PROD MACRS 20
LGE-133600-Ohio Falls Project 289	2.32%	2.32%	LGE ELECTRIC HYDRO PROD MACRS 20
LGE-134020 - TC 10 - Land	0.00%	0.00%	NA
LGE-134020-CT Land	0.00%	0.00%	NA
LGE-134020-EWB Solar Facility Land	0.00%	0.00%	NA
LGE-134020-Simpson Solar Share Land	0.00%	0.00%	NA
LGE-134020-TC 5 CT Land	0.00%	0.00%	NA
LGE-134100-Cane Run 11- Structures	19.67%	19.67%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134100-Cane Run 7 Structures	2.16%	2.16%	LGE ELECTRIC OTHER PROD MACRS 20
LGE-134100-EWB 5 Structures and Imp	3.97%	3.97%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134100-EWB 6 Structures and Imp	4.54%	4.54%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134100-EWB 7 Structures and Imp	4.53%	4.53%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134100-EWB Solar Struc and Imp	4.24%	4.24%	LGE OTHER PROD MACRS 5 - 15% DEPR BASIS ADJ
LGE-134100-Paddys GT - 11 Structure	0.00%	0.00%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134100-Paddys GT - 12 Structure	6.75%	6.75%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134100-PR 13 Structures and Imp	4.25%	4.25%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134100-TC 10 Structures and Imp	3.64%	3.64%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134100-TC 5 Structures and Impr	3.72%	3.72%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134100-TC 6 Structures and Impr	3.70%	3.70%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134100-TC 7 Structures and Impr	3.62%	3.62%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134100-TC 8 Structures and Impr	3.62%	3.62%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134100-TC9 Structures and Impro	3.64%	3.64%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134100-Waterside - Structures &	0.00%	0.00%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134100-Zorn - Structurses & Imp	0.00%	0.00%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134200-Cane Run 11-Fuel Holder	19.79%	19.79%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134200-Cane Run 7 Fuel Holders	2.85%	2.85%	LGE ELECTRIC OTHER PROD MACRS 20
LGE-134200-EWB 5 Fuel Holders, Prod	4.43%	4.43%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134200-EWB 6 Fuel Holders, Prod	6.73%	6.73%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134200-EWB 7 Fuel Holders, Prod	7.88%	7.88%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134200-Paddys GT - 11 Fuel Hold	0.00%	0.00%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134200-Paddys GT - 12 Fuel Hold	9.54%	9.54%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134200-PR 13 Fuel Holders, Prod	4.00%	4.00%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134200-TC 10 Fuel Holders, Prod	3.72%	3.72%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134200-TC 5 Fuel Holders, Produ	3.77%	3.77%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134200-TC 6 Fuel Holders, Produ	3.77%	3.77%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134200-TC 7 Fuel Holders, Produ	3.70%	3.70%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134200-TC 8 Fuel Holders, Produ	3.70%	3.70%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134200-TC 9 Fuel Holders, Produ	3.71%	3.71%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134200-Waterside - Fuel Holders	0.00%	0.00%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134200-Zorn - Fuel Holders, Pro	9.31%	9.31%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134300-Cane Run 11-Prime Mover	0.00%	0.00%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134300-Cane Run 7 Prime Mover	3.33%	3.33%	LGE ELECTRIC OTHER PROD MACRS 20
LGE-134300-EWB 5 Prime Movers	4.40%	4.40%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134300-EWB 6 Prime Movers	6.17%	6.17%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134300-EWB 7 Prime Movers	5.20%	5.20%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134300-Green River CC GT	3.33%	3.33%	LGE ELECTRIC OTHER PROD MACRS 20
LGE-134300-Paddys GT - 11 Prime Mov	43.77%	43.77%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134300-Paddys GT - 12 Prime Mov	43.77%	43.77%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134300-PR 13 Prime Movers	5.60%	5.60%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134300-TC 10 Prime Movers	4.34%	4.34%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134300-TC 5 Prime Movers	4.34%	4.34%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134300-TC 6 Prime Movers	4.35%	4.35%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134300-TC 7 Prime Movers	4.37%	4.37%	LGE ELECTRIC OTHER PROD MACRS 15

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LGE-134300-TC 8 Prime Movers	4.42%	4.42%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134300-TC 9 Prime Movers	4.34%	4.34%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134300-Waterside - Prime Movers	0.00%	0.00%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134300-Zorn - Prime Movers	0.00%	0.00%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134400-Bus Solar Generator-Arch	4.61%	4.61%	LGE OTHER PROD MACRS 5 - 15% DEPR BASIS ADJ
LGE-134400-Cane Run 11- Generators	5.68%	5.68%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134400-Cane Run 7- Generators	2.70%	2.70%	LGE ELECTRIC OTHER PROD MACRS 20
LGE-134400-EWB 5 Generators	4.05%	4.05%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134400-EWB 6 Generators	4.32%	4.32%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134400-EWB 7 Generators	4.38%	4.38%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134400-EWB Solar Generators	4.61%	4.61%	LGE OTHER PROD MACRS 5 - 15% DEPR BASIS ADJ
LGE-134400-Paddys GT - 11 Generator	0.00%	0.00%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134400-Paddys GT - 12 Generator	0.00%	0.00%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134400-PR 13 Generators	4.36%	4.36%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134400-TC 10 Generators	3.66%	3.66%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134400-TC 5 Generators	3.73%	3.73%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134400-TC 6 Generators	3.73%	3.73%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134400-TC 7 Generators	3.64%	3.64%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134400-TC 8 Generators	3.64%	3.64%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134400-TC 9 Generators	3.66%	3.66%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134400-Waterside - Generators	0.00%	0.00%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134400-Zorn - Generators	0.00%	0.00%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134500-Bus Solar Acc Elec-Archd	4.36%	4.36%	LGE OTHER PROD MACRS 5 - 15% DEPR BASIS ADJ
LGE-134500-Cane Run 11- Accessory	5.37%	5.37%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134500-Cane Run 7- Accessory	2.88%	2.88%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134500-EWB 5 Accessory Electric	4.02%	4.02%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134500-EWB 6 Acessory Electric	4.48%	4.48%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134500-EWB 7 Acessory Electric	4.51%	4.51%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134500-EWB Solar Acessory Elec	4.36%	4.36%	LGE OTHER PROD MACRS 5 - 15% DEPR BASIS ADJ
LGE-134500-Paddys GT - 11 Accessory	38.28%	38.28%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134500-Paddys GT - 12 Accessory	18.33%	18.33%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134500-PR 13 Accessory Electric	4.10%	4.10%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134500-TC 10 Accessory Electric	3.88%	3.88%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134500-TC 5 Accessory Electric	4.26%	4.26%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134500-TC 6 Accessory Electric	3.98%	3.98%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134500-TC 7 Accessory Electric	4.06%	4.06%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134500-TC 8 Accessory Electric	3.68%	3.68%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134500-TC 9 Acessory Electric E	3.87%	3.87%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134500-Waterside - Accessory El	0.00%	0.00%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134500-Zorn - Accessory Electri	14.60%	14.60%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134600-Cane Run 11- Misc Power	0.00%	0.00%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134600-Cane Run 7- Misc Power	2.79%	2.79%	LGE ELECTRIC OTHER PROD MACRS 20
LGE-134600-EWB 5 Misc Power Plant E	4.01%	4.01%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134600-EWB 6 Misc Power Plant E	4.36%	4.36%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134600-EWB 7 Misc Power Plant E	4.42%	4.42%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134600-EWB Solar Misc Pwr Plt	4.25%	4.25%	LGE OTHER PROD MACRS 5 - 15% DEPR BASIS ADJ
LGE-134600-Paddys GT - 11 Misc. Pow	23.74%	23.74%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134600-Paddys GT - 12 mIsc. Pow	0.00%	0.00%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134600-PR 13 Misc Power Plant E	4.00%	4.00%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134600-TC 10 Misc. Power Plant	4.40%	4.40%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134600-TC 5 Misc. Power Plant E	3.94%	3.94%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134600-TC 6 Misc. Power Plant E	0.00%	0.00%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134600-TC 7 Misc. Power Plant E	3.69%	3.69%	LGE ELECTRIC OTHER PROD MACRS 15

Louisville Gas & Electric
Depreciation Calculation - Electric

Description	Current Rate	Proposed Rate eff. May-2019	Tax Depr Rate
LGE-134600-TC 8 Misc. Power Plant E	3.69%	3.69%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134600-TC 9 Misc. Power Plant E	3.70%	3.70%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134600-Waterside - Misc. Power	0.00%	0.00%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-134600-Zorn - Misc. Power Plant	17.56%	17.56%	LGE ELECTRIC OTHER PROD MACRS 15
LGE-135010- IN Elec Transmission -	1.14%	1.14%	NA
LGE-135010- KY Elec Transmission -	1.14%	1.14%	NA
LGE-135020-IN Electric Trans	0.00%	0.00%	NA
LGE-135020-KY Electric Trans	0.00%	0.00%	NA
LGE-135210- IN Elec Transmission -	1.75%	1.75%	LGE ELECTRIC TRANS OTHER MACRS 15
LGE-135210- KY Elec Transmission -	1.75%	1.75%	LGE ELECTRIC TRANS OTHER MACRS 15
LGE-135210-TC Sw. Station - Substat	1.75%	1.75%	LGE ELECTRIC TRANS OTHER MACRS 15
LGE-135210-TC Unit 1 - Trans. - Sub	1.75%	1.75%	LGE ELECTRIC TRANS OTHER MACRS 15
LGE-135220-Struct & Improve-System	1.17%	1.17%	LGE ELECTRIC TRANS OTHER MACRS 15
LGE-135310- IN Elec Transmission -	1.61%	1.61%	LGE ELECTRIC TRANS OTHER MACRS 15
LGE-135310- KY Elec Transmission -	1.61%	1.61%	LGE ELECTRIC TRANS OTHER MACRS 15
LGE-135310-Ohio Falls - Substation	1.61%	1.61%	LGE ELECTRIC TRANS OTHER MACRS 15
LGE-135310-TC Sw. Station - Substat	1.61%	1.61%	LGE ELECTRIC TRANS OTHER MACRS 15
LGE-135310-TC Unit 1 - Trans. - Sub	1.61%	1.61%	LGE ELECTRIC TRANS OTHER MACRS 15
LGE-135311-AROP Station Equip	0.00%	0.00%	LGE ELECTRIC TRANS OTHER MACRS 15
LGE-135311-AROP TC1 Station Equip	0.00%	0.00%	LGE ELECTRIC TRANS OTHER MACRS 15
LGE-135320-Station Equip System	0.00%	0.00%	LGE ELECTRIC TRANS OTHER MACRS 15
LGE-135400- IN Elec Transmission -	1.84%	1.84%	LGE ELECTRIC TRANS OTHER MACRS 15
LGE-135400- KY Elec Transmission -	1.84%	1.84%	LGE ELECTRIC TRANS OTHER MACRS 15
LGE-135500- IN Elec Transmission -	2.98%	2.98%	LGE ELECTRIC TRANS OTHER MACRS 15
LGE-135500- KY Elec Transmission -	2.98%	2.98%	LGE ELECTRIC TRANS OTHER MACRS 15
LGE-135600- IN Elec Transmission -	3.32%	3.32%	LGE ELECTRIC TRANS OTHER MACRS 15
LGE-135600- KY Elec Transmission -	3.32%	3.32%	LGE ELECTRIC TRANS OTHER MACRS 15
LGE-135600-Ohio Falls/Canal - Overh	3.32%	3.32%	LGE ELECTRIC TRANS OTHER MACRS 15
LGE-135700-Electric Transmission -	1.83%	1.83%	LGE ELECTRIC TRANS OTHER MACRS 15
LGE-135800-Electric Transmission -	2.44%	2.44%	LGE ELECTRIC TRANS OTHER MACRS 15
LGE-136010-KY Land Right Future Use	0.00%	0.00%	NA
LGE-136020-Elect. Dist. Substation	0.00%	0.00%	NA
LGE-136025-Elect. Dist. Substation	0.00%	0.00%	NA
LGE-136100-Electric Distribution Su	2.05%	2.05%	LGE ELECTRIC DIST MACRS 20
LGE-136200- IN Elect Dist Substati	2.10%	2.10%	LGE ELECTRIC DIST MACRS 20
LGE-136200- KY Elect Dist Substati	2.10%	2.10%	LGE ELECTRIC DIST MACRS 20
LGE-136205-Elect. Dist. Substation	0.00%	0.00%	NA
LGE-136400-Electric Distribution -	3.18%	3.18%	LGE ELECTRIC DIST MACRS 20
LGE-136500-Electric Distribution -	3.25%	3.25%	LGE ELECTRIC DIST MACRS 20
LGE-136600-Electric Distribution -	1.60%	1.60%	LGE ELECTRIC DIST MACRS 20
LGE-136700-Electric Distribution -	2.06%	2.06%	LGE ELECTRIC DIST MACRS 20
LGE-136800-Line Transformers	2.33%	2.33%	LGE ELECTRIC DIST MACRS 20
LGE-136910-Electric Distribution -	3.73%	3.73%	LGE ELECTRIC DIST MACRS 20
LGE-136920-Electric Distribution -	2.63%	2.63%	LGE ELECTRIC DIST MACRS 20
LGE-137000-Meters	2.79%	2.79%	LGE ELECTRIC DIST MACRS 20
LGE-137001- DSM Meters	6.85%	6.85%	LGE ELECTRIC DIST MACRS 20
LGE-137002- MAM Meters	6.85%	6.85%	LGE ELECTRIC DIST MACRS 20
LGE-137020-Meters - CT and PT	3.30%	3.30%	LGE ELECTRIC DIST MACRS 20
LGE-137101 KY Install Charging Sta	10.00%	10.00%	LGE ELECTRIC OTHER PROD MACRS 20
LGE-137310-Electric Distribution -	5.38%	5.38%	LGE ELECTRIC STREET LIGHTS MACRS 7
LGE-137320-Electric Distribution -	3.64%	3.64%	LGE ELECTRIC STREET LIGHTS MACRS 7
LGE-137340-Electric Dist. - Street	0.00%	0.00%	LGE ELECTRIC STREET LIGHTS MACRS 7
LGE-139220-Transportation - Traile	5.33%	5.33%	LGE ELECTRIC CARS TRUCKS MACRS 5

Louisville Gas & Electric
Depreciation Calculation - Electric

Description	Current Rate	Proposed Rate eff. May-2019	Tax Depr Rate
LGE-139400-Tools, Shop, and Garage	4.28%	4.28%	LGE ELECTRIC OTHER MACRS 7
LGE-139500-Laboratory Equipment	0.00%	0.00%	LGE ELECTRIC OTHER MACRS 7
LGE-139620-Power Op Equip-Other	3.57%	3.57%	LGE ELECTRIC POWER OP EQUIP MACRS 5
LGE-139700- KY Microwave,Fiber,Ot	0.00%	0.00%	LGE ELECTRIC OTHER MACRS 7
LGE-139720- DSM Equipment	12.28%	12.28%	LGE ELECTRIC OTHER MACRS 7
LGE-312101-Nonutility Prop - Coal L	0.00%	0.00%	LGE COMMON GENERAL OTHER MACRS 7
LGE-312102-Nonutility-Coal Mineral	0.00%	0.00%	LGE COMMON GENERAL OTHER MACRS 7
LGE-312103-Nonutility-Coal Rts of W	0.00%	0.00%	LGE COMMON GENERAL OTHER MACRS 7
LGE-312104-Nonutility Prop - Misc L	0.00%	0.00%	LGE COMMON GENERAL OTHER MACRS 7
LGE-312192-Nonutility Cars & Trucks	0.00%	0.00%	LGE COMMON GENERAL OTHER MACRS 7
LGE-330100-Common Intangible Plant	0.00%	0.00%	LGE COMMON MISC INTANGIBLE PLT SL 5
LGE-330200-Franchises and Consents	0.00%	0.00%	LGE COMMON MISC INTANGIBLE PLT SL 5
LGE-330300-Misc Intang Plant-Softwa	21.72%	21.72%	LGE COMMON MISC INTANGIBLE PLT SL 5
LGE-330310-CCS Software	10.04%	10.04%	LGE COMMON MISC INTANGIBLE PLT SL 5
LGE-330320-Law Library	0.00%	0.00%	LGE COMMON MISC INTANGIBLE PLT SL 5
LGE-338910-Common - Land	0.00%	0.00%	NA
LGE-338920-Common - Land Rights	1.15%	1.15%	NA
LGE-339010-Common Structures - Gene	2.75%	2.75%	LGE COMMON STRUCTURE IMPROV MACRS 39
LGE-339010-Str LGE Bldg - Joint Own	2.75%	2.75%	LGE COMMON STRUCTURE IMPROV MACRS 39
LGE-339010-Struct and Imp-Actor's	2.75%	2.75%	LGE COMMON STRUCTURE IMPROV MACRS 39
LGE-339010-Struct Broad.- Joint Own	2.75%	2.75%	LGE COMMON STRUCTURE IMPROV MACRS 39
LGE-339010-Struct Broad.-LGE Owned	2.75%	2.75%	LGE COMMON STRUCTURE IMPROV MACRS 39
LGE-339010-Struct-LGE Bldg Owned	2.75%	2.75%	LGE COMMON STRUCTURE IMPROV MACRS 39
LGE-339020-Common Structures - Tran	2.56%	2.56%	LGE COMMON STRUCTURE IMPROV MACRS 39
LGE-339030-Common Structures - Stor	1.94%	1.94%	LGE COMMON STRUCTURE IMPROV MACRS 39
LGE-339040-Common Structures - Othe	2.61%	2.61%	LGE COMMON STRUCTURE IMPROV MACRS 39
LGE-339060-Common Structures - Micr	1.97%	1.97%	LGE COMMON STRUCTURE IMPROV MACRS 39
LGE-339110-Office Furniture	1.41%	1.41%	LGE COMMON OFFICE FURN MACRS 7
LGE-339120-Office Equipment	13.53%	13.53%	LGE COMMON OFFICE FURN MACRS 7
LGE-339130-Computer Eq	18.59%	18.59%	LGE COMMON OFFICE FURN MACRS 7
LGE-339131-Personal Computers	21.71%	21.71%	LGE COMMON OFFICE FURN MACRS 7
LGE-339133-Computer Eq ECR 2006	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-339140-Security Equipment	11.42%	11.42%	LGE COMMON OFFICE FURN MACRS 7
LGE-339220-Trans Equip-Trailers	5.63%	5.63%	LGE COMMON CARS TRUCKS MACRS 5
LGE-339300-Stores Equipment	5.15%	5.15%	LGE COMMON GENERAL OTHER MACRS 7
LGE-339400-Tools, Shop, Garage Equi	4.25%	4.25%	LGE COMMON GENERAL OTHER MACRS 7
LGE-339500-Laboratory Equipment	0.00%	0.00%	LGE COMMON GENERAL OTHER MACRS 7
LGE-339620-Power Op Equip - Other	1.40%	1.40%	LGE COMMON POWER OP EQUIP MACRS 5
LGE-339700-IN Microwave,Fiber,Other	0.79%	0.79%	LGE COMMON COMMUNICATION EQUIP MACRS 7
LGE-339700-KY DSM Communication	0.79%	0.79%	LGE COMMON COMMUNICATION EQUIP MACRS 7
LGE-339700-KY Microwave,Fiber,Other	0.79%	0.79%	LGE COMMON COMMUNICATION EQUIP MACRS 7
LGE-339710- Radios and Telephone	3.13%	3.13%	LGE COMMON COMMUNICATION EQUIP MACRS 7
LGE-339800-Miscellaneous Equipment	0.00%	0.00%	LGE COMMON GENERAL OTHER MACRS 7
LGE-134100-Simp Solar A1 Struc & Im	4.24%	4.24%	LGE OTHER PROD MACRS 5 - 15% DEPR BASIS ADJ
LGE-134400-Simp Solar A1 Generators	4.61%	4.61%	LGE OTHER PROD MACRS 5 - 15% DEPR BASIS ADJ
LGE-134500-Simp Solar A1 Acces Elec	4.36%	4.36%	LGE OTHER PROD MACRS 5 - 15% DEPR BASIS ADJ
LGE-134600-Simp Solar A1 Misc Pwr P	4.25%	4.25%	LGE OTHER PROD MACRS 5 - 15% DEPR BASIS ADJ

Louisville Gas & Electric
Depreciation Calculation - Gas

Description	Current Rate	Current Rate eff. May-2019	Tax Depr Rate
LGE-211700-Gas Stored UG Non-Curren	0.00%	0.00%	LGE GAS UG STOR OTHER MACRS 15
LGE-230200-Franchises and Consents	12.39%	12.39%	LGE GAS MISC INTANGIBLE PLT SLT 5
LGE-230300-Misc Intang Plant-Softwa	21.72%	21.72%	LGE GAS MISC INTANGIBLE PLT SLT 5
LGE-235010-IN Gas Storage Undergr	0.00%	0.00%	NA
LGE-235010-KY Gas Storage Undergr	0.00%	0.00%	NA
LGE-235020-Gas Storage Underground	0.59%	0.59%	NA
LGE-235120-Gas Storage Undg. - Comp	2.06%	2.06%	LGE GAS UG STOR OTHER MACRS 15
LGE-235130-Gas Storage Undg. - Regu	1.04%	1.04%	LGE GAS UG STOR OTHER MACRS 15
LGE-235140- IN Gas Storage Undergr	1.87%	1.87%	LGE GAS UG STOR OTHER MACRS 15
LGE-235140- KY Gas Storage Undergr	1.87%	1.87%	LGE GAS UG STOR OTHER MACRS 15
LGE-235210-Gas Storage Undg. - Leas	0.00%	0.00%	LGE GAS UG STOR OTHER MACRS 15
LGE-235220-Gas Storage Underground	0.00%	0.00%	LGE GAS UG STOR OTHER MACRS 15
LGE-235230-Gas Storage Undg. - Non	0.82%	0.82%	LGE GAS UG STOR OTHER MACRS 15
LGE-235240- IN Gas Storage Undergrd	2.11%	2.11%	LGE GAS UG STOR OTHER MACRS 15
LGE-235240- KY Gas Storage Undergrd	2.11%	2.11%	LGE GAS UG STOR OTHER MACRS 15
LGE-235250- IN AROP Gas Stor UG	0.00%	0.00%	LGE GAS UG STOR OTHER MACRS 15
LGE-235250- KY AROP Gas Stor UG	0.00%	0.00%	LGE GAS UG STOR OTHER MACRS 15
LGE-235255- IN Gas Stor UG	3.01%	3.01%	LGE GAS UG STOR OTHER MACRS 15
LGE-235255- KY Gas Stor UG	3.01%	3.01%	LGE GAS UG STOR OTHER MACRS 15
LGE-235300- IN Gas Storage Undergrd	2.01%	2.01%	LGE GAS UG STOR OTHER MACRS 15
LGE-235300- KY Gas Storage Undergrd	2.01%	2.01%	LGE GAS UG STOR OTHER MACRS 15
LGE-235400-Gas Storage Undg. - Comp	2.27%	2.27%	LGE GAS UG STOR OTHER MACRS 15
LGE-235500-Gas Storage Undg. - Meas	2.55%	2.55%	LGE GAS UG STOR OTHER MACRS 15
LGE-235600-Gas Storage Undg. - Puri	2.37%	2.37%	LGE GAS UG STOR OTHER MACRS 15
LGE-235700- IN Gas Storage Undergrd	2.53%	2.53%	LGE GAS UG STOR OTHER MACRS 15
LGE-235700- KY Gas Storage Undergrd	2.53%	2.53%	LGE GAS UG STOR OTHER MACRS 15
LGE-236520-Gas Transmission Rights	0.13%	0.13%	LGE GAS TRANS RW SL 84
LGE-236700-Gas Transmission - Mains	2.05%	2.05%	LGE GAS TRANS OTHER MACRS 15
LGE-236710-Gas Transmission GLT	2.05%	2.05%	LGE GAS TRANS OTHER MACRS 15
LGE-237412-Gas Distribution Land	0.00%	0.00%	NA
LGE-237413- Land- Gas Line Tracker	0.00%	0.00%	NA
LGE-237422-Gas Distribution Land Ri	0.00%	0.00%	NA
LGE-237510-Gas Distribution - City	1.25%	1.25%	LGE GAS DIST OTHER MACRS 15
LGE-237520-Gas Distribution - Other	4.50%	4.50%	LGE GAS DIST OTHER MACRS 15
LGE-237600-Gas Distribution - Mains	1.62%	1.62%	LGE GAS DIST OTHER MACRS 15
LGE-237610-Gas Distribution - Mains	1.62%	1.62%	LGE GAS DIST OTHER MACRS 15
LGE-237620-Gas Line Tracker - Mains	1.62%	1.62%	LGE GAS DIST OTHER MACRS 15
LGE-237800-Gas Distribution - Measu	2.21%	2.21%	LGE GAS DIST OTHER MACRS 15
LGE-237900-Gas Distribution - City	1.81%	1.81%	LGE GAS DIST OTHER MACRS 15
LGE-238000-Gas Distribution - Gas S	3.24%	3.24%	LGE GAS DIST OTHER MACRS 15
LGE-238010-Gas Distribution - Gas S	3.24%	3.24%	LGE GAS DIST OTHER MACRS 15
LGE-238020-Gas Line Tracker Service	3.24%	3.24%	LGE GAS DIST OTHER MACRS 15
LGE-238100-Meters	3.83%	3.83%	LGE GAS DIST OTHER MACRS 15
LGE-238101-AMS Meters	4.03%	4.03%	LGE GAS DIST OTHER MACRS 15
LGE-238300-Regulators	3.77%	3.77%	LGE GAS DIST OTHER MACRS 15
LGE-238500-Gas Distribution - Indus	2.31%	2.31%	LGE GAS DIST OTHER MACRS 15
LGE-238700-Gas Distribution - Other	1.94%	1.94%	LGE GAS DIST OTHER MACRS 15
LGE-239220-Transportation Equip-Tra	7.16%	7.16%	LGE GAS CARS TRUCKS MACRS 5
LGE-239400-Tools, Shop, and Garage	4.26%	4.26%	LGE GAS OTHER MACRS 7
LGE-239500-Laboratory Equipment	0.00%	0.00%	LGE GAS OTHER MACRS 7
LGE-239620-Power Op Equip - Other	3.34%	3.34%	LGE GAS POWER OP EQUIP MACRS 5
LGE-239720- DSM Equipment	0.00%	0.00%	LGE COMMON GENERAL OTHER MACRS 7
LGE-312101-Nonutility Prop - Coal L	0.00%	0.00%	LGE COMMON GENERAL OTHER MACRS 7

Louisville Gas & Electric
Depreciation Calculation - Gas

Description	Current Rate	Current Rate eff. May-2019	Tax Depr Rate
LGE-312102-Nonutility-Coal Mineral	0.00%	0.00%	LGE COMMON GENERAL OTHER MACRS 7
LGE-312103-Nonutility-Coal Rts of W	0.00%	0.00%	LGE COMMON GENERAL OTHER MACRS 7
LGE-312104-Nonutility Prop - Misc L	0.00%	0.00%	LGE COMMON GENERAL OTHER MACRS 7
LGE-312192-Nonutility Cars & Trucks	0.00%	0.00%	LGE COMMON GENERAL OTHER MACRS 7
LGE-330100-Common Intangible Plant	0.00%	0.00%	LGE COMMON MISC INTANGIBLE PLT SL 5
LGE-330200-Franchises and Consents	0.00%	0.00%	LGE COMMON MISC INTANGIBLE PLT SL 5
LGE-330300-Misc Intang Plant-Softwa	21.72%	21.72%	LGE COMMON MISC INTANGIBLE PLT SL 5
LGE-330310-CCS Software	10.04%	10.04%	LGE COMMON MISC INTANGIBLE PLT SL 5
LGE-330320-Law Library	0.00%	0.00%	LGE COMMON MISC INTANGIBLE PLT SL 5
LGE-338910-Common - Land	0.00%	0.00%	NA
LGE-338920-Common - Land Rights	1.15%	1.15%	NA
LGE-339010-Common Structures - Gene	2.75%	2.75%	LGE COMMON STRUCTURE IMPROV MACRS 39
LGE-339010-Str LGE Bldg - Joint Own	2.75%	2.75%	LGE COMMON STRUCTURE IMPROV MACRS 39
LGE-339010-Struct and Imp-Actor's	2.75%	2.75%	LGE COMMON STRUCTURE IMPROV MACRS 39
LGE-339010-Struct Broad.- Joint Own	2.75%	2.75%	LGE COMMON STRUCTURE IMPROV MACRS 39
LGE-339010-Struct Broad.-LGE Owned	2.75%	2.75%	LGE COMMON STRUCTURE IMPROV MACRS 39
LGE-339010-Struct-LGE Bldg Owned	2.75%	2.75%	LGE COMMON STRUCTURE IMPROV MACRS 39
LGE-339020-Common Structures - Tran	2.56%	2.56%	LGE COMMON STRUCTURE IMPROV MACRS 39
LGE-339030-Common Structures - Stor	1.94%	1.94%	LGE COMMON STRUCTURE IMPROV MACRS 39
LGE-339040-Common Structures - Othe	2.61%	2.61%	LGE COMMON STRUCTURE IMPROV MACRS 39
LGE-339060-Common Structures - Micr	1.97%	1.97%	LGE COMMON STRUCTURE IMPROV MACRS 39
LGE-339110-Office Furniture	1.41%	1.41%	LGE COMMON OFFICE FURN MACRS 7
LGE-339120-Office Equipment	13.53%	13.53%	LGE COMMON OFFICE FURN MACRS 7
LGE-339130-Computer Eq	18.59%	18.59%	LGE COMMON OFFICE FURN MACRS 7
LGE-339131-Personal Computers	21.71%	21.71%	LGE COMMON OFFICE FURN MACRS 7
LGE-339133-Computer Eq ECR 2006	0.00%	0.00%	LGE ELECTRIC STEAM PROD MACRS 20
LGE-339140-Security Equipment	11.42%	11.42%	LGE COMMON OFFICE FURN MACRS 7
LGE-339220-Trans Equip-Trailers	5.63%	5.63%	LGE COMMON CARS TRUCKS MACRS 5
LGE-339300-Stores Equipment	5.15%	5.15%	LGE COMMON GENERAL OTHER MACRS 7
LGE-339400-Tools, Shop, Garage Equi	4.25%	4.25%	LGE COMMON GENERAL OTHER MACRS 7
LGE-339500-Laboratory Equipment	0.00%	0.00%	LGE COMMON GENERAL OTHER MACRS 7
LGE-339620-Power Op Equip - Other	1.40%	1.40%	LGE COMMON POWER OP EQUIP MACRS 5
LGE-339700-IN Microwave,Fiber,Other	0.79%	0.79%	LGE COMMON COMMUNICATION EQUIP MACRS 7
LGE-339700-KY DSM Communication	0.79%	0.79%	LGE COMMON COMMUNICATION EQUIP MACRS 7
LGE-339700-KY Microwave,Fiber,Other	0.79%	0.79%	LGE COMMON COMMUNICATION EQUIP MACRS 7
LGE-339710- Radios and Telephone	3.13%	3.13%	LGE COMMON COMMUNICATION EQUIP MACRS 7
LGE-339800-Miscellaneous Equipment	0.00%	0.00%	LGE COMMON GENERAL OTHER MACRS 7

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 137

Responding Witness: David S. Sinclair

Q-137. With regard to Mr. Seelye's Loss of Load Probability ("LOLP") study, he indicates that hourly loads were utilized for individual classes. In this respect, provide:

a. a detailed narrative description of how class hourly loads were developed;

b. each class hourly load for the forecasted test year (or the period utilized by Mr. Seelye within his CCOSS). Because of the joint dispatch of the Companies' generation facilities, include both KU and LG&E classes (showing KU and LG&E classes separately). In addition, also include each non-jurisdictional class;

c. a detailed explanation of how curtailable load or curtailable load credits are reflected within the class hourly loads;

d. all workpapers, analyses, spreadsheets, etc. showing the development of each hourly load for each class; and,

e. an explanation of whether the hourly loads provided in (b) are measured at the meter or generation level.

Provide all data in executable electronic format, preferably in native Excel format, with all formulas intact and cells unprotected and with all columns and rows accessible. If data is not available in Excel format, contact counsel for the Attorney General to provide the data in ASCII comma-delimited format with all fields defined.

A-137.

a. See Case Nos. 2018-00294 and 2018-00295 Attachment to Filing Requirement 807 KAR 5:001 Sec. 16(7)(c) E.

b. See the attachment being provided in Excel format.

c. The class hourly load forecasts reflect forecasted reductions due to the Companies' Direct Load Control program but not the Curtailable Service Rider ("CSR"). Load reductions associated with CSR are modeled as a supply-side resource.

d. See the attachments being provided in Excel format.

e. The hourly loads provided in response to part b are measured at the generation level.

The attachments are being provided in separate files in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 138

Responding Witness: David S. Sinclair

Q-138. For each of the last two years (or most recent 24-months available), provide actual class hourly loads for both KU and LG&E for every hour during the 24-month period. If the requested data for every hour and every class is not available, provide the most detailed information available.

A-138. The attachment, which is provided in Excel format, contains class hourly loads for the 12-month period from May 2017 to April 2018. Class hourly loads are estimated based on sample recorder data. The Companies have not estimated class hourly loads for the 12 months prior to May 2017.

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018**

Case No. 2018-00295

Question No. 139

Responding Witness: David S. Sinclair

Q-139. With regard to Mr. Seelye's LOLP study, he indicates that hourly characteristics of LG&E and KU's generating facilities were utilized. In this respect, provide:

a. A detailed narrative description of how hourly generation output was developed;

b. Each hourly generation output (by unit) for the forecasted test year (or the period utilized by Mr. Seelye within his CCOSS). Because of the joint dispatch of the Companies' generation facilities, include both KU and LG&E generation resources. For facilities jointly-owned exclusively by LG&E and KU, provide total unit output by hour. For facilities partially owned by LG&E and KU combined, provide KU and LG&E (combined) percentage output;

c. Hourly purchases of electricity (KU and LG&E combined); and,

d. Hourly wholesale sales of electricity (KU and LG&E combined).

Provide all data in executable electronic format, preferably in native Excel format, with all formulas intact and cells unprotected and with all columns and rows accessible. If data is not available in Excel format, contact counsel for the Attorney General to provide the data in ASCII comma-delimited format with all fields defined.

A-139.

a. See attached. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection. The LOLP study is a statistical calculation of hourly LOLP based on the Companies' forecasted resource characteristics and load at an hourly level, however it does not involve developing an hourly dispatch model.

For a general discussion of how the Companies model hourly generation for business planning, see the "Annual Generation Forecast Process" attached at Tab 16 of the Filing Requirements, Section 16(7)(c), Item G.

b. Hourly generation outputs are not produced by the LOLP analysis. See the response to part (a).

c. Hourly purchases outputs are not produced by the LOLP analysis. See the response to part (a).

d. Market off-system sales are not produced by the LOLP analysis. However, wholesale sales to the non-departing municipals are included in the Companies' load obligation. See the response to part (a).

The entire attachment is Confidential and provided separately under seal.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 140

Responding Witness: David S. Sinclair

Q-140. With regard to Mr. Seelye's LOLP study, provide a detailed explanation along with all mathematical formulae showing how hourly LOLP was calculated. In this response, specifically explain how off-system sales, wholesale purchases of power, curtailment capabilities, reserve margin requirements, and outage rates are considered, evaluated, and quantified in developing hourly LOLP.

A-140. See the response to Question No. 139. No off-system sales were modeled in the LOLP study. In addition to the Companies' firm supply-side capacity resources, the analysis assumed that the Companies could purchase up to 558 MW of energy in an hour and could curtail up to 141 MW of CSR-related load. The generation resources in the LOLP study reflect the characteristics of the Companies' existing resources that were acquired to meet the Companies' forecasted load obligations, based on the reserve margin target range developed in the Companies' 2014 Integrated Resource Plan ("IRP"). The Companies' 2018 IRP target reserve margin range resulted in no changes to the Companies' generation portfolio. Forecasted outage rates are included in the generating unit characteristics considered in the LOLP analysis.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018**

Case No. 2018-00295

Question No. 141

Responding Witness: David S. Sinclair

Q-141. With regard to Mr. Seelye's LOLP study, provide all analyses, workpapers, spreadsheets, etc. showing the following:

a. hourly system Loss of Load Probability;

b. hourly system load (MW);

c. hourly forced outage MW (by unit as available);

d. hourly planned outage MW (by unit as available);

e. available generation production from KU/LG&E-owned facilities;

f. wholesale sales (if applicable or utilized in determining hourly LOLP);

g. wholesale purchased power (if applicable or utilized in determining hourly LOLP); and,

h. required reserve margin (percent or MW as applicable)

i. curtailable load available (MW)

j. curtailable load actually curtailed (MW).

In this response, provide all data and formulae necessary to replicate each hourly system Loss of Load Probability. Provide all data in executable electronic format, preferably in native Excel format, with all formulas intact and cells unprotected and with all columns and rows accessible. If data is not available in Excel format, contact counsel for the Attorney General to provide the data in ASCII comma-delimited format with all fields defined.

A-141.

a. See the attachment being provided in Excel format.

b. See the response to part (a).

c. PROSYM's process for calculating LOLP does not simulate forced outages for each unit on an hourly basis. See the response to Question No. 139.

d. Planned outages were not considered in the LOLP calculation.

e. See the attachment being provided in Excel format. Note that maximum capacity in the outage rate table varies by month.

f. See the response to Question No. 140.

g. See the response to Question No. 140.

h. See the response to Question No. 142(a).

i. The sum of the expected curtailment achievable by the Companies' CSR customers is 141 MW.

j. No hourly data regarding the curtailment of CSR customers are produced as a result of the LOLP analysis. See the response to Question No. 139(a).

In addition, a number of PROSYM files are being provided in response to this request. The Company is providing them on separate electronic storage media subject to a motion to deviate because the files cannot be uploaded to the Commission's website. The Company will supply copies on electronic storage media to the Commission, the Attorney General, and all parties who have already requested copies of all responses filed. The Company will provide the files to any other party to this proceeding upon request.

The attachments are being provided in separate files in Excel format.

The attachments are being provided in separate files.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 142

Responding Witness: David S. Sinclair

Q-142. Provide LG&E and KU individual and combined generation reserve margins for the following:

a. fully forecasted test year;

b. most recent actual period available; and,

c. as of December 31, 2017.

A-142. The Companies develop a target reserve margin range for planning sufficient supply resources to reliably meet the combined Companies' anticipated peak hour load obligation and account for resource outage risk and load variability at every moment of the year. At any point in time, the Companies take actions to address momentary demand and system operational issues. The planning reserve margin is designed to allow the combined Companies to reliably address these uncertainties at the lowest reasonable cost. For further information regarding the development of the Companies' target reserve margin, see the Companies' 2018 Integrated Resource Plan. Because the Companies jointly plan the combined system, the Companies do not develop a target reserve margin range or a planning reserve margin for each individual company on a standalone basis. Although a comparison of each company's allocated supply resources and forecasted summer peak load can be performed, there is no target reserve margin range to which these figures can be compared.

a. The planning reserve margin for the forecasted test period is 23.5 percent for the combined Companies. The capacity of the supply resources that have been allocated to each company over the years is higher than the forecasted summer peak demand in the forecasted test period by 33.5 percent for KU and by 9.7 percent for LG&E.

b. The planning reserve margin for 2018 was 24.7 percent for the combined Companies. The capacity of the supply resources that have been allocated to each company over the years was higher than the 2018 forecasted summer peak by 30.3 percent for KU and by 16.4 percent for LG&E.

c. The planning reserve margin for 2017 was 21.6 percent for the combined Companies. The Companies have not developed historical calculations for the individual Companies.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 143

Responding Witness: David S. Sinclair / William Steven Seelye

Q-143. Provide all workpapers, analyses, spreadsheets, etc. showing the development of each class' weighted LOLP as shown in Exhibit WSS-19. Provide all data in executable electronic format, preferably in native Excel format, with all formulas intact and cells unprotected and with all columns and rows accessible. If data is not available in Excel format, contact counsel for the Attorney General to provide the data in ASCII comma-delimited format with all fields defined.

A-143. See the responses to Question No. 137, part b and Question No. 141.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 144

Responding Witness: David S. Sinclair

Q-144. For each of the last ten years, provide the following:

a. annual winter system peak demand (KU and LG&E combined);

b. annual winter native load (jurisdictional) peak demand (KU and LG&E combined);

c. annual summer system peak demand (KU and LG&E combined); and,

d. annual summer native load (jurisdictional) peak demand (KU and LG&E combined).

A-144. See attached.

Year	Maximum Winter System Demand*
2008	6,357
2009	6,555
2010	6,340
2011	6,017
2012	5,704
2013	5,907
2014	7,114
2015	7,079
2016	6,223
2017	5,679
2018	6,699

Year	Maximum Summer System Demand*
2008	6,352
2009	6,367
2010	7,175
2011	6,756
2012	6,856
2013	6,434
2014	6,313
2015	6,392
2016	6,458
2017	6,503
2018	6,490

Year	Maximum Winter Jurisdictional Demand*
2008	Not Available
2009	Not Available
2010	5,725
2011	5,477
2012	5,179
2013	5,368
2014	6,482
2015	6,402
2016	5,653
2017	5,201
2018	6,100

*Winter defined as November through April
*Jurisdictional removes ODP and Muni Loads

Year	Maximum Summer Jurisdictional Demand*
2008	Not Available
2009	Not Available
2010	6,622
2011	6,221
2012	6,333
2013	5,955
2014	5,845
2015	5,923
2016	5,983
2017	6,048
2018	6,053

*Summer defined as May through October

Case No. 2018-00295
Attachment to Response to AG-1 Question No. 144

Sinclair

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 145

Responding Witness: Christopher M. Garrett

Q-145. For each KU and LG&E generating unit owned individually, jointly, or partially, provide the following for the most recent actual 12-month period available:

a. names of owners (and ownership percentages);

b. type of fuel(s);

c. total nameplate (rated) capacity (MW);

d. total and individual company gross investment at the end of the period;

e. total individual company depreciation reserve at the end of the period;

f. total and individual company annual book depreciation expense;

g. gross KWh produced during the period; and,

h. net (less station use) KWh produced during the period.

Provide in executable electronic (Excel) format with all formulas intact and cells unprotected and with all columns and rows accessible.

A-145. See the attachment being provided in Excel format.

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 146

Responding Witness: Daniel K. Arbough / David S. Sinclair

Q-146. For each KU and LG&E generating unit owned individually, jointly, or partially, provide the following for the fully forecasted test year ending April 30, 2020:

a. names of owners (and ownership percentages);

b. type of fuel(s);

c. total nameplate (rated) capacity (MW);

d. total and individual company gross investment at the end of the period;

e. total individual company depreciation reserve at the end of the period;

f. total and individual company annual book depreciation expense;

g. gross KWh produced during the period; and,

h. net (less station use) KWh produced during the period.

Provide in executable electronic (Excel) format with all formulas intact and cells unprotected and with all columns and rows accessible.

A-146.

a. See the attachment being provided in Excel format.

b. See the response to part a.

c. See the response to part a.

d. LG&E does not maintain gross investment information in the forecasted test period at generating unit level.

e. LG&E does not maintain depreciation reserve information in the forecasted test period at a generating unit level.

f. LG&E does not maintain book depreciation expense in the forecasted test period at a generating unit level.

g. The Companies do not produce a forecast of gross generation.

h. See the response to part a.

.

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 147

Responding Witness: David S. Sinclair

Q-147. Provide the combined KU and LG&E generating order of dispatch by unit and the basis for this order of dispatch.

A-147. The Companies' dispatch order as of November 2018 is provided in the table below. It is ranked in ascending order by average generating cost at maximum load, inclusive of variable fuel, emission allowances, and operating and maintenance costs. The dispatch order will vary depending on the price of natural gas and coal and other variables.

Dispatch Order (Lowest Cost to Highest Cost)	Unit	Dispatch Order (Lowest Cost to Highest Cost)	Unit
1	Brown Solar	20	Trimble County 7
2	Hydro (Ohio Falls and Dix Dam)	21	Trimble County 8
3	Trimble County 2	22	Trimble County 9
4	Cane Run 7	23	Trimble County 10
5	Ghent 2	24	Paddy's Run 13
6	Mill Creek 4	25	Bluegrass
7	Trimble County 1	26	Brown 6
8	Mill Creek 1	27	Brown 7
9	Mill Creek 2	28	Brown 5
10	Mill Creek 3	29	Brown 9
11	Brown 2	30	Brown 10
12	Ghent 1	31	Brown 8
13	Ghent 4	32	Brown 11
14	Brown 1	33	Cane Run 11
15	Ghent 3	34	Paddy's Run 11
16	Brown 3	35	Paddy's Run 12
17	OVEC	36	Zorn 1
18	Trimble County 5	37	Haefling
19	Trimble County 6		

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 148

Responding Witness: Christopher M. Garrett

Q-148. For each KU and LG&E generating unit, provide average monthly and annual fuel costs per KWh during the most recent 12-months available. Provide in executable electronic (Excel) format with all formulas intact and unprotected and with all columns and rows accessible.

A-148. See the attachment being provided in Excel format.

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 149

Responding Witness: David S. Sinclair

Q-149. For each KU and LG&E generating unit, provide forecasted average monthly and annual fuel costs per KWh for the fully forecasted test year ending April 30, 2020. Provide in executable electronic (Excel) format with all formulas intact and cells unprotected and with all columns and rows accessible.

A-149. See the attachment being provided in Excel format.

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 150

Responding Witness: David S. Sinclair

Q-150. With regard to wholesale sales, resale sales, and all other non-jurisdictional sales of electricity, provide the following for each customer for the fully forecasted test year for KU and LG&E separately:

a. identification of customer;

b. sales of electricity revenue;

c. KWh at meter;

d. maximum peak demand;

e. maximum contract demand; and,

f. voltage level at delivered service.

A-150. No such customers exist for LG&E.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 151

Responding Witness: William Steven Seelye

Q-151. Explain why sales for resale customers are not allocated any costs in Mr. Seelye's cost of service study, but rather, revenues are credited back to jurisdictional customers. In this regard, also explain how the loads associated with sales for resale are considered and reflected in Mr. Seelye's LOLP method.

A-151. LG&E does not serve any sales-for resale (wholesale) full-requirements customers. Sales-for-resale revenues for opportunity sales are credited back through the Off-System Sales Adjustment Clause (OSS) which are excluded from the determination of revenue requirements in this case.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 152

Responding Witness: William Steven Seelye

Q-152. With regard to the curtailable load credits reflected in the fully forecasted test year and Mr. Seelye's class cost of service study, provide the level (megawatts) of curtailable load embedded in the revenue credit separately by each rate schedule and by CR-1 and CR-2.

A-152. The requested information is provided in attachment Att_LGE_PSC_1-53_ElecScheduleM_Forecasted.xlsx (tab Sch M-2.3 (2)) provided in response to PSC 1-53.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 153

Responding Witness: David S. Sinclair

Q-153. Provide a detailed itemization of each requested curtailment during the last five years. In this response, provide the date, duration, requested load curtailment by individual customer and by CR-1 and CR-2, along with the amount of load actually curtailed.

A-153. The current CSR-1 and CSR-2 tariffs have been in place since Case Nos. 2016-00370 and 2016-00371. Prior to 7/1/17, there was a single Curtailable Service Rider (CSR), which had different parameters (e.g., no buy through option) and was in place from 7/1/15 through 6/30/17. Prior to 7/1/15, there were two riders in place, CSR-10 and CSR-30, also with different parameters (e.g. 10 minute notice and 30 minute notice).

LG&E has not requested physical load curtailment for CSR-1 or CSR-2 since their inception on July 1, 2017. As detailed in the table below, LG&E requested curtailment under the buy-through option of the tariffs on four days in January 2018.

Customer	*Start Date/Time*	*End Date/Time*	Hours	Type
1	01/04/2018 08:00	01/04/2018 22:00	14	Buy Through Option
2	01/04/2018 08:00	01/04/2018 22:00	14	Buy Through Option
3	01/04/2018 08:00	01/04/2018 22:00	14	Buy Through Option
1	01/05/2018 09:00	01/05/2018 23:00	14	Buy Through Option
2	01/05/2018 09:00	01/05/2018 23:00	14	Buy Through Option
3	01/05/2018 09:00	01/05/2018 23:00	14	Buy Through Option
1	01/16/2018 10:00	01/16/2018 23:00	13	Buy Through Option
2	01/16/2018 10:00	01/16/2018 23:00	13	Buy Through Option
3	01/16/2018 10:00	01/16/2018 23:00	13	Buy Through Option
1	01/17/2018 09:00	01/17/2018 23:00	14	Buy Through Option
2	01/17/2018 09:00	01/17/2018 23:00	14	Buy Through Option
3	01/17/2018 09:00	01/17/2018 23:00	14	Buy Through Option

Below is a table detailing the curtailments for the past five years (November 1, 2013 thru November 14, 2018) under the curtailable service rider(s) applicable at the time.

Customer	*Start Date/Time*	*End Date/Time*	*Hours*	*Type*	*Contract/CSR Firm or CSR Reduction*	*Load Not Compliant (kVA)*
1	01/06/2014 18:31	01/06/2014 19:42	1.18	Physical Curtailment	36,000 kVA demand; 3,500 kW firm	978
1	01/07/2014 07:14	01/07/2014 10:00	2.77	Physical Curtailment	36,000 kVA demand; 3,500 kW firm	64

Note: The applicable CSR tariff required a “contract firm demand” or a CSR reduction commitment. In the case of contract firm demand, it is not possible to identify the amount of load actually curtailed, only the amount of load in excess of the contract amount during the CSR curtailment.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 154

Responding Witness: David S. Sinclair

Q-154. Explain in detail how each, KU and LG&E (acting alone or in conjunction with affiliates), treats interruptible/curtailable load in:

a. developing its long-run load forecast;

b. determining its long-run need for future supply-side resources;

c. determining its need for operating reserve capacity;

d. providing ancillary services; and,

e. determining whether such load qualifies as spinning reserve.

A-154.

a. The Companies incorporate an expected hourly-integrated impact of the Direct Load Control program, into the peak load forecast.

b. The Companies treat interruptible CSR customers as a supply-side resource. Long-term resource plans include an expected hourly-integrated impact of CSR interruptions as a component of the Companies' generating portfolio.

c-e. Curtailable load under the CSR tariffs does not affect operating reserves, which consist of spinning reserves and non-spinning (supplemental) reserves. Both spinning and non-spinning reserves must be available to serve load within a 15 minute period. For curtailable load to qualify as operating reserves, the curtailable load must be fully removable from system load within a 15 minute period. The execution of a CSR event requires a 60 minute notice. Therefore, CSR does not qualify as an operating reserve and is not considered when determining the need for operating reserve capacity. Similar limitations also exist for considering CSR capacity for contingency and regulating reserves. Contingency reserves must be available within 15 minutes and regulating reserves must be immediately reactive to Automatic Generation Control to provide normal regulating margin.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 155

Responding Witness: Robert M. Conroy / William Steven Seelye

Q-155. Explain in detail how KU and LG&E treat curtailment buy-through revenues in setting base rates and/or modifying its Fuel Adjustment Clause.

A-155. The Companies did not include any curtailment buy-through revenues in the forecasted test year for determining base rates in this proceeding. Regardless, curtailment buy-through revenues are recorded to fuel revenues and therefore would not affect the determination of base rates.

For Fuel Adjustment Clause purposes, buy-through revenues are credited to monthly fuel costs for determining the FAC factor. LG&E and KU decrease the total fuel costs represented by F(m) by the excess of the curtailment buy-through revenues over the revenues received from the CSR customer's standard rate schedule billings. The latter recovers the CSR customer's portion of the actual fuel and purchase power costs incurred by the Company from the CSR customer.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 156

Responding Witness: Robert M. Conroy / William Steven Seelye

Q-156. Identify and explain in detail how KU and LG&E treats test-year curtailment buy-through revenue in the electric cost-of-service study filed in this case. This request refers to the methodology that KU and LG&E would use even if it received no test-year CSR buy-through revenue.

A-156. The Companies did not include any curtailment buy-through revenues in the forecasted test year in this proceeding. Buy-through revenues are credited to Kentucky retail customers through the fuel adjustment clause. See also the response to Question No. 155.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 157

Responding Witness: William Steven Seelye

Q-157. Provide the most recent loss factors for energy and demand separated by voltage level; i.e., transmission, sub-transmission, primary, secondary.

A-157. See the attachment to the response to KIUC 1-7, part c.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 158

Responding Witness: Elizabeth J. McFarland

Q-158. Provide the current number of customers (accounts) by rate schedule for each zip code within the Company's service area. Note: street lighting accounts may be excluded from this data set. Provide in executable electronic (Excel) format with all formulas intact and cells unprotected and with all columns and rows accessible.

A-158. See the attachment being provided in Excel format.

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 159

Responding Witness: William Steven Seelye

Q-159. With regard to the Company's CCOSS, explain why Rate PS-Secondary, Rate TOD-Secondary, and Outdoor Sports Lighting (OSL) are not allocated any secondary line (overhead or underground) costs.

A-159. It is the Company's practice not to install secondary conductor runs for customers served on the Rate PS-Secondary, TOD-Secondary, and Outdoor Sports Lighting rate schedules.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 160

Responding Witness: William Steven Seelye

Q-160. Provide references to each instance known to Mr. Seelye that the LOLP method has been proposed before State regulatory commissions to allocate generation plant for retail class cost allocations purposes. In this response, provide the name of the utility, year, jurisdiction, docket number, and proposing party as available. Further, indicate whether the State regulatory commission that the LOLP was proposed to explicitly found the LOLP method to be reasonable to CCOSS purposes.

A-160. See the response to KIUC 1-15.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 161

Responding Witness: William Steven Seelye

Q-161. Provide an itemized list as well as a copy of all investor-owned electric utility testimony prepared by Mr. Seelye and provided to a regulatory commission on issues concerning class cost of service during the last five years. If such testimony is available electronically on Commission websites, simply provide a link to the respective testimony.

A-161. See testimony filed by William Steven Seelye in KU's and LG&E's most recent base rate proceedings (Case No. 2016-00370 and Case No. 2016-00371, respectively).

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 162

Responding Witness: Robert M. Conroy

Q-162. Refer to the direct testimony of William Steven Seelye, page 15, wherein he states "The Companies want customers, stakeholders, and employees to be aware that two types of costs are included in the energy charge for Rate RS and other rates that have a two-part rate structure consisting of a Basic Service Charge and an Energy Charge."

a. Why do the Companies want customers, stakeholders and employees to be aware that the energy charge includes these two types of costs?

A-162.

a. The reasons for separating the current energy charge into a fixed-cost component (Infrastructure Energy Charge) and a variable-cost component (Variable Energy Charge) are explained in detail on pages 17-20 of the testimony of Mr. Conroy and pages 15-20 of the testimony of Mr. Seelye.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 163

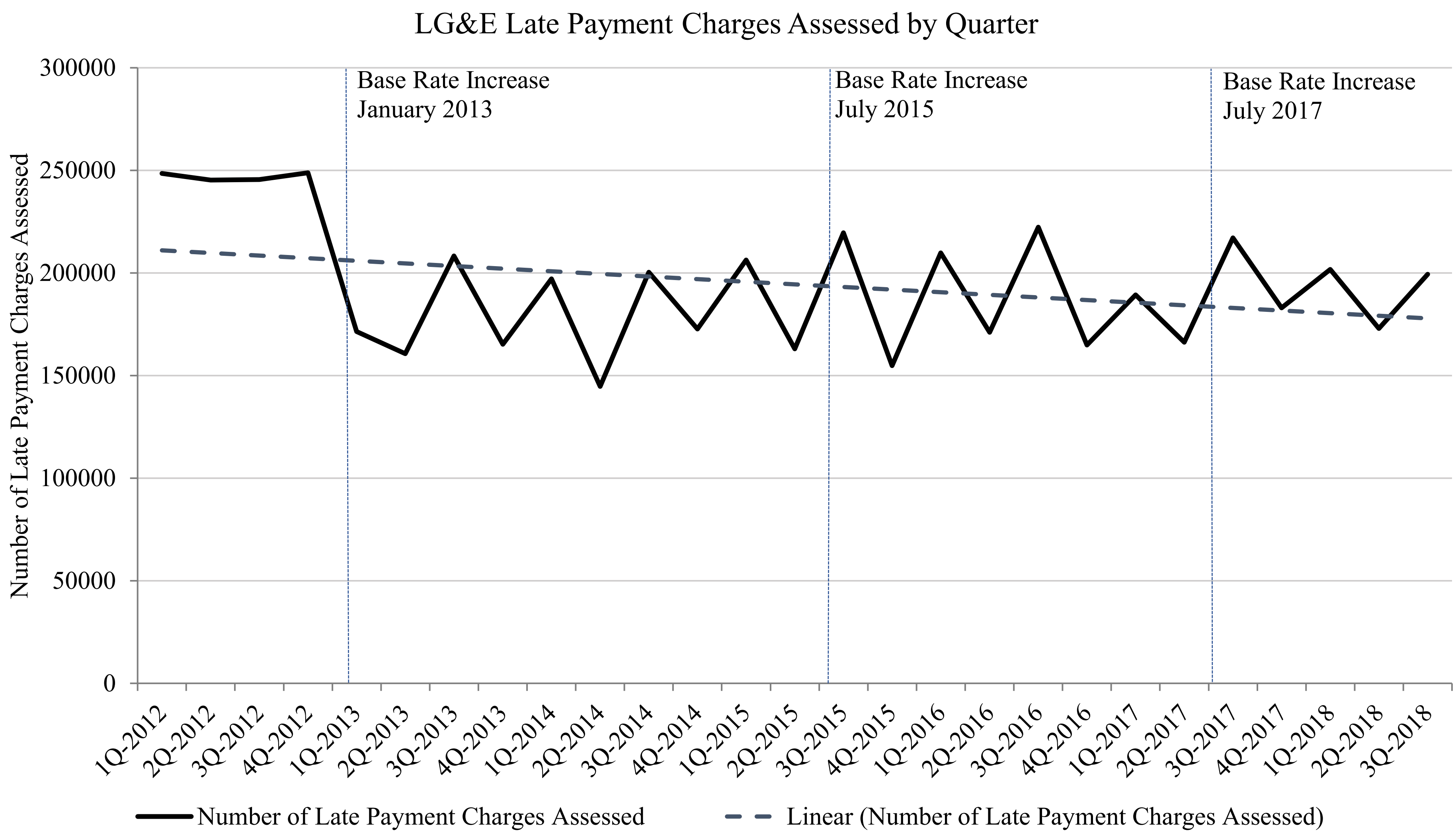
Responding Witness: Elizabeth J. McFarland

Q-163. Refer to the direct testimony of William Steven Seelye, pages 66-67, wherein he discusses late payments.

a. Following previous base rate cases, have the Companies noticed or identified that late payments tend to increase following increases in base rates?

A-163.

a. The Companies have not identified an increase in late payments following increases in base rates. See attached.


LG&E Late Payment Charges Assessed by Quarter
Number of Late Payment Charges Assessed
300000
250000
200000
150000
100000
50000
0
Base Rate Increase
January 2013
Base Rate Increase
July 2015
Base Rate Increase
July 2017
1Q-2012
2Q-2012
3Q-2012
4Q-2012
1Q-2013
2Q-2013
3Q-2013
4Q-2013
1Q-2014
2Q-2014
3Q-2014
4Q-2014
1Q-2015
2Q-2015
3Q-2015
4Q-2015
1Q-2016
2Q-2016
3Q-2016
4Q-2016
1Q-2017
2Q-2017
3Q-2017
4Q-2017
1Q-2018
2Q-2018
3Q-2018
Number of Late Payment Charges Assessed
Linear (Number of Late Payment Charges Assessed)

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 164

Responding Witness: William Steven Seelye

Q-164. Refer to the direct testimony of William Steven Seelye, page 74, wherein he states that the LOLP "was supported by several of the intervenors in those proceedings." Further,

a. Identify the intervenors who "supported" the LOLP in the Companies' last base rate proceedings.

A-164.

a. Kentucky League of Cities, Walmart, and Kentucky School Board Association

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Question No. 165

Responding Witness: Robert M. Conroy

Q-165. Refer to the direct testimony of Robert M. Conroy, page 7, wherein he cites to the Edison Electric Institutes' Typical Bills and Average Rates Report Winter 2018.

a. Provide a copy of this report.

A-165.

a. See the response to PSC 2-2.

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Question No. 166

Responding Witness: Robert M. Conroy / William Steven Seelye

Q-166. Refer to the direct testimony of Robert M. Conroy, page 9, wherein he states, "I believe an LOLP approach to conducting a cost of service study is appropriate."

a. Explain whether Mr. Seelye approached the Companies about using the LOLP approach or if the Companies initiated the idea and tasked Mr. Seelye with conducting that approach.

b. Is the LOLP approach the only time-differentiated embedded cost of service study approach available?

A-166.

a. Over the past years as the Companies have been filing rate cases, the Companies and The Prime Group have had numerous discussions related to cost of service studies and methodologies. In the last rate case, those discussions included the use of the LOLP methodology. After discussion, the Companies directed Mr. Seelye to present both the historical modified BIP and the LOLP methodology. In the current proceeding, the Companies directed Mr. Seelye to only present the LOLP methodology.

b. No.

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Question No. 167

Responding Witness: Robert M. Conroy

Q-167. Refer to the direct testimony of Robert M. Conroy, page 14, wherein he notes that a change to a daily from a monthly Basic Service Charge "avoids any need to prorate service for customers who begin or end service mid-billing period."

a. Provide the amount of savings included in the forecasted period due to the identifiable savings from this efficiency.

A-167.

a. The Companies have not claimed there are savings from going to a daily Basic Service Charge. As such, there is no identifiable savings included in the forecasted period.

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Question No. 168

Responding Witness: Robert M. Conroy

Q-168. Refer to the direct testimony of Robert M. Conroy, page 14, wherein he discusses "splitting the energy charge into two components for informational purposes on the tariff sheets for rate schedules that do not have demand charges." Further, visit the following link to the Companies' own website: https://lge-ku.com/regulatory/rates-and-tariffs

a. Provide the number of times a month for the year 2017 and 2018 to date that visitors to the site have clicked on/visited the following categories in order to download the PDFs:

i. LG&E Electric Rates

ii. LG&E Gas Rates

iii. KU Electric Rates

All three categories are listed in two separate locations on the website and the response may combine the clicks/visits between the two distinct locations. If discernable, the response should differentiate between unique visits/clicks and subsequent visits/clicks.

A-168.

a. The attached file contains unique visits to lge-ku.cm/regulatory/rates-and-tariffs as well as the unique PDF downloads for each rate schedule. The current analytics tool the Companies' use for this data set was not operational in January and February 2017. The previous analytics tool did not track PDF downloads.

The Companies' website provides a copy of their tariffs to provide transparency to the pricing structures of the services provided. The attached table demonstrates the non-employee interest in this information.

Visits to lge-ku.com/regulatory/rates-and-tariffs

	Employees	Non-Employees	All Visitors
Mar-17	27	429	456
Apr-17	26	489	515
May-17	26	455	481
Jun-17	35	463	498
Jul-17	26	572	598
Aug-17	34	518	552
Sep-17	37	482	519
Oct-17	18	511	529
Nov-17	26	458	484
Dec-17	24	523	547
Jan-18	40	932	972
Feb-18	34	642	676
Mar-18	41	535	576
Apr-18	29	516	545
May-18	34	528	562
Jun-18	35	719	754
Jul-18	40	712	752
Aug-18	53	630	683
Sep-18	60	601	661
Oct-18	95	646	741
Nov-18 (partial)	73	372	445
	813	**11,733**	**12,546**

PDF views/downloads

	LGE Gas Tariff	LGE Electric Tariff	KU Electric Tariff
Mar-17	20	64	63
Apr-17	80	236	208
May-17	96	224	236
Jun-17	78	244	235
Jul-17	74	310	330
Aug-17	87	268	278
Sep-17	43	135	146
Oct-17	20	82	63
Nov-17	71	211	167
Dec-17	85	217	154
Jan-18	123	430	322
Feb-18	77	277	232
Mar-18	83	255	212
Apr-18	68	223	157
May-18	57	205	151
Jun-18	57	200	144
Jul-18	50	223	209
Aug-18	59	242	190
Sep-18	61	221	177
Oct-18	68	113	188
Nov-18 (partial)	35	119	93
	1,392	**4,499**	**3,955**

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Question No. 169

Responding Witness: Robert M. Conroy

Q-169. Refer to the direct testimony of Robert M. Conroy, pages 15-16, wherein he answered affirmatively whether "recovering a larger proportion of customer-specific fixed costs through the Basic Service Charge rather than through the energy charge . . . [has] the effect of stabilizing customers' monthly bills[.]"

a. Confirm that recovery of revenues through fixed charges rather than through energy charges has the effect of stabilizing the Companies' monthly revenues.

b. When did the Companies first begin recovering what it considers "customer-specific fixed costs" through residential customers' energy charge?

A-169.

a. All else being equal, recovering fixed costs through fixed charges will tend to stabilize revenues. However, there are other factors that affect the amount of fixed cost recovered from customers.

b. The Basic Service Charge has always been lower than the true cost of service, which has always allowed some fixed costs to be recovered through the Energy Charge.

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Question No. 170

Responding Witness: Robert M. Conroy / David S. Sinclair

Q-170. Refer to the direct testimony of Robert M. Conroy, page 22, wherein he discusses the "third Green Tariff option" and the proposed Green Tariff.

a. Explain the purpose and need for the eligible customer to "be willing to enter into an obligation for 10 MW or more of new (not already existing) renewable capacity."

b. Do the Companies anticipate that either Company may be the entity that develops the "renewable resource" envisioned under Option #3?

c. Do customers interested in Option #3 get to choose or have input into what type of "renewable resource" it receives electricity for under Option #3, or any input into which "renewable resource" developer is chosen?

d. Are any of the interconnection requests for solar located at the link below requested by either of the Companies?

https://www.oasis.oati.com/woa/docs/LGEE/LGEEdocs/LG&E_and_KU_GI_Queue_Posting_November_05,_2018.pdf

e. Will the projects chosen under Option #3 be pursuant to a formal RFP process?

f. If the response to subpart e., above, is in the affirmative, explain who sets the parameters of the RFP and if the ultimate customer will be consulted during the process.

g. Can customers with multiple locations throughout a service territory aggregate new load in order to participate under Option #3? If not, why not?

h. Have the Companies considered providing a pro-forma mock contract in the tariffs so that interested customers will understand the terms the Companies may consider under Option #3 (e.g., what effect the agreement may have on demand charges, ECR costs, etc.)?

i. If the Companies are unwilling to provide a pro-forma mock contract to provide interested customers additional certainty up-front, why do the Companies believe potential customers would be any more interested with Option #3 than they are now?

A-170.

a. Green Tariff Option #3 is targeted at customers who desire utility scale renewable options (hence 10 MW or more) that will support adding new renewable resources to the grid. The concept of supporting "additionality" (i.e., new renewables) is an important attribute of green tariffs since just purchasing energy from an existing project does nothing to alter the quantity of renewables on the grid.

b. As with all potential generation resources, the Companies may develop a "self-build option" as an alternative for the Green Tariff Option #3 customer to consider. However, the Companies are not proposing that they be required to develop a "self-build option" nor can they force the Green Tariff Option #3 customer to select a proposed "self-build option."

c. Yes.

d. The 10 MW Brown Solar facility is in the list and has been constructed. None of the other requests for solar are by the Companies or related to the Companies in any way.

e. Yes.

f. The Companies will work with the potential Green Tariff Option #3 customer throughout the RFP process.

g. For a customer that has multiple accounts, the renewable energy associated with Option #3 would be proportioned to those specific accounts through the mutually agreed to bilateral contract. The individual accounts will continue to be billed on their associated individual tariff rate. Option #3 is available to any customer addressed in the Availability section of the tariff and not just new loads.

h. No because the terms will be jointly determined in consultation with the potential Green Tariff Option #3 customer and what possible counterparties are willing to propose and accept.

i. The Companies experience in the wholesale marketplace tells us that there is no "certainty up-front" when one issues an RFP for capacity and energy. Any customer interested in pursuing Green Tariff Option #3 must be willing to accept the vagaries and realities of procuring utility-scale renewables in the wholesale electricity markets.

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Question No. 171

Responding Witness: Elizabeth J. McFarland

Q-171. Refer to the direct testimony of Robert M. Conroy, page 32, wherein he describes the proposed changes to the Economic Development Rider.

a. For the five most-recent customers who have taken service under each Company's Economic Development Rider, provide the demand, by year, for the first 5 years under each contract.

b. As a general matter, would the Companies agree that customers who have taken service under the Economic Development Rider, have increased, rather than decreased their usage over the discount period of the Rider?

A-171.

a. See table of KW/KVA demand below:

Demand While Under Contract by Year for Five Most-Recent EDR Customers*

Year	**Company 1**	**Company 2**	**Company 3**	**Company 4**	**Company 5**
2012	5,069				
2013	4,712				
2014	5,391		152	268	
2015	5,367	1,325	1,155	566	2,139
2016	4,956	1,196	1,204	566	2,299
2017		1,282	1,342	552	2,328
2018		1,211	1,346	579	2,346

*The values in the table are the average monthly measured base kW or kVA demand for the calendar years shown. The demand value in the first calendar year of an EDR billing arrangement typically does not reflect a full 12 months of measured demand, and the value shown for 2018 are year to date.

b. The data for these customers would not tend to support the question's premise on the whole. For these five customers, demand and energy usage have remained relatively stable over the periods requested (within normal bounds of seasonal or other ordinary fluctuations), though in certain instances demand and energy in the earliest months of an EDR billing arrangement have been slightly lower than in subsequent months. On the whole, the differences are not significant.

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Question No. 172

Responding Witness: Elizabeth J. McFarland

Q-172. Refer to the direct testimony of Robert M. Conroy, pages 32-33, wherein he describes the minimum load factor of 50% in order to take service under the EDR.

a. Explain how this minimum load factor does not preclude high energy intensity, low load factor customers from expanding in the Companies' territories. Any response should include an explanation as to how many of the new industrial or large commercial customers that have recently located in the Companies' territories satisfy this minimum.

A-172.

a. The load factor requirement to participate in the Economic Development Rider (EDR) tariff does not restrict "high energy intensity, low load factor customers" from locating or expanding within the Company's service territory or taking service under any of the Company's electric tariffs. This requirement is only related to the EDR tariff. The Company is not aware of this requirement precluding a customer from locating within the Company's service territory. This provision incentivizes the attraction of high load factor customers who are more efficient users of the electric system, which provides broad benefits to customers in general.

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Question No. 173

Responding Witness: Christopher M. Garrett

Q-173. Refer to the direct testimony of Paul W. Thompson, page 2, wherein he discusses the number of customers served by LG&E and KU.

a. Provide a breakout, between LG&E and KU, of the number of unique customers each utility has (e.g., one business with 5 meters on site, or one home with a residential meter at the home and another on a pool house, etc.). The response should not consider businesses with multiple locations located across service territories as one "unique" customer, but rather, the request is seeking information on the number of discrete locations customers are served. If possible, any response should provide the number of unique residential locations, separate from non-residential.

A-173.

a. See the response to PSC 1-27. The information provided reflects the *average* customer count for the periods presented, compared to the *actual* customer count as of December 31, 2017, provided in Mr. Thompson's testimony.

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Question No. 174

Responding Witness: Kent W. Blake

Q-174. Refer to the direct testimony of Paul W. Thompson, page 2, wherein he notes that "20 years of common ownership has allowed KU and LG&E to streamline and fully integrate their operations, and jointly plan all aspects of their business, including safety, electric generation, transmission, distribution, customers service, information technology, and all service functions."

a. Confirm that although the Companies plan many of their aspects jointly, the legal separation between LG&E and KU requires the Companies to file separate rate cases for their electric operations and perform separate cost of service studies and revenue requirement models.

A-174.

a. As shown in the Companies' study filed on August 8, 2018 in Case No. 2017-00415[16], the evaluation considered the costs and benefits of a legal merger in every area of the Companies, including potential regulatory savings noted above. Ultimately, the study confirmed that the Companies operate as an integrated company in virtually all operational areas and the integrated approach has achieved significant savings for customers. The study concluded by recommending against the legal merger of the two utilities because the savings are not enough to bring all customer rates to the lowest rate offered by each company. The Study in conclusion states:

> The potential legal merger of the two utilities would result in some savings in the accounting, tax, treasury, and regulatory areas, but also result in an increase of ongoing costs in other areas. In addition, the legal merger would require significant one-time costs to achieve the legal merger. Perhaps most importantly, the potential legal merger creates winners and losers among the

[16] *In the Matter of: Joint Application of PPL Corporation, PPL Subsidiary Holdings, LLC, PPL Energy Holdings, LLC, LG&E and KU Energy LLC, Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of an Indirect Change of Control of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2017-00415, Order (Ky. PSC Apr., 2018).

> customers because the savings are not enough to bring all customer rates to the lowest rate offered by each company. KU customers would be adversely impacted in most cases while LG&E customers could benefit from the legal merger. For these reasons, the Companies do not recommend proceeding with the legal merger of LG&E and KU.[17]

The Companies file separate rate cases, perform separate cost of service studies, and calculate separate revenue requirements because as separate legal entities they have distinct costs of providing service.

[17] Case No. 2017-00415, LG&E and KU Internal Study of Potential Legal Merger at 21 (Ky. PSC Aug. 8, 2018).

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Question No. 175

Responding Witness: David S. Sinclair / Robert M. Conroy / William Steven Seelye

Q-175. Refer to the direct testimony of David S. Sinclair, pages 9-10, wherein he discusses the impact from existing distributed generation, "almost all of it in the form of solar generation."

a. Explain what cost of service impact the 2.4 GWh and 2.6 GWh for KU and LG&E, respectively, have on other customers in the Forecasted Test Year.

b. Explain how much of this 2.4 GWh and 2.6 GWh is due to customers who "net-meter" pursuant to KRS Chapter 278.465 and 278.466.

   i. Provide the cost of service impact those "net-metering" customers have on other customers in the Forecasted Test Year.

A-175.

a. The Companies have not performed an analysis of the cost of service impact of the 2.4 GWh and 2.6 GWh of distributed generation.

b. All of the volumes included in this reference are customers who "net-meter."

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Question No. 176

Responding Witness:

Q-176. [THIS REQUEST INTENTIONALLY LEFT BLANK IN ORDER TO MAINTAIN NUMBERING WITH CASE NO. 2018-00294]

A-176. Not applicable.

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Question No. 177

Responding Witness: John K. Wolfe

Q-177. Refer to the direct testimony of Paul W. Thompson, page 8.

a. Provide a narrative explanation as to how the Companies calculated the avoided customers interruptions and minutes due to the installation of electronic reclosers. Provide all workpapers used in determining these amounts in executable electronic format, preferably in native Excel format, with all formulas intact and cells unprotected and with all columns and rows accessible.

b. Provide the actual and budgeted costs of installing the 350 electronic reclosers, broken out by Capital and O&M.

c. Confirm that due to the magnitude of the referenced July 2018 Storms, impacts arising from them would not be included in the calculation of System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI"). If this cannot be confirmed, explain why not.

d. Provide the SAIDI and SAIFI information in Exhibit LEB-5 that is redacted, specifically the redacted information on page 4 of 16 through page 8 of 16.

A-177.

a. For each instance when a DA recloser operates to isolate a fault, the number of customers affected by the outage is compared to the number of customers who would have been affected if the recloser had not been in place. This difference determines the number of Customer Interruptions (CI) saved by the recloser. The outage duration, which is the time required for crews to arrive at the damage location and make repairs, is assumed to be the same in both cases. Thus, Customer Minutes of Interruption (CMI) saved is determined by multiplying the difference in the number of customers affected by the outage duration. See attached.

b. All costs are Capital for the combined Companies.
Actual Cost: $20,838,888

Forecasted Cost: $21,975,977
Original Budgeted Cost: $22,243,937

c. It is confirmed that due to the magnitude of the referenced July 2018 Storms, impacts arising from them would not be included in calculations of System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI") that exclude major event days (values typically reported).

d. The referenced section of LEB-5 contains the Companies' combined historical SAIDI and SAIFI performance charted against first, second and third quartile performance according to two different industry surveys. The quartile data from these surveys is subject to strict confidentiality obligations imposed by the survey entities. The Companies have sought consent from each survey entity to provide the information responsive to this request. Both entities have refused consent. The Companies are still negotiating for appropriate disclosure of the requested information.

						Totals	3019	4831448.03
Substation	**Circuit**	**Inc #**	**Outage Date**	**Out Duration**	**Customers Out**	**Customers Would Have Been Out**	**CI Saved by Recloser**	**CMI Saved by Recloser**
LANSDOWNE	106	18083741	7/20/18 4:12 PM	1703.5	299	1332	1033	1759749.93
IBM	103	18085223	7/20/18 4:13 PM	176.6	599	1155	556	98189.6
LANSDOWNE	118	18090355	7/20/18 4:14 PM	3079.9	208	444	236	726864.267
LIBERTY ROAD	42	18090252	7/20/18 4:27 PM	2177.9	1040	1777	737	1605100.02
BRYANT ROAD	874	18087564	7/20/18 10:35 PM	1403.8	1956	2413	457	641544.216

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Question No. 178

Responding Witness: Lonnie E. Bellar

Q-178. Refer to the direct testimony of Lonnie E. Bellar, page 36, wherein he discusses the 2018 transmission SAIDI through July.

a. Provide the Companies' transmission SAIDI for the last 5 calendar years and 2018 to-date as well as each month in 2018 in which the Companies have data. Provide an update to this response as monthly information becomes available.

b. For each year the information is available, provide the annual SAIDI by transmission line voltage (i.e. 69 kV, 115, kV, 230 kV, etc.).

A-178.

a. See tables below.

Year	SAIDI
2013	13.525
2014	12.141
2015	9.467
2016	12.188
2017	5.976
2018	5.377

Year	Month	SAIDI
2018	1	0.057
2018	2	0.014
2018	3	0.366
2018	4	0.729
2018	5	0.130
2018	6	1.642
2018	7	0.029
2018	8	1.827
2018	9	0.573
2018	10	0.008

b. See table below.

Year	SAIDI By Voltage by Year				
	69	138	161	345	500
2013	13.173	0.352	-	-	-
2014	11.050	1.091	-	-	-
2015	8.721	0.746	-	-	-
2016	10.890	1.298	-	-	-
2017	5.541	0.435	-	-	-
2018	5.263	0.114	-	-	-

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Question No. 179

Responding Witness: Lonnie E. Bellar

Q-179. Refer to the direct testimony of Lonnie E. Bellar, page 36, wherein he discusses the Companies' transmission OHMY.

a. Provide the Companies' transmission OHMY for the last 5 calendar years, and 2018 to-date, as well as each month in 2018 in which the Companies have data. Provide an update to this response as monthly information becomes available.

b. For each year the information is available, provide the annual OHMY by transmission line voltage (i.e. 69 kV, 115, kV, 230 kV, etc.).

A-179.

a.

Year	OHMY
2013	9.692
2014	10.742
2015	11.166
2016	10.484
2017	9.065
2018	8.512 through 10/31/2018

Year	Month	OHMY
2018	1	0.571
2018	2	0.350
2018	3	0.387
2018	4	0.645
2018	5	1.400
2018	6	1.308
2018	7	1.198
2018	8	1.363
2018	9	0.811
2018	10	0.479

b.

	OHMY By Year and Voltage				
Year	**69**	**138**	**161**	**345**	**500**
2013	7.978	0.682	0.663	0.313	0.055
2014	8.586	1.087	0.571	0.479	0.018
2015	7.886	1.898	0.700	0.663	0.018
2016	8.070	1.013	0.866	0.534	-
2017	7.131	0.755	0.811	0.369	-
2018	6.504	0.755	0.442	0.737	0.074

2018 is through October 31, 2018.

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Question No. 180

Responding Witness: Lonnie E. Bellar

Q-180. Refer to the direct testimony of Lonnie E. Bellar, page 44, wherein he discusses the move of LG&E's distribution SCADA to the Distribution Control Center.

a. From what center is KU's distribution SCADA function operated?

b. Provide the savings realized from this move.

A-180.

a. The KU distribution SCADA function is operated from the Lexington Distribution Control Center located in the KU General Office building.

b. LG&E distribution SCADA was moved from the Transmission Control Center (TCC) to the Distribution Control Center (DCC) in order to consolidate all distribution functions and to allow the TCC to focus solely on transmission functions. This move will create consistency between LG&E and KU, prepare for the centralization of the DCC facility in 2nd Quarter 2019, and more closely align to the Distribution strategy of centralized grid operations. The Companies have not quantified the savings resulting from this move, however, the efficiencies achieved have been considered in the forecast test period.

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Question No. 181

Responding Witness: John K. Wolfe

Q-181. Refer to the direct testimony of Lonnie E. Bellar, page 46.

a. Provide each Companies' SAIDI and SAIFI for the last five (5) complete years, 2018 to-date and each month in 2018, proving each annual number with and without the inclusion of major event days ("MED").

A-181.

	LG&E			
	Excluding Major Events		Including Major Events	
	SAIDI	SAIFI	SAIDI	SAIFI
2013	78.50	0.933	147.39	1.136
2014	73.75	0.897	158.62	1.156
2015	74.45	0.927	119.10	1.123
2016	73.03	0.861	89.70	0.936
2017	71.93	0.835	90.81	0.912
Jan-18	5.70	0.062	5.70	0.062
Feb-18	6.09	0.055	6.09	0.055
Mar-18	3.94	0.040	8.34	0.054
Apr-18	5.02	0.052	5.02	0.052
May-18	8.56	0.086	51.37	0.180
Jun-18	13.04	0.115	35.09	0.187
Jul-18	11.15	0.099	86.89	0.228
Aug-18	5.85	0.068	5.85	0.068
Sep-18	8.68	0.086	8.68	0.086
Oct-18	5.26	0.051	16.75	0.089
YTD Oct 2018	73.29	0.713	229.77	1.062

	KU (Kentucky)			
	Excluding Major Events		Including Major Events	
	SAIDI	SAIFI	SAIDI	SAIFI
2013	82.79	0.752	94.45	0.795
2014	79.28	0.752	156.54	1.000
2015	78.10	0.773	102.13	0.893
2016	99.40	0.858	106.18	0.882
2017	66.51	0.661	92.89	0.739
Jan-18	7.72	0.069	7.72	0.069
Feb-18	5.27	0.045	5.27	0.045
Mar-18	6.73	0.052	6.73	0.052
Apr-18	5.78	0.054	10.63	0.069
May-18	6.50	0.066	13.15	0.099
Jun-18	11.77	0.099	14.78	0.125
Jul-18	10.56	0.068	270.58	0.252
Aug-18	10.08	0.082	10.08	0.082
Sep-18	6.32	0.051	6.32	0.051
Oct-18	6.77	0.063	10.64	0.082
YTD Oct 2018	77.48	0.650	355.89	0.927

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Question No. 182

Responding Witness: John K. Wolfe

Q-182. Refer to the direct testimony of Lonnie E. Bellar, page 54, wherein he discusses the use of and possible expansion of substation monitoring and controls system.

a. Provide the cost savings, including reduction in manual intervention or field service personnel, of the current substation monitoring and controls system.

b. How many substation monitoring and controls systems do the Companies currently have, where are they located, and what criteria did the Companies employ in selecting the current substations?

A-182.

a. The expansion of the Substation Monitoring and Control (SMAC) will result in an annual $182,000 savings when completed. The savings are based on the avoidance of hiring two additional substation operators and an estimated 25% reduction in average annual labor hours for certain substation tasks.

b. The Companies currently have 53 Substation Monitoring and Control (SMAC) systems located in the LG&E service territory. The current substations employing substation monitoring and control were selected because they lacked analog monitoring and supervisory control function.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 183

Responding Witness: Lonnie E. Bellar / David S. Sinclair

Q-183. Refer to Exhibit LEB-2 to the direct testimony of Lonnie E. Bellar, page 30 of 40, Appendix D, wherein the document discusses the Companies "NERC requirements," including the Companies' ability "to meet the NERC reliability standards contingency reserve requirements."

a. Explain what the Companies' NERC reliability standards contingency reserve requirements is, and if the information is public, where in the public domain it may be accessed.

A-183.

a. As defined by NERC, the Contingency Reserve is a "provision of capacity that may be deployed by the Balancing Authority (BA) to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard)."

The Companies participate in a Contingency Reserve Sharing Group with TVA to fulfill the BAL-002 Standard Requirements. More details are contained in the SERC Regional Criteria-Contingency Reserve Policy, located at the following link: http://serc1.org/docs/default-source/program-areas/standards-regional-criteria/regional-criteria-and-guidelines/archive/contingency-reserve-policy-(serc-regional-criteria).pdf?sfvrsn=432d34ff_2 beginning on page 8. The TCRSG Deliverability Certificate is located on the Companies' Transmission OATI OASIS website (under Miscellaneous): http://www.oatioasis.com/LGEE/index.html. The current LG&E/KU contingency reserve allocation is equal to the TRM deliverability value contained in this document.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 184

Responding Witness: David S. Sinclair

Q-184. Refer to the direct testimony of David S. Sinclair, page 26, wherein he discusses target summer and winter reserve margin ranges of 17 to 25 and 28 to 38 percent, respectively.

Are the Companies aware of any other utility in the country with such a high season reserve margin as the Companies' winter target reserve margin? If the response is in the affirmative, provide the names of those utilities and the seasonal reserve margin.

A-184. Yes. NERC's 2017/2018 Winter Reliability Assessment showed anticipated winter reserve margins above 30 percent for many assessment areas, including MISO at 45.0 percent and PJM at 39.7 percent. See NERC's report at the following link:

https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_05252018_Final.pdf.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 185

Responding Witness: John K. Wolfe

Q-185. With regard to the Companies' distribution automation program, state whether the Companies will incorporate the IEEE 1547 standard for interconnection and interoperability of distributed energy resources with associated electric power system interfaces. If they will not, explain why not.

A-185. Yes. The Companies' distribution automation program does incorporate the IEEE 1547 standard for interconnection and interoperability of distributed energy resources.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 186

Responding Witness: Lonnie E. Bellar

Q-186. With regard to the Companies' deployment of smart grid technologies, state how the Companies intend to comply with FERC's recent approval of NERC's Critical Infrastructure Protection Standards (CIP-013-1).

A-186. The Companies assembled a team comprised of Supply Chain, Generation, Transmission, IT, Compliance, and Legal to address the implementation of CIP-013. This team began work during the second quarter of 2018 and has put together a project to address all the requirements of CIP-013. These tasks consist of risk ranking suppliers based on their Cyber profile, contract language added to contracts for suppliers of in scope assets, processes to mitigate issues before the installation of assets and processes to monitor those suppliers and assets for any new cyber issues. The project team is on track to meet the compliance date of the newly approved standard.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 187

Responding Witness: John K. Wolfe

Q-187. With regard to the Companies' deployment of smart grid technologies, state whether they will be deploying additional volt/VAR projects for circuits with high amounts of resistive load.

a. If so, provide copies of all cost/benefit analyses the Companies may have conducted regarding the cost effectiveness of volt/VAR projects.

A-187.

a. The Companies do not have an active volt/VAR program at this time.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 188

Responding Witness: John K. Wolfe

Q-188. With regard to the Companies' deployment of ADMS technology, state whether the Companies have conducted any ADMS Testbed demonstrations in order to model and evaluate ADMS applications. If demonstrations were conducted, provide documents regarding the results of the Testbed demonstrations.

A-188. The Companies have not yet implemented ADMS technology and have not conducted ADMS Testbed demonstrations. However, demonstration of ADMS technology has taken place throughout the industry and has shown solid results.

As stated in Exhibit LEB-5, Section 1.2 of Mr. Bellar's testimony: Demonstrated smart grid technology benefits cited in the Department of Energy's Smart Grid Investment Grant Program Final Report final report include:

- Fewer and shorter outages that result in less inconvenience and lower outage costs for customers.

- Improved grid resilience to extreme weather events by automatically limiting the extent of major outages and improving operator ability to diagnose and repair damaged equipment.

- Faster and more accurate outage location identification for improved repair crew dispatching and service restoration, reducing operating costs, truck rolls, and environmental emissions.

Furthermore, PPL Electric Utilities has reported SAIDI and SAIFI improvements of 21% and 31%, respectively, on circuits where DA, incorporating ADMS, has been deployed.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 189

Responding Witness: John K. Wolfe

Q-189. Identify the value streams the Companies hope to bring about through the deployment of ADMS.

A-189. See demonstrated smart grid technology benefits cited in the Department of Energy's Smart Grid Investment Grant Program Final Report as stated in Exhibit LEB-5, Section 1.2 of Mr. Bellar's testimony and in the response to Question No. 188. See also Exhibit PWT-5, Section 2 of Mr. Thompson's testimony in the 2016 rate case, Case No. 2016-00371.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 190

Responding Witness: John K. Wolfe

Q-190. With regard to the Companies' deployment of smart grid technologies, state to what extent they have examined the use of technologies involving: (i) Geographic Information System (GIS); and (ii) Blockchain, as a potential means of reducing costs associated with the use of both current and planned smart grid technology deployments. Include in your response:

a. whether GIS and/or Blockchain technologies could be used as cost-effective alternatives to such deployments;

b. whether any cost-effective GIS technologies could decrease the need and scope of further planned ADMS and SCADA deployments;

c. whether GIS and/or Blockchain technologies could be used to integrate other IT and operational technologies in such a manner as to reduce costs;

d. whether GIS and/or Blockchain technologies can be utilized to reduce costs associated with reliability, resilience and grid security;

e. in the event the Companies do at some point utilize GIS and/or Blockchain technologies, whether they could adopt existing platforms that would be interoperable with other systems, rather than creating a unique platform specially customized for the Company's use;

f. copies of any studies/analyses the Companies may have conducted regarding the cost effectiveness, or cost/benefit studies regarding the use of such technologies.

A-190.

a. The Companies currently utilize a Geographic Information System (GIS) to house distribution asset data with spatial representation. This data is automatically exported on a daily basis from the GIS and placed into the connectivity model utilized by both the Oracle Outage Management System (OMS) and the Oracle Distribution Management System (DMS). Blockchain is not utilized by the Companies, but would be evaluated as distributed energy resources became more prevalent within the Commonwealth. Both Information Technology (IT) and Operational Technology (OT) personnel stay abreast on current technologies and best practices across the utility industry.

b. See the response to part a.

c. See the response to part a.

d. See the response to part a.

e. See the response to part a.

f. The Companies have been utilizing a single GIS platform since 2002. Also, see the response to part a.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 191

Responding Witness: Lonnie E. Bellar

Q-191. Reference the Bellar testimony, p. 22, footnote 22, wherein he references the Companies' "Annual TSIP Report" filed under the post-case files in Case Nos. 2016-00370 and 2016-00371. Page 5 of that document states: "The bulk of the additional spending is attributable to the Companies' accelerated replacement of line equipment, in particular, wood poles." Discuss why wood poles have proven to be the primary reason for variances from projected TSIP spending levels.

a. Discuss whether the quality of the wood, its age, and/or the treatment used on the poles' exterior have proven to be problematic.

b. Do the problems have a greater incidence with certain pole vendors?

c. Has unseasoned/green wood proven to be a problem?

d. Identify any criteria utilized when evaluating damaged wood poles as to whether repairs such as further weatherization treatment would suffice, versus outright pole replacement.

e. Identify any criteria utilized when evaluating whether wood poles that need replacing should be replaced with another wood pole, or a metal pole.

f. Provide a table or graph illustrating the total number of wood pole failures over the last fifteen (15) years that have required a replacement, regardless of whether the replacement is wood or metal.

g. Has a survey or study been done of other utilities with similar types of poles and how failure rates have impacted them? If so, provide a copy.

A-191. As described in the "Annual TSIP Report", the Companies pole inspections in 2017 yielded a higher number of defective wood structures in need of replacement than anticipated. As defective structures are a reliability and safety risk, the Companies increased spending to replace more wood structures than originally planned.

a. While the Companies do not have historical records on ages of specific wood poles and structures, they believe the reason for the higher number of defective poles found are due to their age exceeding the expected life of this vintage.

b. The Companies have no data to indicate there is an issue with specific vendors.

c. No, the Companies do not use unseasoned/green wood.

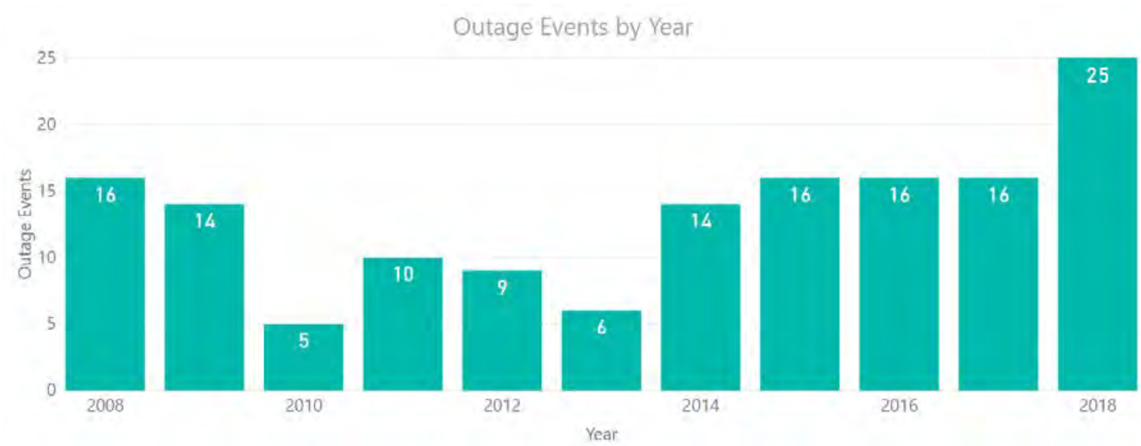
d. As highlighted in the "Annual TSIP Report", the Companies pole inspections include detailed visual observation, sounding, and, when possible, climbing of the poles to observe their condition. These pole inspections are completed by line technicians trained to identify and evaluate wood pole defects and degradation. These technicians do seek opportunities to make repairs, which often include patching of woodpecker holes.

   The Companies also consider component replacement in lieu of outright replacement when feasible. Examples include replacing insulators, replacing crossarms, repairing/replacing guy wires, and repairing/replacing anchors.

e. As the Companies highlighted in the "Annual TSIP Report", "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."

   Criteria such as pole height, applied loads, material and labor costs, and service conditions are considered when evaluating the use wood or steel poles. See response to AG DR1-Q196 pages 461-465 and pages 587-591 for examples of cost benefit analysis of wood versus steel construction.

f. The chart below shows annual outages caused by a broken poles/structures and broken cross-arms. Some outages could have involved more than a single pole and sometimes poles failed without causing an outage, therefore this summary is not all inclusive, but is the best data available.



g. The Companies are not aware of any such surveys or studies.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 192

Responding Witness: John Wolfe

Q-192. Reference the Bellar testimony beginning at p. 45, where he has an extended discussion regarding the Companies' distribution system. State whether the Companies have been experiencing the same types of problems with wood poles used in the distribution system as they have encountered with wood poles used in the transmission system. If so:

a. Discuss whether the quality of the wood, its age, and/or the treatment used on the poles' exterior have proven to be problematic.

b. Do the problems have a greater incidence with certain pole vendors?

c. Has unseasoned/green wood proven to be a problem?

d. Identify any criteria utilized when evaluating damaged wood poles as to whether repairs such as further weatherization treatment would suffice, versus outright pole replacement.

e. Identify any criteria utilized when evaluating whether wood poles that need replacing should be replaced with another wood pole, or a metal pole.

f. Provide a table or graph illustrating the total number of wood pole failures over the last fifteen (15) years that have required a replacement, regardless of whether the replacement is wood or metal.

g. Has a survey or study been done of other utilities with similar types of poles and how failure rates have impacted them? If so, provide a copy.

A-192. The Companies are not experiencing the same levels of problems with wood poles used in the distribution system as they are experiencing with wood poles deployed in the transmission system. The Companies implemented a Distribution Wood Pole Inspection and Treatment Program beginning in 2010. By year end 2018, approximately 497,000 distribution poles will have been inspected. The overall distribution pole replacement rate for the program is 3.8 percent.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 193

Responding Witness: John Wolfe

Q-193. Reference the Bellar testimony generally, the discussion regarding the Distribution Reliability and Resiliency Program ("DRRIP"). Other than enhanced reliability measures, provide copies of any and all cost/benefit analyses the Companies may have conducted indicating the costs of the DRRIP and the monetary savings to ratepayers that the DRRIP is projected to yield.

A-193. The Companies' existing Investment Proposals (i.e., those approved through November 27, 2018) for DRRIP programs included in the base year through the forecasted test period are attached. See also the attachments provided in response to Question No. 43.

Investment Proposal for Investment Committee Meeting on: N/A

Project Name: Breckenridge 1351 Circuit Hardening

Total Expenditures: $850k (Including $77k of contingency)

Project Number(s): 155870

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Chase Mills

Executive Summary

LG&E Electric Distribution and LKE Electric Reliability propose to invest $850k on reliability improvements for Breckenridge Circuit 1351 (BR1351). BR1351 circuit hardening project was approved and included in the 2018 Business Plan (BP) under the Circuit Hardening and Reliability Program. The funding for this specific project was approved as a reallocation from the budgeted circuit hardening project during the April RAC process.

This project proposes to reconductor 6,100' of three phase, 13.8 kV distribution circuit along Breckenridge Lane between Brownlee Road and Shelbyville Road. Existing copper conductor is prone to failure. Existing conductor will be replaced with 795 ACSR conductor. This will provide reliability improvements and enhanced contingency capabilities for electric customers in the St. Matthews Mall area.

Background

The proposed circuit hardening project will replace 6,100'of three phase, paralleled, copper conductor with three phase, 795 ACSR overhead conductor on Breckenridge Circuit 1351. This conductor is located along Breckenridge Lane between Brownlee Road and Shelbyville Road. Historically, the existing copper conductor is prone to failure, resulting in significant reliability impacts in a highly sensitive area. Furthermore, replacement of the paralleled conductor is required to improve pole spacing and allow for Distribution Automation (DA) investments to be made.

BR1351 experienced 19 interruptions between 2013 and 2017. Five of these interruptions are attributable to the mainline section of BR1351 which will be addressed with this project. Estimated reliability improvements for this circuit as a direct result of this project are 18,162 CMI and 96 CI annually. In addition to numerous commercial customers, BR1351 is the primary feed for a large assisted living facility and Trinity High School. BR1351 is the backup feed for the St. Matthews Mall.

BR1351 shares poles with transmission and 12kV distribution (BR1177). Due to the location along Breckenridge Ln., this project will require continuous flagging of traffic. Costs are also elevated as the line is underbuilt on transmission structures, shares a route with a 12kV circuit, and is parallel overhead construction.

Completion of the proposed investments will enable the company to make future investments through Distribution Automation. Existing construction does not allow for the installation of electronic reclosers. Improved pole spacing as a result of this project will permit the installation of reclosers on both BR1351 and BR1177 along Breckenridge Lane. This project will be completed as part of the Distribution Automation program following the completion of the proposed investments. All other Breckenridge distribution circuits were completed in 2017. Estimated reliability improvements from the implementation of DA on this circuit will be 68,170 CMI and 1,056 CI annually at an estimated cost of 180k. Completing DA on BR1177 and BR1351 is only possible following the completion of the proposed reconductor project. A portion of the benefits from this project were included in the Do Nothing NPVRR calculations.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $1,078
  2. Alternative #1 (Do Nothing): NPVRR: ($000s) $1,289
     The cost of "do nothing" is based on the value gained by reducing average annual circuit outage duration. Using the corporate "cost of unserved energy" ($17.2/kWh), the value of reducing outage duration (CMI) based on average circuit loads is $72k in 2019, escalated annually.

Project Description

- **Project Scope and Timeline**

The LGE EDO Electric Distribution Design group has completed the engineering design. Existing contractor resources will be assigned following the approval of the project and existing EDO construction blanket contracts and resources will be used. Project will be scheduled following project approval.

- **Project Cost**

Total project costs are $850k which includes a 10% contingency.
Project will be funded from 2018 LGE System Hardening Reliability Project (153006), which was approved by the April 2018 Corporate RAC.

Economic Analysis and Risks

- **Bid Summary**

Field construction work will be completed under existing contracts with overhead distribution line business partners. All required materials will be procured using established materials contracts.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	**2018**	**2019**	**2020**	**Post 2020**	**Total**
1. Capital Investment Proposed	758				758
2. Cost of Removal Proposed	92				92
3. Total Capital and Removal Proposed (1+2)	850	-	-	-	850
4. Capital Investment 2018 BP	-				-
5. Cost of Removal 2018 BP	-				-
6. Total Capital and Removal 2018 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(758)	-	-	-	(758)
8. Cost of Removal variance to BP (5-2)	(92)	-	-	-	(92)
9. Total Capital and Removal variance to BP (6-3)	(850)	-	-	-	(850)

Financial Detail by Year - O&M ($000s)	**2018**	**2019**	**2020**	**Post 2020**	**Total**
1. Project O&M Proposed					-
2. Project O&M 2018 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The EDO 2018 BP includes a Circuit Hardening and Reliability program budget, which the funding for this project was reallocated from during the April RAC process.

Financial Summary ($000s):	
Discount Rate:	6.58%
Capital Breakdown:	
Labor:	$ 0
Contract Labor:	$ 637
Materials:	$ 63
Local Engineering:	$ 56
Burdens:	$ 17
Contingency:	$ 77
Reimbursements:	($ 0)
Net Capital Expenditure:	$ 850

- **Assumptions**
  The CEM model used the cost of unserved energy for the “Do Nothing” alternative NPVRR. Useful life of the project is 30 years.

- **Environmental**
  There are no environmental issues associated with this project.

- **Risks**
  Delaying this investment will result in further deterioration of the copper conductor and will result in more frequent conductor failures and electrical service interruptions resulting in decreased customer satisfaction and increased customer complaints.

Conclusions and Recommendation

It is recommended that BR1351 Circuit Hardening Project be approved the Breckenridge for $850k. The hardening of this circuit will resolve ongoing reliability and restoration issues.

Investment Proposal Project 134198 Canal-Del Park Conductor Replacement

Investment Proposal for Investment Committee Meeting on: July 31, 2018

Project Name: Canal-Del Park Conductor Replacement

Total Expenditures: $8,089k
Total Contingency: $737k (10%)

Project Number(s): Transmission Lines - 134198
Distribution Operations – 157697

Business Unit/Line of Business: Transmission Lines/Distribution Operations

Prepared/Presented By: John Doll/Adam Smith

Executive Summary
The proposed project is to replace 2.84 miles of overhead transmission line conductor that is over 60 years old and beyond its expected useful life. Performance of this line has diminished, with the most recent wire failure occurring in 2011 from a failed static. Over 3,700 customers with a peak load over 11 MVA are served by the facilities being replaced, with the largest customer being Reynolds Foil, Inc. This project will improve reliability, maintain system integrity, and reduce the risk of failures and unplanned transmission interruptions to the Del Park, Falls City, Shawnee, and Vermont areas of Louisville, Kentucky.

A Transmission System Improvement Plan was submitted as support in the 2016 Rate Case, outlining programs and projects aimed at reducing the risk of failure, avoiding extended sustained outages, and limiting costly emergency repairs. The programs submitted with the plan were selected to ensure long-term system integrity and modernize the transmission system to avoid degradation of performance over time due to aging infrastructure. Replacement of overhead wires beyond or approaching their expected useful lives were included as part of the Transmission System Improvement Plan to replace aging infrastructure.

Transmission Lines plans to replace the 2.84 mile 69kV line between the Canal and Del Park substations with aluminum conductor steel-reinforced (ACSR) conductor and the deteriorating 3/8” HS static wire will be replaced with optical ground wire (OPGW). In addition, sixty-seven (67) wood structures will be replaced with new steel structures, two (2) lattice towers will be replaced with new steel structures, and seven (7) existing steel structures will remain. Distribution Operations will transfer distribution equipment along this route from the existing to new transmission structures.

The total project cost is $8,089k ($6,805k Transmission Lines, $1,284k Distribution Operations). This project was included in the 2018 Business Plan (BP) for $3,500k, with estimated spend of $200k in 2018, $2,663k in 2019, and $637k in 2020. This was a preliminary estimate based on "per mile" costs for similar past projects. This estimate did not include the installation of eight drilled shaft foundations or the replacement of a double circuit lattice tower within the constrained space near the Canal substation. The need for this work was determined only after a detailed engineering analysis. Additionally, multiple adjustments in the alignment were made to facilitate construction and improve the configuration of this circuit for future accessibility and maintenance, including minimizing the footprint of the circuit within railroad right of way.

The current total project cost is $8,089k, with estimated spend of $662k in 2018, $6,808k in 2019, and $619k in 2020. The 2018 spend was approved by the RAC in the 6+6 forecast. The 2019-2020 spend is consistent with the proposed 2019 BP.

Background

The existing 2.84 mile section of 69kV line between Canal and Del Park contains aging 4/0 copper conductor which dates back to 1955 and has experienced diminishing performance in recent years. Similar copper conductors with 60+ years of service life often have sections with broken conductor strands and significant corrosion at the clamps where the conductor attaches to the structure. Furthermore, multiple static and cross arm failures have occurred in recent years, causing significant damage to the already brittle and aged wire. The most recent event occurred in 2018 due to a cross arm failure.

Due to the condition of this line, there is risk for additional failures that will expose the transmission network to further unscheduled outages. The following pictures are representative of the 4/0 conductor, static, and cross arm conditions on sections of this line.

The first picture shows conductor damaged by a static failure, there are multiple instances of this along this circuit. The second picutre depicts a fractured crossarm and is representative of most structures along this route.

The aging conductor will be replaced with aluminum conductor steel-reinforced (ACSR) conductor and the deteriorating 3/8" HS static wire will be replaced with OPGW (optical ground wire). In addition, new steel structures will be installed in place of existing wood structures. A Comprehensive Visual Inspection was completed on this line in 2016. From this inspection, two

(2) structures were found to be in need of replacement. The two (2) structures found during inspection will be addressed as part of this project.

In January of 2018, the transmission project was opened for detailed design. The detailed engineering identified underground utilities at strategic locations along the route to facilitate structure placement and foundation design. Soil borings were also taken to provide geotechnical reports to support design of the drilled shaft foundations. In addition, plats were provided for the properties adjacent to the railroad to assist with easement acquisition and permitting. The transmission line design was provided to all departments involved for comment and review.

Additional easements are required along the southernmost section of this circuit, namely the three spans closest to the Del Park substation. The existing structures are double circuited wood poles. This configuration will be replaced with steel poles on davit arms which allow for necessary energized working clearances in the future, and proper separation between conductors. Additional separation from the existing wood pole structures is required to allow the existing circuits to remain energized while this work is performed. In order to achieve this, the new alignment must be shifted to the north, beyond the existing easement. The Real Estate and Right of Way department indicates the easement acquisition is feasible and likely.

Furthermore, easements will be acquired for seven spans paralleling 32nd street between Alford Avenue and Rowan Street. Accessing this section of the circuit is difficult due to the proximity to the railroad right of way to the east and housing to the west. Homeowners have fenced in several properties in this section and have severely limited access to both transmission and distribution facilities as well as third party attachments. Easements at this location would grant LG&E improved access and allow construction and maintenance activities to be performed without requiring permission from the railroad.

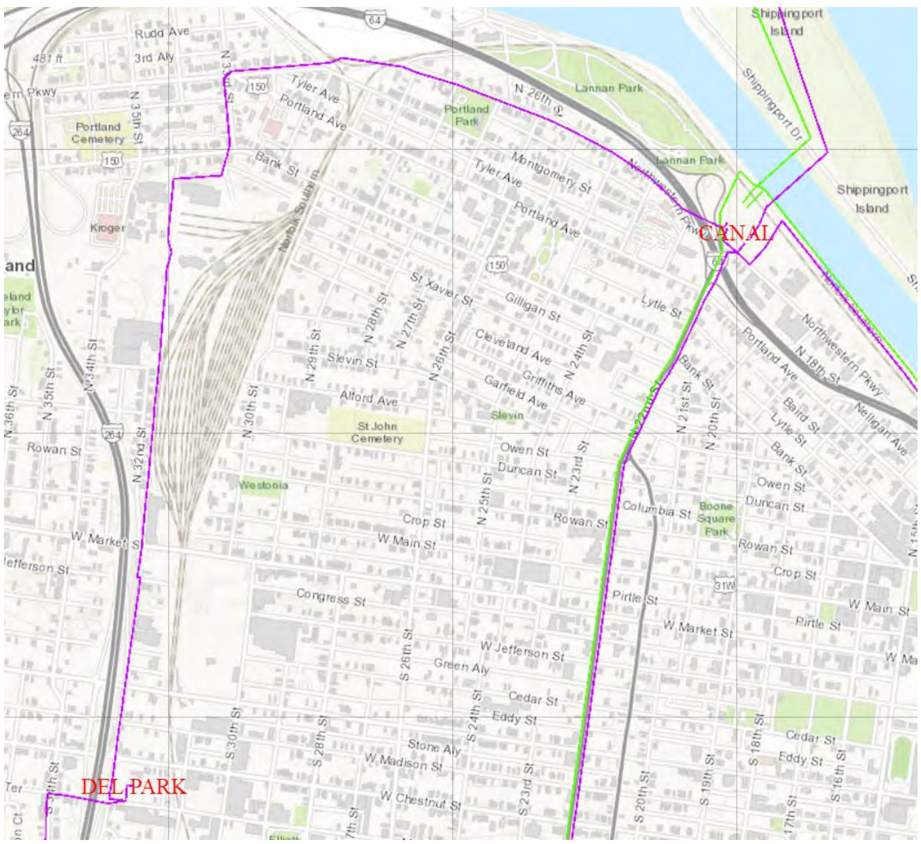
This project also includes a supporting project from Distribution Operations. Distribution Operations plans to transfer distribution equipment from the existing to new transmission structures.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $9,575
     The recommendation is to replace 2.84 miles containing 4/0 copper with new ACSR conductor, and the existing 3/8" static wire with new OPGW. In addition, 67 wood structures will be replaced with new steel structures, two lattice towers will be replaced with new steel structures, and seven existing steel structures will remain.

  2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
     This option is not advisable as this line is nearing the end of its useful life and puts Transmission at risk of not being able to accomplish the objectives established as part of the Transmission System Improvement Plan that was filed as support in the 2016 Rate Case and assumed the completion of this project. These objectives include reducing the risk of failure, avoiding an extended sustained outage, and costly emergency repairs.

3. Alternative #2 – Construct Alternate Route: NPVRR: ($000s) $9,740
   The next best alternative would be to construct a new 2.5 mile transmission line which would provide an alternate route beginning at structure 1 and would parallel the line along different roadways for 2.5 miles. Constructing a new route would require the purchase of 2.5 miles of new right of way that customers may not be willing to sell. Selecting a new route for this alternative would likely cause project delays and result in community concerns and opposition over the new route.

Project Description
Recommendation – Canal-Del Park Conductor Replacement Facility Map



- **Project Scope and Timeline**
  Transmission Lines Project Description – Project 134198
  The Transmission Lines project involves the upgrade of 2.84 miles of existing conductor with ACSR and existing static wire with OPGW between the Canal and Del Park 69kV line. This project also involves the replacement of 67 existing wood structures with new steel structures, and the replacement of two lattice towers.

Transmission Lines Project Scope and Timeline

Design Start	January 2018
Design Complete	June 2018
Space reserved for steel pole production with manufacturer	July 2018
Materials Delivered	January 2019
Construction Start	April 2019
Facility In-Service	July 2019
Permit Close Out / Project Completion	February 2020

Distribution Operations Project Description – Project 157697
Distribution Operations plans to transfer distribution equipment to the new transmission structures. In addition, Distribution Operations plans to replace existing cross-arms, LB switches, transformers and capacitor banks.

Distribution Operations Project Scope and Timeline

Design Start	February 2018
Design Complete	January 2019
Materials Ordered	1st Quarter 2019
Materials Delivered	1st Quarter 2019
Construction Start	1st Quarter 2019
Construction Finish	December 2019

- **Project Cost**

	Transmission Lines	Distribution Operations	Total
Total 2018	$662k	$0k	$662k
Total 2019	$5,524k	$1,284k	$6,808k
Total 2020	$619k	$0k	$619k
Contingency	10%	10%	

Economic Analysis and Risks

- **Bid Summary**
  Transmission Lines

Based on detailed engineering, Transmission Lines has estimated the material package for this project to be $868k. The project will utilize conductor, OPGW, custom steel structures, standard steel structures, and material. The OPGW will be purchased through AFL. The conductor will be competitively bid through normal Supply Chain processes. The line construction will be based on continuing contracts with our line contractors. B&B Electric, Davis H. Elliot, William E. Groves and Pike Electric are the four contractors awarded the Transmission Overhead Construction and Maintenance contract from the October 2011 Investment Committee (IC) meeting. The contract extension was re-approved by the IC in April of 2017.

Distribution Operations:

Distribution Operations line relocation will be performed by company labor (no bids required).

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	**2018**	**2019**	**2020**	**Post 2020**	**Total**
1. Capital Investment Proposed	662	5,352	619	-	6,632
2. Cost of Removal Proposed	-	1,457	-	-	1,457
3. Total Capital and Removal Proposed (1+2)	662	6,808	619	-	8,089
4. Capital Investment 2018 BP	200	2,047	637		2,885
5. Cost of Removal 2018 BP		616	-		616
6. Total Capital and Removal 2018 BP (4+5)	200	2,663	637	-	3,500
7. Capital Investment variance to BP (4-1)	(462)	(3,304)	18	-	(3,747)
8. Cost of Removal variance to BP (5-2)	-	(841)	-	-	(841)
9. Total Capital and Removal variance to BP (6-3)	(462)	(4,145)	18	-	(4,589)

Financial Detail by Year - O&M ($000s)	**2018**	**2019**	**2020**	**Post 2020**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2018 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Discount Rate: 6.59%
Capital Breakdown:

	148857 Trans Lines	**157697 Dist Ops**	**Total**
Labor	$341k	$0k	$341k
Contract Labor	$3,680k	$910k	$4,590k
Materials	$868k	$144k	$1,012k
Local Engineering	$904k	$84k	$988k
Burdens	$391k	$28k	$419k
Contingency	$619k	$118k	$737k
Other	$2k	$0	$2k
Reimbursements	$0	$0	$0
Net Capital Expenditure	$6,805k	$1,284k	$8,089k

- **Assumptions**
  Recommendation - This assumes that the 2.84 miles of existing conductor will be replaced with ACSR and the existing static wire will be replaced with OPGW. An outage must be obtained to complete the project and is scheduled for 2019. This also assumes that all highway and railroad crossing permits will be granted by the Kentucky Transportation Cabinet (KYTC), and associated railroads. It is anticipated that no customers will be out of service for the duration of this work.

  Alternative #1 – Do Nothing - This option is not advisable as this line is nearing the end of its useful life and puts Transmission at risk of not being able to accomplish the objectives established as part of the Transmission System Improvement Plan, that was filed as support in the 2016 Rate Case, which assumed the completion of this project. These objectives include reducing the risk of failure, avoiding an extended sustained outage, and costly emergency repairs.

  Alternative #2 – Next Best Alternative – This alternative assumes that a new 2.5 mile transmission line would be constructed. This option would require additional funding due to the need to purchase 2.5 miles of new right of way, in which the property owners may not be willing to sell. The impacts associated with this option would be more disruptive and have a larger negative impact on the community during construction.

- **Environmental**
  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

- **Customer Experience**
  A communication plan is being developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the community and businesses along the route.

- **Risks**
  - Without the proposed replacement of the existing wire in the Canal-Del Park 69kV line, the company risks increased exposure to line outages. The wire along the 2.84 miles has deteriorated over time, and is beyond its expected useful life. There have been notable failures in the conductor's 60 year service life. Unplanned outages are often time-consuming and costly when it comes to repairs.
  - The Louisville Metro Department of Public Works requires permits for lane closures and flagging. The permit application will be submitted prior to construction. Lane closure permits are typically obtained in a timely manner from this agency to support our projects.
  - This project requires an easement acquisition from Bethel United Ministries, Inc. This easement has been informally agreed upon and is currently being processed for formal execution.
  - A Norfolk Southern railroad permit is required for a line segment being constructed over an existing crossing. The permit application was submitted in June 2018.

- o The local community may react negatively to the work and potential inconvenience of the project. A communication plan is being developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the community and businesses.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the Canal-Del Park Conductor Replacement project for $8,089k to improve the reliability of the electric transmission system.

Approval Confirmation for Capital Projects Greater Than $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	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

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

Project Name: Distribution Automation (DA) and Distribution Management System (DMS)

Total Approved Expenditures: $ 14,122k (Approved on 12/19/2016)

Total Revised Expenditures: $ 112,170k

Project Number(s): DA – 154092, 154093; DMS – 154094, 154095, 154096

Business Unit/Line of Business: Electric Distribution Operations (EDO)

Prepared/Presented By: Steve Woodworth, Denise Simon

Reason for Revision

Electric Distribution Operations (EDO) Distribution Automation (DA) and Distribution Management System (DMS) Investment Proposal was approved by the Investment Committee on December 19, 2016 (see Appendix A). Through the Investment Proposal, EDO requested agreement with the overall $112,357k DA plan as well as specific capital funding authority of $14,122k from the Investment Committee, to enable execution of initial DA phases:

- $80k for communications preliminary engineering and design in 2016
- $800k for communications infrastructure in 2017
- $7,120k for recloser installations in 2017
- $6,122k for DMS in 2017 – 2019 ($2,500k in 2017, $2,922k in 2018, and $700k in 2019)

As part of the 2017 Rate Case, the Kentucky Public Service Commission (KPSC) approved a Certificate of Public Convenience and Necessity (CPCN) for EDO's DA Program. Based on this approval, EDO is now requesting full capital funding authority of $112,170k to enable full execution of the DA Program, through 2022. Funding authority for the entire program will provide needed flexibility to the project team as they manage the complex nature of field work that can be directly impacted by resource availability, local weather events, customer requests, and mutual assistance activities.

Movement of capital funds between years is a natural by-product of multi-year capital programs that are as complex as DA. The project team will continue to utilize the Project Steering Committee to review and approve funding deviations between years, and will work with the EDO and Corporate RAC to address “puts and takes” that will occur throughout the six-year program.

The requested $112,170k is slightly less than the $112,357k in the original proposal. The tables below provide details of changes in annual spend.

All $ in 000's	2016/2017 Original	2016/2017 Revised	2018 Original	2018 Revised	2019 Original	2019 Revised	2020 Original	2020 Revised	2021 Original	2021 Revised	2022 Original	2022 Revised	Total Original	Total Revised
Reclosers and Communications	$8,000	$7,394	$22,328	$22,393	$21,300	$22,476	$18,203	$20,203	$18,203	$20,202	$18,201	$12,201	$106,235	$104,869
DMS / DSCADA	$2,500	$2,920	$2,922	$2,857	$700	$1,524	-	-	-	-	-	-	$6,122	$7,301
Total	$10,500	$10,314	$25,250	$25,250	$22,000	$24,000	$18,203	$20,203	$18,203	$20,202	$18,201	$12,201	$112,357	$112,170
Distribution SAIFI Reduction	1.0%	1.6%	1.9%	2.2%	10.7%	6.9%	2.2%	6.7%	1.4%	0.8%	1.4%	0.5%	18.6%	18.7%
Distribution SAIDI Reduction	0.4%	0.9%	1.2%	1.3%	6.7%	4.2%	1.5%	4.4%	1.1%	0.7%	1.0%	0.4%	11.9%	11.9%

All $ in 000's	Original	Revised	Variance	Reason for Change
Reclosers and Communications	$ 106,235	$ 104,869	$ (1,366)	1) Reclosers are now being delivered with communications equipment pre-installed by the manufacturer resulting in all communications costs being embedded in the total cost of the reclosers. 2) Reduction in contingency by $1,179k to provide additional funding for DMS/DSCADA. This reduction will not impact the number of recloser installations identified in the original IP. With this reduction, recloser contingency is $9,500k. 3) Change in burden rate lowered 2017 costs ($187k).
DMS / DSCADA	$ 6,122	$ 7,301	$ 1,179	1) Change in scope for integration to the Transmission Energy Management System (EMS). The solution requires additional hardware ($406k), software ($267k), vendor services ($98k), and internal labor ($300k). 2) Additional cost for testing ($108k).
Total	**$ 112,357**	**$ 112,170**	$ (187)	1) Change in burden rate lowered 2017 costs ($187k).

Financial Summary

Financial Summary ($000s):	**Approved**	**Revised**
Discount Rate:	6.5%	6.32%
Capital Breakdown:		
Labor:	$2,000	$11,373
Contract Labor:	$3,676	$34,541
Materials:	$3,812	$36,452
Local Engineering:	$1,281	$7,881
Burdens	$1,605	$12,424
Contingency:	$1,748	$9,499
Reimbursements:	($0)	($0)
Net Capital Expenditure:	$14,122	$112,170
NPVRR:	$122,722	$131,429

The capital breakdown originally approved was for 2017-2019 for DMS and 2016-2017 for DA; however the NPVRR calculation reflected the full DA program costs and benefits. The capital for the full program in the original document was $112,357k.

Financial Detail by Year - Capital ($000s)	**2017**	**2018**	**2019**	**Post 2019**	**Total**
1. Capital Investment Proposed	10,314	25,250	24,000	52,606	112,170
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	10,314	25,250	24,000	52,606	112,170
4. Capital Investment 2018 BP	10,314	25,250	24,000	52,606	112,170
5. Cost of Removal 2018 BP	-	-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	10,314	25,250	24,000	52,606	112,170
7. Capital Investment variance to BP (4-1)	-	-	-	-	-
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	-	-	-	-

Financial Detail by Year - O&M ($000s)	**2017**	**2018**	**2019**	**Post 2019**	**Total**
1. Project O&M Proposed	213	1,096	1,234	2,655	5,198
2. Project O&M 2018BP	212	1,086	1,213	2,549	5,060
3. Total Project O&M Variance to BP (2-1)	(1)	(10)	(21)	(106)	(138)

The incremental O&M is associated with telecommunications costs that were not included in the 2018 BP; however, they will be covered through the EDO RAC process.

Conclusions and Recommendation

EDO recommends Investment Committee approval of the Distribution Automation and Distribution Management System project for $112,170k. The funding requested in this revised proposal will provide for installation of electronic SCADA connected reclosers and deployment of the DMS and DSCADA systems. The overall DA program is projected to improve SAIDI by 11.9%, and SAIFI by 18.7%.

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

Victor A. Staffieri
Chairman and Chief Executive Officer

Template for Revised Capital Investment Proposal

Investment Proposal for Investment Committee Meeting on: N/A

Project Name: LG&E Downtown Network Vault Structural Repairs Project 2018

Total Approved Expenditures: $1,231k (Approved on 1/22/2018)

Total Revised Expenditures: $1,731k

Project Number(s): 148898

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Jason Tipton

Reason for Revision

Electric Distribution Operations (EDO) is authorized to invest $1,231k during 2018 towards continuation of its Downtown Network Vault Structural Repairs Program. The program was initiated in 2017 to address aged, defective, and deteriorating network vault structural assets that have been identified through PSC mandated inspections.

A structural engineering firm has been engaged to evaluate and prioritize repairs across the roughly 200 vault structures in the downtown network area in Louisville. Through this prioritization process, three network vaults had been initially identified for significant structural repairs in 2018 due to deficiencies that were found. These vaults are: Greater Louisville Vault, Brown Office Bldg Vault, and Kentucky Towers Vault. Since the 2018 project was approved, two more vaults (Lincoln Bank Vault and Galleria Towers Vault) have needed emergency repairs. Both vaults were already on the vault repair prioritization list but needed to be escalated due to accelerated deterioration of the vault tops.

While crews were performing a PSC inspection of Lincoln Bank Vault, it was observed that the condition of the roofing structure had significantly worsened since the initial evaluation, and a street plate was placed on the damaged top for public safety until repairs were completed. During PILC project work in the Galleria Towers Vault, it was discovered that two transformers in the vault had damaged high side compartments resulting in replacement of both transformers. Unfortunately, the vault slabs were rusted in such a manner that the slab could not be removed without cutting the vault top to replace these transformers. The additional $500k requested will cover the cost of the additional two vault top replacements that were not in the original scope of work.

Financial Summary

Financial Summary ($000s):	Approved	Revised	Explanation
Discount Rate:	6.58%	6.59%	
Capital Breakdown:			
Labor:	$ 69	$ 85	
Contract Labor:	$ 626	$ 900	Additional vault tops needing replacement, not included in original scope of work
Materials:	$ 345	$ 485	Additional vault tops needing replacement, not included in original scope of work
Local Engineering:	$ 94	$ 140	
Burdens:	$ 97	$ 121	
Contingency:	$ 0	$ 0	
Reimbursements:	($ 0)	($ 0)	
Net Capital Expenditure:	$1,231	$1,731	See above.
NPVRR:	$1,568	$2,195	

Financial Detail by Year - Capital ($000s)	Pre-2018	2018	2019	Post 2019	Total
1. Capital Investment Proposed	-	1,731	-	-	1,731
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	-	1,731	-	-	1,731
4. Capital Investment 2018 BP	-	1,231	-	-	1,231
5. Cost of Removal 2018 BP	-	-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	-	1,231	-	-	1,231
7. Capital Investment variance to BP (4-1)	-	(500)	-	-	(500)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	(500)	-	-	(500)

Financial Detail by Year - O&M ($000s)	Pre-2018	2018	2019	Post 2019	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2018 BP	-	-	-	-	-
3. Total Project O&M Variance to BP (2-1)	-	-	-	-	-

The incremental funding was approved through the August EDO RAC process.

Conclusions and Recommendation

EDO recommends approval of the LG&E Downtown Network Vault Structural Repairs Project for $1.731M in 2018 in order to ensure the ongoing operating reliability and safety of the Downtown Louisville Network.

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.

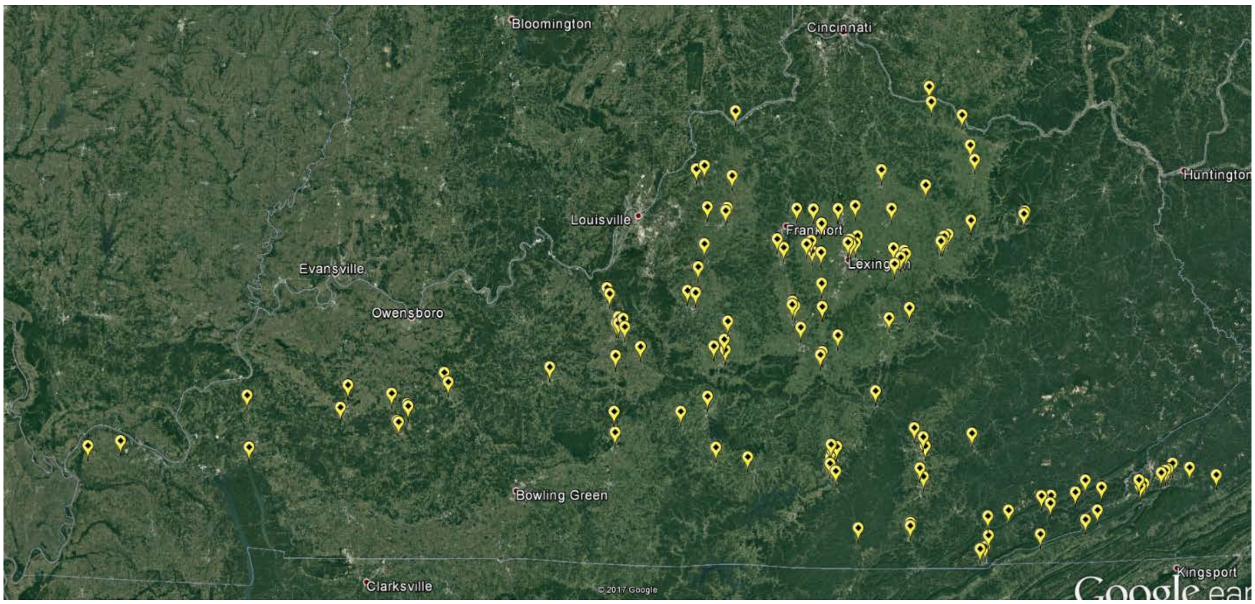
This project's main focus is to bring SCADA capabilities to distribution substations. This will be accomplished primarily through the replacement of 170 power circuit breakers and 160 electromechanical relay packages and the retrofit of 100 circuits with communications equipment. Legacy electromechanical 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	Paul W. Thompson
Chief Financial Officer	President and Chief Operating Officer

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

Project Name: SCM Enhanced Substation Wildlife Protection

Total Expenditures: $5,180k

Project Number(s): 156330 (budget on 155293)

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Jude Beyerle

Executive Summary

Electric Distribution Operations (EDO) proposes to secure capital funding for enhanced wildlife protection at 40 KU substations. From 2012-2017, wildlife was the single largest contributor to distribution substation level outages at KU, representing 38% of all SAIDI (System Average Interruption Duration Interval) at KU substations.

Wildlife protection is included in the design and construction of new and expanded distribution substations. However, EDO's current design practice was only formalized as of 2012, and numerous previously constructed KU distribution substations continue to utilize legacy standards that are sometimes less than adequate in providing the highest level of station protection. Primary wildlife threats to these stations include raccoons, squirrels, birds and snakes.

There are 471 KU substations with distribution facilities. Of these, 329 have some degree of wildlife protection and 142 have no wildlife protection. As previously noted, even those substations that have some level of existing wildlife protection are not secured at a standard necessary to provide enough protection to substantially impact the number and duration of interruptions.

Priorities for a substation's inclusion in this project will include: history of past interruptions or repetitive interruptions, amount of load served, and SAIDI impact. Substations with some or no level of wildlife protection will be targeted by the project.

The 2018 Business Plan (BP) includes $510k in 2018, $1,250k in 2019, $1,700k in 2020 and $1,720k in 2021 for this project.

Background

From the period January 2012 to December 2017, KU experienced a total 17.06 minutes of SAIDI, or an average of 2.9 minutes per year of SAIDI impact from wildlife outages in distribution substations. This leading outage cause was the single largest contributor to KU distribution substation SAIDI by a factor of four above any other cause, and was higher than the next six causes combined.

For reference, the 20 most impactful wildlife outages from 2012 – 2017 were as follows:

Date	Substation	Customer Count	Outage Minutes	SAIDI Minutes	Load (kW, estimated)	Animal
5/6/2012	Dawson Springs	966	273	0.48	1900	Bird
10/7/2012	Parker Seal	2194	83	0.33	9700	Raccoon
3/23/2013	Rockwell	3122	70	0.40	17300	Squirrel
6/30/2013	Stonewall	5470	80	0.80	26600	Squirrel
8/13/2013	Hamblin	1499	128	0.35	5600	Raccoon
9/29/2014	Sonora	1854	169	0.57	4700	Squirrel
9/24/2014	Reynolds	3186	36	0.21	26600	Squirrel
1/9/2015	London	2632	102	0.49	10500	Squirrel
5/28/2015	Wilson Downing	5312	70	0.68	14000	Squirrel
6/19/2015	Shavers Chapel	2464	188	0.84	8000	Snake
6/30/2015	Greenville	1875	129	0.44	6300	Bird
9/21/2015	Stonewall	5492	67	0.67	28600	Squirrel
10/24/2015	London	2637	83	0.40	9700	Squirrel
8/16/2016	Buena Vista	1890	125	0.43	7100	Squirrel
8/28/2016	Lansdowne	6643	64	0.77	24700	Squirrel
9/27/2016	IBM	4082	54	0.40	18600	Raccoon
11/23/2016	Stonewall	5570	47	0.48	21800	Squirrel
12/24/2016	East Bernstadt	1224	261	0.58	9400	Squirrel
3/16/2017	Bryant Road	2785	55	0.28	15500	Bird
7/4/2017	Alexander	5442	74	0.73	15400	Bird

EDO formalized its internal wildlife protection design and construction standards in 2012. All distribution substations constructed or expanded since 2012 have been equipped with wildlife protection in accordance with these standards. This proposed investment will provide for the upgrade or installation of wildlife protection at KU distribution substations which were constructed prior to EDO's establishment of the new design and construction standards. The enhanced protection will address wildlife threats such as raccoons, squirrels, birds and snakes. Each species has unique motives and methods for intruding electrical substations, and optimizing protection against all threats may require overlapping protective schemes. The planned protection schemes will utilize solutions from leading suppliers including Midsun, Green Jacket, TE Connectivity and Vanquish.

Some of the largest substations in the Lexington area are of particular concern. These stations, including Stonewall, Wilson Downing, Alexander and Lansdowne have high customer counts (> 5,000) and, despite the addition of a level of wildlife protection at these locations in the mid 2000's, they continue to experience outages at an unacceptable rate.

The proposed project scope includes installation of enhanced substation protection at an estimated 40 substations where wildlife outages have had or can be expected to have the most substantial SAIDI impact in the future. The 40 substation locations have accounted for 15.5 minutes of SAIDI impact, or 91% of all distribution substation wildlife outages from 2012 to date. Substations were selected for the program based on their history of past interruptions or repetitive interruptions, amount of load served, and SAIDI impact.

LG&E substations are not a part of this initiative. LG&E substations largely use metalclad switchgear construction with underground exit cables for distribution. This provides a very effective wildlife barrier (see example construction photos). At LG&E, wildlife outages represent only 5% of SAIDI impact.

Figure 1Metalclad Switchgear Indoor 12kV Bus Construction

Figure 2 KU Outdoor 12kV Bus Construction

- **Alternatives Considered (1 –Recommendation, 2 –Do nothing, 3 –Next Best Alt)**

1. Recommendation: NPVRR: ($000s) $29,192k

Install enhanced wildlife protection at approximately 40 KU distribution substations. The estimated total cost of this option is $5,180k.

With a focus on larger KU distribution substations with a history of wildlife outages, there is an estimated 50% reduction in wildlife related incidents at project completion, with a smaller, proportional benefit as the project progresses.

An analysis of 2012 – Dec 2017 wildlife outages for the 40 substations expected to be addressed by this initiative provides the following averages:

- 8 outages per year
- 112 minutes (1.87 hours)/per outage
- 10,200 kW interrupted load/per outage

A review of recent MxOrders and associated charges indicates a cost per outage for actual repair and clean-up is $8k, or $64k/per year for 8 wildlife outages per year.

With reference to the project scope and timeline; the calculation of the cost of unserved energy and repairs yield a total assumed cost of $57,713k:

- (8 outages) x (10,200 kW) x (1.87 Hours) x ($17.20/kW-Hr) + $64k = $2,689k per year, for 2018.
- (8 Failures) x (.95{10% project benefit}) x (10,200 kW) x (1.87 Hours) x ($17.20/kW-Hr) + (.95{10% project benefit}) x $64k = $2,554k per year, for 2019.
- (8 Failures) x (.84{32% project benefit}) x (10,200 kW) x (1.87 Hours) x ($17.20/kW-Hr) + (.84{32% project benefit}) x $64k = $2,258k per year, for 2020.
- (8 Failures) x (.68{63% project benefit}) x (10,200 kW) x (1.87 Hours) x ($17.20/kW-Hr) + (.68{63% project benefit}) x $64k = $1,828k per year, for 2021.
- (8 Failures) x (.5{100% project benefit}) x (10,200 kW) x (1.87 Hours) x ($17.20/kW-Hr) + (.5{100% project benefit}) x $64k = $1,344k per year, for 2022 and forward.

2. Do Nothing (alternative #1) NPVRR: ($000s) $40,156k

Electing not to fund this project will result in future wildlife outages continuing at levels consistent with 2012-2017 averages. The cost of unserved energy and repairs will continue as per the 2018 calculation in the recommended option for a total assumed cost of $107,560k:

The calculation of the cost of unserved energy and repairs yields:

- (8 outages) x (10200 kW) x (1.87 Hours) x ($17.20/kW-Hr) + $64k = $2,689k per year

3. Next Best Alternative(s): NPVRR: ($000s) N/A

No other alternative is seen as viable or a cost effective use of capital funding. LG&E has very few wildlife outages due to the historical use of metalclad switchgear. To complete upgrades to metalclad switchgear at the equivalent number of KU substations as this project entails is estimated at $2M per substation, or $80M total.

Project Description

- **Project Scope and Timeline**

1st half 2018	Finalize design and scope of work and substation list, place PO with EPCM as required, order materials
2nd half 2018	Complete wildlife protection installations at 3-5 substations
2019	Complete wildlife protection installations at 8-10 substations
2020	Complete wildlife protection installations at 12-15 substations
2021	Complete wildlife protection installations at 12-15 substations

- **Project Cost**
  The estimated project cost is $510k in 2018, $1,250k in 2019, $1,700k in 2020 and $1,720k in 2021.

  This project is estimated with no contingency. Multiple locations will be targeted, and project funding will be managed and optimized to adequately complete as many stations as possible within the funding allocation.

Economic Analysis and Risks

- **Bid Summary**
  Competitive bids will be solicited from qualified material suppliers. Distribution Substations has established existing CPAs with a number of qualified construction contractors and EPCM firms.

- **Budget Comparison and Financial Summary**

This funding for this project has been approved as a part of the 2018 BP.

Financial Detail by Year - Capital ($000s)	**2018**	**2019**	**2020**	**Post 2020**	**Total**
1. Capital Investment Proposed	510	1,250	1,700	1,720	5,180
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	510	1,250	1,700	1,720	5,180
4. Capital Investment 2018 BP	510	1,250	1,700	1,720	5,180
5. Cost of Removal 2018 BP		-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	510	1,250	1,700	1,720	5,180
7. Capital Investment variance to BP (4-1)	-	-	-	-	-
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	-	-	-	-

Financial Detail by Year - O&M ($000s)	**2018**	**2019**	**2020**	**Post 2020**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2018 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project has been approved as a part of the 2018 BP.

Financial Summary ($000s):

Discount Rate:	6.58%
Capital Breakdown:	
Labor:	$ 85
Contract Labor:	$2,280
Materials:	$2,205
Transportation:	$ 10
Local Engineering:	$ 350
Burdens:	$ 250
Contingency:	$ 0
Reimbursements:	($ 0)
Net Capital Expenditure:	$5,180

Assumptions

- Project costs are based upon previous wildlife protection projects and vendor estimates for enhanced installations. The project estimates 40 stations will be completed, but the final count will vary based upon actual pricing and the exact stations chosen.
- EPCM contractors will be utilized as needed to complete the project scope.
- EPCM contractors will be utilized as needed to coordinate installations, requiring minimal company resources.

Environmental

- No environmental issues are known at this time.

Risks

- Installations in isolated substations may require a portable substation or work procedures using hot line techniques.
- There is a cost risk since each substation is unique to some degree; driving design, material and installation costs to vary from site to site. This risk will be mitigated by advanced planning and review of each location in the early phases of the project.
- There is a possible schedule risk due to the number of stations to be protected and coordination with numerous other capital upgrade initiatives. This risk can be mitigated by coordinating with other projects and scheduled outages, securing outages early in the year and involving the DCC earlier in the scheduling.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the SCM Enhanced Substation Wildlife Protection project for $5,180k to increase reliability on the KU system, enhance customer service and reduce operating and capital costs associated with wildlife outages.

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	Date	Paul W. Thompson	Date
Chief Financial Officer		President and Chief Operating Officer	

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

Project Name: LG&E Downtown Network Vault Structural Repairs Project 2019

Total Expenditures: $1.7M (includes no contingency)

Project Number(s): 151485

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Jason Tipton

Executive Summary

LG&E Electric Distribution Operations (EDO) seeks funding authority to invest $1.7M on secondary network vault reconstruction and repair during 2019. LG&E's electric distribution secondary network in downtown Louisville, located between the Ohio River, 9th Street, York Street, and Floyd Street, is comprised of 200 electrical vaults, some of which were originally constructed as far back as the early 1930's. These vaults house critical electrical equipment needed to serve customers in Louisville's primary downtown business district and hospital zone. The vaults are primarily constructed of concrete or brick walls and floors, and their ceilings are supported with beams or columns to support the weight of pedestrians and vehicles. The majority of these vaults are under public sidewalks.

LG&E Electric Distribution Operations (EDO) inspects its secondary network vaults every six months, in accordance with 807 KAR 5:006. Through these inspections, LG&E has noted considerable and accelerating deterioration of some vaults to the point substantial replacement or repairs are needed. During 2018, EDO continued prioritizing vaults identified with structural deficiencies and consulted with a third party structural engineering firm to develop a strategic plan for future reconstruction and repair. Through this initiative, four network vaults are targeted for remedial action during 2019.

The total estimated cost is included in the 2019 Business Plan. Future year vault reconstruction and repair investment targets will be established annually, as vaults are identified and prioritized for remedial action based on EDO's semi-annual inspections and ongoing external structural engineering evaluation and counsel.

Background

General
The LG&E EDO Downtown Network was originally constructed in the 1930's, and contains five separate secondary network systems with 27 circuits within the core downtown Louisville business and medical districts. The network area is roughly bounded by the Ohio River (north), Floyd Street (east), York Street (south) and 8th Street (west). Louisville's downtown network is roughly one square mile, and contains 200 network vaults within its borders.

Justification for Improvements
There are four main drivers for making structural improvements to the Downtown Network vault system.

1. Structural Issues - Some vaults have brick walls with mortar missing and walls threatening to cave in, concrete walls with cracks and spalling concrete, or beam supports with severe cracks that are rusted and damaged. The concrete ceilings have deteriorated over time and display damage from decades of deicing salts. The metal framework on some removable concreate slabs have rusted, complicating worker efforts to handle the slabs and gain access to associated vaults.

2. Outdated Construction Standards - Concrete encased steel beams used to be a common building practice that has been utilized in many of the LG&E EDO network vaults. However, it is now known that this is a poor choice of construction in an exterior environment. The concrete encasements are cracked or crumbling due to steel beam corrosion, and chunks of concrete are falling off in many locations, leading to potential damage to equipment and safety concerns for workers.

3. Public and Company Safety - The metal framework rusts and causes the vault top panels to buckle, creating tripping hazards for pedestrians. The concrete pieces falling from the ceiling beams pose a risk to workers in the vaults, both from direct hits and from the potential to fall on energized equipment in the vault while they are present. Also, in the unlikely event that a vault top becomes compromised, it could lead to portions of the sidewalk caving in.

4. Regulatory Requirements - In accordance with PSC regulation 807 KAR 5:006, LG&E is required to inspect vaults and document deficiencies with vault structures every 6 months. Upon finding a potentially hazardous condition with a facility, LG&E is required to make repairs and document our actions for future PSC review.

<u>*3rd Party Evaluation*</u>
In 2016, LG&E hired a structural engineering firm to evaluate several of the LG&E EDO network vaults to assist in starting the first year of this program. Since the initial assessment, more vaults have been evaluated and prioritized by the engineering firm to be addressed in future years of this project. For 2019, it was determined that four vaults need significant structural repairs due to deficiencies that were noted.

Three of the vaults have similar insufficiencies: 224 S. 4th Street, Standard Gravure at 627 S. 6th Street, and South Bell 480V at 521 W. Chestnut Street. These vaults all exhibit extensive damage to the vault top removable panels due to deicing agents over the years, and concrete encased beams that are significantly deteriorated. The vault walls have substantial spalling to the point that rebar is exposed in several locations. The steel columns are rusted beyond repair in most cases, to the extent of visible holes through the column in some areas near the base.

The fourth vault is 518 S. 4th Street, which is unique in that half of the vault top is a driving lane for cars entering an alley near the Seelbach Hotel, which goes to the rear of the hotel for deliveries along with access to the parking garage. This vault top has support beams that are rusted significantly and need to be replaced with an updated design reflecting the most recent standards and codes for a traffic rated driveway.

Alternatives Considered

1. <u>Recommendation:</u> NPVRR: ($000s) $2,156
   It is recommended that the LG&E Downtown Network Vault Structural Repairs Project be approved for $1.7M for 2019 in order to ensure the ongoing operating reliability of the Downtown Louisville Network distribution system by addressing aged, defective, and deteriorating network vault structural assets.

2. <u>Do Nothing:</u> NPVRR: ($000s) N/A
   The do nothing approach is not a viable option. Failure to proceed with the LG&E Downtown Network Vault Structural Repairs Project introduces a growing probability that vault structural failures caused by increasingly aging infrastructure will occur. While the total loss of one of the three grid networks in downtown Louisville is a very low probability event, it would likely occur if a vault were to collapse upon itself and damage multiple primary circuits inside the vault. Along with the primary circuits being damaged, the vault top could be compromised, leading to the collapse of the sidewalk into the vault. A lengthy network outage would severely impact downtown central business district customers, comprised of metro and federal government agencies (police, security, traffic, etc.), judicial and legal systems, hospitals and medical offices, banking and investment institutions as well as other commercial businesses, including entertainment and tourism.

Project Description

- **Project Scope and Timeline**
  The total estimated cost will provide for reconstruction and repair of four vaults identified and prioritized through internal inspection and 3rd party evaluation:
  - 224 S. 4th Street
  - Standard Gravure at 627 S. 6th Street
  - South Bell 480V at 521 W. Chestnut Street
  - 518 S. 4th Street

- **Project Cost**
  The total estimated cost is $1.7M. This total will provide for reconstruction and repair of the prioritized vaults, and includes funding for structural engineering analysis of future year candidates for corrective actions.

Economic Analysis and Risks

- **Bid Summary**
  Each vault reconstruction and repair project will be competitively bid using standard Supply Chain procedures.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	1,700	-	-	-	1,700
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	1,700	-	-	-	1,700
4. Capital Investment 2019 BP	1,699	-	-	-	1,699
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	1,699	-	-	-	1,699
7. Capital Investment variance to BP (4-1)	(1)	-	-	-	(1)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(1)	-	-	-	(1)

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:	$ 82
Contract Labor:	$ 936
Materials:	$ 429
Local Engineering:	$ 117
Burdens:	$ 113
Transportation	$ 23
Contingency:	$ 0
Reimbursements:	($ 0)
Net Capital Expenditure:	$ 1,700

- **Assumptions**
  Cost estimates are based on current vault conditions and planned remedial actions.

- **Environmental**
  No environmental issues are anticipated at this time.

- **Risks**
  Network system reliability, worker and public safety, and Company image could be negatively impacted in the future if the prioritized vaults are not addressed as proposed.

Conclusions and Recommendation

EDO recommends that Management approve the LG&E Downtown Network Vault Structural Repairs Project for $1.7M for 2019 in order to ensure the ongoing operating reliability and safety of the Downtown Louisville Network.

Investment Proposal for Investment Committee Meeting on: N/A

Project Name: LG&E Downtown Network Vault Structural Repairs Project 2018

Total Expenditures: $1.231M (includes no contingency)

Project Number(s): 148898

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Jason Tipton

Executive Summary

LG&E Electric Distribution Operations (EDO) seeks funding authority to invest $1.231M on secondary network vault reconstruction and repair during 2018. LG&E's electric distribution secondary network in downtown Louisville, located between the Ohio River, 9th Street, York Street, and Floyd Street, is comprised of 200 electrical vaults, some of which were originally constructed as far back as the early 1930's. These vaults house critical electrical equipment needed to serve customers in Louisville's primary downtown business district and hospital zone. The vaults are primarily constructed of concrete or brick walls and floors, and their ceilings are supported with beams or columns to support the weight of pedestrians and vehicles. The majority of these vaults are under public sidewalks.

LG&E Electric Distribution Operations (EDO) inspects its secondary network vaults every six months, in accordance with 807 KAR 5:006. Through these inspections, LG&E has noted considerable and accelerating deterioration of some vaults to the point substantial replacement or repairs are needed. During 2017, EDO prioritized vaults identified with structural deficiencies and consulted with a third party structural engineering firm to develop a strategic plan for future reconstruction and repair. Through this initiative, three network vaults were targeted for remedial action during 2018.

The total estimated cost is included in the 2018 Business Plan. Future year vault reconstruction and repair investment targets will be established annually, as vaults are identified and prioritized for remedial action based on EDO's semi-annual inspections and ongoing external structural engineering evaluation and counsel.

Background

General
The LG&E EDO Downtown Network was originally constructed in the 1930's, and contains five separate secondary network systems with 27 circuits within the core downtown Louisville business and medical districts. The network area is roughly bounded by the Ohio River (north), Floyd Street (east), York Street (south) and 8th Street (west). Louisville's downtown network is roughly one square mile, and contains 200 network vaults within its borders.

Justification for Improvements
There are four main drivers for making structural improvements to the Downtown Network vault system.

1. Structural Issues - Some vaults have brick walls with mortar missing and walls threatening to cave in, concrete walls with cracks and spalling concrete, or beam supports with severe cracks that are rusted and damaged. The concrete ceilings have deteriorated over time and display damage from decades of deicing salts. The metal framework on some removable concreate slabs have rusted, complicating worker efforts to handle the slabs and gain access to associated vaults.

2. Outdated Construction Standards - Concrete encased steel beams used to be a common building practice that has been utilized in many of the LG&E EDO network vaults. However, it is now known that this is a poor choice of construction in an exterior environment. The concrete encasements are cracked or crumbling due to steel beam corrosion, and chunks of concrete are falling off in many locations, leading to potential damage to equipment and safety concerns for workers.

3. Public and Company Safety - The metal framework rusts and causes the vault top panels to buckle, creating tripping hazards for pedestrians. The concrete pieces falling from the ceiling beams pose a risk to workers in the vaults, both from direct hits and from the potential to fall on energized equipment in the vault while they are present. Also, in the unlikely event that a vault top becomes compromised, it could lead to portions of the sidewalk caving in.

4. Regulatory Requirements - In accordance with PSC regulation 807 KAR 5:006, LG&E is required to inspect vaults and document deficiencies with vault structures every 6 months. Upon finding a potentially hazardous condition with a facility, LG&E is required to make repairs and document our actions for future PSC review.

<u>3rd Party Evaluation</u>

In 2016, LG&E hired a structural engineering firm to evaluate several of the LG&E EDO network vaults to assist in starting the first year of this program. Since the initial assessment, more vaults continue to be evaluated and prioritized by the engineering firm to help drive future years of this project. For 2018, it was determined that three vaults needed significant structural repairs due to deficiencies that were noted. Greater Louisville Vault at 130 S 4th Street has extensive damage to the vault top removable panels due to deicing agents over the years and concrete encased beams that are significantly deteriorated. For general public safety, this vault currently has a street plate over the slab opening. Brown Office Bldg. Vault at 321 W Broadway has a duct bank routing through this vault, which is no longer allowed in today's construction practices. This has led to telecommunications and primary cable splices inside of the vault. The duct bank is in very poor condition and is supported by the roof system which has been compromised over the years due to deicing agents and outdated construction designs. Kentucky Towers at 509 S. 5th Street has rusted beams that are beyond repair, the wall adjacent to street contains spalling concrete, and the interior walls are formed from inadequate brick structure. Kentucky Towers was initially listed for structural repair in 2017. This vault was reassigned to the 2018 project scope due to EDO addressing recently discovered structural concerns in other vaults that were reprioritized by the structural engineer on the project.

Alternatives Considered

1. <u>Recommendation:</u> NPVRR: ($000s) $1,568
   It is recommended that the LG&E Downtown Network Vault Structural Repairs Project be approved for $1.231M for 2018 in order to ensure the ongoing operating reliability of the Downtown Louisville Network distribution system by addressing aged, defective, and deteriorating network vault structural assets.

2. <u>Do Nothing:</u> NPVRR: ($000s) N/A
   The do nothing approach is not a viable option. Failure to proceed with the LG&E Downtown Network Vault Structural Repairs Project introduces a growing probability that vault structural failures caused by increasingly aging infrastructure will occur. While the total loss of one of the three grid networks in downtown Louisville is a very low probability event, it would likely occur if a vault were to collapse upon itself and damage multiple primary circuits inside the vault. Along with the primary circuits being damaged, the vault top could be compromised, leading to the collapse of the sidewalk into the vault. A lengthy network outage would severely impact downtown central business district customers, comprised of metro and federal government agencies (police, security, traffic, etc.), judicial and legal systems, hospitals and medical offices, banking and investment institutions as well as other commercial businesses, including entertainment and tourism.

Project Description

- **Project Scope and Timeline**
  The total estimated cost will provide for reconstruction and repair of three vaults identified and prioritized through internal inspection and 3rd party evaluation:
  - Greater Louisville Vault at 130 S 4th Street.
  - Brown Office Bldg. Vault at 321 W Broadway.
  - Kentucky Towers at 509 S. 5th Street.
- **Project Cost**
  The total estimated cost is $1.231M. This total will provide for reconstruction and repair of the prioritized vaults, and includes funding for structural engineering analysis of future year candidates for corrective actions.

Economic Analysis and Risks

- **Bid Summary**
  Each vault reconstruction and repair project will be competitively bid using standard Supply Chain procedures.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	1,231	-	-	-	1,231
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	1,231	-	-	-	1,231
4. Capital Investment 2018 BP	1,231	-	-	-	1,231
5. Cost of Removal 2018 BP	-	-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	1,231	-	-	-	1,231
7. Capital Investment variance to BP (4-1)	-	-	-	-	-
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	-	-	-	-

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2018 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.58%
Capital Breakdown:	
Labor:	$ 69
Contract Labor:	$ 626
Materials:	$ 345

Local Engineering:	$ 94
Burdens:	$ 97
Contingency:	$ 0
Reimbursements:	($ 0)
Net Capital Expenditure:	$1,231

- **Assumptions**
  - Cost estimates are based on current vault conditions and planned remedial actions.

- **Environmental**
  No environmental issues are anticipated at this time.

- **Risks**
  Network system reliability, worker and public safety, and Company image could be negatively impacted in the future if the prioritized vaults are not addressed as proposed.

Conclusions and Recommendation
EDO recommends that Management approve the LG&E Downtown Network Vault Structural Repairs Project for $1.231M for 2018 in order to ensure the ongoing operating reliability and safety of the Downtown Louisville Network.

Investment Proposal for Investment Committee Meeting on: August 29, 2018

Project Name: LGE PILC UG Network Cable Replacement Program-2018

Total Approved Expenditures: $8.758M (Approved on 10/25/17)

Total Revised Expenditures: $11.333M

Project Number(s): 148899

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Jason Tipton / Shawn Stickler

Reason for Revision

Electric Distribution Operations (EDO) is authorized to invest $8.758M during 2018 towards continuation of its Paper Insulated Lead Covered (PILC) Cable Replacement Program. The program was initiated early in 2013, and originally scheduled to be completed by the end of 2023. During the 2018 business planning period, EDO decided to compress the schedule of the PILC cable replacement program by two years, to take advantage of ongoing work efficiencies and projected program benefits.

Current year inspections of program duct routes continue to reveal substantially deteriorated subsurface conditions, necessitating complete replacement of duct sections. To assure annual cable replacement targets can be met with the compressed schedule, EDO proposes to increment its 2018 capital allocation by $2.6M to increase focus on duct replacement during the remainder of 2018. The proposed funding will be pulled from EDO's 2021 PILC Cable Replacement Program allocation.

The Total Revised Expenditures of $11.333M includes 2018 burden reductions of $25k.

Financial Summary

Financial Summary ($000s):	**Approved**	**Revised**	**Explanation**
Discount Rate:	6.32%	6.59%	
Capital Breakdown:			
Labor:	$ 95	$ 95	
Contract Labor:	$ 7,187	$ 9,417	See explanation below.
Materials:	$ 455	$ 555	
Local Engineering:	$ 699	$ 947	Increase in Contract Labor & Materials.
Burdens:	$ 297	$ 293	
Transportation:	$ 25	$ 25	
Contingency:	$ 0	$ 0	
Reimbursements:	($ 0)	($ 0)	
Net Capital Expenditure:	$ 8,758	$11,333	
NPVRR:	$ 11,394	$14,371	

To ensure increased yearly cable target objectives can be achieved, EDO proposes to focus on duct infrastructure replacement throughout the remainder of 2018.

Financial Detail by Year - Capital ($000s)	**2018**	**2019**	**Post 2019**	**Total**
1. Capital Investment Proposed	11,333	-	-	11,333
2. Cost of Removal Proposed	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	11,333	-	-	11,333
4. Capital Investment 2018 BP	8,758	-	-	8,758
5. Cost of Removal 2018 BP	-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	8,758	-	-	8,758
7. Capital Investment variance to BP (4-1)	(2,575)	-	-	(2,575)
8. Cost of Removal variance to BP (5-2)	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(2,575)	-	-	(2,575)

Financial Detail by Year - O&M ($000s)	**2018**	**2019**	**Post 2019**	**Total**
1. Project O&M Proposed				-
2. Project O&M 2018 BP				-
3. Total Project O&M Variance to BP (2-1)	-	-	-	-

The incremental funding was approved through the July Corporate RAC process.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the revised authority requested for the 2018 PILC Replacement Project for $11.333M. This will enable EDO to meet its compressed PILC Cable Replacement Program schedule, and provide for continued safe and reliable operation of the Downtown Louisville Network.

Approval Confirmation for Capital Projects Greater Than $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	Date	Paul W. Thompson Chairman, CEO and President	Date

Investment Proposal for Investment Committee Meeting on: N/A

Project Name: Rogers Gap 0451 Circuit Hardening

Total Expenditures: $1,800k (Including $300k of contingency)

Project Number(s): 156250

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Jeffrey Poston

Executive Summary

KU Electric Distribution and LKE Electric Reliability propose to invest $1,800k on reliability improvements for the Rogers Gap 0451 circuit. The 0451 Circuit Hardening project was approved during the 2017 AIS process and included in the 2018 Business Plan under the Circuit Hardening Reliability Program. Additional funding for 2018 and 2019 is required to address all necessary improvements. This project is currently approved for $553k (June 2018) and was originally expected to be completed in 2018. Additions to the scope of work are expected to be completed in 2019.

This project proposes to reconductor 13 miles of 3-phase #4 copper while also replacing defective poles and equipment along U.S. Highway 25 from Georgetown to Corinth. Portions of the 13 miles will be relocated to the highway as the existing route travels through rough terrain, making restoration efforts increasingly difficult. The existing copper conductor is prone to failure and will be replaced with 2/0 ACSR conductor. Electric customers will experience fewer interruptions and shortened outage durations upon completion of this project.

The incremental funding needed in 2018 was approved through the October Corporate RAC process. The 2019 funding will be covered through the Circuit Hardening Reliability Program.

Background

Rogers Gap 0451 is located in the Lexington Operations Center area and serves over 1,100 customers from Georgetown to Sadieville and on to Corinth. Circuit 0451 is one of the longest in the LKE Distribution System with over 60 miles of overhead conductor. Thirteen miles of defective, 3-phase mainline #4 copper on the circuit has proven to be unreliable and needs to be replaced. Portions of the mainline were constructed off the highway through rough terrain. The project will relocate several portions to locations along the highway Right-of-Way (R-O-W). Additionally, the small conductor size has limited the available fault current at the end of the line making successful fault coordination exceptionally challenging. This project will replace the remaining 13 miles of defective copper along with defective poles and equipment. The project has been designed and estimated at $1,800k (including $300k of contingency).

Due to the location of the project along U.S. Highway 25, continuous flagging is required. Vegetation management is also required along new and existing R-O-W. Design and Engineering have been completed collectively by UCS and the Electric Reliability group. Acquisition of R-O-W has been contracted to O.R. Colan and will be managed by the Real Estate & Right-of-Way group.

By hardening the circuit as proposed, the number of outages, outage response times, and coordination for sectionalizing devices will be improved. It is expected that 1,020 customer interruptions and 168,945 customer minutes will be saved annually after completion of the project and nine "Critical" customers will experience reliability improvements including local fire and water departments, railroad, and communications. Recent PSC complaints will be also addressed.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $2,038
  2. Alternative #1: (Do Nothing) NPVRR: ($000s) $3,151
     The cost of "do nothing" is based on the value gained by reducing average annual circuit outage duration through completion of the Recommendation. Using the corporate "cost of unserved energy" ($17.2/kWh), the value of reducing outage duration (CMI) based on average circuit loads is $170k annually.

Project Description

- **Project Scope and Timeline**
  The engineering and design have been collectively completed by UCS and the Electric Reliability group. Acquisition of R-O-W, where needed, has been contracted to O.R. Colan. Existing contractor resources will be assigned following the approval of the project and existing EDO construction blanket contracts and resources will be used. The first sections should be completed by the end of 2018, and the remainder of the work will be finished in 2019.

- **Project Cost**
  Total project costs are $1,800k including 20% contingency. The project will be funded from the 2018 and 2019 KU System Hardening Reliability Project (152999).

Economic Analysis and Risks

- **Bid Summary**
  Field construction work will be completed under existing contracts with overhead distribution line business partners. All required materials will be procured using established materials contracts.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	680	990			1,670
2. Cost of Removal Proposed	50	80			130
3. Total Capital and Removal Proposed (1+2)	730	1,070	-	-	1,800
4. Capital Investment 2019 BP	-	-			-
5. Cost of Removal 2019 BP	-	-			-
6. Total Capital and Removal 2019 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(680)	(990)	-	-	(1,670)
8. Cost of Removal variance to BP (5-2)	(50)	(80)	-	-	(130)
9. Total Capital and Removal variance to BP (6-3)	(730)	(1,070)	-	-	(1,800)

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed					-
2. Project O&M 2019 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This is funded from the System Hardening Reliability program.

Financial Summary ($000s):

Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$ 88
Contract Labor:	$1,066
Materials:	$ 104
Local Engineering:	$ 151
Burdens:	$ 91
Contingency:	$ 300
Reimbursements:	($)
Net Capital Expenditure:	$1,800

- **Assumptions**
  The CEM model used the cost of unserved energy for the "Do Nothing" alternative NPVRR. Useful life of the project is 30 years.

- **Environmental**
  None

- **Risks**
  Delaying this investment will result in further deterioration of the copper conductor. Conductor failures and associated electrical service interruptions will become more prevalent. Customer satisfaction will decline as customer complaints continue to rise.

Conclusions and Recommendation
It is recommended that Management approve the revised Rogers Gap 0451 Circuit Hardening project for $1,800k to resolve ongoing reliability, restoration, and coordination issues.

Investment Proposal for Investment Committee Meeting on: April 26, 2017

Project Name: LG&E Substation Monitoring and Control (SMAC) Program

Total Expenditures: $5,076k (including contingency of $461k)

Project Number(s):148727

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Robin Chacko/Tony Durbin

Executive Summary

Electric Distribution Operations (EDO) - Substation Construction and Maintenance (SC&M) seeks funding authority to expand the use of Substation Monitoring and Control (SMAC) at fourteen (14) LG&E distribution substations. Currently, LG&E Substation Operations expends a considerable amount of time and resources traveling to the fourteen substations to manually remove circuit reclosing, ground relaying, and automatic transformer tap changing from service per the direction of the Distribution Control Center (DCC). SC&M's proposed four-year project will add the necessary control circuitry within the targeted substations to enable DCC Restoration Coordinators to complete these routine tasks remotely through Substation Control and Data Acquisition (SCADA) and eliminate the requirement of LG&E Substation operators to travel to the fourteen substations to perform the tasks manually.

The majority of LG&E existing substations already include SMAC functionality, and SMAC is standard on all new or expanded substations. SC&M's proposed four year program will start in 2017 and equip remaining unequipped LG&E substations with this functionality. The addition of SCADA control for circuit reclosing, ground relaying, and automatic transformer tap changer control will also speed up restoration efforts, increase LG&E Substation Operation's productivity and reduce wait times of other Distribution Operations groups who cannot begin work until these routine substation tasks are completed.

EDO's 2017 Business Plan (BP) allocated $3,377k for the proposed SMAC project. This investment proposal includes an incremental $1,699k for the project in 2020, based on bids received for the 14 substations since the 2017 BP was finalized. The 2017 BP allocation was based on unit pricing experienced in 2016 on LG&E's Fern Valley Substation SMAC Project.

The additional $1,699k for 2020 will be addressed in the 2018 BP. Once this project is complete, all LG&E 12kV and 14kV substations will be equipped with SMAC technology.

Background

The LG&E SMAC program is driven by the need to automate substation processes which will improve operational efficiency, and in turn, reduce truck rolls by LG&E Substation Operations to manually remove circuit reclosing, ground relaying, and automatic transformer tap changing from service, per the direction of the DCC for routine operations. Eliminating these manual tasks will reduce the annual workload of LG&E Substation Operations by approximately 2,400 hours annually, eliminate the need to hire two additional employees in the workgroup, and eliminate standby time of electric distribution crews as they cannot begin work on circuits served from the aforementioned 14 substations until these routine substation tasks are completed.

This proposed project will add the necessary SCADA control technology on the remaining 14 LG&E substations that do not have SMAC functionality, enabling the DCC to remotely control reclosing, ground relaying (14kV only), and automatic transformer tap changing

Where SCADA control of the reclosing function is not installed, a considerable amount of LG&E Substation Operations' duties are devoted to manual control of reclosing and the application of associated "caution cards". Caution, or Hot Line Clearance, is the assurance that automatic reclosing features of a circuit have been made inoperative. A caution card is applied as a safety feature to protect the distribution crews while working on circuits by preventing automatic reclosing or manual closing of the circuit if it trips out. Manual application of caution cards requires rolling a truck to the substation, manual control of the reclosing relay within the substation control house, and hanging (or removing) a physical caution card on the control panel door. Today, these caution visits are almost exclusively concentrated at the 14 distribution substations in the LG&E territory that are SCADA capable and without automatic reclosing SMAC capability. Specifically, 14 out of a total of 93 SCADA capable distribution substations in the LG&E system do not have SMAC capability. From 2013 to 2016, LG&E Substation Operations spent an average of 1,918 hours per year to complete caution applications at distribution substations.

Another area where SCADA control can be improved is at the LG&E 14kV distribution substations. Although not requested as frequently as reclosing control, ground relay control is requested when 14kV distribution circuits are switched out for load swaps. This feature prevents the misoperation of the ground relay when single phase switching takes place on the 14kV impedance-grounded distribution circuits. From 2014 to 2016, LG&E Substation Operations spent an average of 514 hours per year to complete load swap applications at distribution substations.

Additionally, when switching takes place between distribution circuits, the load tap changers on the substation transformers associated with these distribution circuits are locked to prevent the substation transformer taps from changing due to changes in the distribution load, which can cause substantial and potentially dangerous voltage differences across opened circuit ties. This is accomplished by the taps' control feature on the substation transformers.

This project was recently reviewed to determine if there were any synergies to be gained with upcoming DMS work associated with the Distribution Automation project. It was determined that the SMAC functionality would be implemented on sixteen (16) feeders by upgrading the existing electromechanical relays to modern, digital relays. This will provide better integration with future DMS requirements.

Alternatives Considered

1. Recommended option: NPVRR ($000s): $6,522
   Complete the LG&E Substation Monitoring and Control (SMAC) program.

   Between 2017 and 2020, LG&E Substation Operations should invest $5,067k towards the acquisition, engineering and installation of SCADA control technology at fourteen LG&E substations, to enable remote circuit reclosing, ground relaying, and automatic transformer tap changing by DCC System Operators. This option will eliminate approximately 1,216 O&M labor hours annually, associated with drive times, and manual operation of fourteen substations by LG&E Substation Operators. An additional 4,863 labor hours (O&M and capital) associated with distribution crew (tree trimmers, line technicians, and network technicians) standby time will also be eliminated.

2. Do nothing option: NPVRR ($000s): $8,144

   Substation Operations' do nothing option assumes continuation of current operating practices, including utilization of Substation Operators to manually perform caution and load swap applications at the fourteen (14) remaining LG&E substations without SCADA control.

   The Do Nothing option is not recommended because it would necessitate the hiring of two incremental employees due to the overall workload demands and scheduling limitations of the work group. Additional operational efficiencies would also not be realized, including improved customer restoration times and implementation of Distribution Automation strategies.

   The average annual labor expenses associated with the manual tasks for the fourteen substations is $57k (1,216 hours). The estimated average annual labor expenses associated with distribution crew standby time is $116k (2,857 hours). The estimate average annual labor capital cost associated with distribution crew standby time is $134k (2,006 hours).

Project Description

- **Project Scope and Timeline**
  2017 Preliminary engineering and detailed scope development.
  2017 Bid work at all fourteen (14) distribution substations and award Contract Purchase Agreement (CPA) to successful Engineering, Procurement, and Construction Management (EPCM) firms.
  2017 Complete SCADA modifications at Breckenridge and Shively substations.
  2018 Complete SCADA modifications at Del Park, Floyd, Grady, and Madison substations.
  2019 Complete SCADA modifications at Algonquin, Magazine, and Seminole substations.
  2020 Complete SCADA modifications at Canal, Clay, Clifton, Highland, and Hillcrest substations.

- **Project Cost**
  The total estimated cost of the program is $5,076k. The costs used in the estimates are consistent with bids received from Engineering Procurement & Construction Management (EPCM) contractors in 2017. A 10 % contingency is incorporated into the project cost estimates. There is no distribution work associated with this project.

Economic Analysis and Risks

- **Bid Summary**
  - Bids for the substation material, services, and labor have been received and are being evaluated for the SMAC program.

Budget Comparison and Financial Summary

Financial Detail by Year ($000s)	2017	2018	2019	2020	Total
1. Capital Investment Proposed	748	1,163	1,370	1,642	4,923
2. Cost of Removal Proposed	22	34	40	57	153
3. Total Capital and Removal Proposed (1+2)	770	1,197	1,410	1,699	5,076
4. Capital Investment 2017 BP	736	1,184	1,343		3,263
5. Cost of Removal 2017 BP	34	13	67		114
6. Total Capital and Removal 2017 BP (4+5)	770	1,197	1,410	-	3,377
7. Capital Investment variance to BP (4-1)	(12)	21	(27)	(1,642)	(1,660)
8. Cost of Removal variance to BP (5-2)	12	(21)	27	(57)	(39)
9. Total Capital and Removal variance to BP (6-3)	-	-	-	(1,699)	(1,699)

Financial Detail by Year - O&M ($000s)	2017	2018	2019	2020	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2017 BP	-	-	-	-	
3. Total Project O&M variance to BP (2-1)	-	-	-		-

The 2017 BP has these projects in separate project numbers for each year but once approved, the work will all be completed under one project number. The project estimates are higher than the 2017 BP in total, so the increases needed in 2020 will be addressed through the 2018 BP process.

Financial Summary ($000s):

Discount Rate:	6.5%
Capital Breakdown:	
Labor:	$ 888
Contract Labor:	$ 1,469
Materials:	$ 1,056
Transportation:	$ 52
Local Engineering:	$377
Burdens:	$773
Contingency:	$461
Reimbursements:	
Net Capital Expenditure:	$5,076

- **Assumptions**
  - Estimates are based on bids received from EPCM contractors in 2017.
  - Two EPCM contractors will be utilized to complete the entire project scope.

- **Environmental**
  There are no known environmental issues at this time.

- **Risks**
  - The estimates are based on engineering and installation unit pricing for reclosing control panel modifications, ground relay control panel modifications, and transformer tap changer control panel modifications. Unit prices were also estimated for conduit installation, cable installation, trench installation, and functional testing. There is a cost risk since the conduit and cable installation will vary from site to site. This risk will be mitigated by detailed and accurate scope documents.
  - 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-SC&M recommends that the Investment Committee approve the LG&E Substation Monitoring and Control (SMAC) program for $5,076k 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: May 30, 2018

Project Name: LG&E Southern Substation Exit Circuit Replacement

Total Expenditures: $2,114k (includes 15% contingency)

Project Number(s): 156526 (Duct Replacement) and 156527 (Cable Replacement)

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Rob Wolf / Shawn Stickler

Executive Summary

Electric Distribution Operations (EDO) seeks approval to invest $2,114k on the proactive changeout of the exit circuit cables and duct banks at the Southern Substation. This funding will cover the costs to replace the existing Paper Insulated, Lead Covered (PILC) cable technology and duct system between the exit circuit cable poles and the substation switchgear.

Due to the deteriorated condition and small size of the existing duct, a failure in an existing circuit would require an extended exit circuit outage in order to install new duct and cable. The existing duct is too small to accommodate modern cable sizes, and LG&E stopped installing new PILC in the early 1980s. The existing PILC cables have been in service for approximately 70 years, and are well past their expected service life.

The total project cost of $2,114k was not included in the 2018 Business Plan. EDO is requesting incremental funding of $903k in 2018 for replacement of the duct banks, which was approved by the Corporate RAC in April. Funding for 2019 of $1,211k for replacement of the cable will be requested in the 2019 Business Plan. The new duct bank and cable at Southern Substation is expected to be placed in service during the fourth quarter of 2019.

Background

Southern Substation is a 4kV substation located behind 1475 South 3rd St. in Old Louisville. The bus arrangement consists of nine (9) circuits serving just over 4,000 customers and businesses. The exit cables for these circuits are PILC construction that were installed in the 1940's. These circuits were routed in 3.5" duct from the substation switchgear to cable poles throughout the area, but arranged predominantly along South 3rd St. between West Lee St. and West Kentucky St.

This exit circuit replacement project will provide for the replacement of approximately 8,000 feet of underground duct bank and approximately 20,000 feet of cable.

Alternatives to the proposed replacement include reactive replacement of failed cables on a run-to-failure basis. This run to failure alternative is more costly and is not recommended due to the known impacts that cable failures have on system reliability and the customer experience.

- **Alternatives Considered (1 –Recommendation, 2 –Do nothing)**

  1. Recommendation: NPVRR: ($000s) $2,603
     The recommended option is to proactively replace the Southern Substation exit circuits and underground duct for $903k in 2018 and $1,211k in 2019 in order to prevent extended outages due to failure on the aged PILC cable systems and duct systems presently operating beyond designed life expectancy.

  2. Do Nothing: NPVRR: ($000s) N/A
     This is not considered a viable option as LG&E has an obligation to serve and would not be able to serve the customers' anticipated load. If no action is taken, the aging infrastructure will put reliability at risk for over 4,000 customers. The existing PILC cables will be allowed to run to failure prior to replacement, which will lead to extended outage times for the circuit. In most cases, the circuit can be switched out to feed from another station temporarily, but the circuit will be left in this contingency situation for months until new duct and cable can be installed. The cables have been in service for approximately 70 years. This exceeds the normal life expectancy of medium voltage power cables by almost double. The failed cables cannot be replaced without new duct being installed due to the existing duct being in poor condition and undersized for modern cable sizes.

Project Description

- **Project Scope and Timeline**
  The LG&E Southern Substation underground duct will be replaced in 2018, while the exit circuit cables will be replaced in 2019.

- **Project Cost**
  The proposed estimate for this work is $903k in 2018 and $1,211k in 2019. Project costs include the ancillary costs associated with terminations and splices. There is a 15% contingency of $276k included for this project.

Economic Analysis and Risks

- **Bid Summary**
  Contract labor for the duct and cable replacement will be handled by LG&E resident contract crews under their existing approved contracts.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	903	1,079	-	-	1,982
2. Cost of Removal Proposed	-	132	-	-	132
3. Total Capital and Removal Proposed (1+2)	903	1,211	-	-	2,114
4. Capital Investment 2018 BP	-	-	-	-	-
5. Cost of Removal 2018 BP	-	-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(903)	(1,079)	-	-	(1,982)
8. Cost of Removal variance to BP (5-2)	-	(132)	-	-	(132)
9. Total Capital and Removal variance to BP (6-3)	(903)	(1,211)	-	-	(2,114)

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed					-
2. Project O&M 2018 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$ 0
Contract Labor:	$ 883
Materials:	$ 750
Local Engineering:	$ 130
Burdens:	$ 75
Contingency:	$ 276
Reimbursements:	($ 0)
Net Capital Expenditure:	$2,114

- **Assumptions**
  Successful completion of this project assumes availability of qualified contractors to complete the work on time.

- **Environmental**
  The existing PILC will be removed and disposed of appropriately.

- **Risks**
  The higher density of utilities in the ground downtown, getting timely and accurate locates, metro permitting, and crew availability are all risks for completing the project on time and on budget.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the LG&E Southern Substation Exit Circuit Replacement Project for $2,114k to ensure the ongoing operating reliability of the Southern Substation feeders.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

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	Date	Paul W. Thompson Chairman, CEO and President	Date

Investment Proposal for Investment Committee Meeting on: N/A

Project Name: UPS GL1335 Cable Replacement

Total Expenditures: $1,150k (includes 10% contingency)

Project Number(s): 155235

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Shawn Stickler/Steve Woodworth

Executive Summary

LG&E Electric Distribution Operations (EDO) seeks funding authority to invest $1,150k for replacement of both sets of cable on the first half of the GL1335 (Grade Lane) circuit feeding UPS Worldport. The replaced portion of the circuit (3.7 miles of cable) will originate at the Grade Lane Substation and terminate at the new mid-point switchgear yard across from Midfield Access Rd. LG&E supplies power to UPS Worldport with four parallel 13.8KV circuits from both Grade Lane Substation (2.86 mile primary feed) and Seminole Substation (2.39 mile backup feed). Both of these feeder paths are submerged in water the majority of the time.

UPS Worldport has had four (4) cable failures since 2006. All four failures have occurred at cable splices, and all of the splice failures occurred on GL1335 in the first half of the circuit. After analyzing the splices following these failures, each one exhibited evidence of water ingress into the splice under the copper tape shield, and demonstrated observable corrosion and evidence of heating. Using a modern designed concentric neutral cable and splicing techniques with this cable replacement will allow GL1335 to better withstand the wet environment. It is also believed that significant amounts of cable thumping used to locate previous failures have caused damage to the first half of GL1335. Because the Grade Lane circuits are close to 3 miles long, extensive thumping was required in order to find faults on the unusually long feeder.

The technique of finding faults is to 'thump' the cable. When a high voltage is applied to a faulted cable, the resulting high-current arc from the failed cable to a ground source makes a noise audible above ground. Cable thumping requires a current on the order of tens of thousands of amps at voltages as high as 25kV to make an underground noise loud enough to hear above ground. The heating from this high current often causes some degradation of the cable insulation. This is a necessary outcome and accepted throughout the industry because if cable thumping time is minimal, so is the cable insulation damage. There is no existing technology (or combination of technologies) that can entirely replace cable thumping. In conjunction with this project, LG&E is taking steps in 2017 to install mid-point switches to sectionalize all 8 UPS feeders in order to reduce thumping time and locate faults quicker to minimize any potential future damage from fault finding activities.

The total project cost of $1,150k will be reallocated from the general reliability Circuits Identified For Improvement (CIFI) project through defined RAC processes and was not specified in the 2017 or 2018 Business Plans (BP). The 2017 spending was approved in the July Corporate RAC meeting. The GL1335 cable replacement will be completed by the third quarter of 2018.

Background

Worldport is the worldwide air hub for UPS (United Parcel Service) located at the Louisville International Airport. The facility is currently 5.2 million square feet (90 football fields). With over 20,000 employees, UPS is one of the largest employers in Louisville, and in the Commonwealth of Kentucky. Worldport is the largest fully automated package handling facility in the world. UPS has invested more than $1 billion at the Worldport location.

LG&E supplies power to UPS Worldport with four parallel 13.8KV circuits from both Grade Lane Substation (2.86 mile primary feed) and Seminole Substation (2.39 mile backup feed). Both of these feeder paths are submerged in water the majority of the time due to the area geology. Worldport and the surrounding areas are in ‘Wet Woods’, which means there is a hardened impervious layer of clay below the soil that impairs drainage. There have been 4 cable/splice failures on the first half of GL1335 circuit since 2006.

Alternative Considered

1. Recommendation: NPVRR: $1,453K

Move forward with the LEO UPS GL1335 Cable Replacement Project in order to ensure the ongoing operating reliability of the feeders supplying the UPS Worldport campus.

2. Do Nothing: NPVRR: N/A

The do nothing approach is not a viable option. Failure to proceed with the LG&E UPS Cable Replacement Project introduces a growing probability that we will continue to see faults on the GL1335 feeder serving the UPS Worldport facility. Further failures on the circuit would severely impact the operations of a major customer, and cause harm to LG&E’s reputation as a reliable energy supplier.

Project Description

- **Project Scope and Timeline**
  The total estimated cost will provide for the replacement of 19,600 circuit feet (3.7 miles) of cable, and will include both set 1 and set 2 of GL1335 cable originating at the Grade Lane Substation and terminating at the new mid-point switchgear yard across from Midfield Access Rd. This project will be completed by the third quarter of 2018.

- **Project Cost**
  The total estimated cost for the project is $1,150k, which includes a 10% contingency. In 2017, $500k will be spent to purchase materials for the project and complete prep work for the replacement. The remaining $650k will be spent in 2018 to perform the replacement work.

Economic Analysis and Risks

- **Bid Summary**
  This project will use existing material and labor contracts and will follow established Supply Chain procedures.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	500	650	-	-	1,150
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	500	650	-	-	1,150
4. Capital Investment 2017 BP	-	-	-	-	-
5. Cost of Removal 2017 BP	-	-	-	-	-
6. Total Capital and Removal 2017 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(500)	(650)	-	-	(1,150)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(500)	(650)	-	-	(1,150)

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2017 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The project is not individually included in the 2017 BP, but will be covered by a reallocation from the budgeted reliability CIFI project through the Corporate RAC.

Financial Summary ($000s):

Discount Rate:	6.32%
Capital Breakdown:	
Labor:	$ 0
Contract Labor:	$ 503
Materials:	$ 417
Local Engineering:	$ 97
Burdens:	$ 28
Contingency:	$ 105
Reimbursements:	($ 0)
Net Capital Expenditure:	$1,150

- **Assumptions**
  Successful completion of this project on time assumes availability of qualified contractors to complete the work and the cooperation of UPS to allow access to specified areas to complete the project on time.

- **Environmental**
  No environmental issues are anticipated at this time.

- **Risks**
  - System reliability and Company image could be negatively impacted in the future if the feeder is not replaced as proposed.
  - UPS will need to allow LG&E to transfer the UPS facilities to their backup circuits from Seminole substation. Additionally, UPS will have to run their sorts without an immediate backup circuit present since all Grade Lane feeders will need to be deenergized in order for LG&E crews to complete the work safely. In the event of a failure on a Seminole circuit during this work, UPS will sustain a 30-60 minute outage while LG&E personnel vacate the manholes and manually roll UPS over to the other Grade Lane circuits.

Conclusions and Recommendation
It is recommended that Management approve the LG&E UPS GL1335 Cable Replacement Project for $1,150k in order to ensure the ongoing operating reliability of the UPS Worldport feeders.

Investment Proposal for Investment Committee Meeting on: N/A

Project Name: LG&E URD Cable Replacement/Rejuvenation Program-2019

Total Expenditures: $1.701M

Project Number(s): 151553

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Rob Wolf / Steve Woodworth

Executive Summary

Electric Distribution Operations (EDO) seeks approval to invest $1.701M on proactive and reactive cable rejuvenation and replacement during 2019. This proposed program will target LG&E Underground Residential Development (URD) direct buried cables installed between the mid-1960s and mid-1980s.

Cable rejuvenation is a cable life extension technology where a dielectric fluid is injected into conductor strands of in-service medium voltage cable to restore its dielectric characteristics to near-new cable levels. The technology provides a cost effective alternative to traditional cable replacement when used in a proactive cable infrastructure renewal program.

EDO's proposed funding level will provide for proactive rejuvenation of targeted LG&E URD cable sections prioritized based on cable age, failure and repair history, customer impact, and overall circuit performance. Additionally, the funding level will provide for replacement of any prioritized cable sections that cannot be rejuvenated with the life extension technology. The 2019 Business Plan (BP) includes $1.701M. These funds will continue the proactive program EDO has traditionally used, and will also allow for a small number of reactive cable injections. Reactive rejuvenation will enable EDO to rejuvenate a cable immediately after a repair following a cable failure.

Alternatives to the proposed rejuvenation program include proactive replacement of cables and/or reactive repair or replacement of failed cables on a run-to-failure basis. These alternatives are more costly, and the run to failure alternative is not recommended due to the known impacts that cable failures have on system reliability and customer experience.

EDO included $1.701M in its proposed 2019 Business Plan for cable rejuvenation or replacement.

Background

Over the last five years, LG&E has averaged 156 URD primary cable failures per year, with a maximum single year failure rate of 166 in 2016. Over 95% of failures occurred on 1st and 2nd generation solid dielectric cables installed in underground residential subdivisions between the mid-1960's and mid-1980's. Failure rates on these 30-year design life systems have been steadily increasing over the past 35 years.

During 2010, LG&E successfully initiated a URD cable rejuvenation pilot project to evaluate the feasibility of utilizing an insulation rejuvenation technology in aged, direct buried, underground cables that were exhibiting increasing failure rates. The technology provides a cost effective alternative to traditional cable replacement when used in a proactive cable infrastructure renewal program and is warranted to add 20 or more years of extended cable life at approximately one-half the cost of traditional replacement alternatives.

EDO's proposed funding will enable LG&E to continue with the program initiated in 2010, allow for proactive rejuvenation or replacement (where rejuvenation is not viable) of LG&E's oldest and poorest performing URD direct buried cable, and allow for limited reactive rejuvenation of failed URD cable. This will help increase system reliability, minimize customer disruptions, and reduce the likelihood of accelerated reactive URD cable replacement costs in future years. The program prioritizes selected assets by age, failure history, customer impact, and URD circuits identified for improvement (CIFI).

The URD cable rejuvenation process includes the following activities:

- Capacity and condition assessment of the cable neutral;
- Flow test through phase conductor strands to verify injectability;
- Replacement of existing terminating equipment with injection capable devices;
- Injection of proprietary dielectric fluid into the cable stranding;
- Migration of dielectric fluid throughout cable insulation wall to restore dielectric strength; and,
- Tracking and tagging of rejuvenated segments for warranty and asset records.

Benefits of the process are:

- Significantly reduces the probability of in-service failures on rejuvenated circuit segments. To date, there have been (23) in-service failures of the rejuvenated cables segments in the LG&E service territory, which is less than 1% of the more than 2,600 rejuvenated segments. This also equates to one failure for every 32,075 circuit feet (or 6.1 circuit miles) of rejuvenated cables.
- Increases the remaining life of cables by 20 years or more at approximately half the cost of traditional physical replacement.
- Avoids future repair costs of rejuvenated cable segments, otherwise allowed to run-to-failure.

- **Alternatives Considered**

1. Recommendation: NPVRR: ($000s) $2,157k
   The recommended option is the LG&E URD Cable Rejuvenation/Replacement project for $1.701M for 2019 in order to reduce in-service failure rates on aged, medium voltage direct buried cable systems presently operating beyond designed lives. The average blended cost to replace or rejuvenate (when viable) is $13.60/ft.

2. Do Nothing: NPVRR: ($000s) $4,534k
   If no action is taken, the aged and failing population of direct buried residential (URD) cables will be allowed to run-to-failure prior to replacement. The existing LG&E run-to-failure program permits each cable segment on a URD circuit to fail up to three times prior to scheduled replacement. The average residential underground customer on a system with an average of 7 segments per URD circuit will experience up to 21 outage events of 4 hour durations (and additional short term interruptions following subsequent repair) before a URD circuit is replaced in its entirety. It is expected that all untreated original pre-1980 cable will require replacement during the next 8 years. A do-nothing alternative will subject underground residential customers to significantly greater outages caused by cable failure. The do-nothing alternative provides a total annualized cost of $577k, which is comprised of two parts. The first is the cost of unscheduled outages, which can be avoided by proactively and reactively replacing cable ($264k). The second cost is from the unserved energy during these unscheduled outages ($313k). This contributes an estimated 1.38 SAIDI minutes at the LG&E system level.

3. Alternative #2: NPVRR: ($000s) $3,965k
   There are no favorable economic alternatives to a balanced rejuvenation/replacement program for addressing aged and deteriorating URD primary cable systems.
   A proactive replacement only program requires the complete physical replacement of the aged cables prior to reaching unacceptable failure rates and reliability levels. A proactive replacement only program can address less than half of the number of segments for the same level of funding as the rejuvenation and replacement program recommended, and thus would be a more costly program. The cost to replace the injectable cable in recommendation #1 is on average $25/ft, or $3.127M for the same 125,000 ft of cable.

Project Description

- **Project Scope and Timeline**
  The LG&E subdivisions determined to be the worst performing URD circuits composed of direct buried, pre-mid-1980's assets, are planned for the 2019 rejuvenation and replacement work. Additionally, a number of failed cables will be evaluated for reactive repair and rejuvenation.

- **Project Cost**
  The 2019 proposed estimate for this work is $1.701M for both rejuvenation and replacement (where rejuvenation is not viable). Project costs include the ancillary costs associated with replacing terminations and splices. There is no contingency in this project.

  Based on past rejuvenation experience, the program provides a 24% replacement and 76% rejuvenation split. The $1.701M proposed in 2019 is estimated to address approximately 125,000 feet of cable at a blended cost of approximately $13.60/ft.

Economic Analysis and Risks

- **Bid Summary**
  Contract labor for the proposed rejuvenation program will be provided by Novinium Inc. under an existing cable rejuvenation contract, which took effect on January 1, 2017. Novinium purchased UtilX, who was their only competitor in this space.

  Replacement contract labor will be provided by LG&E resident contract crews under their existing approved contracts.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	1,701	-	-	-	1,701
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	1,701	-	-	-	1,701
4. Capital Investment 2019 BP	1,701	-	-	-	1,701
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	1,701	-	-	-	1,701
7. Capital Investment variance to BP (4-1)	-	-	-	-	-
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
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:	$ 3
Contract Labor:	$ 1,536
Materials:	$ 12
Transportation:	$ 1
Local Engineering:	$ 124
Burdens:	$ 25
Contingency:	$ 0
Reimbursements:	($ 0)
Net Capital Expenditure:	$ 1,701

- **Assumptions**
  Labor resource availability, weather conditions and work volumes will enable the proposed scope of work to be completed before December 2019.

- **Environmental**
  There is no environmental impact with this project.

- **Risks**
  There is minimal technical risk with this project as cable rejuvenation methods have a long history within the industry and are proven to extend cable system life. Prior to the pilot project in 2010, references from Duke Power, Dayton Power and Seattle Power & Light were contacted to discuss their cable rejuvenation experiences. The companies gave positive feedback on their cable rejuvenation processes and continue to use cable rejuvenation services.

  Rejuvenation services are warrantied against cable insulation failure by natural, age related causes for at least 20 years. In the event of a failure on a rejuvenated segment, Novinium will reimburse the original rejuvenation injection fee any time in the 20 year warranty period. An average of 2.6 segments per year have failed after having been injected, which yields a less than 1% failure rate.

Conclusions and Recommendation

EDO recommends that Management approve the LG&E URD Cable Replacement/Rejuvenation Program for 2019 spending of $1.701M as a program to rejuvenate or replace aging URD direct buried cables, helping to improve system reliability and customer satisfaction.

Investment Proposal for Investment Committee Meeting on: November 28, 2017

Project Name: LG&E URD Cable Replacement/Rejuvenation Program-2018

Total Expenditures: $2.162M

Project Number(s): 148920

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Rob Wolf / Steve Woodworth

Executive Summary

Electric Distribution Operations (EDO) seeks approval to invest $2.162M on proactive and reactive cable rejuvenation and replacement during 2018. This proposed program will target LG&E Underground Residential Development (URD) direct buried cables installed between the mid-1960s and mid-1980s.

Cable rejuvenation is a cable life extension technology where a dielectric fluid is injected into conductor strands of in-service medium voltage cable to restore its dielectric characteristics to near-new cable levels. The technology provides a cost effective alternative to traditional cable replacement when used in a proactive cable infrastructure renewal program.

EDO's proposed funding level will provide for proactive rejuvenation of targeted LG&E URD cable sections prioritized based on cable age, failure and repair history, customer impact, and overall circuit performance. Additionally, the funding level will provide for replacement of any prioritized cable sections that cannot be rejuvenated with the life extension technology. The 2018 Business Plan (BP) includes $2.162M. These funds will continue the proactive program EDO has traditionally used, and will also allow for a small number of reactive cable injections. Reactive rejuvenation will enable EDO to rejuvenate a cable immediately after a repair following a cable failure.

Alternatives to the proposed rejuvenation program include proactive replacement of cables and/or reactive repair or replacement of failed cables on a run-to-failure basis. These alternatives are more costly, and the run to failure alternative is not recommended due to the known impacts that cable failures have on system reliability and customer experience.

EDO included $2.162M in its proposed 2018 Business Plan for 2018 cable rejuvenation or replacement.

Background

Over the last five years, LG&E has averaged 156 URD primary cable failures per year, with a maximum single year failure rate of 166 in 2016. Over 95% of failures occurred on 1st and 2nd generation solid dielectric cables installed in underground residential subdivisions between the mid-1960's and mid-1980's. Failure rates on these 30-year design life systems have been steadily increasing over the past 35 years.

During 2010, LG&E successfully initiated a URD cable rejuvenation pilot project to evaluate the feasibility of utilizing an insulation rejuvenation technology in aged, direct buried, underground cables that were exhibiting increasing failure rates. The technology provides a cost effective alternative to traditional cable replacement when used in a proactive cable infrastructure renewal program and is warranted to add 20 or more years of extended cable life at approximately one-half the cost of traditional replacement alternatives.

EDO's proposed funding will enable LG&E to continue with the program initiated in 2010, allow for proactive rejuvenation or replacement (where rejuvenation is not viable) of LG&E's oldest and poorest performing URD direct buried cable, and allow for limited reactive rejuvenation of failed URD cable. This will help increase system reliability, minimize customer disruptions, and reduce the likelihood of accelerated reactive URD cable replacement costs in future years. The program prioritizes selected assets by age, failure history, customer impact, and URD circuits identified for improvement (CIFI).

The URD cable rejuvenation process includes the following activities:

- Capacity and condition assessment of the cable neutral;
- Flow test through phase conductor strands to verify injectability;
- Replacement of existing terminating equipment with injection capable devices;
- Injection of proprietary dielectric fluid into the cable stranding;
- Migration of dielectric fluid throughout cable insulation wall to restore dielectric strength; and,
- Tracking and tagging of rejuvenated segments for warranty and asset records.

Benefits of the process are:

- Significantly reduces the probability of in-service failures on rejuvenated circuit segments. To date, there have been (17) in-service failures of the rejuvenated cables segments in the LG&E service territory, which is less than 1% of the more than 2,100 rejuvenated segments. This also equates to one failure for every 35,700 circuit feet (or 6.8 circuit miles) of rejuvenated cables.
- Increases the remaining life of cables by 20 years or more at approximately half the cost of traditional physical replacement.
- Avoids future repair costs of rejuvenated cable segments, otherwise allowed to run-to-failure.

- **Alternatives Considered**

1. Recommendation: NPVRR: ($000s) $2,813k
   The recommended option is the LG&E URD Cable Rejuvenation/Replacement project for $2.162M for 2018 in order to reduce in-service failure rates on aged, medium voltage direct buried cable systems presently operating beyond designed lives. The average blended cost to replace or rejuvenate (when viable) is $13.75/ft.

2. Do Nothing: NPVRR: ($000s) $6,773k
   If no action is taken, the aged and failing population of direct buried residential (URD) cables will be allowed to run-to-failure prior to replacement. The existing LG&E run-to-failure program permits each cable segment on a URD circuit to fail up to three times prior to scheduled replacement. The average residential underground customer on a system with an average of 7 segments per URD circuit will experience up to 21 outage events of 4 hour durations (and additional short term interruptions following subsequent repair) before a URD circuit is replaced in its entirety. It is expected that all untreated original pre-1980 cable will require replacement during the next 9 years. A do-nothing alternative will subject underground residential customers to significantly greater outages caused by cable failure. The do-nothing alternative provides a total annualized cost of $725k, which is comprised of two parts. The first is the cost of unscheduled outages, which can be avoided by proactively and reactively replacing cable ($393k). The second cost is from the unserved energy during these unscheduled outages ($332k). This contributes an estimated 1.43 SAIDI minutes at the LG&E system level.

3. Alternative #2: NPVRR: ($000s) $5,106k
   There are no favorable economic alternatives to a balanced rejuvenation/replacement program for addressing aged and deteriorating URD primary cable systems.
   A <u>proactive replacement only</u> program requires the complete physical replacement of the aged cables prior to reaching unacceptable failure rates and reliability levels. A proactive replacement only program can address less than half of the number of segments for the same level of funding as the rejuvenation and replacement program recommended, and thus would be a more costly program. The cost to replace the injectable cable in recommendation #1 is on average $25/ft, or $3.925M for the same 157,000 ft of cable.

Project Description

- **Project Scope and Timeline**
  The LG&E subdivisions determined to be the worst performing URD circuits composed of direct buried, pre-mid-1980's assets, are planned for the 2018 rejuvenation and replacement work. Additionally, a number of failed cables will be evaluated for reactive repair and rejuvenation.

- **Project Cost**
  The 2018 proposed estimate for this work is $2.162M for both rejuvenation and replacement (where rejuvenation is not viable). Project costs include the ancillary costs associated with replacing terminations and splices. There is no contingency in this project.

  Based on past rejuvenation experience, the program provides a 25% replacement and 75% rejuvenation split. The $2.162M proposed in 2018 is estimated to address approximately 157,000 feet of cable at a blended cost of approximately $13.75/ft.

Economic Analysis and Risks

- **Bid Summary**
  Contract labor for the proposed rejuvenation program will be provided by Novinium Inc. under an existing cable rejuvenation contract, which took effect on January 1, 2017. Novinium purchased UtilX, who was their only competitor in this space.

  Replacement contract labor will be provided by LG&E resident contract crews under their existing approved contracts.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	2,162	-	-	-	2,162
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	2,162	-	-	-	2,162
4. Capital Investment 2018 BP	2,162	-	-	-	2,162
5. Cost of Removal 2018 BP	-	-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	2,162	-	-	-	2,162
7. Capital Investment variance to BP (4-1)	-	-	-	-	-
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	-	-	-	-

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2018 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.32%
Capital Breakdown:	
Labor:	$ 0
Contract Labor:	$ 1,623
Materials:	$ 299
Local Engineering:	$ 173
Burdens:	$ 67
Contingency:	$ 0
Reimbursements:	($ 0)
Net Capital Expenditure:	$ 2,162

- **Assumptions**
  Labor resource availability, weather conditions and work volumes will enable the proposed scope of work to be completed before December 2018.

- **Environmental**
  There is no environmental impact with this project.

- **Risks**
  There is minimal technical risk with this project as cable rejuvenation methods have a long history within the industry and are proven to extend cable system life. Prior to the pilot project in 2010, references from Duke Power, Dayton Power and Seattle Power & Light were contacted to discuss their cable rejuvenation experiences. The companies gave positive feedback on their cable rejuvenation processes and continue to use cable rejuvenation services.

  Rejuvenation services are warrantied against cable insulation failure by natural, age related causes for at least 20 years. In the event of a failure on a rejuvenated segment, Novinium will reimburse the original rejuvenation injection fee any time in the 20 year warranty period.. An average of 2.1 segments per year have failed after having been injected, which yields a less than 1% failure rate.

Conclusions and Recommendation

EDO recommends that the Investment Committee approve the LG&E URD Cable Replacement/Rejuvenation Program for 2018 spending of $2.162M as a program to rejuvenate or replace aging URD direct buried cables, helping to improve system reliability and customer satisfaction.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $2 million</u>:

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	Paul W. Thompson
Chief Financial Officer	President and Chief Operating Officer

Investment Proposal for Investment Committee Meeting on: December 20, 2017

Project Name: Distribution Wood Pole Inspection and Maintenance Program - 2018

Total Expenditures: $11,920k (Including $238k of contingency)

Project Number(s): LGE: 18PITP340, KU: 18PITP216, 18PITP156, 18PITP246, 18PITP315, 18PITP766, 18PITP416, 18PITP366, 18PITP236 and 18PITP426

Business Unit/Line of Business: Electric Distribution Operations / Distribution

Prepared/Presented By: John Ashton / Denise Simon

Executive Summary

The Investment Committee approved the Electric Distribution Operations' Distribution Wood Pole Inspection and Maintenance Program on February 24, 2010, with the provision that future year investments in the program be presented and approved annually. The purpose of this Investment Proposal is to obtain 2018 program funding authority from the Investment Committee. The 2018 program scope is focused on providing a detailed pole inspection, preservative re-treatment and load analysis of approximately 65,000 poles and the reinforcement or replacement of structures found to be defective. The program projections for 2018 include replacement of 2,300 defective poles and reinforcement of 200 poles.

The other option considered is to inspect only on the 2-year KPSC required inspection cycle. This type of inspection is not rigorous enough to adequately identify at-risk poles, does not inspect for ground line rot and does not include pole loading calculations. Foregoing a pole inspection and treatment program and depending only on the regulatory cycle inspections will result in decreased life of the assets and will increase pole failures and associated outages.

The 2018 Business Plan (BP) includes $11,920k for this program in 2018.

Background

The Distribution Wood Pole Inspection and Maintenance Program was implemented in 2010. By year end 2017, approximately 432,000 poles will have been inspected, and 138,000 poles will have been treated, 16,800 poles will have been replaced and 1,500 poles will have been reinforced by splinting. Cumulative spend from 2010-2016 is $68 million with the 2017 forecasted spend at $10.4 million.

EDO has more than 516,000 distribution wood poles in the asset base with an estimated average age of 30 years. An additional 156,000 foreign-owned poles have LG&E and KU attachments.

Wood poles are initially treated with a preservative during processing to extend the life of the pole. The effectiveness of the initial preservative treatment declines with age. Wood poles become more susceptible to deterioration from fungal decay and insect damage. In most cases, the decay is difficult to detect because it occurs out of sight just below the ground-line where conditions of moisture, temperature and air are most favorable for growth of fungi. Ground-line is also the point of maximum loading stress for a pole.

In addition to the wood pole inspection program, distribution poles receive an inspection every two years in accordance with KPSC requirements. During these inspections, only a small percentage of poles are inspected near ground-line or tested to detect internal decay. No poles are excavated to inspect below ground-line which is critical for detecting decay. Continuing the wood pole inspection program as proposed will enhance the ability to detect decay and extend the life of the treated and reinforced poles.

A survey of utilities confirms that the industry typical program generally involves inspecting and applying a supplemental treatment to the ground-line area on every pole. The supplemental treatment arrests any decay present and can significantly increase the useful life of the pole at a very small cost relative to the cost to replace a pole. One industry study indicates the predicted pole life with no remedial treatment is 32.5 years compared to a predicted pole life of greater than 50 years for poles with remedial treatment.

By associating historical pole failure outage data with previously completed PITP circuits, there is an annual SAIDI and SAIFI benefit of 0.52 minutes and 0.002 interruptions per customer, respectively, through the Pole Inspection and Treatment Program.

EDO's program is "condition based," such that the level of inspection and re-treatment is dependent on each pole's actual condition. The use of a "condition based" approach provides a cost effective strategy to inspect and re-treat poles. Inspection will include above and below grade evaluations. Re-treating and load analysis will only be performed on the poles that indicate a need. The program entails a progressive level of inspection for each pole and re-treatment only when necessary. In conjunction with the pole inspection, pole loading will be assessed. Any pole found to be loaded beyond acceptable limits will be reinforced or replaced. Joint-use poles not owned by LGE and KU will only receive a loading analysis.

The estimated 2018-2022 capital costs included in the 2018BP are shown below. This proposal only requests funding for 2018.

	2018	2019	2020	2021	2022
Amount in 000s	$11,920	$12,278	$12,646	$13,025	$13,416

- **Alternatives Considered**

1. Recommendation: NPVRR: ($000s) $16,060

2. Alternative #1: NPVRR: ($000s) $48,643
   Electing not to continue the PITP program would result in an increase in pole failures and outages. The NPVRR shown is the combination of the investment to replace poles as they fail rather than proactively (capital costs of $10,358k), and the resulting cost of unserved energy from these failures (costs of $37,193k). Projections indicate approximately 2,300 poles will be replaced as part of the PITP program during 2018. Without remedial actions, these 2,300 poles are projected to fail within 2 years. The cost of unserved energy was calculated using the projected number of pole failures over the next two years along with the 5-year average outage duration of preventable, pole-related failures. During a pole-failure outage, the time required to restore the outage is nearly 2.5 times longer than that of an outage taken for planned pole replacement work.

Project Description

- **Project Scope and Timeline**
  - The 2018 pole inspection and treatment program will begin in January of 2018. Inspection crews will plan to complete work in 9 months. Pole replacement crews will begin work in January and work through December of 2018. This program covers distribution poles only. Transmission poles are covered under a separate inspection program.

- **Project Cost**
  - The total estimated capital project cost for 2018 is $11,920k and $63,285k over the BP period of 2018-2022.

  - A capital contingency of 2% for the program is included to cover any variables that may deviate from the business plan projections (i.e. higher pole reject rates and miscellaneous costs such as ground-wire repairs).

Economic Analysis and Risks

- **Bid Summary**
  - The inspection and treatment work is completed by Lost Time Control West (DBA GeoForce Utility Technologies). The contract was approved at the November 2014 Investment Committee and will expire December 31, 2019.

  - Pole replacements will be performed by contract labor under currently approved contracts and unit prices. The wood poles used will be purchased under an existing contract for wood poles.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	**2018**	**2019**	**2020**	**Post 2020**	**Total**
1. Capital Investment Proposed	10,598	-	-	-	10,598
2. Cost of Removal Proposed	1,322	-	-	-	1,322
3. Total Capital and Removal Proposed (1+2)	11,920	-	-	-	11,920
4. Capital Investment 2018 BP	10,598	-	-	-	10,598
5. Cost of Removal 2018 BP	1,322	-	-	-	1,322
6. Total Capital and Removal 2018 BP (4+5)	11,920	-	-	-	11,920
7. Capital Investment variance to BP (4-1)	-	-	-	-	-
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	-	-	-	-

Financial Detail by Year - O&M ($000s)	**2018**	**2019**	**2020**	**Post 2020**	**Total**
1. Project O&M Proposed	490	-	-	-	490
2. Project O&M 2018 BP	490	-	-	-	490
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The 2018 Business Plan includes this funding in projects 123136 and 123137 in the Reliability department. The projects listed on page 1 are the specific projects (in the applicable operations centers' departments) for which approval is requested. Funds will be moved from the budgeted projects to the specific operations center projects through the Corporate RAC process.

Financial Summary ($000s):

Discount Rate:	6.32%
Capital Breakdown:	
Labor:	$0
Contract Labor:	$8,875
Materials:	$1,320
Local Engineering:	$1,125
Burdens:	$362
Contingency:	$238
Reimbursements:	($0)
Net Capital Expenditure:	$11,920

- **Assumptions**
  - Estimates are based on field experience from EDO inspections during the first eight years of the pole inspection and treatment program.
  - A minimal number of poles associated with structure loading will be replaced and the associated cost can be managed within existing funding.

- **Environmental**
  - There are no environmental issues. Chemicals used for the re-treatment of wood poles are EPA approved and will be applied by qualified contractors licensed for their application.

- **Risks**
  - Actual rejection rates could be greater than those experienced in previous years of the program resulting in the need for additional funding or an extended cycle to complete the program.
  - Average cost to replace a pole could increase significantly if the majority of rejects are located in metro areas.

Conclusions and Recommendation
EDO recommends the Investment Committee approve continuation of the Distribution Wood Pole Inspection and Maintenance Program, and authorize 2018 investments of $11,920k for the project. The program continues to enhance the life of EDO wood pole assets and contribute to improved reliability performance for 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 — Date
Chief Financial Officer

Paul W. Thompson — Date
President and Chief Operating Officer

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 194

Responding Witness: Robert M. Conroy / John K. Wolfe

Q-194. Reference the Bellar testimony at p. 50, wherein he states the Companies are considering an expansion of the Distribution Automation ("DA") program.

a. If the Companies decide to expand the program as Mr. Bellar discusses, will they file a new CPCN with the Commission? If not, why not?

b. Regarding any potential expansion of the DA program, provide any and all cost benefit analyses the Companies may have conducted as to the proposed expansion, separate and distinct from the DA program as it currently exists.

A-194.

a. See the response to Question No. 42(a).

b. See the response to Question No. 42(b).

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 195

Responding Witness: Lonnie E. Bellar

Q-195. Reference the Bellar testimony, p. 44, where he states: "The Transmission Reliability Outage Database System ("TRODS"), first implemented in 2014, has been continuously refined to simplify engineer access to disparate data to more readily determine the source of outages and prevent future outages."

a. Provide examples of the types of "disparate data" that the TRODS system provides to engineers.

b. Explain how the TRODS system has provided savings to ratepayers, and provide any and all quantifications of those savings, if applicable.

A-195.

a. TRODS combines data from the following data sources:

1. TOA (Transmission Outage Application – Operational process tool)
2. Cascade (substation asset management)
3. LOAD (facility ratings tool)
4. Power Plan (financial information)
5. Lightning database
6. AP SADE (vegetation)
7. Geospatial information for facility locations and outage locations
8. Customer outage information
9. InSITE (GIS and work management system for transmission lines)

b. As stated in testimony, TRODS simplifies the access to information which allows engineers to spend less time gathering data and make better decisions. However, no quantification of savings has been developed for TRODS.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 196

Responding Witness: Lonnie E. Bellar

Q-196. Reference the Bellar testimony, pp. 35-45, wherein he discusses the Companies' transmission system. With regard to the Companies' Transmission System Improvement Plan ("TSIP"), provide copies of any and all cost benefit analyses the Companies may have conducted regarding alternatives to the projects and methods the Companies intend to pursue.

A-196. See attached for the Alternatives Considered section of the TSIP project Investment Proposals. Consistent with the Companies' Accounting Policy 650 – Capital – Additions and Retirements Policy, an Investment Proposal is required for all capital projects greater than $750k. Accounting Policy 650 – Capital – Additions and Retirements Policy and Procedures was provided as an attachment to the response to PSC 1-8. Some of the information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

Investment Proposal

Investment Proposal for Investment Committee Meeting on: February 24, 2015
Project Name: Ghent 345kV Control House
Total Expenditures: $2,748k (Including $250k of Contingency)
Project Number(s): 131338
Business Unit/Line of Business: Transmission Substations Protection & Controls
Prepared/Presented By: Brent Birchell – Manager Protection & Controls

Executive Summary
This project is part of an overall plan to upgrade the protection and control (P&C) equipment for Ghent 345kV substation. During the first part of the plan, implemented in 2013-2014, a new 345kV control house was purchased and commissioned for the addition of two new 345/25kV auxiliary transformers for the Ghent Plant, as several P&C panels had to be added and the existing control house did not have the space to accommodate these new panels. The new control house was sized to accommodate the future relocation of the existing P&C equipment, which consists primarily of electromechanical relays located in the original control house.
This project will implement the second part of the overall plan. This proposed project will move the electro-mechanical relays from the old control house and replace them with micro-processor-based technology in the new control house to improve the reliability of the Bulk Electric System (BES) and enhance the Louisville Gas & Electric and Kentucky Utility (LKE) Smart Grid asset portfolio. With the implementation of microprocessor relays, all buses, transformers and lines will have redundant protection and more reliable digital high-speed protection will be implemented on three of the four 345kV lines.

The total cost of this project will be $2,748k. The 2015 spending was approved by the RAC in the 1+11 forecast. $1,800k was included in 2015 through 2018 in the 2015 BP for this project. The additional spending over the BP in 2016 will be funded by LRTU-16 ($830k) and LRELAY-16 ($296k) and in 2017 will be funded by 144117 Alcalde Control House. The estimated total project figure includes a 10% contingency.

The IP estimate is higher than the amount in the BP. Since creating cost estimates for BP purposes, a closer review of the project produced the following items that affected the estimate:

- It is proposed to replace all of the existing control cables to the plant (the BP estimated only accounted for replacement of a portion of the cables). Additional cable will also be installed for redundant station service. ($190k)
- The cost of a Digital Fault Recorder (DFR) was not accounted for in the original estimate. ($160k)

- The complexity and length of the project will add project management and other labor costs for coordination with the following ($550k)
  - Generator outages, interconnecting utilities, and major customers
  - Interfaces with generator protection
  - A concurrent project in the 138kV switchyard.
  - P&C design so construction coordinates with items above.

Background
A previous project (139210), completed in 2014, installed a new control house for the expansion of the 345kV substation bus, to accommodate auxiliary transformer feeds to the Ghent Plant. The new control house was designed not only to provide space to accommodate the new panels for that project, but also to accommodate replacement of the electromechanical P&C equipment in the existing 345kV control house.

The scope of this project includes moving all the 345kV P&C equipment to the new control house and replacing them with microprocessor relays, as there are several concerns with the existing relays and aging AC and DC Distribution infrastructure. The electromechanical relays are becoming obsolete, and replacement parts are difficult to find. The complexity associated with testing of the electromechanical relays, required by North American Electric Reliability Corporation (NERC) standards, would be significantly reduced by installing microprocessor relays.

The current design of the P&C equipment does not provide redundant protection for all transmission equipment in the substation. The existing bus and transformer protection only consist of a single level of protection utilizing electromechanical relays. With the implementation of microprocessor relays, all buses, transformers and lines will have redundant protection. Also, the new equipment will provide improved reliability, increased functionality, engineering access, and disturbance event reporting. Three of the transmission lines currently have Directional Comparison Blocking (DCB) for one level of protection which utilizes Power Line Carrier (PLC) equipment and electromechanical relays. DCB protection is undesirable with today's available protection systems as it is prone for mis-operations and requires annual testing and calibration. With the implementation of microprocessor relays on all transmission lines the DCB schemes can be retired and digital high speed protection can be utilized.

Furthermore, the new control house will replace the aging physical structure of the existing facilities and facilitate implementation of measures to comply with NERC critical infrastructure protection (CIP) physical and electronic security standards.

The original 345kV control house will remain as it houses part of the DC distribution and cable routing infrastructure for the 138kV switchyard. Electromechanical components and relays will be scrapped, and any existing microprocessor relays will be returned to stock.

- **Alternatives Considered**

  Recommendation – It is recommended that the P&C equipment currently located in the older 345kV control house be retired and new microprocessor protection systems be installed in the new 345kV control house.

  NPVRR: ($000s) $3,313k

  Do Nothing – This option is not recommended as the existing electromechanical equipment is aging and replacement parts are becoming obsolete. In addition, when two separate control houses are utilized for the protection of one substation (existing configuration), the P&C design, maintenance, troubleshooting and operation of the station significantly increase in difficulty. Also, with this alternative, redundant protection would not be implemented on the 345kV equipment that currently only has one level of protection.

  NPVRR: ($000s) $0k

  Next Best Alternative(s) – The next best alternative is to increase the time frame for this project from three years to four years. This is not recommended, as a longer period of time for moving of the P&C equipment would increase project management and other labor costs. Also, it would extend the state of transition where the P&C equipment is shared between two control houses. This condition would reduce the reliability of the protection schemes for the transmission equipment and generator feeds, as the additional auxiliary relays and cables between houses would add exposure to the equipment. Also, it would create a condition where personnel have to maintain and troubleshoot in two control houses, increasing related costs and the chance of human error.

  NPVRR: ($000s) $3,469k

Project Description

- **Project Scope and Timeline**

Description	Date
Project Approved	February, 2015
Engineering Started	March, 2015
Materials Ordered	January, 2016
Materials Received	March, 2016
Installation of Control Panels into New Control House	March, 2016
Commissioning of 942, 944 and 946 Bay	September/October, 2016
Commissioning of 922, 924 and 926 Bay	October/November, 2016
Commissioning of 904, 912 and 914 Bay	March, 2017
Commissioning of 932, 934 and 936 Bay	April, 2017
Commissioning of 954 and 964 Bay	May, 2017
Commissioning of North Bus	October, 2017
Commissioning of South Bus	November, 2017
Complete Removal of Existing Equipment	December, 2017

- **Project Cost**
  The total cost of this project will be $2,748k. The 2015 spending was approved by the RAC in the 1+11 forecast. $1,800k was included in 2015 through 2018 in the 2015 BP for this project. The additional spending over the BP in 2016 will be funded by LRTU-16 ($830k) and LRELAY-16 ($296k) and in 2017 will be funded by 144117 Alcalde Control House. The estimated total project figure includes a 10% contingency.

Economic Analysis and Risks

- **Bid Summary**
  Certain components of the project cost were estimated from budgetary proposals based on existing blanket contracts.
  Relay panels suppliers and external engineering resources are selected based on project-specific needs, including lead times and processes implemented for general engineering of the project. In this case, Systems Control supplied the recently installed control house and relay panels. Using the same supplier for the panels and additional control house infrastructure will present a reduced burden on engineering resources and benefit the project schedule.
  Burns & McDonnell (BMcD) will perform the Engineering, Procurement, and Construction Management (EPCM) role. BMcD has familiarity with LKE P&C designs and standards, and has recent experience engineering and managing projects at an LKE generation plant substation.
  Both Systems Control and BMcD are part of bid awards to provide substation control houses and EPCM services respectively, which were approved by the Investment Committee.
  Commissioning services will be performed by LKE technicians. Other equipment and labor will be bid out after preliminary engineering is complete.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	**2015**	**2016**	**2017**	**Post 2017**	**Total**
1. Capital Investment Proposed	308	2,126	282	-	2,716
2. Cost of Removal Proposed	-	-	31	-	31
3. Total Capital and Removal Proposed (1+2)	308	2,126	313	-	2,748
4. Capital Investment 2015 BP	500	1,000	250	50	1,800
5. Cost of Removal 2015 BP	-	-	-	-	-
6. Total Capital and Removal 2015 BP (4+5)	500	1,000	250	50	1,800
7. Capital Investment variance to BP (4-1)	192	(1,126)	(32)	50	(916)
8. Cost of Removal variance to BP (5-2)	-	-	(31)	-	(31)
9. Total Capital and Removal variance to BP (6-3)	192	(1,126)	(63)	50	(948)

Financial Detail by Year - O&M ($000s)	**2015**	**2016**	**2017**	**Post 2017**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2015 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):
Discount Rate: 6.5%
Capital Breakdown:
Labor: $100k
Contract Labor: $971k
Materials: $1,101k
Other: $0k
Local Engineering: $176k
Burdens: $150k
Contingency: $250k
Reimbursements: ($0k)
Net Capital Expenditure: $2,748k

Financial Analysis - Project Summary ($000)	**2015**	**2016**	**2017**	**2018**	**2019**	**Life of Project**
Project Net Income	$ (4)	$ (23)	$ (25)	$ 9	$ 148	$ 3,237
Project ROE	-4.4%	-3.2%	-1.8%	0.6%	11.2%	10.1%

- **Assumptions**
Coordination of outages will be based on planned unit outages and coordinated with plant personnel. Outages that may affect major customers will be coordinated with Operations and

Account Managers. All equipment replacements, including controls and cables to unit breakers, will be coordinated with plant personnel.

- **Environmental**
  This project does not require permitting and there are no known issues regarding air, water, waste, lead, or asbestos.

- **Risks**
  1. Inability to obtain outages may lengthen the project timeline and costs.
  2. As P&C equipment is transitioned to the new control house, there will be some risk to equipment that is in service. Such risks will be minimized by arranging the project schedule so that work is performed on transmission lines only when the adjacent generator is in a scheduled outage.
  3. There is a possibility of mis-operations on the BES due to aging electro-mechanical relays (PRC-004).
  4. The single level of bus and transformer protection (as currently designed) affects system reliability, as the failure of a non-redundant relay will result in remote breakers operating to clear a fault, resulting in the loss of more facilities and longer exposure to faults.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the Ghent 345kV Control House project for $2,748k to enhance the reliability of the Transmission system.

Revised Capital Investment Proposal for Project 131338 Ghent 345kV Control House

Investment Proposal for Investment Committee Meeting on: October 26, 2016
Project Name: Ghent 345kV Control House
Total Approved Expenditures: \$2,748k (approved February 24, 2015)
Total Revised Expenditures: \$3,982k (an incremental value of \$1,234k)
Project Number(s): 131338
Business Unit/Line of Business: Transmission Substations Protection & Controls
Prepared/Presented By: Brent Birchell – Manager Protection & Controls

Reason for Revision

The initial scope of this project was to move the electro-mechanical relays from the old 345kV control house at Ghent and replace them with micro-processor-based technology in the new 345kV control house at Ghent to improve the reliability of the Bulk Electric System (BES) and enhance the Louisville Gas & Electric and Kentucky Utility (LKE) Smart Grid asset portfolio. With the implementation of microprocessor relays, all buses, transformers and lines would have redundant protection and more reliable digital high-speed protection on three of the four 345kV lines.

Due to the issues described below, contract and company labor were initially underestimated:

- Panel installation and cable pulling of internal house wires were more involved than expected due primarily to the condition of the existing duct bank system between the plant and the substation.
- The complexity of commissioning and the outage sequence changed as bus outages moved from the end of the project to the beginning as a result of a change in compliance needs associated with the TPL standards.
- The general complexity of the commissioning with generation units and the overall project extended the field work as a result of outages being planned around generator outages.
- The oversight of design and engineering was not expected to be as involved.
- The firm performing engineering (Burns & McDonnell) significantly underestimated their labor required to engineer this project.

In addition, scope changes included the following:

- Two new sections of trench and conduit were required to route cables into the new control house, because the existing cable infrastructure didn't have the capacity for additional cables.
- Duke RTU and metering funding requirements changed from the initial project estimates. The additional CIP gateways and associated equipment were not defined in the original project estimate.

The total revised project cost is \$3,982k (an incremental value of \$1,234k) is included in the 2016 BP for \$2,834k. The 2016 spending was approved by the RAC in the 9+3 forecast. The 2017 spending shortfall of \$128k will be covered by project 131864 CIP-KU-2017.

Financial Summary ($000s):	**Approved**	**Revised**	**Explanation**
Discount Rate:	6.5%	6.5%	
Capital Breakdown:			
Labor:	$100k	$330k	Complexity of commissioning and outage sequence changed as bus outages moved from end of project to the beginning due to compliance. General complexity of project and commissioning with generation units. Oversight of design and engineering was not expected to be as involved.
Contract Labor:	$963k	$1,653k	The complexity of the project was greater than originally estimated. Labor associated with panel installation and cable pulling of internal house wires was more involved than expected. Labor associated with cables from the plant to the control house was significantly under estimated due to existing duct bank system between plant and substation.
Materials:	$1,101k	$1,334k	Duke RTUs and metering requirements changed from initial estimate. Additional CIP gateways and associated equipment were not defined in original estimate. Additional underground conduit systems were required for plant cables.
Other	$0	$16k	
Local Eng.:	$184k	$326k	
Burdens	$150k	$323k	
Contingency:	$250k	$0	
Net Capital	$2,748k	$3,982k	
Expenditure:			
NPVRR:	$3,313k	$4,815k	

Financial Detail by Year - Capital ($000s)	2015	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	577	2,964	411			3,952
2. Cost of Removal Proposed			31			31
3. Total Capital and Removal Proposed (1+2)	577	2,964	441	-	-	3,982
4. Capital Investment 2016 BP	658	1,863	283	-	-	2,804
5. Cost of Removal 2016 BP	-	-	31			31
6. Total Capital and Removal 2016 BP (4+5)	658	1,863	314	-	-	2,834
7. Capital Investment variance to BP (4-1)	81	(1,101)	(128)	-	-	(1,148)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	81	(1,101)	(128)	-	-	(1,148)

Financial Detail by Year - O&M ($000s)	2015	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed						-
2. Project O&M 2016 BP						-
3. Total Project O&M Variance to BP (2-1)	-	-	-	-	-	-

The 2016 spending was approved by the RAC in the 9+3 forecast. The 2017 spending shortfall of $128k will be covered by project 131864 CIP-KU-2017.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the revised Ghent 345kV Control House project for $3,982k to enhance the reliability of the Transmission system.

Approval Confirmation for Capital Projects Greater Than or Equal to $1 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.

Kt W Blake
Kent W. Blake
Chief Financial Officer

Victor A. Staffieri
Chairman, CEO and President

Investment Proposal

Investment Proposal for Investment Committee Meeting on: February 24, 2015
Project Name: Tyrone Control House
Total Expenditures: $2,378k (Including $216k of Contingency)
Project Number(s): 131350
Business Unit/Line of Business: Transmission Substations Protection & Controls
Prepared/Presented By: Brent Birchell – Manager Protection & Controls

Executive Summary

The Tyrone generation facility currently houses the Transmission Protection and Controls (P&C) equipment for the 69kV bus. This facility has been decommissioned and demoliton of the plant building is currently set for 2020-2021. The protective equipment inside the building will be relocated and replaced by this project due to age, obsolescence, and reliability. By building a new control house, the P&C equipment for the 69kV substation will be centrally located in the substation switching area, affording the opportunity to upgrade the system to a reliable, digital protection scheme and further enhance Louisville Gas & Electric and Kentucky Utility's (LKE) Smart Grid portfolio of assets.

The total cost of this project will be $2,378k. The 2015 BP included a total of $1,500k, comprised of $1,000k in 2015 and $500k in 2016. The 2015 spending of $1,462k was approved by the 2015 1+11 RAC. The 2016 spending above plan of $415k will be covered by reductions to the Alcalde Control House project 144117. The current estimate is higher than the BP since subsequent detailed design review revealed that two new sets of 69kV Potential Transformers (PT's), their stands, and foundations, in addition to a new Station Service transformer, are required to power the control house, yard equipment, and digital protection schemes. Additionally, contract project management was not included in the original estimate, but existing workloads necessitate outsourcing this work. These details are outlined in the Financial Summary section.

Background
The Tyrone property includes a decommissioned generation facility, a 69kV bus connecting five lines, and a 138kV bus connecting three lines. The power plant building currently houses P&C equipment for the 69kV substation, batteries that provide DC for the 69kV and 138kV yard, and sump pumps to prevent lower-level flooding for the power plant. This proposal addresses the installation of a control house in the switchyard, which will house P&C equipment for the 69kV substation and merge the AC and DC distribution system for both the 69kV and 138kV substations. Removing the equipment located in the power plant building will allow for demolition of the building which is scheduled for 2020-2021.

The existing 69kV P&C equipment is composed of electromechanical relays. The new microprocessor based relays will provide improved reliability, increased functionality, and disturbance event reporting. Additionally, the Westinghouse Electromechanical HZ type relays (eighteen installed at this location) have been targeted by the Transmission P&C Department for priority replacement due to their high percentage of mis-operations and age. Throughout the early design phase, several key stakeholders have been identified and consulted, including the general manager and production manager of the Tyrone generation facility, a transmission substation construction engineer, team leader, inspector, engineer from Protection and Controls, and Environmental Affairs.

- **Alternatives Considered**
  Recommendation – It is recommended that all the P&C equipment, currently located inside the decommissioned power plant, be relocated to a new control house within the substation yard and all equipment be upgraded to microprocessor relays.
  NPVRR: ($000s) $2,956k

  Delay Project – Delaying this project for three years has less of an NPVRR but is not the recommended alternative for transmission system reliability and safety reasons. The relays associated with the existing control house have a known issue with misoperation. NERC CEO, Gerry Cauley, has identified the misoperation of protection systems as one of NERC's top priority reliability issues[1]. Additionally, this option is not recommended as housing the P&C equipment in an inoperable generation facility introduces risks for safety, maintenance, and troubleshooting as building conditions deteriorate.
  NPVRR: ($000s) $2,635k

Project Description

- **Project Scope and Timeline**
  - Installation of a new control house and relay panels.
  - Installation of cable trench to all breakers and substation equipment, along with connecting to existing cable trenches.
  - Installation of other substation expansion; such as fence, ground grid, and PTs.

[1] http://www.ferc.gov/CalendarFiles/20111208072453-Cauley, NERC, Panel.pdf

- Existing cables to the plant will be abandoned in place and disconnected from the substation hardware; with the exception of the facility's required legacy protection equipment.

Milestones	Date
Project Awarded	March 2015
Begin Engineering	March 2015
Purchase Control House	April 2015
Start Site Improvements	October 2015
Receive Control House, Begin Installation	March 2016
Start Installation of Station Service, Control Cables	April 2016
Start Connection, Commissioning of Existing Equipment to Control House	May 2016
Complete Connection, Commissioning of Existing Equipment to Control House	December 2016

- **Project Cost**
  The total cost of this project will be \$2,378k. The 2015 BP included a total of \$1,500k, comprised of \$1,000k in 2015 and \$500k in 2016. The 2015 spending of \$1,462k was approved by the 2015 1+11 RAC. The 2016 spending above plan of \$415k will be covered by reductions to the Alcalde Control House project 144117. The estimated total project figure includes a 10% contingency.

Economic Analysis and Risks

- **Bid Summary**
  Certain components of the project cost were estimated from budgetary proposals based on existing blanket contracts.

  The control house panels will be purchased under the existing control house blanket contract agreement. Relay panels suppliers and external engineering resources are selected based on project-specific needs, including lead times and processes implemented for general engineering of the project. In this case, Systems Control recently engineered and manufactured a house for LKE of the same size and design that we need for this project. This situation will present a reduced burden on company engineering resources and benefit the project schedule, as it will minimize lead times for engineering and state permits.

  Similarly, Worley Parsons will perform the Engineering, Procurement and Construction Management role. Worley Parsons has recent experience engineering projects for LKE and has familiarity with LKE substation designs.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	**2015**	**2016**	**2017**	**Post 2017**	**Total**
1. Capital Investment Proposed	1,462	884	-	-	2,347
2. Cost of Removal Proposed		31	-	-	31
3. Total Capital and Removal Proposed (1+2)	1,462	915	-	-	2,378
4. Capital Investment 2015 BP	1,000	500	-	-	1,500
5. Cost of Removal 2015 BP	-	-	-	-	-
6. Total Capital and Removal 2015 BP (4+5)	1,000	500	-	-	1,500
7. Capital Investment variance to BP (4-1)	(462)	(384)	-	-	(847)
8. Cost of Removal variance to BP (5-2)	-	(31)	-	-	(31)
9. Total Capital and Removal variance to BP (6-3)	(462)	(415)	-	-	(878)

Financial Detail by Year - O&M ($000s)	**2015**	**2016**	**2017**	**Post 2017**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2015 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.5%
Capital Breakdown:	
Labor:	$133k
Contract Labor:	$624k
Materials:	$1,099k
Other:	$0k
Local Engineering:	$141k
Burdens:	$165k
Contingency:	$216k
Reimbursements:	($0k)
Net Capital Expenditure:	$2,378k

Financial Analysis - Project Summary ($000)	**2015**	**2016**	**2017**	**2018**	**2019**	**Life of Project**
Project Net Income	$ (17)	$ (15)	$ 46	$ 66	$ 122	$ 2,765
Project ROE	-4.4%	-1.5%	3.9%	5.8%	11.2%	10.2%

Spend (000's)	**Construction**	**P&C**	**Total**
Company Labor	$ 35	$ 98	**$ 133**
Contract Labor	$ 153	$ 472	**$ 624**
Materials	$ 181	$ 918	**$ 1,099**
Burdens	$ 67	$ 239	**$ 306**
Contingency	$ 44	$ 173	**$ 216**
Total	**$ 479**	**$1,899**	**$ 2,378**

- **Assumptions**
  Outages are assumed to be obtained within the requested timeframe. Also, Environmental Affairs will own and coordinate all necessary permitting and hazardous material reporting within the project timeline. KU Brown personnel will provide access to the facility and P&C equipment for integration of the new digital protection scheme. Finally, KU Brown personnel will maintain ownership of the out of service and auxiliary transformers currently located within the 69kV substation area.

- **Environmental**
  The Environmental Affairs group has identified three potential issues.

  The first is the floodplain. Parts of the substation are inside the 100 year floodplain. Therefore, any construction within this space would require a Stream Construction Permit from the Kentucky Division of Water, along with a local floodplain permit from Woodford County. The control house will not be in this flood plain.

  There is also a requirement to submit annual "Tier II" reports to state and local fire departments and Emergency Planning Commissions if hazardous chemicals are stored at sites in quantities greater than 10,000 lbs., or extremely hazardous substances are stored at sites in quantities greater than their Reportable Quantity (often 500 lbs.). Lead-acid batteries contain a sulfuric acid electrolyte which must be reported on Tier II reports if stored in a quantity greater than 500 lbs. Tyrone is already subject to Tier II reporting for a number of chemicals including their existing lead-acid batteries. Once the new control house batteries are installed, it is required that they be added to the Tyrone chemical inventory report. Fortunately, these permits, along with those for KY Division of Water, are provided with no cost.

  Finally, sites containing 1,320 gallons of oil or greater require a Spill Prevention Control and Countermeasures (SPCC) plan which includes, inspections, secondary containment to prevent oil releases from reaching waterways, and an accurate inventory of oil-containing equipment on–site. Tyrone's substations already have a quantity of oil over 1,320 gallons; therefore, a SPCC plan (combined for the two substations) currently exists. There are two potential-transformers which may need to be added to the site, depending on design specifications. If these structures contain 55 gallons of oil or greater, they will be added to the Tyrone SPCC inventory. The current secondary containment uses a combination of Strongwell berms and an oil-water separator; which will likely serve any new installed equipment. When the design is complete, these factors will be re-examined for confirmation of conformance.

- **Risks**
  \- The risk of 'not doing this project' would be continued poor reliability of P&C equipment.
  \- If the existing substation control equipment is not relocated to a new control house, the decommissioned power plant will require repair and continuous maintenance.
  \- If the existing substation control equipment is not relocated to a new control house, and if the currently inoperable power plant were ever to be demolished, this equipment will need to be relocated at that time.

- Any required outages would need to be planned and coordinated with the construction efforts to avoid the risk of project timeline extension. Inability to obtain outages may lengthen the project timeline and costs.
- This project has a two year timeline; however, if this time is insufficient, daily operations will be able to continue until completion. This is, of course, assuming the legacy P&C equipment acts without incident, which is a primary cause for initiating this project.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Tyrone Control House project for $2,378k to facilitate relocation and upgrade of P&C equipment and improve the reliability of the transmission system.

Template for Revised Investment Proposal

Investment Proposal for Investment Committee Meeting on: N/A

Project Name: Tyrone Control House

Total Approved Expenditures: $2,378k (approved on 2/24/2015)

Total Revised Expenditures: $2,768k (an incremental value of $390k)

Project Number(s): 131350

Business Unit/Line of Business: Transmission Substations Protection & Controls

Prepared/Presented By: Brent Birchell – Manager Protection & Controls

Reason for Revision
This revision is requested for the Tyrone Control House project due to several factors. Initially, contract labor forecast was underestimated and was not updated upon receipt and awarding of bids from various contractors. Additionally, it was discovered that the 138kV control house's AC & DC power is fed from the power plant. Modifying the 138kV control house power source was not the initial scope of this project. New power cables will be necessary to feed the 138kV control house from the 69kV control house so as to remove all Transmission dependency on the power plant building.

In addition to the need for new power cables, the control house material was also underestimated and a change order was issued from the provider for standard changes identified during the engineering phase of the project. This materials and engineering change order was funded with a full reduction of contingency on this project ($215k).

Lastly, due to unexpected overtime work needed as the result of a delayed bus outage, company labor was also slightly underestimated.

Financial Summary

Financial Analysis - Project Summary ($000)	2015	2016	2017	2018	2019	Life of Project
Project Net Income	$ 51	$ 113	$ 114	$ 130	$ 124	$ 3,079
Project ROE	9.6%	8.4%	8.1%	9.2%	10.0%	9.8%

Financial Summary ($000s):	Approved	Revised	Explanation
Discount Rate:	6.5%	6.5%	
Capital Breakdown:			
Labor:	$133k	$175k	Fall 2016 costs initially underestimated and costlier overtime needed due to delayed bus outage
Contract Labor:	$624k	$931k	Initially underestimated and forecast not revised after receiving bids.
Materials:	$1,099k	$1,173k	Control house material underestimated by contractor, additional control cable needed to feed 138kV control house from the 69kV control house
Other	$0	$51k	
Local Engineering:	$141k	$249k	
Burdens	$165k	$189k	
Contingency:	$216k	$0	
Net Capital Expenditure:	$2,378k	$2,768k	
NPVRR:	$2,956k	$3,368k	

Financial Detail by Year - Capital ($000s)	2015	2016	2017	Post 2017	Total
1. Capital Investment Proposed	1,004	1,758			2,762
2. Cost of Removal Proposed		7			7
3. Total Capital and Removal Proposed (1+2)	1,004	1,764	-	-	2,768
4. Capital Investment 2016 BP	912	1,396			2,308
5. Cost of Removal 2016 BP					-
6. Total Capital and Removal 2016 BP (4+5)	912	1,396	-	-	2,308
7. Capital Investment variance to BP (4-1)	(92)	(362)	-	-	(454)
8. Cost of Removal variance to BP (5-2)	-	(7)	-	-	(7)
9. Total Capital and Removal variance to BP (6-3)	(92)	(369)	-	-	(460)

Financial Detail by Year - O&M ($000s)	2015	2016	2017	Post 2017	Total
1. Project O&M Proposed					-
2. Project O&M 2015 BP					-
3. Total Project O&M Variance to BP (2-1)	-	-	-	-	-

Conclusions and Recommendation
It is recommended that the Investment Committee approve the revised Tyrone Control House project for $2,768k to facilitate the relocation and upgrade of P&C equipment to improve the reliability of the transmission system.

Approval Confirmation for Capital Projects Greater Than or Equal to $1 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	Victor A. Staffieri Chairman, CEO and President

Investment Proposal

Investment Proposal for Investment Committee Meeting on: February 24, 2015
Project Name: KU Park Control House
Total Expenditures: $3,552k (Including $325k of Contingency)
Project Number(s): 132674
Business Unit/Line of Business: Transmission Substations Protection & Controls
Prepared/Presented By: Brent Birchell – Manager Protection & Controls

Executive Summary
The existing protection and control (P&C) equipment owned by Louisville Gas & Electric and Kentucky Utilities (LKE) and by Tennessee Valley Authority (TVA) for the substations adjacent to the decommissioned KU Park generating facility are currently located inside the retired power plant building. As the generation equipment in the building is no longer functioning, KU-Brown personnel has requested that the P&C equipment be removed from the building due to the building's deteriorating conditions. The scope of the project will also include relocation of TVA control equipment to an existing TVA control house on site.

The total cost of this project will be $3,552k, with $1,374k in 2015 and $2,177k in 2016. $1,500k had been budgeted in each of 2015 and 2016. The 2015 spending was approved by the RAC in the 2015 1+11 forecast. The 2016 funding in excess of the BP will be covered by KRELAY-16 ($510k) and LRELAY-16 ($167k). The total cost includes TVA's estimated cost of $2,625k of which LKE will only be responsible for $1,313k. The estimated total project figure includes a 10% contingency. The proposed total cost is higher than the budgeted amount due to the increased cost of the TVA portion of work. TVA's estimate was originally $2,000k (of which LKE would pay $1,000k) so there is an increase of $313k. The remaining $239k is due to developing a more detailed scope of work after preliminary site visits.

Background
The KU Park facilities include a power plant building and the LKE and TVA substations. The power plant building houses P&C equipment for both substations, in addition to equipment that was needed for the operation of the now decommissioned generation equipment. KU-Brown personnel operate and maintain a sump pump system to prevent lower-level flooding that would damage relays. Therefore, to completely abandon the building and maintenance activities, the P&C equipment must be removed from the building and relocated to a different location.

As removal of P&C equipment is a key component of the procedure to abandon the building, this proposal addresses the installation of a control house in the switchyard. The new control house will house AC and DC distribution and protection & control panels that will replace the equipment inside the power plant building. Also, as the existing P&C is composed of electromechanical relays which are subject to misoperation and for which parts are no longer available, P&C is using the relocation as an opportunity to upgrade the equipment with new microprocessor-based relays which will provide improved reliability, increased functionality, and disturbance event reporting.

The scope of the project will also include relocation of TVA control equipment to an existing TVA control house. This portion of the project will be engineered, managed, and executed by TVA. Under Section 6 of the Interconnection Agreement between KU and TVA dated September 1, 1944, LKE is obligated to pay for ½ of TVA's cost to relocate their facilities.[1]

- **Alternatives Considered (1 –Recommendation, 2 –Do nothing, 3 –Next Best Alt)**
  Recommendation – It is recommended that the P&C equipment currently located in the retired power plant building be relocated to a new control house out in the substation yard and that the equipment be upgraded to microprocessor-based relays. The scope of the project will also include relocation of TVA control equipment to an existing TVA control house on site.
  NPVRR: ($000s) $4,330k

  Do Nothing – This option is not advisable as the location of the P&C equipment within the retired power plant building is rapidly deteriorating and poses various safety concerns for Kentucky Utilities personnel.
  NPVRR: ($000s) $0k

  Next Best Alternative(s) – The next best alternative is to reconfigure transmission lines to the Pineville 192 Substation and install protection and control panels inside the existing Pineville control house. This alternative requires considerable bus work, substation equipment addition, and line re-work so that three lines could be moved into the Pineville substation. Under this alternative, we would not add an additional control house at KU Park, thus eliminating the task of maintaining that asset. However, it does not improve other maintenance activities, as it would still leave some equipment in the flood plane at KU Park and also add substation assets at Pineville 192 Substation. This option would cost upwards of $3,818k (including TVA costs). This alternative is not recommended due to its higher cost.
  NPVRR: ($000s) $4,660k

Project Description

- **Project Scope and Timeline**
  - Installation of a new control house and relay panels.

[1] In the event the Company, during the term of this agreement, determines to enlarge or re-arrange its plant or facilities in such manner that the maintenance of Authority's said facilities at their present location will constitute an interference, Authority will forthwith upon receipt of written demand from the Company for it so to do, remove said facilities to other places on Company's property as designated by the Company, and the net cost of such relocation shall be divided equally between the parties. From Section 6, page 4 of the "Agreement For Interconnection and Sale of Power between Tennessee Valley Authority and Kentucky Utilities Company", Dated September 1, 1944.

- Installation of station service to sump pump, control house, and distribution equipment.
- Installation of above-ground cable trench to all breakers and substation equipment.
- Installation of other substation expansion such as fence and ground grid.
- Removal of existing cables to equipment inside plant building.
- Relocation of TVA equipment to existing switchyard building (by TVA).

Milestones	Date
Begin Engineering	February, 2015
Purchase Control House	April, 2015
Start Site Improvements	September, 2015
Receive Control House, Begin Installation	November, 2015
Start Installation of Station Service, Control Cables	November, 2015
Start Connection of Control House & Relaying to Existing Breakers & Commissioning of Breakers & Relays	February, 2016
Complete Commissioning of Breakers & Relays	June, 2016
Complete Removal of Cables to Plant Building	July, 2016
Start Relocation of TVA Equipment to Switchyard Control House (by TVA)	January, 2016
Complete Relocation of TVA Equipment to Switchyard Control House (by TVA)	December, 2016

- **Project Cost**
  The total cost of this project will be $3,552k, with $1,374k in 2015 and $2,177k in 2016. $1,500k had been budgeted in each of 2015 and 2016. The 2015 spending was approved by the RAC in the 2015 1+11 forecast. The 2016 funding in excess of the BP will be covered by KRELAY-16 ($510k) and LRELAY-16 ($167k). The total cost includes TVA's estimated cost of $2,625k of which LKE will only be responsible for $1,313k. The estimated total project figure includes a 10% contingency. The proposed total cost is higher than the budgeted amount due to the increased cost of the TVA portion of work. TVA's estimate was originally $2,000k (of which LKE would pay $1,000k) so there is an increase of $313k. The remaining $239k is due to developing a more detailed scope of work after preliminary site visits.

Economic Analysis and Risks

- **Bid Summary**
  Certain components of the project cost were estimated from budgetary proposals based on existing blanket contracts.

  The control house will be purchased under the existing control house blanket contract agreement. Control panels suppliers and external engineering resources are selected based on project-specific needs, including lead times and processes implemented for general engineering of the project. In this case, Systems Control has recently engineered and manufactured a house for LKE of the same size and design that we need for this project. This situation will present a reduced burden on company engineering resources and benefit the project schedule, as it will minimize lead times for engineering and state permits.

Worley Parsons will perform the Engineering, Procurement, and Construction Management (EPCM) role. Worley Parsons has recent experience with LKE substations and has performed the design for several projects.

Both Systems Control and Worley Parsons are part of bid awards to provide substation control houses and EPCM services respectively, which were approved by the Investment Committee. Other equipment and labor will be bid out after preliminary engineering is complete.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	**2015**	**2016**	**2017**	**Post 2017**	**Total**
1. Capital Investment Proposed	1,368	2,058	-	-	3,426
2. Cost of Removal Proposed	6	119	-	-	125
3. Total Capital and Removal Proposed (1+2)	1,374	2,177	-	-	3,552
4. Capital Investment 2015 BP	1,384	1,366	-	-	2,750
5. Cost of Removal 2015 BP	116	134	-	-	250
6. Total Capital and Removal 2015 BP (4+5)	1,500	1,500	-	-	3,000
7. Capital Investment variance to BP (4-1)	16	(692)	-	-	(676)
8. Cost of Removal variance to BP (5-2)	110	15	-	-	125
9. Total Capital and Removal variance to BP (6-3)	126	(677)	-	-	(551)

Financial Detail by Year - O&M ($000s)	**2015**	**2016**	**2017**	**Post 2017**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2015 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.50%
Capital Breakdown:	
Labor:	$196k
Contract Labor:	$2,064k
Materials:	$638k
Other:	$0k
Local Engineering:	$113k
Burdens:	$216k
Contingency:	$325k
Reimbursements:	($0k)
Net Capital Expenditure:	$3,552k

Financial Analysis - Project Summary ($000)	2015	2016	2017	2018	2019	Life of Project
Project Net Income	$ (16)	$ (36)	$ 16	$ 58	$ 182	$ 4,033
Project ROE	-4.40%	-2.80%	0.90%	3.40%	11.20%	10.00%

Spend (000's)	Construction	P&C	TVA	Total
Company Labor	$ 82	$ 113	$ -	**$ 196**
Contract Labor	$ 272	$ 479	$ 1,313	**$ 2,064**
Materials	$ 72	$ 566	$ -	**$ 638**
Burdens	$ 118	$ 210	$ -	**$ 329**
Contingency	$ 56	$ 138	$ 131	**$ 325**
Total	**$ 601**	**$1,506**	**$ 1,444**	**$ 3,552**

- **Assumptions**
  Assumptions are that requested outages will be obtained within the requested timeframe. It is also assumed that Generation Services will lead and manage any decommissioning of equipment inside the power plant building.

- **Environmental**
  This project does not require permitting and there are no known issues regarding air, water, waste, lead, or asbestos.

- **Risks**
  - If the existing substation control equipment is not relocated to a new control house, the power plant building would require repair and continuous maintenance. There are also various safety issues related to the continual use of the retired power plant facility.
  - Any required outages would need to be planned and coordinated with the construction efforts to avoid the risk of project timeline extension. Inability to obtain outages may lengthen the project timeline and costs.
  - The construction and some outages have to closely be coordinated with TVA's project schedule. Any delays in TVA's project may affect this project and increase its timeline and costs.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the KU Park Control House project for $3,552k to facilitate relocation and upgrade of P&C equipment and improve the reliability of the transmission system.

Investment Proposal Project 134198 Canal-Del Park Conductor Replacement

Investment Proposal for Investment Committee Meeting on: July 31, 2018

Project Name: Canal-Del Park Conductor Replacement

Total Expenditures: $8,089k
Total Contingency: $737k (10%)

Project Number(s): Transmission Lines - 134198
Distribution Operations – 157697

Business Unit/Line of Business: Transmission Lines/Distribution Operations

Prepared/Presented By: John Doll/Adam Smith

Executive Summary

The proposed project is to replace 2.84 miles of overhead transmission line conductor that is over 60 years old and beyond its expected useful life. Performance of this line has diminished, with the most recent wire failure occurring in 2011 from a failed static. Over 3,700 customers with a peak load over 11 MVA are served by the facilities being replaced, with the largest customer being Reynolds Foil, Inc. This project will improve reliability, maintain system integrity, and reduce the risk of failures and unplanned transmission interruptions to the Del Park, Falls City, Shawnee, and Vermont areas of Louisville, Kentucky.

A Transmission System Improvement Plan was submitted as support in the 2016 Rate Case, outlining programs and projects aimed at reducing the risk of failure, avoiding extended sustained outages, and limiting costly emergency repairs. The programs submitted with the plan were selected to ensure long-term system integrity and modernize the transmission system to avoid degradation of performance over time due to aging infrastructure. Replacement of overhead wires beyond or approaching their expected useful lives were included as part of the Transmission System Improvement Plan to replace aging infrastructure.

Transmission Lines plans to replace the 2.84 mile 69kV line between the Canal and Del Park substations with aluminum conductor steel-reinforced (ACSR) conductor and the deteriorating 3/8" HS static wire will be replaced with optical ground wire (OPGW). In addition, sixty-seven (67) wood structures will be replaced with new steel structures, two (2) lattice towers will be replaced with new steel structures, and seven (7) existing steel structures will remain. Distribution Operations will transfer distribution equipment along this route from the existing to new transmission structures.

The total project cost is $8,089k ($6,805k Transmission Lines, $1,284k Distribution Operations). This project was included in the 2018 Business Plan (BP) for $3,500k, with estimated spend of $200k in 2018, $2,663k in 2019, and $637k in 2020. This was a preliminary estimate based on "per mile" costs for similar past projects. This estimate did not include the installation of eight drilled shaft foundations or the replacement of a double circuit lattice tower within the constrained space near the Canal substation. The need for this work was determined only after a detailed engineering analysis. Additionally, multiple adjustments in the alignment were made to facilitate construction and improve the configuration of this circuit for future accessibility and maintenance, including minimizing the footprint of the circuit within railroad right of way.

The current total project cost is $8,089k, with estimated spend of $662k in 2018, $6,808k in 2019, and $619k in 2020. The 2018 spend was approved by the RAC in the 6+6 forecast. The 2019-2020 spend is consistent with the proposed 2019 BP.

Background
The existing 2.84 mile section of 69kV line between Canal and Del Park contains aging 4/0 copper conductor which dates back to 1955 and has experienced diminishing performance in recent years. Similar copper conductors with 60+ years of service life often have sections with broken conductor strands and significant corrosion at the clamps where the conductor attaches to the structure. Furthermore, multiple static and cross arm failures have occurred in recent years, causing significant damage to the already brittle and aged wire. The most recent event occurred in 2018 due to a cross arm failure.

Due to the condition of this line, there is risk for additional failures that will expose the transmission network to further unscheduled outages. The following pictures are representative of the 4/0 conductor, static, and cross arm conditions on sections of this line.

The first picture shows conductor damaged by a static failure, there are multiple instances of this along this circuit. The second picutre depicts a fractured crossarm and is representative of most structures along this route.

The aging conductor will be replaced with aluminum conductor steel-reinforced (ACSR) conductor and the deteriorating 3/8" HS static wire will be replaced with OPGW (optical ground wire). In addition, new steel structures will be installed in place of existing wood structures. A Comprehensive Visual Inspection was completed on this line in 2016. From this inspection, two

(2) structures were found to be in need of replacement. The two (2) structures found during inspection will be addressed as part of this project.

In January of 2018, the transmission project was opened for detailed design. The detailed engineering identified underground utilities at strategic locations along the route to facilitate structure placement and foundation design. Soil borings were also taken to provide geotechnical reports to support design of the drilled shaft foundations. In addition, plats were provided for the properties adjacent to the railroad to assist with easement acquisition and permitting. The transmission line design was provided to all departments involved for comment and review.

Additional easements are required along the southernmost section of this circuit, namely the three spans closest to the Del Park substation. The existing structures are double circuited wood poles. This configuration will be replaced with steel poles on davit arms which allow for necessary energized working clearances in the future, and proper separation between conductors. Additional separation from the existing wood pole structures is required to allow the existing circuits to remain energized while this work is performed. In order to achieve this, the new alignment must be shifted to the north, beyond the existing easement. The Real Estate and Right of Way department indicates the easement acquisition is feasible and likely.

Furthermore, easements will be acquired for seven spans paralleling 32nd street between Alford Avenue and Rowan Street. Accessing this section of the circuit is difficult due to the proximity to the railroad right of way to the east and housing to the west. Homeowners have fenced in several properties in this section and have severely limited access to both transmission and distribution facilities as well as third party attachments. Easements at this location would grant LG&E improved access and allow construction and maintenance activities to be performed without requiring permission from the railroad.

This project also includes a supporting project from Distribution Operations. Distribution Operations plans to transfer distribution equipment from the existing to new transmission structures.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $9,575
     The recommendation is to replace 2.84 miles containing 4/0 copper with new ACSR conductor, and the existing 3/8" static wire with new OPGW. In addition, 67 wood structures will be replaced with new steel structures, two lattice towers will be replaced with new steel structures, and seven existing steel structures will remain.

  2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
     This option is not advisable as this line is nearing the end of its useful life and puts Transmission at risk of not being able to accomplish the objectives established as part of the Transmission System Improvement Plan that was filed as support in the 2016 Rate Case and assumed the completion of this project. These objectives include reducing the risk of failure, avoiding an extended sustained outage, and costly emergency repairs.

3. Alternative #2 – Construct Alternate Route: NPVRR: ($000s) $9,740
The next best alternative would be to construct a new 2.5 mile transmission line which would provide an alternate route beginning at structure 1 and would parallel the line along different roadways for 2.5 miles. Constructing a new route would require the purchase of 2.5 miles of new right of way that customers may not be willing to sell. Selecting a new route for this alternative would likely cause project delays and result in community concerns and opposition over the new route.

Project Description
Recommendation – Canal-Del Park Conductor Replacement Facility Map

- **Project Scope and Timeline**
  Transmission Lines Project Description – Project 134198
  The Transmission Lines project involves the upgrade of 2.84 miles of existing conductor with ACSR and existing static wire with OPGW between the Canal and Del Park 69kV line. This project also involves the replacement of 67 existing wood structures with new steel structures, and the replacement of two lattice towers.

Transmission Lines Project Scope and Timeline

Design Start	January 2018
Design Complete	June 2018
Space reserved for steel pole production with manufacturer	July 2018
Materials Delivered	January 2019
Construction Start	April 2019
Facility In-Service	July 2019
Permit Close Out / Project Completion	February 2020

Distribution Operations Project Description – Project 157697
Distribution Operations plans to transfer distribution equipment to the new transmission structures. In addition, Distribution Operations plans to replace existing cross-arms, LB switches, transformers and capacitor banks.

Distribution Operations Project Scope and Timeline

Design Start	February 2018
Design Complete	January 2019
Materials Ordered	1st Quarter 2019
Materials Delivered	1st Quarter 2019
Construction Start	1st Quarter 2019
Construction Finish	December 2019

- **Project Cost**

	Transmission Lines	Distribution Operations	Total
Total 2018	$662k	$0k	$662k
Total 2019	$5,524k	$1,284k	$6,808k
Total 2020	$619k	$0k	$619k
Contingency	10%	10%	

Economic Analysis and Risks

- **Bid Summary**
  Transmission Lines

Based on detailed engineering, Transmission Lines has estimated the material package for this project to be $868k. The project will utilize conductor, OPGW, custom steel structures, standard steel structures, and material. The OPGW will be purchased through AFL. The conductor will be competitively bid through normal Supply Chain processes. The line construction will be based on continuing contracts with our line contractors. B&B Electric, Davis H. Elliot, William E. Groves and Pike Electric are the four contractors awarded the Transmission Overhead Construction and Maintenance contract from the October 2011 Investment Committee (IC) meeting. The contract extension was re-approved by the IC in April of 2017.

Distribution Operations:

Distribution Operations line relocation will be performed by company labor (no bids required).

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	662	5,352	619	-	6,632
2. Cost of Removal Proposed	-	1,457	-	-	1,457
3. Total Capital and Removal Proposed (1+2)	662	6,808	619	-	8,089
4. Capital Investment 2018 BP	200	2,047	637		2,885
5. Cost of Removal 2018 BP		616	-		616
6. Total Capital and Removal 2018 BP (4+5)	200	2,663	637	-	3,500
7. Capital Investment variance to BP (4-1)	(462)	(3,304)	18	-	(3,747)
8. Cost of Removal variance to BP (5-2)	-	(841)	-	-	(841)
9. Total Capital and Removal variance to BP (6-3)	(462)	(4,145)	18	-	(4,589)

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2018 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Discount Rate: 6.59%
Capital Breakdown:

	148857 Trans Lines	157697 Dist Ops	Total
Labor	$341k	$0k	$341k
Contract Labor	$3,680k	$910k	$4,590k
Materials	$868k	$144k	$1,012k
Local Engineering	$904k	$84k	$988k
Burdens	$391k	$28k	$419k
Contingency	$619k	$118k	$737k
Other	$2k	$0	$2k
Reimbursements	$0	$0	$0
Net Capital Expenditure	$6,805k	$1,284k	$8,089k

- **Assumptions**
  Recommendation - This assumes that the 2.84 miles of existing conductor will be replaced with ACSR and the existing static wire will be replaced with OPGW. An outage must be obtained to complete the project and is scheduled for 2019. This also assumes that all highway and railroad crossing permits will be granted by the Kentucky Transportation Cabinet (KYTC), and associated railroads. It is anticipated that no customers will be out of service for the duration of this work.

  Alternative #1 – Do Nothing - This option is not advisable as this line is nearing the end of its useful life and puts Transmission at risk of not being able to accomplish the objectives established as part of the Transmission System Improvement Plan, that was filed as support in the 2016 Rate Case, which assumed the completion of this project. These objectives include reducing the risk of failure, avoiding an extended sustained outage, and costly emergency repairs.

  Alternative #2 – Next Best Alternative – This alternative assumes that a new 2.5 mile transmission line would be constructed. This option would require additional funding due to the need to purchase 2.5 miles of new right of way, in which the property owners may not be willing to sell. The impacts associated with this option would be more disruptive and have a larger negative impact on the community during construction.

- **Environmental**
  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

- **Customer Experience**
  A communication plan is being developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the community and businesses along the route.

- **Risks**
  - Without the proposed replacement of the existing wire in the Canal-Del Park 69kV line, the company risks increased exposure to line outages. The wire along the 2.84 miles has deteriorated over time, and is beyond its expected useful life. There have been notable failures in the conductor's 60 year service life. Unplanned outages are often time-consuming and costly when it comes to repairs.
  - The Louisville Metro Department of Public Works requires permits for lane closures and flagging. The permit application will be submitted prior to construction. Lane closure permits are typically obtained in a timely manner from this agency to support our projects.
  - This project requires an easement acquisition from Bethel United Ministries, Inc. This easement has been informally agreed upon and is currently being processed for formal execution.
  - A Norfolk Southern railroad permit is required for a line segment being constructed over an existing crossing. The permit application was submitted in June 2018.

- The local community may react negatively to the work and potential inconvenience of the project. A communication plan is being developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the community and businesses.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the Canal-Del Park Conductor Replacement project for $8,089k to improve the reliability of the electric transmission system.

Approval Confirmation for Capital Projects Greater Than $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	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal Project 135361 REL Lexington Plant-Pisgah 69kV Rebuild

Investment Proposal for Investment Committee Meeting on: October 26, 2016

Project Name: REL Lexington Plant-Pisgah 69kV Rebuild

Total Expenditures: $9,140k
Total Contingency: $712k (8%)

Project Number(s): 135361, 152826

Business Unit/Line of Business: Transmission

Prepared/Presented By: Chris Balmer – Director, Transmission Strategy & Planning

Executive Summary
The Lexington Plant-Pisgah Rebuild project is a transmission reliability project that will improve reliability for Lexington area customers by significantly reducing future outages primarily due to equipment failure and lightning strikes. This project is the last major project of a plan to address the reliability performance of this circuit.

The project will upgrade 2.58 miles of 69kV transmission line between the Lexington Plant substation and Versailles Road and add shield wire where it does not exist. Equipment, at or near the end of its expected useful life, will be replaced. Specifically, deteriorating copper conductor will be replaced by aluminum conductor steel-reinforced cable (ACSR) and more reliable steel structures will be installed in place of existing wood structures. The project will also include distribution underbuild work on the lower voltage distribution lines which are built below the higher voltage transmission lines and which are attached to the same transmission pole.

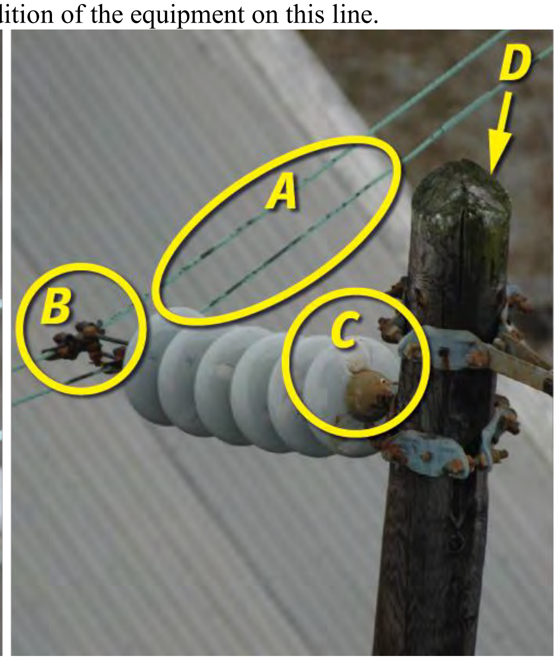
Approximately 6,050 customers are impacted by this section of line. Without this project, reliability to these customers will decline further as equipment failures are expected to continue and likely accelerate. Seven of the ten sustained outages since 2009 occurred on areas of the line this project addresses; five were caused by lightning and failed equipment and the two remaining causes were vegetation. This project will eliminate or minimize future outages with these root causes.

The total project cost is $9,140k ($8,590k Transmission, $550k Distribution). The Transmission project was included in the 2016 BP for $8,066k (all Transmission) based on a formula rate similar to that experienced on prior projects. Subsequent engineering, along with a change in scope to add shield wire and distribution underbuild work, increased the proposed total. The 2017 BP reallocated dollars to cover these additions, plus other projects were identified to cover the remaining shortfall. The project was included in the proposed 2017 Business Plan for $7,550k ($7,000k Transmission, $550k Distribution), the total for which was based on preliminary engineering, inclusive of distribution underbuild work, but which was prior to the decision to add 9,850 feet of shield wire at an additional cost of $1,645k and other small estimate changes. Projects 150687 Pocket to Pennington Gap pole replacement ($200k) and 151554 Hardin County to Hardinsburg pole replacement ($400k) were identified to cover the remaining shortfall in 2017 and project 148821 Floyd to Seminole static replacement to cover the remaining shortfall of $1,077k in 2018.

Background
The Lexington Plant-Pisgah transmission line is an 11.4 mile line that winds through downtown Lexington and ends at the Pisgah substation just west of Keeneland and the Lexington airport (see map below). This line has been the worst performing transmission SAIDI circuit since 2012 and serves over 13,000 customers. Customers served by this line have averaged about two hours of interruption per year since 2012.

Previously completed projects added a breaker at Parkers Mill and motor operated switches at the Parkers Mill tap point; however, about 6,050 remain impacted by the outdated line section between Lexington Plant and Versailles Road being addressed by this project. The project will significantly reduce future outages, primarily due to equipment failure and lightning strikes.

The following pictures of the line section between Lexington Plant and Versailles Road were taken in 2015. They represent the typical condition of the equipment on this line.



The picture on the left shows a broken strand of the existing copper conductor that will be replaced with new ACSR conductor. The picture on the right highlights evidence of equipment age and relibility risks of a typical structure predominant on this line section:

A. Indication of lightning strikes, which likely caused an outage and weakens integrity of the conductor. Conductor will be replaced and lightning strikes to the conductor will be minimized by new shield wire.
B. Corrosion of conductor clamps, which could lead to disconnection of conductor. Clamps will be replaced when new conductor is installed.
C. Indication of flashover caused by lightning strike that likely resulted in an outage and may be avoided with a new shield wire.
D. Deteriorating wood pole to be replaced by steel.

- **Alternatives Considered**

1. Recommendation: NPVRR: ($000s) $11,942k
   Upgrade and add new shield wire to targeted sections of the Lexington Plant-Pisgah transmission line.

2. Alternative #1: Do Nothing NPVRR: ($000s) $14,851k
   Line sectionalization of this circuit has been made, which will yield reliability improvements; however, sectionalization will not eliminate the event causes and continued outages from this section of line. By not rebuilding this section of line and adding shield wire where non-existent, customers will continue to have service interruptions that can be eliminated or minimized with this project. In addition, the copper conductor and other equipment on this section of line are at the end of their useful lives. Without the proposed project, the Company not only risks increased customer outages but unplanned repairs would be necessary on an as-needed basis. Likely repairs would include splicing the failed conductor back together. While the splice does reconnect the damaged wire, repairing the conductor does not address the poor mechanical condition of the wire. This alternative assumes one (1) failure repair would be needed during 2017, increasing by 0.25 repairs per year during 2018-2020, two repairs per year thereafter as the conductor continues to age, and full replacement in 2025. In addition, the NPVRR includes the cost of unserved energy of $0.8M per year each year that the wire needs repair until the full replacement is in service. Assuming 6,050 customers, 2.0 average hours of interruption during the last 5 years, and a cost of unserved energy of $17,200 per MWh, the total incremental cost of doing nothing would be $0.8M per year until full replacement is in service.

3. Alternative #2: Delay recommendation by 5 years NPVRR: ($000s) $14,499k
   Delay the recommendation by splicing the conductor as it fails until the fifth year when a full replacement is made. This alternative assumes one (1) failure repair would be needed during 2017, increasing by 0.25 repairs per year during 2018-2019, with full replacement of the conductor in year 2020. In addition, the NPVRR

includes the cost of unserved energy of $0.8M per year each year that the wire needs repair until the full replacement is in service. Assuming 6,050 customers, 2.0 average hours of interruption during the last 5 years, and a cost of unserved energy of $17,200 per MWh, the total incremental cost of delaying the recommendation by five years would be $0.8M per year until full replacement is in service.

Project Description

- **Project Scope and Timeline**
  The line construction will be based on continuing contracts from our line contractors. B&B, Elliot, Groves and Pike are the four contractors awarded the T&D Overhead Construction and Maintenance contract from the October 2011 Investment Committee meeting. The contract extension was re-approved by the IC in July of 2014. Construction is scheduled to begin in January of 2017 and be completed in March of 2018.

Project Milestones	
August 2016	Engineering and Design
November 2016	Lines Steel Poles Ordered
December 2016	Lines Steel Poles Delivered
January 2017	Line Construction Begins
May 2017	Distribution Construction Begins
November 2017	Lines Static Wire Ordered
December 2017	Lines Static Wire Received
December 2017	Distribution Construction Complete
January 2018	Lines Static Replacement Begins
March 2018	Line Construction Completed

A map of the Lexington Plant-Pisgah 69kV line targeted for reliability improvements is shown below. The blue line represents sections of line where the conductor and poles are being replaced, with a static wire being added. The red line represents sections of line where a static wire is being added and the poles are being replaced.
Total line length: 11.43 miles

- **Project Cost**
  The total project cost is $9,140k. The Transmission project was included in the 2016 BP for $8,066k based on a formula rate similar to that experienced on prior projects. Subsequent preliminary engineering, along with a change in scope to add static wire and distribution work, increased the proposed total. The project was also included in the proposed 2017 Business Plan for $7,550k, the total for which was based on preliminary engineering, inclusive of distribution work, but which was prior to the decision to add 9,850 feet of static wire at an additional costs of $1,645k and other small estimate changes. Historical and existing contract and purchasing agreements were used to estimate the cost of material and contract labor. This project includes an 8% contingency which is reasonable based on the level of detailed engineering, confidence in the cost of materials and contractors, and potential unknown risks such as weather delays, outage delays, reclamation, and structure access.

Economic Analysis and Risks

- **Bid Summary**
  Based on preliminary engineering, Transmission Lines has estimated the material package for construction of this project to be $1,260k. Distribution has estimated the material package for construction to be $107k. The steel structures will be purchased through our steel pole alliance partner, Trinity Meyer. Hardware will be purchased through Brownstown Electrical Supply. The line construction will be based on continuing contracts with our line contractors. Davis H. Elliot, Pike Electric, B&B Electric and William E. Groves are the four main contractors which have been awarded the T&D Overhead Construction and Maintenance contracts.

Material Cost Breakdown	
Material	**Cost**
Steel Poles	$613k
Wire	$568k
Hardware	$79k
Distribution	$107k
Total	$1,367k

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	**2016**	**2017**	**2018**	**Post 2018**	**Total**
1. Capital Investment Proposed	995	6,578	900	-	8,473
2. Cost of Removal Proposed	-	490	178		667
3. Total Capital and Removal Proposed (1+2)	995	7,067	1,077	-	9,140
4. Capital Investment 2016 BP	1,112	6,954	-	-	8,066
5. Cost of Removal 2016 BP	-	490	-	-	490
6. Total Capital and Removal 2016 BP (4+5)	1,112	7,444	-	-	8,556
7. Capital Investment variance to BP (4-1)	117	376	(900)	-	(407)
8. Cost of Removal variance to BP (5-2)	-	-	(178)	-	(178)
9. Total Capital and Removal variance to BP (6-3)	117	376	(1,077)	-	(584)

Financial Detail by Year - O&M ($000s)	**2016**	**2017**	**2018**	**Post 2018**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2016 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The shortfall of the proposed amount as compared to the 2016 BP has been covered in the 2017 BP plus additional projects were identified to cover the remaining shortfall. The project was included in the proposed 2017 Business Plan for $7,550k ($7,000k Transmission, $550k Distribution). Projects 150687 Pocket to Pennington Gap pole replacement ($200k) and 151554 Hardin County to Hardinsburg pole replacement ($400k) were identified to cover the remaining shortfall in 2016 and project 148821 Floyd to Seminole static replacement to cover the remaining shortfall of $1,077k in 2018.

Financial Summary ($000s):

Discount Rate: 6.49%

Capital Breakdown:

Labor:	$349k
Contract Labor:	$5,717k
Materials:	$1,367k
Local Engineering:	$598k
Burdens:	$395k
Contingency:	$712k

Transportation	$2k
Reimbursements:	($0)
Net Capital Expenditure:	$9,140k

Financial Analysis - Project Summary ($000)	2016	2017	2018	2019	2020	Life of Project
Project Net Income	$ -	$ 242	$ 526	$ 449	$ 427	$ 9,280
Project ROE	0.0%	5.0%	8.5%	10.6%	10.0%	9.8%

Spend (000's)	Lines	Distribution	Total	
Company Labor	$ 344	$ 5	**$ 349**	
Contract Labor	$ 5,367	$ 350	**$ 5,717**	
Materials	$ 1,260	$ 107	**$ 1,367**	
Local Engineering	$ 539	$ 59	**$ 598**	
Burdens	$ 368	$ 27	**$ 395**	
Transportation	$ -	$ 2	**$ 2**	
Contingency	$ 712	$ -	**$ 712**	
Total	**$ 8,590**	**$ 550**	**$ 9,140**	

- **Assumptions**
  - The proposed traffic control plans will be approved without significant modification by the city of Lexington.
  - The work will be conducted during normal working hours.
  - A railroad permit to move a section of line onto railroad property will be approved by Norfolk Southern.
  - Required outages to perform the work will be approved as planned.

- **Environmental**
  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

- **Risks**

1. Construction will be in a heavily congested area of Lexington with a number of underground utilities and other challenges.
   a. Working with External Affairs to notify appropriate elected officials. We also plan to work with Communications and Customer Service to develop and implement a Customer Experience plan for the project.
2. Relocation of a small section of line onto railroad property requires approval of a railroad permit.
   a. Their initial review of our plans has been approved and we do not expect delays at this time.

3. Transmission outages will not be approved when requested. This work will be completed in sections between switches to mitigate the risk.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the REL Lexington Plant-Pisgah 69kV Rebuild project for $9,140k to improve reliability for Lexington area customers.

Approval Confirmation for Capital Projects Greater Than or Equal to $1 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	Victor A. Staffieri Chairman, CEO and President

Investment Proposal: Hardin County-Smith 345kV P2 Pole Replacements

Investment Proposal for Investment Committee Meeting on: August 26 , 2014

Project Name: Hardin County-Smith 345kV P2 Pole Replacements

Total Expenditures: $5,060k
Total Contingency: $460k (10%)

Project Number(s): 137745

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Kelly Mefford

Executive Summary

The proposed project is to replace forty-one (41) wood structures on the Hardin County – Smith 345kV line with steel based on the results of a routine line inspection completed in 2011. The results of the inspection revealed that these poles should be classified as Priority Two (P2) structures, meaning that they could fail within 3-6 years following the inspection. As such, this proposal is to proactively replace them over the course of the next couple of years, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

The alternative of replacing poles upon failure will result in much higher long term replacement costs due to mobilization of crews and the probable overtime work involved. This alternative also will have a negative impact on network reliability.

The total project cost of $5,060k is included in the 2014 Business Plan for $5,976k and is included in the 2015 Business Plan for $5,060k.

Background
Above ground pole inspections are performed by the company at defined intervals in order to discover problems that may impact the integrity and reliability of the Transmission System. During a routine climbing inspection of the Hardin County-Smith 345kV line in 2011, forty-one (41) structures were identified as P2 poles and determined to be in need of replacement in order to ensure the integrity and reliability of this line. There are 451 structures total on the Hardin County – Smith 345kV line.

- **Alternatives Considered (1 –Recommendation, 2 –Do nothing, 3 –Next Best Alt)**
  1. Recommendation: NPVRR: $6,625k
  2. Do Nothing: NPVRR: $11,906k
     The alternative of do nothing would result in replacing poles upon failure, which would result in a much higher long term replacement cost and have negative impact on network reliability.
  3. Next Best Alternative(s): NPVRR: $5,271k
     The next best alternative would be to replace the P2 poles with wood structures in the same time frame. This alternative poses additional risk to the company. The inspection reports indicate that the majority of the structures were damaged by woodpeckers. Since woodpeckers are so common in this region, we would not be able to ensure the long term integrity and reliability of this line by replacing the P2 poles with wood structures. The manufacturer's recommended life span of a wood pole is 30-35 years whereas steel poles have a recommended life span of 90 years.

Project Description

- **Project Scope and Timeline**
  The scope of work will consist of installing (41) steel H-frame structures and associated hardware and material, and the removal of (33) H-frame wood structures, (2) 3-pole wood structures and (6) 4-pole wood structures. Hardware and material will be purchased through Brownstown Electric Supply. The line construction will be based on continuing contracts from our line contractors. B and B, Elliot, Groves and Pike are the four contractors awarded the T&D Overhead Construction and Maintenance contract from the October, 2011 Investment Committee meeting. The contract extension was reapproved by the IC July 2014. Construction is scheduled to begin in January 2016 and to be completed in November 2018.

  The construction milestones for this project are provided below:

Construction Milestones	
September 2014	Engineering and Design
December 2014	Steel Pole Order Placed
February 2015	Fabrication of Steel Poles
June 2015	Steel Poles Delivered
January 2016	Line Construction Begins
November 2018	Line Construction Completed

A facility map of the Hardin County-Smith 345kV line constructed in 1971, shown below:

Line Length: 66 miles

- **Project Cost**
  Total project cost of $5,060k was included in the 2014 Business Plan for $5,976k and is included in the 2015 Business Plan for $5,060k. Historical and existing contract and purchasing agreements were used to estimate the cost of material and contract labor. Detailed engineering analysis lowered the cost of labor and material from the original estimate.

Economic Analysis and Risks

- **Bid Summary**
  Based on preliminary engineering, Transmission Lines have estimated the material packages for construction of this project to be $1,867k. The steel structures will be purchased through our current alliance contract with Thomas and Betts. Hardware and material will be purchased through Brownstown Electrical Supply. The line construction will be based on continuing contracts with our line contractors. Davis H. Elliot, Pike Electric, B&B Electric and William E. Groves are the four contractors which have been awarded the T&D Overhead Construction and Maintenance contracts.

Transmission Lines Material Cost Breakdown	
Material	Cost
Steel Poles	$1,640k
Hardware	$227k
Total	$1,867k

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2014	2015	2016	Post 2016	Total
1. Capital Investment Proposed	-	2,080	701	1,882	4,663
2. Cost of Removal Proposed	-	-	97	300	397
3. Total Capital and Removal Proposed (1+2)	-	2,080	798	2,182	5,060
4. Capital Investment 2014 BP	5,559	-	-	-	5,559
5. Cost of Removal 2014 BP	417	-	-	-	417
6. Total Capital and Removal 2014 BP (4+5)	5,976	-	-	-	5,976
7. Capital Investment variance to BP (4-1)	5,559	(2,080)	(701)	(1,882)	896
8. Cost of Removal variance to BP (5-2)	417	-	(97)	(300)	20
9. Total Capital and Removal variance to BP (6-3)	5,976	(2,080)	(798)	(2,182)	916

The proposed amounts by year match the 2015 BP.

Financial Summary ($000s):
Discount Rate: 6.50%
Capital Breakdown:
Labor: $113
Contract Labor: $2,066
Materials: $1,867
Local Engineering: $332
Burdens: $222
Contingency: $460
Reimbursements: ($0)
Net Capital Expenditure: $5,060

Financial Analysis - Project Summary ($000)	2014	2015	2016	2017	2018	Life of Project
Project Net Income	-	(36)	(49)	103	91	5,562
Project ROE	0.0%	-6.5%	-3.7%	5.7%	3.9%	10.2%

- **Assumptions**
  Alternative 2 - the cost of this alternative would be almost double due to overtime labor charges and the cost to mobilize and demobilize the construction crews.
  Alternative 3 – the cost of this alternative assumes the cost of wood poles is 71% of the cost of steel poles.

- **Environmental**
  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

- **Risks**
  Without the proposed replacement of the P2 poles on the Hardin County to Smith 345kV line, the company risks unplanned outages and increased costs of repairs in emergency situations. The Hardin County to Smith 345kV line is very difficult to get an outage on because it is critical to network reliability and North-South power flows through Kentucky.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the Hardin County-Smith 345kV P2 priority pole replacement project for $5,060k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Investment Proposal

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

Project Name: Lexington Underground

Total Expenditures: $14,937k
Total Contingency: 10%

Project Number(s): Transmission Lines - 139696
Transmission Substation – SU-000247
Distribution Operations – 156381
Distribution Substation – 156378, 156380, and 156384
Telecom – IT0193L, and IT0193K

Business Unit/Line of Business: Transmission Lines/Transmission Substation/Distribution Operations/Distribution Substation/Telecom

Prepared/Presented By: Terry Snow/Adam Smith

Executive Summary

The proposed project is to replace two underground transmission circuits that are over 45 years old and are beyond their expected useful life. Performance of these facilities has diminished, with the most recent failure occurring in 2012 from a failed splice. Over 7,000 customers with a peak load of almost 57 MVA in the downtown Lexington area are served by the facilities being replaced. These customers include the University of Kentucky, Lexington-Fayette Urban County Government (LFUCG), Lextran, Lexington Police Station, Rupp Arena, several large hotels, banks, churches, and many more business and commercial customers in the downtown area. This project will improve reliability, maintain system integrity, and reduce the risk of failures and unplanned transmission interruptions to downtown Lexington.

A Transmission System Improvement Plan was submitted as support in the 2016 Rate Case, outlining programs and projects aimed at reducing the risk of failure, avoiding extended sustained outages, and limiting costly emergency repairs. The programs submitted with the plan were selected to ensure long-term system integrity and modernize the transmission system to avoid degradation of performance over time due to aging infrastructure. Replacement of underground transmission lines in downtown Lexington was included as part of the Transmission System Improvement Plan to replace aging infrastructure.

Transmission Lines plans to replace the existing 69kV underground transmission lines serving the Race Street, Vine Street, West High Street, and University of Kentucky Medical Center substations. The scope of work includes installation of 1.94 miles of new 69kV underground transmission line and creates a separate interruptible circuit to the University of Kentucky Medical Center substation.

This project also includes supporting projects from Transmission Substation, Distribution Substation, Distribution Operations, and Telecom. Transmission Substation plans to expand the Race Street substation to support the separate interruptible circuit to the University of Kentucky Medical Center substation. Distribution Substation plans to replace the existing stone retaining wall at Vine Street and expand the West High Street substation to accommodate the installation of the new underground transmission lines. Similarly, Distribution Operations will relocate underground distribution facilities at the Vine Street substation to accommodate the installation of the new underground transmission lines. Telecom also plans to install fiber optic telecommunication cable along the new transmission underground duct system, providing connectivity to the West High Street substation.

The project was included in the 2018 Business Plan (BP) with estimates of $16,561k. Estimated spend included $458k in 2017, $7,915k in 2018, and $8,188k in 2019. As the scope, timing and certainty of work has evolved, the estimates have been further refined. The current total project cost is $14,937k, with actuals of $585k in 2017, estimated spend of $7,462k in 2018 and $6,890k in 2019. 2018 spend was approved by the RAC in the 2+10 forecast.

Background

Kentucky Utilities (KU) plans to replace two (2) 69kV underground electric transmission circuits presently serving Vine Street Substation and the West High Street underground dip in Lexington, Kentucky. The existing ductbank system was built using “Orangeburg” pipes that are known for collapsing and failing over time. Due to this type of construction, utilizing the existing ductbank system to install new cables is not feasible. During the existing underground system’s 45+ year life, there have been notable failures. Both in 1981 and 2012, a custom-made, hand-taped, T-splice failed at the Vine Street tap point of the Race Street – University of Kentucky Medical Center 69kV line (see Figure 1 below). There have also been failures of the underground terminations at the Vine Street substation.

The bulk dielectric strength of the cable insulation degrades as the cable system ages, and this can be accelerated by water ingress, insulation contaminants, and voids in the insulation. The exact way in which the insulation degrades will depend on many factors such as voltage, thermal stress, maintenance, system age, cable system technology, and environment.[1] Aging models quantifying the impacts from these factors are theoretical, and are still being developed by the industry. The Electric Power Research Institute (EPRI) Underground Transmission Systems Reference Book (2007) suggests the typical life of an underground cable is estimated to be 40 years. Substantial improvements have been made in materials, cable designs, and manufacturing methods since the early 1970’s that improve production quality and reduce the likelihood of insulation degradation. These changes have been embraced by the industry particularly for XLPE cables to the extent that higher operating stress cables (thin walls) have been accepted alternatives since the early 2000’s.

[1] Rick Hartlein and Nigel Hampton, *Diagnostic Testing of Underground Cable Systems* (NETRAC; 2010)

Figure 1: Failed underground splice from 2012

The existing 1500kcmil aluminum cable circuits, one routed west to West High Street Substation and the other east then north to Race Street Substation with existing T-Splice to riser pole at Rose Street, will be replaced with three new 69kV underground circuits. This project will route two new circuits from Race Street Substation, one terminating at Vine Street and the other terminating at a riser pole at Rose Street before transitioning to overhead and going to the University of Kentucky Medical Center Substation. This will eliminate the T-Splice and provide a separate interruptible circuit to University of Kentucky Medical Center. A third circuit will be routed between the substations at Vine and West High Streets. The short West High Street underground dip will also be replaced between the station and a new riser pole. With this project, the reliability of the downtown Lexington 69kV underground system will be greatly improved with the reconfiguration of the system that eliminates the need for a T-splice. Removing this splice replaces a three terminal line with a pair of two terminal lines, providing improved reliability and additional operational benefits to the area. Furthermore, it improves reliability by adding a third feed into the Race Street substation.

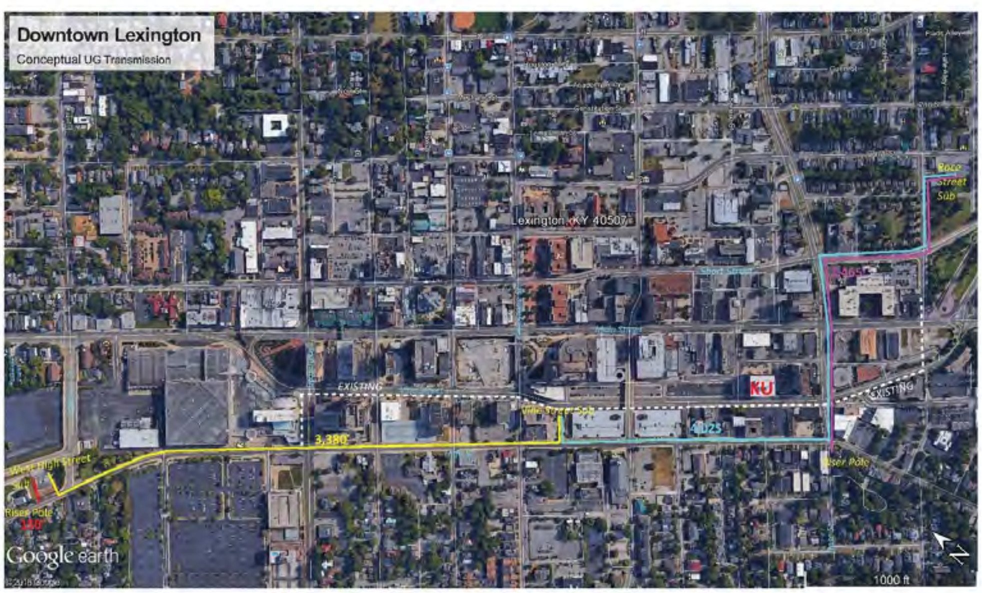
In February 2017, the transmission line engineering phase of this project was approved and initiated. KU partnered with AGE Engineering to complete the civil engineering, and USi to complete the electrical engineering aspects of this project. The engineering phase of the project consisted of a detailed subsurface utility investigation, determination of the preferred line route, cable ampacity studies, development of the construction drawings and specifications and the bidding of the underground construction and cable. The extensive subsurface investigation consisted of sixty-eight (68) vacuum excavations to verify the location of known utilities. Additionally, the top of bedrock was determined at ten locations along the route.

Addition of the separate circuit for the University of Kentucky Medical Center will require expansion at the Race Street Substation and include a breaker addition. The real estate purchase supporting this expansion and new 69kV underground feeds was completed in 2017 under a separate project (154503) in the amount of $135k.

- **Alternatives Considered**
    1. Recommendation: NPVRR: ($000s) $17,231
       As described in the current document.
    2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
       This option is not advisable as this line is nearing the end of its useful life and puts Transmission at risk of not being able to accomplish the objectives established as part of the Transmission System Improvement Plan that was filed as support in the 2016 Rate Case and assumed the completion of this project. These objectives include reducing the risk of failure, avoiding and extended sustained outage, and costly emergency repairs.
    3. Alternative #2: Next Best Alternative NPVRR: ($000s) $17,987
       The next best alternative would be to route the underground cable down Vine Street in lieu of High Street. This is option would require additional funding, as the route has additional underground utilities to navigate and additional impacts to traffic. The traffic impacts associated with this option would be more disruptive and have a larger negative impact on the community during construction.

Project Description

Lexington Underground Layout



The solid lines (red, yellow, blue, and magenta) represent new transmission lines being installed as part of this project. The dashed line (white) represents the location where the existing underground transmission line deviates from the planned route.

The existing and proposed one line electrical diagrams are included in the Appendix for reference.

Transmission Lines Project Description – Project #139696
Below Grade Scope: The project involves (1) the construction of a new underground duct bank from Race Street Substation to West High Street Substation with route deviations to accommodate circuit terminations at Vine Street station and the Rose Street riser pole, (2) the design and placement of new underground to overhead transition riser poles at Rose Street and at West High Street, (3) the routing of the new circuits within the substation areas, (4) the removal (or abandonment) of the existing cables, riser assemblies and cable terminations, (5) the installation of new 69kV transmission cables and accessories and (6) field testing and commissioning. The scope of the underground work will consist of building approximately 1.45 miles of new 69kV ductbank with manholes, installing approximately 1.94 miles of 69kV underground cable, twenty-four (24) 69kV cable terminations, and eighteen (18) 69kV splices.

Above Grade Scope: The scope of the overhead transmission line work will consist of installing one (1) new steel riser pole at West High Street, and one (1) new steel riser pole at Rose Street, and the removal of the overhead lines along Northeastern Avenue and into the Race Street substation.

- **Electric Transmission Lines Project Scope and Timeline**

Design Start	February 2017
Design Complete	December 2017
Materials Ordered	April 2018
Materials Delivered	July 2018
Construction Start	April 2018
Construction Finish	October 2019

Transmission Substation Project Description – Project SU-000247
Transmission Substation plans to expand the Race Street substation to support the separate interruptible circuit to the University of Kentucky Medical Center substation being added as part of this project. This expansion includes site work, a breaker installation, and re-configuration of the existing bus work at Race Street. In addition, protection and control settings will need to be updated at Race Street, Vine Street, West High Street, and University of Kentucky Medical Center substations.

Below Grade Scope: Expand the Race Street Substation grounding grid (6,000 sq ft), fencing (720 ft), and Spill Prevention, Control, and Countermeasure (SPCC) protection to allow for a new 69kV breaker foundation. As part of the substation expansion, an additional site gate with drive access will be added. This project also requires demolition of a residential house and site clearing to accommodate the substation expansion and underground feeds into the station. The real estate purchase supporting this expansion was completed in 2017 under a separate project (154503).

Above Grade Scope: Update protection and control settings for four substations (Race Street, Vine Street, West High Street, and University of Kentucky Medical Center), which includes the installation of one new 69kV line position consisting of one (1) new breaker, six (6) new hookstick switches, the addition of two (2) underground riser structures, two (2) new gang-operated switches, re-configuring the existing bus work, and modification of the existing line-side connections at Race Street.

- **Transmission Substation Project Scope and Timeline**

Design Start	June 2017
Design Complete	June 2018
Materials Ordered	April 2018
Materials Delivered	May 2018
Construction Start	May 2018
Construction Finish	October 2019

Distribution Substation Project Description – Project 156378, 156380, and 156384
Distribution Substation plans to replace the existing stone retaining wall at Vine Street to accommodate the installation of the new underground transmission lines. In addition, expansion of the West High Street substation is needed to accommodate the underground feeds into the station.

The scope of work will be to support transmission in the replacement of existing underground cables feeding Vine Street substation by re-building the existing stone retaining wall (below grade) and raise the steel structure on 69V line (above grade). A small portion of land will be acquired that is directly next to the Vine Street Substation to allow for adequate space for construction. In addition, the existing transmission underground conductors feeding West High Street Substation will also be replaced. In order to accommodate the West High Street replacement, one side of the station fence will be expanded above grade, and below grade work will be performed to procure and install grounding for the fence expansion.

- **Distribution Substation Project Scope and Timeline**

Design Start	November 2017
Design Complete	April 2018
Materials Ordered	April 2018
Materials Delivered	April 2018
Construction Start	April 2018
Property Acquisition-Vine Street	May 2018
Construction Finish	December 2018

Distribution Operations Project Description – Project 156381
Distribution Operations will relocate underground distribution facilities at the Vine Street substation to accommodate the installation of the new underground transmission lines. In addition, distribution will use this opportunity to install distribution ducts in the transmission duct bank for future distribution circuits.

This scope of work includes replacement of 240 feet of 750 Al 3/c underground primary & 4/0 Cu neutral from Manhole #10 to Manhole #33 (ckts # 125 and # 1201) with 250 feet of 1000 Al

3/c 15kV JCN underground primary in the relocated distribution duct bank into the Vine Street Substation. Relocation of this distribution circuit will accommodate installation of the 69kV underground transmission feeds into the Vine Street substation. This work will also include the installation of eight (8) 12' x 6' x 7' distribution manholes, the installation of 2700 feet of (6) - 6" concrete-encased duct bank along East and West High Street from Mill Street to Rose Street, and the installation of 1500 feet of six (6) - 6" concrete-encased duct bank from East Main Street, along Elm Tree Lane, East Short Street, and Eastern Avenue to the Race Street substation. The distribution ducts follow sections of the transmission route and will share the duct bank with transmission. The High Street corridor and the area close to Vine Street Substation are likely to be developed in the future and it is highly likely the customers or developers will request underground. The desire is to have 12kV in that area by that time. The proposed developments and concerns are:

- A future upgrade or replacement of the YMCA is expected; development on the vacant land beside the post office is expected; also, there is the possibility of an expansion on top of the bus garage.
- Some of the conduits could be used to support the Town Branch project due to conflicts with existing circuits along Vine Street in front of the Bus Transit Garage.
- System Planning is researching options to eliminate the Vine Street 4kV substation. Although the details have not been worked out or finalized yet, it is highly likely there will need to be utilization of the future conduit installation in the vicinity of the Rose Street/High Street intersection and/or along High Street toward the YMCA in order to convert Vine Street Cir 0021 from 4kV to 12kV.
- Along the same lines, there has been some discussion regarding the retirement of the Vine Street 12kV substation. To accomplish this, a new substation site would likely be necessary. The parking lot located at 176-180 East High Street could be a possible option and could have access to a transmission circuit (when the transmission project is complete) and distribution conduits (if pursued as a part of the transmission project).
- The University of Kentucky may pursue plans along South Limestone from Good Samaritan Hospital to downtown and the possibility of needing these conduits to provide a new circuit to their development exists.
- Also of concern is the number of “orangeburg” conduits that have failed the downtown system and these new conduits could be used to support needed tie circuits.

- **Distribution Operations Project Scope and Timeline**

Design Start	August 2017
Design Complete	December 2017
Materials Ordered	April 2018
Materials Delivered	May 2018
Construction Start	August 2018
Construction Finish	February 2019

Telecommunications Project Description – Project IT0193L and IT0193K
Telecom plans to install fiber optic telecommunication cable along a new transmission underground duct system. This will provide connectivity to the West High Street substation and

increase the capacity between the Race Street, Vine Street, and University of Kentucky Medical substations. It will also provide additional redundancy to the Kentucky Utilities General Office at One Quality.

Below Grade Scope: The telecom scope includes approximately 7,500 feet of dielectric fiber cable installed along the underground duct system.

Above Grade Scope: Above grade work will include the installation of equipment cabinets/termination panels for the respective endpoints. Project resources will include both contract and internal labor for installation and testing.

- **Telecommunications Project Scope and Timeline**

Design Start	August 2017
Design Complete	May 2018
Materials Ordered West High-Vine	May 2018
Materials Delivered West High-Vine	July 2018
Construction Start West High-Vine	August 2018
Construction Finish West High-Vine	November 2018
Materials Ordered Vine-Race	November 2018
Materials Delivered Vine-Race	January 2019
Construction Start Vine-Race	August 2019
Construction Finish Vine-Race	October 2019

- **Project Cost**

	Transmission Lines	Transmission Substation	Distribution Substation	Distribution Operations	Telecom	Total
Total Cost	$10,857k	$1,350k	$1,319k	$1,286k	$125k	$14,937k
Contingency	9%	9%	10%	10%	10%	

Economic Analysis and Risks

- **Bid Summary**
  Transmission Lines:
  Based on detailed engineering and bids received for the underground cable and installation labor, Transmission Lines has estimated the underground cable and accessories package for this project is $675k and the construction package is $7,770k. The bids for the cable and construction packages have been evaluated and will be awarded to the successful bidders following internal processes upon project approval.

  Transmission Substation:
  Bids for this project will cover demolition of the house on Lot 162 and possible commissioning services for the Race Street Substation portion. Design documents have been

developed for the transmission substation work, providing a solid basis for the substation estimate.

Distribution Operations:
Underground distribution work for cable relocation will be performed by company labor (no bids required). Cost of distribution duct bank is included in the Transmission Line bid.

Distribution Substation:
Currently all projects have been estimated and bids will go out after the project is open and design completed if applicable.

Telecom:
There are not expected to be any telecom bid requirements for this project. The bulk of the materials and contract labor will be acquired under the authority of existing contracts.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	585	7,277	6,765	-	14,627
2. Cost of Removal Proposed	-	185	125	-	310
3. Total Capital and Removal Proposed (1+2)	585	7,462	6,890	-	14,937
4. Capital Investment 2018 BP	458	7,915	8,188	-	16,561
5. Cost of Removal 2018 BP	-	-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	458	7,915	8,188	-	16,561
7. Capital Investment variance to BP (4-1)	(127)	638	1,423	-	1,934
8. Cost of Removal variance to BP (5-2)	-	(185)	(125)	-	(310)
9. Total Capital and Removal variance to BP (6-3)	(127)	453	1,298	-	1,624

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2018 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Discount Rate: 6.58%
Capital Breakdown:

	139696 Trans Lines	SU-000247 Trans Subs	156378 Dist Subs	156380 Dist Subs	156384 Dist Subs	156381 Dist Ops	IT0193 IT0193K Telecom	Total
Labor	$431k	$49k	$93k	$0	$33k	$67k	$0	$673k
Contract Labor	$4,462k	$739k	$345k	$0	$257k	$881k	$0	$6,684k
Materials	$3,516k	$306k	$18k	$181k	$20k	$7k	$0	$4,048k
Other	$14k	$1	$0	$0	$0	$23k	$112k	$150k
Local Engineering	$629k	$70k	$55k	$22k	$37k	$117k	$0	$930k
Burdens	$867k	$75k	$80k	$24k	$34k	$74k	$2k	$1,156k
Contingency	$938k	$110k	$59k	$23k	$38k	$117k	$11k	$1,296
Reimbursements	$0	$0	$0	$0	$0	$0	$0	$0
Net Capital Expenditure	$10,857k	$1,350k	$650k	$250k	$419k	$1,286k	$125k	$14,937k

- **Assumptions**
  Recommendation – This alternative assumes that the line outage will be available and that the work will be completed during this timeframe. This alternative also assumes that the City of Lexington and Kentucky Transportation Cabinet (KYTC) will approve a traffic control plan which will allow for lane closures from 6pm – 6am to support construction. During the design phase, KU worked closely with the City and KYTC to review this proposed construction project. Both the City and KYTC have given their verbal approvals regarding this project. However, the plan cannot be submitted for final approval until a contractor has been selected. Once the plans and permit applications have been submitted, the approval process should just be a formality.

- Alternative #1-Do Nothing – This option is not advisable as this line is nearing the end of its useful life and puts Transmission at risk of not being able to accomplish the objectives established as part of the Transmission System Improvement Plan, that was filed as support in the 2016 Rate Case, which assumed the completion of this project. These objectives include reducing the risk of failure, avoiding and extended sustained outage, and costly emergency repairs.

- Alternative #2 – Next Best Alternative – This alternative assumes that the underground cable would be routed down Vine Street in lieu of High Street. This is option would require additional funding, as the route is has additional underground utilities to navigate and additional impacts to traffic. The traffic impacts associated with this option would be more disruptive and have a larger negative impact on the community during construction.

- **Environmental**
  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

- **Customer Experience**
  In partnership with External Affairs, initial awareness and discussions with the City of Lexington regarding the project have occurred. Additionally, we have preliminary approval regarding lane closure permits and acceptable working hours from the City of Lexington. A communication plan is being developed to enhance the customer experience and community awareness regarding this project. In addition to the project proponents, corporate communications, external affairs, customer experience, major accounts, and the local business office have been engaged to provide input and feedback on the plan. Customer experience training is also planned for the successful underground contractor.

- **Risks**
  - The existing underground cable is over 45 years old and beyond the expected design life of 40 years per the Electric Power Research Institute. There have been notable failures during the existing underground system's life. Both in 1981 and 2012, a custom-made, hand-taped, T-splice failed at the Vine Street tap point of the Race Street – UK Med Center 69kV line. There have also been failures of the underground terminations at the Vine Street substation. Without completion of the proposed project, the company risks unplanned outages and increased cost of repairs in emergency situations.
  - A single underground transmission failure would leave one 45+ year old cable feeding approximately 1,600 customers at Vine Street for three (3) to five (5) weeks while the failure repairs were complete. A second underground failure during this time would leave no transmission feed into Vine Street. This would be especially concerning during summer and winter high load demand and have a direct impact many large customers, including Lexington-Fayette Urban County Government (LFUCG), Lextran, Lexington Police Station, and many more commercial customers.
  - This project involves building an underground ductbank through the oldest developed part of Lexington, KY. There is the inherent risk of construction being delayed due to the discovery of undocumented underground facilities. The detailed engineering phase included advanced ground penetrating radar and 68 subsurface utility vacuum excavations to limit the risk of delays associated with undocumented facilities.
  - The limestone retaining wall at the rear of the Vine Street substation will be a reliability risk during the construction phase. Proper shoring and bracing of the wall will need to be done to facilitate replacement with a properly engineered solution. In order to build the replacement wall, an easement will needed. The KY League of Cities has already granted an easement for the transmission line and has indicated they are willing to grant an easement for the wall.
  - Both existing transmission feeds into the Vine Street substation could potentially be out of service for 4-8 weeks to accommodate installation of the new underground feeds. Distribution Planning is reviewing options to move load from Vine Street to other stations to support this outage window. Similarly, Transmission is evaluating building a temporary line from Rose Street along High Street (on the University of Kentucky Medical Center circuit) to Vine Street to support the outage window.
  - The property owner for the parcel adjacent to Race Street is scheduled to vacate the property by March 31st. A delay in their move could impact the expansion at Race Street.

- Schedule delays may also occur if the city of Lexington or KYTC do not approve the recommended traffic control plan. Advance meetings were held with the city of Lexington and KYTC during the project design to discuss permitting and traffic control requirements. Both the City and KYTC have given their verbal approvals regarding this project. However, the plan cannot be submitted for final approval until a contractor has been selected. Once the plans and permit applications have been submitted, the approval process should just be a formality.
- The local community and businesses may react negatively to the work and potential inconvenience of the traffic plan. A communication plan is being developed in coordination with the project proponents, corporate communications, external affairs, customer experience, major accounts, and the local business office. This plan will be executed to limit the impacts to the community and businesses.

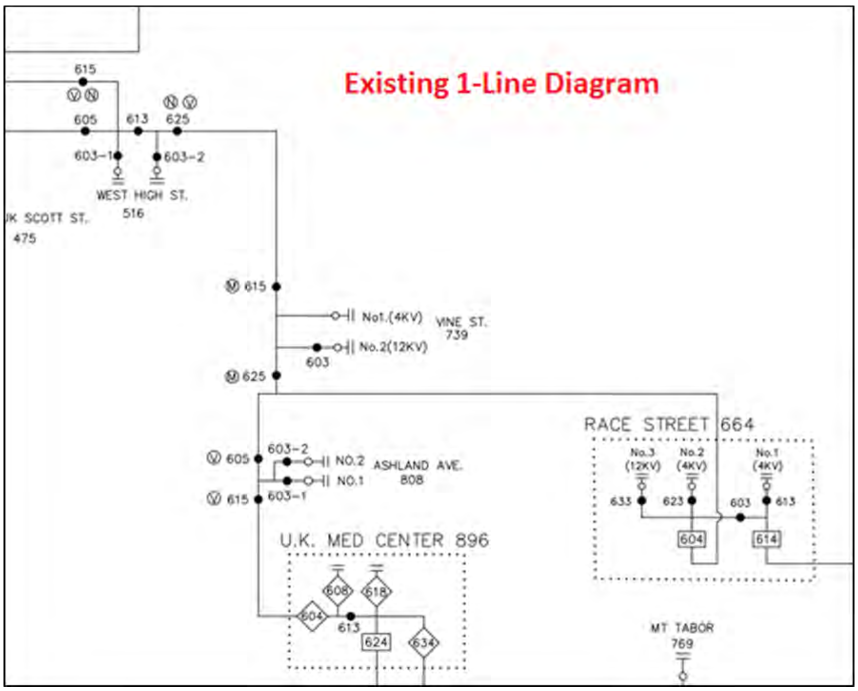
Conclusions and Recommendation
It is recommended that the Investment Committee approve the Lexington Underground project for $14,937k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

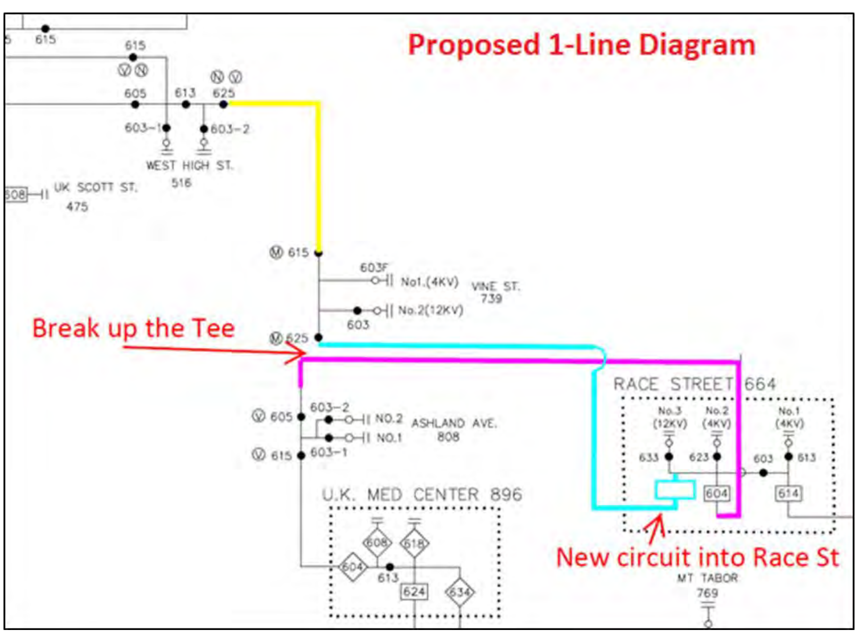
Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:

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	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Appendix:


Existing 1-Line Diagram
WEST HIGH ST.
516
UK SCOTT ST.
475
VINE ST.
739
ASHLAND AVE.
808
RACE STREET 664
U.K. MED CENTER 896
MT TABOR
769


Proposed 1-Line Diagram
Break up the Tee
New circuit into Race St
WEST HIGH ST.
516
UK SCOTT ST.
475
VINE ST.
739
ASHLAND AVE.
808
RACE STREET 664
U.K. MED CENTER 896
MT TABOR
769

Capital Investment Proposal

Investment Proposal for Investment Committee Meeting on: April 25, 2018

Project Name: PCH-Lynch Control House

Total Expenditures: $5,119k (Includes $465k (10%) Contingency)

Project Number(s): 144116

Business Unit/Line of Business: Transmission Substation Construction & Maintenance

Prepared/Presented By: Nel Ciurdar, Burns & McDonnell/Brent Birchell

Executive Summary

This project includes the replacement of (4) 69kV breakers, (8) 69kV disconnect switches, (4) sets of line arresters, the addition of (1) new 69kV U.S. Steel tie-breaker and (2) 69kV disconnect switches. This project also includes the replacement of the transmission control house at Lynch Substation, which will be installed uphill just outside the existing substation fence. This project is part of the existing Transmission System Improvement Plan (TSIP) and represents the aggregation of several system integrity programs into one holistic project.

The station has numerous cap and pin and hollow post insulators on the switches which are documented in the TSIP and the control house has relays (HZs & GCX-17s) that are slated for replacement due to poor performance and lack of parts. For additional information regarding material breakdown for replacement needs, see Appendix A.

This project was originally approved for $84k during July 2017 for preliminary engineering with the understanding that it would be presented to the Investment Committee for approval of full funding once detailed engineering was completed. During September 2017, the approval for preliminary engineering was increased to $227k. Based on the results of detailed engineering, the total cost of this project will be $5,119k with $93k in 2017, $600k in 2018, $3,272k in 2019, and $1,154k in 2020. This project was included in the 2018 BP for $227k in 2017, $600k in 2018, $1,350k in 2019 and $50k in 2020. The higher estimates for 2019 and 2020 will be addressed in the 2019 BP.

The higher estimate compared to the budget is due to the inclusion of four breakers that were budgeted in project SU-000014 ($1,000k), a fifth breaker that was added to improve reliability by reducing exposure related to an outage at the nearby US Steel substation, and higher than anticipated cost of installing the control house due to the limited space and grade of the terrain in the area.

Background

The (4) 69kV breakers 031-604, 031-614, 031-624, and 031-634 are vintage 1950's and 1960's breakers. In addition to age, these breakers have a history of maintenance issues. Routine testing of the breakers indicates that the dielectric ratings of the breakers have deteriorated, increasing the risk of failure. These breakers are in proximity to water, increasing the likelihood of oil reaching navigable water in the event of a catastrophic failure. These breakers have a direct impact on SAIDI and SAIFI if a failure were to occur due to the potential loss of customer load associated with these breakers.

In addition to the above criteria, these breakers are accessed via wooden decking due to their installed positions on a steeply inclining slope. Due to the slope and lack of space between breakers, replacement of these breakers under existing conditions is nearly impossible. As part of this proposed project, the wooden deck will be replaced with a steel maintenance platform that will allow installation and replacement of all 69kV breakers.

The (4) sets of line surge arresters are being replaced as part of a program due to the limited protection they provide.

The (8) 69kV switches with cap and pin and hollow post insulators are being targeted per the TRP insulator program "Replace Substation Insulators". These insulators have a known history of failures and will be removed from service. This targeted approach allows LKE to maximize the impact of these replacements, lower the number of in-service failures and minimize customer outages.

The substation control house currently houses transmission protection and control (P&C) equipment that is aging past the date of reasonable repair. Maintenance of said equipment is also becoming more difficult as replacement parts are difficult to find. By installing a new, pre-fabricated control house with microprocessor relays, the obsolete, aging equipment will be replaced with reliable, digital protective relays while also ensuring safe and reliable performance of the Transmission protection system. The new control house will include integrated relay panels, batteries, AC and DC systems, etc. for the protection of bus and lines within the Lynch substation. Due to the limited space and steep incline of the substation, installation of this new control house will be uphill from the existing substation near the drivepath.

Also included in this project scope is the optional addition of (1) 69kV breaker as a tie-breaker to the neighboring US Steel substation. Currently, without a bus-tie breaker a bus fault at the US Steel substation causes a bus outage at Lynch Substation. The addition of a bus-tie breaker would provide separation and increase the transmission reliability by reducing unnecessary exposure. This would include (1) breaker protection panel and associated cables. Additionally, the US Steel substation bus will no longer have independent protection once a tie breaker is installed, so a cost for a bus relay is included in this estimate.

For pictures of the substation today see Appendix A – Site Photos.
For site aerial photo and proposed general arrangement see Appendix A – Aerial Photo and General Arrangement.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $5,266
   It is recommended that the breakers, disconnect switches, arresters, and control house be replaced to reduce the potential risk to the Transmission system.

2. Alternative #1: NPVRR: ($000s) $8,194
   This option would involve installing a new greenfield substation and re-routing all 69kV lines and distribution equipment to a new location. See the alternate site in Appendix A

3. Do Nothing: NPVRR: ($000s) N/A
   This option is not advisable as it puts Transmission at risk of not being able to accomplish targets established as part of the Transmission Reliability Plan.

Project Description

- **Project Scope and Timeline**

Description	Date
Project Originally Approved for Preliminary Engineering	July 2017
Project Approved for additional Preliminary Engineering	September 2017
Full project funding requested	April 2018
Materials Ordered	October 2018
Materials Received	February – May 2019
Project Complete	December 2020

Project Cost

The total cost of this project will be $5,119k with $93k in 2017, $600k in 2018, $3,272k in 2019, and $1,154k in 2020. The estimated total project figure includes a 10% contingency. This contingency is reasonable based on the level of detailed engineering and is expected to cover uncertainty with the contract labor costs based upon variances that have been observed on past similar projects.

Economic Analysis and Risks

- **Bid Summary**
  Previously established blanket contract agreements will be utilized for related materials. Bids for any other necessary materials, as well as the below and above grade construction, will be sent out soon after project approval.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	94	600	3,133	1,154	4,981
2. Cost of Removal Proposed	-	-	138	-	138
3. Total Capital and Removal Proposed (1+2)	94	600	3,272	1,154	5,119
4. Capital Investment 2018 BP	227	600	1,300	50	2,177
5. Cost of Removal 2018 BP	-	-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	227	600	1,300	50	2,177
7. Capital Investment variance to BP (4-1)	133	0	(1,833)	(1,104)	(2,804)
8. Cost of Removal variance to BP (5-2)	-	-	(138)	-	(138)
9. Total Capital and Removal variance to BP (6-3)	133	0	(1,972)	(1,104)	(2,942)

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2018 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Four of the breakers being installed were budgeted in 2019 for $1,000k under project SU-000014.

Financial Summary ($000s):
Discount Rate:
Capital Breakdown:

Labor:	$274k
Contract Labor:	$2,180k
Materials:	$1,384k
Other:	$67k
Local Engineering:	$337k
Burdens:	$413k
Contingency:	$465k
Net Capital Expenditure:	$5,119k

Assumptions

No major assumptions were included in the capital evaluation model. It is assumed material can be obtained in a timely manner.

- **Environmental**

  This project does not require permitting in order to install the new control house in a currently unused area. This project has potential asbestos issues in the existing control house which will be demolished. An environmental assessment will be completed in the early stages of the project. Environmental costs of $50k associated with demolishing the existing control house are included in this estimate. There are no known issues regarding air, water, waste, or lead. It is assumed the oil in the breaker, the breaker bushings, and the bushing potential devise are PCB free.

- **Risks**
  Completing the project involves risk related to high voltage substation construction work. Not completing the project decreases the reliability of Lynch substation. Delaying this project exposes our system to the continuing risk of impacts from other potential transmission failures.

Conclusions and Recommendation
It is recommended that the Investment Committee approve replacement of Lynch 69kV breakers, disconnect switches, insulators, arresters, and control house for $5,119k to enhance the reliability of the Transmission system.

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	Date	Paul Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Appendix A – Material Breakdown

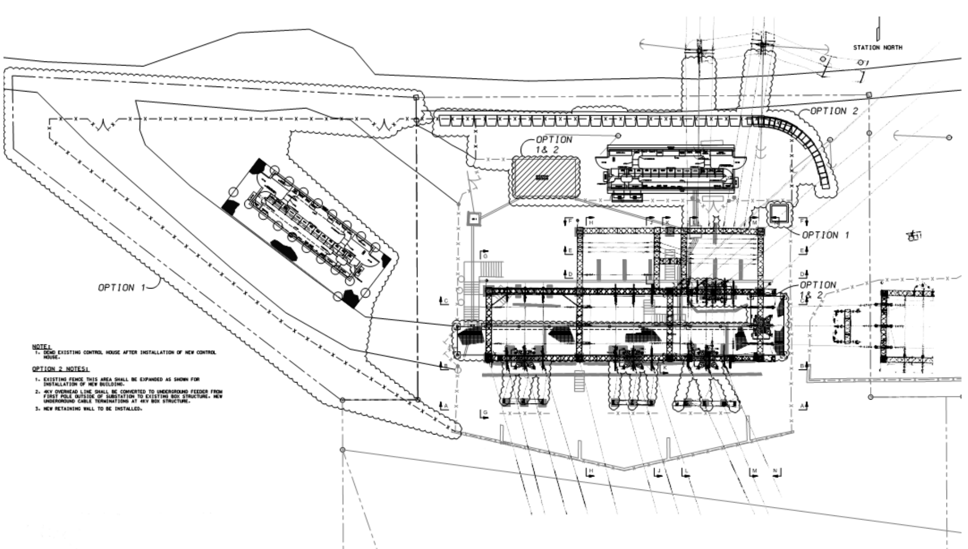
This project for the Lynch Substation is for proactive replacement of assets. All equipment being targeted for replacement under this project is part of the Transmission System Improvement Plan.

The project shall include:

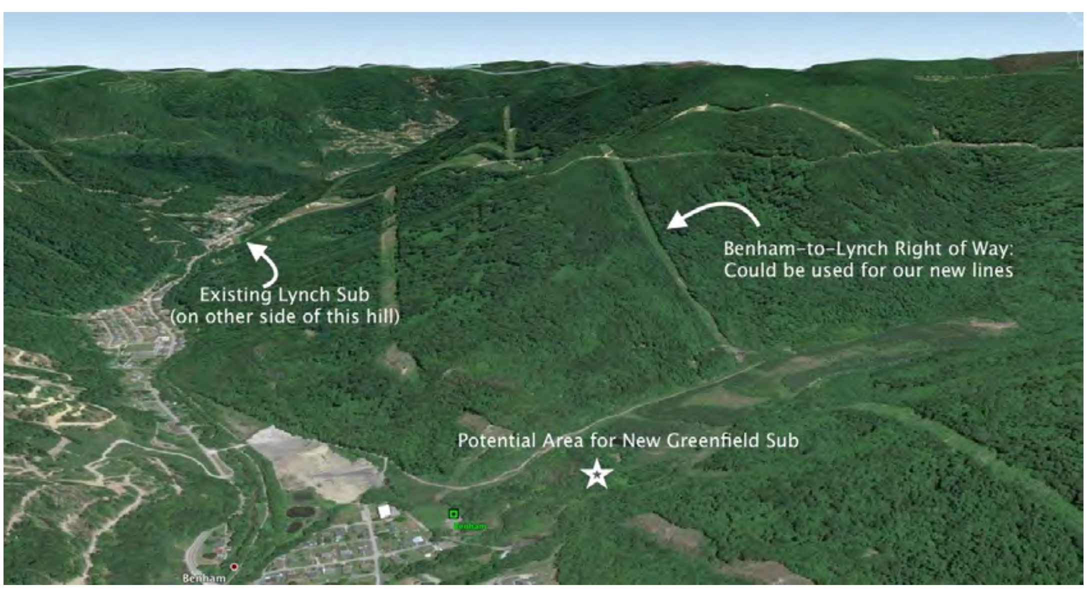
- Replace (4) 69kV breakers (031-604, 031-614, 031-624, and 031-634).
- Replace (4) sets of 69kV arresters (031-604, 031-614, 031-624, and 031-634).
- Replace (8) 69kV switches (031-604B, 031-604L, 031-614B, 031-614L, 031-624B, 031-624L , 031-634B, and 031-604L).
- Replace existing transmission control house with a new pre-fabricated control house.
- Install (1) 69kV breaker as a U.S. Steel bus-tie, with (2) breaker disconnect switches.

Site Photos

Aerial Photo and General Arrangement Drawing



Alternate Lynch Location.



Capital Investment Proposal

Investment Proposal for Investment Committee Meeting on: February 23, 2017
Project Name: Green River 69kV Control House
Total Expenditures: $3,931k (Includes $357k Contingency)
Project Number(s): 144118
Business Unit/Line of Business: Transmission Protection & Controls
Prepared/Presented By: Brent Birchell – Manager Protection & Controls

Executive Summary

Transmission protection and controls (P&C) equipment for the Green River 69kV substation yard is currently housed in the Green River generation plant building, which has been decommissioned. Demolition of the plant is currently scheduled for 2018-2019. As a result, a complimentary project (153861) has been created to eliminate all power feeds going into and out of the plant for the 161KV, 138KV and 69KV substations, and replace those feeds with a 69KV station service transformer and (2) separate distribution feeds. This complimentary project will allow for removal of the existing power plant in the 2018-2019 timeframe. Building a new control house will allow the P&C equipment to be relocated to the substation switchyard area and allow for the equipment inside the plant to be abandoned or salvaged, as appropriate, due to age and obsolescence of the assets. Additionally, the new relays will upgrade the system to a reliable, digital protection scheme.

The project was approved for $100k during 2016 for preliminary engineering with the understanding that the project would be presented for approval once detailed engineering was completed. The total cost of this project will be $3,931k, with $45k in 2016, $2,850k in 2017, and $1,036k in 2018. $3,933k of funding was included in the 2017 BP for this project, with $1,573k budgeted for 2017 and $2,360k budgeted for 2018. Since this project was accelerated to meet the demolition project schedule, the change in timing caused a budget variance in 2017 ($1,277k) which was approved by the RAC in the 2017 0+12 forecast. The estimated total project figure includes a 10% contingency. This contingency is expected to cover uncertainty with the contract labor costs and is based upon historical experience with similar projects.

Background
The Green River property includes a decommissioned generation facility (Green River Power Plant), a 69kV bus connecting eleven lines, a 138kV bus connecting ten lines, and a 161kV bus connecting six lines. The power plant building currently houses P&C equipment for the 69kV substation, batteries that provide DC for the 69kV yard, and sump pumps to prevent lower-level flooding for the power plant. Demolition of the plant is scheduled for 2018-2019. As a result, a complimentary project (153861) has been created to eliminate all power feeds going into and out of the plant for the 161KV, 138KV and 69KV substations equipment, and replace with a 69KV station service transformer and (2) separate distribution feeds. This complimentary project will allow for removal of the existing power plant in 2018-2019 timeframe.

This proposal addresses the installation of a control house in the switchyard, which will house P&C equipment for the 69kV substation. The scope of the project cost will include a new control house, foundations, cable pulling, yard equipment, and digital protection schemes. Additionally, new AC and DC distribution systems will be installed for the switchyard. Abandoning the equipment located in the power plant building will allow for demolition of the building. The new microprocessor based relays will also provide improved reliability, increased functionality, and disturbance event reporting.

- **Alternatives Considered**
  1. Recommendation NPVRR: $4,344k
     It is recommended that all the P&C equipment, currently located inside the decommissioned power plant, be relocated to a new control house within the substation yard and all equipment be upgraded to microprocessor relays.

  2. Alternative #1: Delay Project for two years NPVRR: N/A
     This project is required prior to the Green River Plant Demolition project which is currently planned to begin in 2018.

  3. Do Nothing NPVRR: N/A
     This project is required prior to the Green River Plant Demolition project.

Project Description

- **Project Scope and Timeline**

Milestones	Date
Project Originally Approved	August, 2016
Project Fully Approved	February, 2017
Order Control House	March, 2017
Install Control House Foundation	October 2017
Receive Control House	November, 2017
Start At Grade, Above Grade Construction	November , 2017
Start Connection, Commissioning of Existing Equipment to Control House	March, 2018
Complete Connection, Commissioning of Existing Equipment to Control House	June, 2018

- **Project Cost**
  The total cost of this project will be $3,931k, with $45k in 2016, $2,850k in 2017, and $1,036k in 2018. $3,933k of funding was included in the 2017 BP for this project. The estimated total project figure includes a 10% contingency. This contingency is expected to cover uncertainty with the contract labor costs and is based upon historical experience with similar projects.

Economic Analysis and Risks

- **Bid Summary**
  Certain components of the project cost were estimated from budgetary proposals based on existing blanket contracts.

  The control house panels will be purchased under the existing control house blanket contract agreement. Relay panels suppliers and external engineering resources are selected based on project-specific needs, including lead times and processes implemented for general engineering of the project. In this case, Systems Control recently engineered and manufactured a house for LKE of the same size and design that is needed for this project. This situation will present a reduced burden on company engineering resources and benefit the project schedule, as it will minimize lead times for engineering and state permits.

  Similarly, MESA will provide the engineering, procurement and construction management services under the existing EPCM contracts. MESA has recent experience engineering projects for LKE and has familiarity with LKE substation designs, including Green River Substation.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	45	2,850	1,036	-	3,931
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	45	2,850	1,036	-	3,931
4. Capital Investment 2017 BP	-	1,556	2,360	-	3,916
5. Cost of Removal 2017 BP	-	17	-	-	17
6. Total Capital and Removal 2017 BP (4+5)	-	1,573	2,360	-	3,933
7. Capital Investment variance to BP (4-1)	(45)	(1,294)	1,323	-	(15)
8. Cost of Removal variance to BP (5-2)	-	17	-	-	17
9. Total Capital and Removal variance to BP (6-3)	(45)	(1,277)	1,323	-	2

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2017 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):
Discount Rate: 6.5%
Capital Breakdown:
Labor: $174k
Contract Labor: $1,487k
Materials: $1,497k
Other: $1k
Local Engineering: $232k
Burdens: $183k
Contingency: $357k
Net Capital Expenditure: $3,931k

Expenditure Type	Protection	Construction	Total (000s)
Company Labor	$ 68	$ 106	$ 174
Contract Labor	$ 1,038	$ 449	$ 1,487
Purchased Materials	$ 1,346	$ 151	$ 1,497
Other	$ 1		$ 1
Local Engineering	$ 187	$ 45	$ 232
Burdens	$ 90	$ 93	$ 183
Contingency	$ 273	$ 84	$ 357
Total (000s)	$ 3,003	$ 928	$ 3,931

- **Assumptions**
  Outages are assumed to be obtained within the requested timeframe. Also, Environmental Affairs will own and coordinate all necessary permitting and hazardous material reporting within the project timeline. KU Green River personnel will provide access to the facility and P&C equipment for integration of the new digital protection scheme. Station service to the plant will be coordinated with the plant demolition project.

- **Environmental**

  Permitting – Based on the preliminary layout, the project location is not within floodplain or "Waters of the US" (wetlands, streams, etc.). Additionally, total disturbance size is expected to be less than 1 acre. Appropriate erosion controls will be installed and inspected as needed to comply with the Green River Best Management Practices Plan which includes a section addressing construction projects. No Land and Water (L&W) environmental permits are required based on current proposed location.

  Batteries –There is a requirement to submit annual "Tier II" reports to state and local fire departments and Emergency Planning Commissions if hazardous chemicals are stored at sites in quantities greater than 10,000 lbs. or extremely hazardous substances are stored at sites in quantities greater than their reportable Quantity (often 500 lbs.). Lead-acid batteries contain a sulfuric acid electrolyte which must be reported on Tier II reports if stored in a quantity greater than 500 lbs. Green River is already subject to Tier II reporting for a number of chemicals including existing lead-acid batteries.

  Oil-containing equipment –Sites that contain 1,320 gallons of oil or greater require a Spill Prevention Control and Countermeasures (SPCC) plan which includes, inspections, secondary containment to prevent oil releases from reaching waterways and an accurate inventory of oil-containing equipment on –site, among other requirements. Green River's substations already have a quantity of oil over 1,320 gallons, therefore already have a SPCC plan (combined for the 2 substations). There is a station service transformer which may need to be added to the site, depending on design specifications. If this equipment (or other additions) contain 55 gallons of oil or greater, they will be added to the SPCC inventory. These pieces of equipment would have to be added to the SPCC inventory. Secondary containment is a combination of the Strongwell berms, DGA berms and Oil Stop valves. Secondary containment for new equipment would most likely be provided by existing containment, however this should be confirmed based on the size and location of the equipment.

  Waste Considerations – Excess soil generated from areas outside of the substation footprint should either be re-used on-site or disposed of properly off-site. Excess soil generated from inside the substation fence should be treated as "PCB-contaminated". Disposal should be arranged with Environmental Affairs. Additionally, other legacy items potentially present within the substation subsurface (cables/conduit connecting to the plant, etc.) will be addressed as needed.

- **Risks**
  - Required outages will be planned and coordinated with the construction efforts to avoid the risk of project timeline extension. Inability to obtain necessary outages may lengthen the project timeline and costs and also delay demolition of the plant.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the Green River 69kV Control House project for $3,931k to support the demolition of the Green River Plant while maintaining the reliability of the transmission system.

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

Investment Proposal for Investment Committee Meeting on: January 27, 2015
Project Name: Parkers Mill Breaker Addition
Total Expenditures: $1,838k ($167k of Contingency)
Project Number(s): 144364
Business Unit/Line of Business: Transmission Substation Reliability
Prepared/Presented By: Keith Yocum – Manager Transmission Reliability

Executive Summary

The Lexington Plant to Pisgah 69kV line feeds four Distribution stations (Parkers Mill, Kunkel, Trafton and Buchanan) which serve over 13,000 customers in total. The line is about 14 miles long and runs from east of downtown Lexington, through downtown and out to the western border of Fayette County. This line has been chronically underperforming the rest of the Transmission system from a SAIDI/SAIFI perspective and ranks first in SAIDI contribution for the last several years. The performance in 2014 has worsened with a total SAIDI of 4.72 minutes inclusive of Major Event Days (MED).

The proposed project will include the purchase and installation of two breakers and the associated protection and control equipment (including a control house) at Parkers Mill which will cut the transmission line outage exposure to zero for the 7,000 customers served from Parkers Mill. This would reduce the total customer line outage exposure of 13,000 customers at the four Distribution stations by almost 60%. The Parkers Mill station provides service to the Bluegrass Airport, Keeneland, KY American Water company, Lexington Fayette Urban County Government, 4 schools, and Beaumont Centre Circle commercial development.

The total cost of this project is forecasted to be $1,838k and was approved by the RAC in the 2015 0+12 forecast. All of the projected spend will take place in 2015. This project was included in the 2015 BP for $1,700k, with $1,600k in the Substations budget (Project 144364) and $100k in the Lines (Project 144166). The total cost of $1,838k includes a 10% contingency.

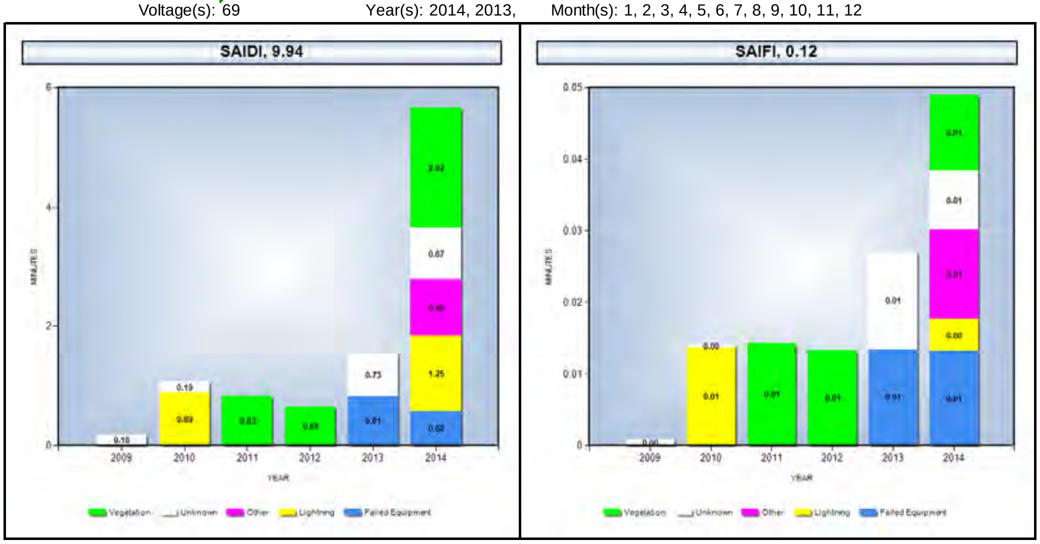
Background

The following chart shows the historical SAIDI/SAIFI for the Lexington Plant to Pisgah 69kV line inclusive of MEDs.

Transmission SAIDI/SAIFI Including MEDs

Lexington Plant to Pisgah 69 kV line

Voltage(s): 69 Year(s): 2014, 2013, Month(s): 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12

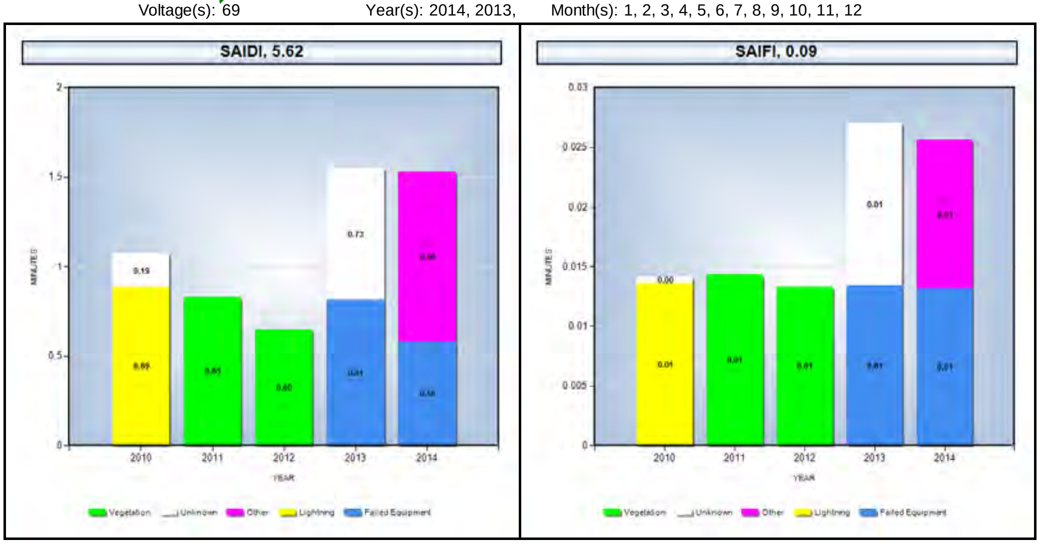


If you exclude Major Event Days, the numbers improve significantly (especially in 2014) as shown in the following graph. However, from a prioritization standpoint, Transmission believes that MEDs should be included unless they are a result of a low probability event such as a tornado outbreak, ice storm or other significant event.

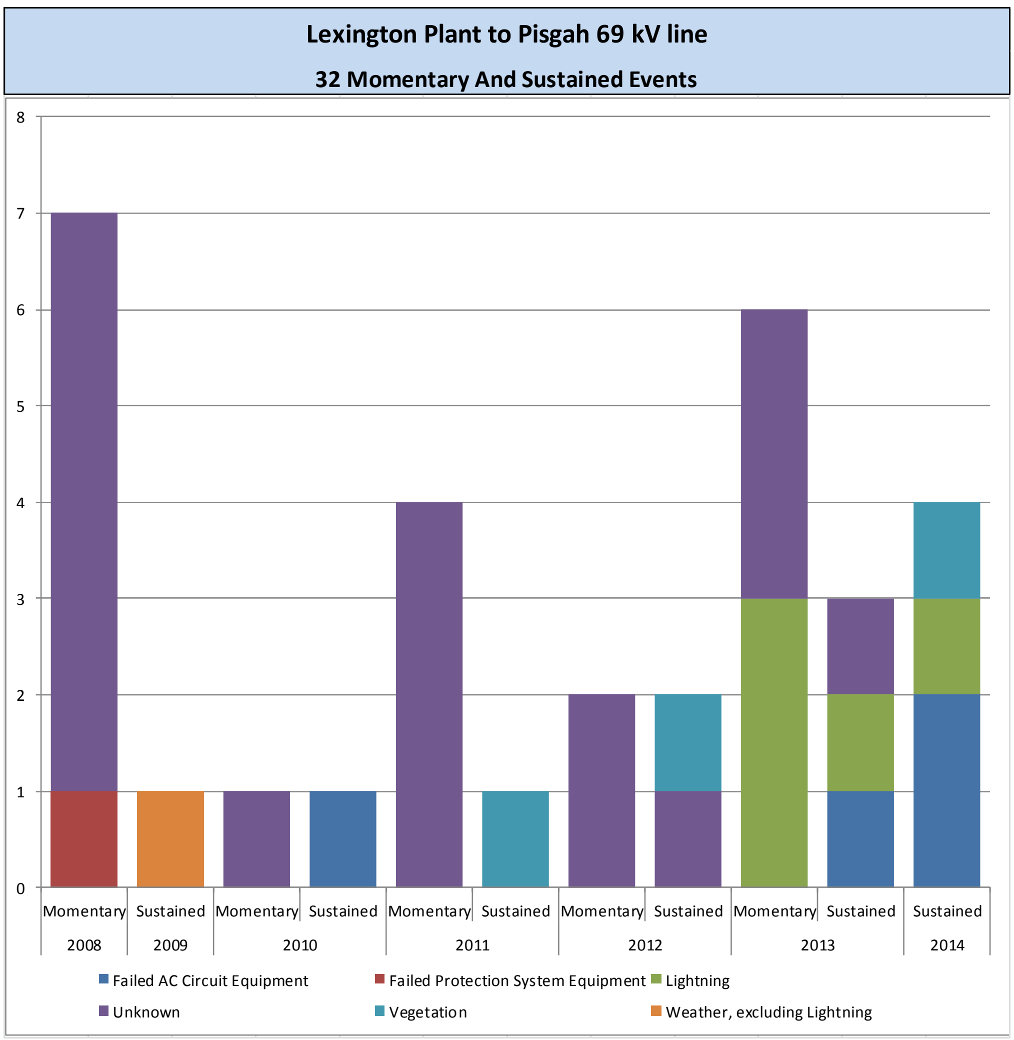
Transmission SAIDI/SAIFI Excluding MEDs

Lexington Plant to Pisgah 69 kV line

Voltage(s): 69 Year(s): 2014, 2013, Month(s): 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12



There have been many relay events on this line in the last 5 years in addition to those resulting in a SAIDI impact. The following chart shows the quantity and cause code for this line.



The performance on this line has degraded significantly in 2014 and has been one of our worst performing circuits from a SAIDI perspective for several years. This line does not rank in the top 10 for MW-Mile exposure or MW-Mile² exposure but due to its continued poor performance, a project was developed to mitigate the SAIDI/SAIFI impacts.

The Lexington Plant to Pisgah line is nearly 14 miles long and runs from east of downtown Lexington, through downtown and out to the western border of Fayette County as shown in the

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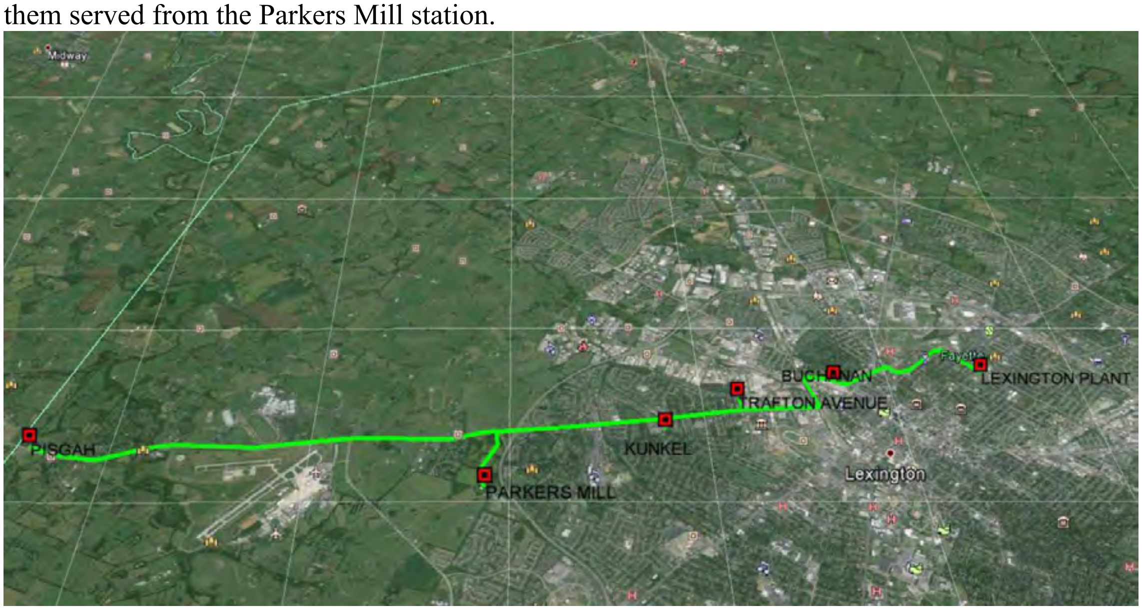
picture from Google Earth below. The line serves over 13,000 customers with over 7,000 of them served from the Parkers Mill station.



A one-line diagram of the line is shown below along with nearby stations:

[redacted]

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The proposed project will add two breakers at Parkers Mill as shown in the following one-line depiction:

[redacted]

The addition of these two breakers will shield Parkers Mill from outage events on the rest of the line and provide a second source into the substation via the American Avenue to Higby Mill line. Based on historical events, these breakers would have reduced the Transmission SAIDI impact by more than 50% for the line and 100% for the Parkers Mill customers.

- **Alternatives Considered (1 –Recommendation, 2 –Do nothing, 3 –Next Best Alt)**
  Recommendation – Install two breakers at Parkers Mill which will reduce the line exposure for 7,000 customers to zero.
  NPVRR: ($000s) $2,307k

  Do Nothing – If nothing is done, the SAIDI/SAIFI impact will continue to degrade and customer satisfaction will be negatively impacted. This line will continue to be one of our worst performers.
  NPVRR: ($000s) $0k

  Next Best Alternative(s) – The next best alternative for this project would be to loop the feed into Parkers Mill from the Lexington Plant to Pisgah line and install 3 breakers at Parkers Mill. This will reduce the overall line exposure only slightly more than the recommended option for a much larger cost.
  NPVRR: ($000s) $6,798k

Project Description

- **Project Scope and Timeline**

Description	Date
Project Approved	February, 2015
Substation Construction Materials Ordered	March, 2015
Control House Ordered	March, 2015
Substation Construction Materials Received	June-July, 2015
Below Grade Work Begins	June, 2015
Below Grade Work Completed	July, 2015
Above Grade Work Begins	July, 2015
Control House Received	August, 2015
Above Grade Work Completed	September, 2015
Testing & Commissioning	September-October, 2015
Project Complete	October, 2015

- **Project Cost**
  The total cost of this project is forecasted to be $1,838k and was approved by the RAC in the 2015 0+12 forecast. All of the projected spend will take place in 2015. This project was included in the 2015 BP for $1,700k, with $1,600k in the Substations budget (Project 144364) and $100k (Project 144166) in the Lines. The estimated figure includes a 10% contingency.

Economic Analysis and Risks

- **Bid Summary**
  Bids for the necessary materials as well as the civil, below, and above grade work will be sent out early in 2015. The (2) 69kV breakers will be purchased under the existing breaker purchase agreement. The control house will also be purchased under the existing control house purchase agreement.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	**2015**	**2016**	**2017**	**Post 2017**	**Total**
1. Capital Investment Proposed	1,791	-	-	-	1,791
2. Cost of Removal Proposed	47	-	-	-	47
3. Total Capital and Removal Proposed (1+2)	1,838	-	-	-	1,838
4. Capital Investment 2015 BP	1,700	-	-	-	1,700
5. Cost of Removal 2015 BP	-	-	-	-	-
6. Total Capital and Removal 2015 BP (4+5)	1,700	-	-	-	1,700
7. Capital Investment variance to BP (4-1)	(91)	-	-	-	(91)
8. Cost of Removal variance to BP (5-2)	(47)	-	-	-	(47)
9. Total Capital and Removal variance to BP (6-3)	(138)	-	-	-	(138)

Financial Detail by Year - O&M ($000s)	**2015**	**2016**	**2017**	**Post 2017**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2015 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):
Discount Rate: 6.5%
Capital Breakdown:
Labor: $149k
Contract Labor: $626k
Materials: $633k
Other: $0k
Local Engineering: $101k
Burdens: $162k
Contingency: $167k
Reimbursements: ($0k)
Net Capital Expenditure: $1,838k

Financial Analysis - Project Summary ($000)	**2015**	**2016**	**2017**	**2018**	**2019**	**Life of Project**
Project Net Income	$ (30)	$ (4)	$ 99	$ 97	$ 90	$ 2,159
Project ROE	-6.4%	-0.5%	11.2%	11.6%	11.2%	10.6%

Spend (000's)	**Construction**	**P&C**	**Lines**	**Total**
Company Labor	$ 46	$ 89	$ 14	**$ 149**
Contract Labor	$ 205	$ 238	$ 183	**$ 626**
Materials	$ 175	$ 411	$ 47	**$ 633**
Burdens	$ 80	$ 145	$ 38	**$ 263**
Contingency	$ 51	$ 88	$ 28	**$ 167**
Total	**$ 557**	**$ 972**	**$ 310**	**$1,838**

- **Assumptions**
  - The installation locations of substation equipment and control house will be inside of the Parkers Mill substation. Adequate drive access can be maintained with the proposed layout; therefore, no new land is required to be purchased for the substation.
  - Right of way changes are expected for the Transmission Lines work and it is assumed that this will be completed with minimum costs and no project delays.
  - The Transmission Substation estimate assumes new equipment will have a nominal 1200A continuous current rating with 40 kA fault interrupting ratings.
  - There are no special geotechnical or site conditions including rock removal, drainage, special foundation considerations, environmental or flooding mitigation related to the site in question.
  - Control house installation will be of typical cost, with no major obstacles to site entry.
  - The provided estimate assumes no modifications are necessary to the existing equipment that remains, including Distribution transformers, breakers, and RTU.
  - The requested outages will be attainable and assumes five days a week, eight hour day work schedule with no special construction requirements or costs to minimize required outages.
  - A ground grid or lightning protection study for the whole substation is not included in this estimate. Costs to expand the ground grid or lightning protection in the existing station to meet current standards or codes are not included in this estimate. The existing ground grid impedance to remote ground along with touch and step potential is assumed to be adequate and new grid is only installed in the substation expansion for touch and step potential concerns.

- **Environmental**
  This project does not require permitting and there are no known issues regarding air, water, waste, lead, or asbestos.

- **Risks**
  Without the addition of the breakers at Parkers Mill, we will continue to have the station exposed to the high frequency of outages and will most likely continue to have this line be our worst SAIDI offender.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the Parkers Mill Breaker Additions project for $1,838k to enhance the reliability of the Transmission system and to address the poor SAIDI performance of the Lexington Plant to Pisgah 69kV line.

Investment Proposal for Investment Committee Meeting on: N/A

Project Name: REL-Parkers Mill 604 Breaker Addition

Total Approved Expenditures: $1,838k

Total Revised Expenditures: $1,989k

Project Number(s): 144364

Business Unit/Line of Business: Transmission Substation Reliability

Prepared/Presented By: Keith Yocum – Manager Transmission Reliability

Reason for Revision
The Parkers Mill 604 Breaker Addition project exceeded the AIP by $151K (8%). The overrun was primarily caused by adding the transfer bus which provides needed switching flexibility in the event of an outage at the substation but was missed in the original scope of work. It was expected that cost would be covered by project contingency, but contract labor was higher than original estimates.

Financial Summary ($000s):	**Approved**	**Revised**	**Explanation**
Discount Rate:	6.50%	6.50%	
Capital Breakdown:			
Labor:	$149k	$80k	More contract labor performed due to scope changes
Contract Labor:	$626k	$816k	Contract engineering and construction exceeded initial estimates Transfer bus and full transformer transfer capability added
Warehouse Materials:	$0	$37k	
Purchased Materials:	$633k	$695k	Additional switches, steel, bus work, and connectors
Other:	$0	$22k	Vehicle/food/travel/misc. charges
Local Engineering:	$101k	$203k	Additional burdens due to additional overall costs
Burdens:	$162k	$136k	
Contingency:	$167k	$0	
Reimbursements:	$0	$0	
Net Capital Expenditure:	$1,838k	$1,989k	
NPVRR:	$2,307k	$2,562k	

Financial Detail by Year - Capital ($000s)	**2015**	**2016**	**2017**	**Post 2017**	**Total**
1. Capital Investment Proposed	2,059	(100)	-	-	1,959
2. Cost of Removal Proposed	18	12	-	-	30
3. Total Capital and Removal Proposed (1+2)	2,077	(88)	-	-	1,989
4. Capital Investment 2016 BP	1,810	-	-	-	1,810
5. Cost of Removal 2016 BP	49	-	-	-	49
6. Total Capital and Removal 2016 BP (4+5)	1,859	-	-	-	1,859
7. Capital Investment variance to BP (4-1)	(249)	100	-	-	(149)
8. Cost of Removal variance to BP (5-2)	31	(12)	-	-	19
9. Total Capital and Removal variance to BP (6-3)	(218)	88	-	-	(130)

Financial Detail by Year - O&M ($000s)	**2015**	**2016**	**2017**	**Post 2017**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2015 BP	-	-	-	-	-
3. Total Project O&M Variance to BP (2-1)	-	-	-	-	-

Financial Analysis - Project Summary ($000)	**2015**	**2016**	**2017**	**2018**	**2019**	**Life of Project**
Project Net Income	$ (24)	$ 2	$ 95	$ 97	$ 102	$ 2,416
Project ROE	-4.4%	0.1%	9.5%	10.2%	11.2%	10.4%

Conclusions and Recommendation

It is recommended that the Investment Committee approve the revised Parkers Mill 604 Breaker Addition project for $1,989k to accommodate the additional costs associated with the change in scope of adding a transfer bus.

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Appendix A: Single Line Comparison

As existed in initial Investment Proposal: [redacted]

As built: [redacted]

These design changes provide much greater operational flexibility and restoration time compared to the initial layout. The transfer bus necessitated (6) additional switches, as well as additional steel, foundations, buswork, connectors, and associated construction labor and engineering costs.

Capital Investment Proposal

Investment Proposal for Investment Committee Meeting on: N/A

Project Name: REL-Cawood 604 Breaker Add

Total Expenditures: $869k (Including $79k of Contingency)

Project Number(s): 144632

Business Unit/Line of Business: Transmission Reliability Performance & Standards

Prepared/Presented By: Keith Yocum – Manager Reliability Performance & Standards

Executive Summary

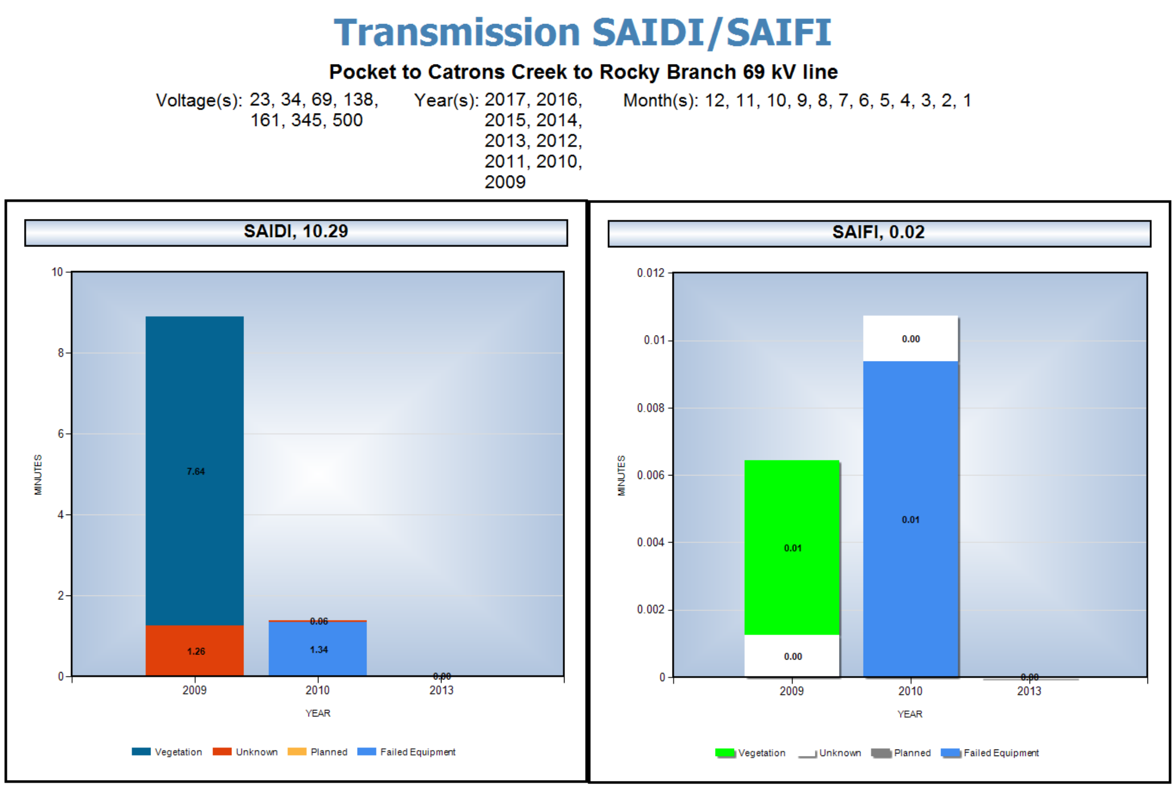
The Transmission Reliability Performance and Standards group identified the need for a breaker at the Cawood substation to reduce the System Average Interruption Duration Index (SAIDI) and the MegaWatt-Mile (MW-Mile is calculated by multiplying total miles of line exposure times the MWs served from the line) exposure on the Pocket to Catrons Creek to Rocky Branch 69 kV line. This line has significant MW-Mile exposure and has been a significant SAIDI contributor for Transmission.

The Pocket to Catrons Creek to Rocky Branch 69 kV line is 37.79 miles long and has 10 distribution transfomers tapped off of it which serve around 5,083 customers and 27.51 MW of load. A fault anywhere along this line will result in an outage on all 10 distribution stations. The placement of a breaker at Cawood will reduce MW-Mile exposure from 1040 to 491, a 52.8% reduction, resulting in only 47% as many customers losing power during a given fault. Diagram 1 include in Appendix A depicts the configuration for the Pocket to Catrons Creek to Rocky 69 kV line.

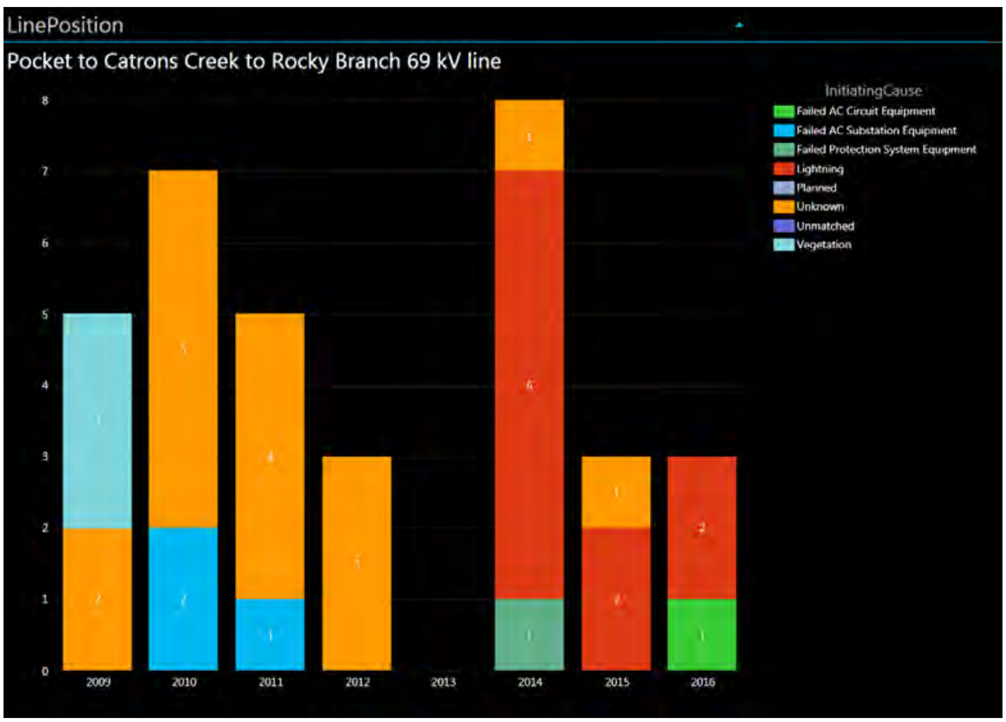
This project was initially opened for $100k to conduct preliminary engineering in an effort to better estimate the total funding needed to complete the project with the understanding that the cost of the full project would be presented for approval once those estimates were completed. The total cost of this project will be $869k with $62k in 2016 and $807k in 2017. The 2017 BP included $850k for this project with $100k in 2016 and $750k in 2017. The budgeted amount was estimated based on similar projects that have been previously completed and has been updated based on the preliminary engineering performed. The funding needed above the budget in 2017 is $57k. $35k of this was approved by the RAC 1+11 forecast. The remaining $22k was funded by a reduction in project #153706 (Earlington N Xfmr Rpl). The estimated total project figure includes a 10% contingency. This contingency is expected to cover uncertainty with the contract labor costs based upon variances that have been noticed on past similar projects.

Background
The Pocket to Catrons Creek to Rocky Branch 69 kV line was identified as a high MW-Mile exposure line. The line has also had about 1.4 minutes of SAIDI since 2010, but in 2009 there was an extended outage that resulted in almost 9 minutes of SAIDI. The 2009 event was excluded from reporting due to it being declared a Major Event Day (MED). The addition of this breaker will reduce the mileage exposure by half for all of the customers served by this line as Cawood is located in the approximate middle of the line. Therefore, for a given fault, only half as many customers will go out in the case with the breaker, as compared to the case without the breaker. This will also speed up restoration in that the line section requiring patrol will also be cut in half.

The chart below shows the historical SAIDI/SAIFI (including MED) for this line:



The following graph shows the number of relay events since 2009 and their associated cause codes.



- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $944 k
     It is recommended that a breaker be installed on the Pocket to Catrons Creek to Rocky Branch 69 kV line to limit the exposure of customers on a line that has historically had SAIDI issues. This recommendation assists Transmission in achieving the SAIDI targets established as part of the Transmission Reliability Plan (TRP), as well as reduces the number of customers that would otherwise experience a power outage during an event. In addition, this recommendation provides additional relay data to aid in restoring service quickly that includes information to help determine the cause and location of the event.

  2. Alternative #1: NPVRR: ($000s) $615k
     The next best alternative is to add an automated motor operated switch instead of a breaker in the substation steel at Cawood. An automated switch at Cawood would sectionalize the line and improve the restoration process, however, all customers on this line will continue to experience a power outage during an event. This option is

not advisable as this circuit has ranked in the top ten of MW-Mile (customer outage) exposure. These switches also will not provide the additional relaying event data that the breaker option will provide which helps in determining the cause and location of an outage. This option, although not the lowest cost alternative, is not recommended because it does not achieve all of the objectives of the project.

3. Do Nothing: NPVRR: N/A
   This option is not advisable as this circuit has ranked in the top ten of MW-Mile (customer outage) exposure and the current state of the line puts Transmission at risk of not being able to accomplish SAIDI targets established as part of the Transmission Reliability Plan which assumed the completion of this project.

Project Description

- **Project Scope and Timeline**

Description	Date
Project Initially Approved for preliminary engineering	September, 2016
Materials Ordered	November, 2016
Materials Received	January, 2017
Project Approved for Full Funding	March, 2017
Below Grade Work Begins	March, 2017
Below Grade Work Completed	April, 2017
Above Grade Work Begins	April, 2017
Above Grade Work Completed	May, 2017
Project Complete	June, 2017

- **Project Cost**
  This project was initially opened for $100k to conduct preliminary engineering in an effort to better estimate the total funding needed to complete the project with the understanding that the cost of the full project would be presented for approval once those estimates were completed. The total cost of this project will be $869k with $62k in 2016 and $807k in 2017. The 2017 BP included $850k for this project with $100k in 2016 and $750k in 2017. The budgeted amount was estimated based on similar projects that have been previously completed and has been updated based on the preliminary engineering performed. The funding needed above the budget in 2017 is $57k. $35k of this was approved by the RAC 1+11 forecast. The remaining $22k was funded by a reduction in project #153706 (Earlington N Xfmr Rpl). The estimated total project figure includes a 10% contingency. This contingency is expected to cover uncertainty with the contract labor costs based upon variances that have been noticed on past similar projects.

Economic Analysis and Risks

- **Bid Summary**
  Previously established blanket contract agreements will be utilized for related materials. Bids for any other necessary materials, as well as the below and above grade construction, will be sent out soon after project approval.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	62	807	-	-	869
2. Cost of Removal Proposed			-	-	-
3. Total Capital and Removal Proposed (1+2)	62	807	-	-	869
4. Capital Investment 2017 BP	100	750	-	-	850
5. Cost of Removal 2017 BP	-	-	-	-	-
6. Total Capital and Removal 2017 BP (4+5)	100	750	-	-	850
7. Capital Investment variance to BP (4-1)	38	(57)	-	-	(19)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	38	(57)	-	-	(19)

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2017 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):
Discount Rate: 6.5%
Capital Breakdown:
Labor: $63k
Contract Labor: $381k
Materials: $232k
Other: $0k
Local Engineering: $50k
Burdens: $64k
Contingency: $79k
Net Capital Expenditure: $869k

Spend (000's)	Construction	P&C	Telecom	Total
Company Labor	$ 39	$ 19	$ 5	**$ 63**
Contract Labor	$ 257	$ 122	$ 2	**$ 381**
Materials	$ 69	$ 153	$ 10	**$ 232**
Burdens	$ 67	$ 41	$ 6	**$ 114**
Contingency	$ 43	$ 33	$ 3	**$ 79**
Total	**$ 475**	**$ 368**	**$ 26**	**$ 869**

- **Assumptions**
  - Suppliers and contractors will meet reasonable and customary delivery dates for materials and services.

  - The testing and validation for the operation of the new breaker is completed in the time frame scheduled for the project and not delayed due to the availability of resources. Delays could require additional mobilization costs for construction removal and cut-over to the new system.
  - Telecommunications will install a new Verizon cellular communications at the site to provide communication for the new breaker.
  - Construction costs are estimated and not based on bid pricing.

- **Environmental**
  This project does not require permitting and there are no known issues regarding air, water, waste, lead, or asbestos.

- **Risks**
  - Completing the project involves risk related to construction work within an operating substation. This project involves installing new underground conduits and reconfiguring the existing system.
  - If the breaker is not added, Transmission will continue to see negative SAIDI impacts associated with this line.

Conclusions and Recommendation
It is recommended that Management approve the Cawood Breaker Addition project for $869k to enhance the reliability of the Transmission system.

CONFIDENTIAL INFORMATION REDACTED

Appendix A

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DIAGRAM 1

Capital Investment Proposal

Investment Proposal for Investment Committee Meeting on: N/A
Project Name: REL-FMC 604 Breaker Add
Total Expenditures: $1,350k (Including $121k of Contingency)
Project Number(s): 144634
Business Unit/Line of Business: Transmission Reliability Performance & Standards
Prepared/Presented By: Keith Yocum – Manager Reliability Performance & Standards

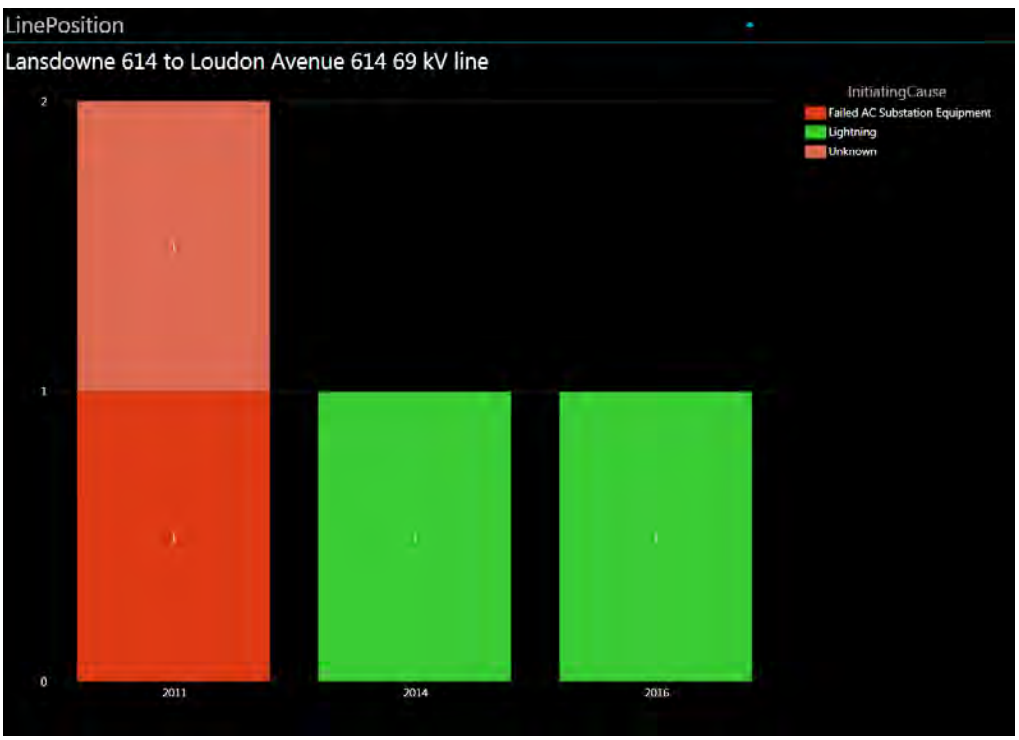
Executive Summary
The Transmission Reliability Peformance and Standards group identified the need for a breaker at the FMC substation to reduce the MegaWatt-Mile (MW-Mile is calculated by multiplying total miles of line exposure times the MWs served from the line) exposure on the Lansdowne 614 to Loudon Avenue 614 69 kV line. This line has significant MW-Mile exposure and potential to adversely impact the System Average Interuption Duration Index (SAIDI).

The Lansdowne 614 to Loudon Avenue 614 69 kV line is 10.25 miles long and has 5 distribution transformers tapped off of it which serve around 14,909 customers and 110.25 MW of load. A fault anywhere along this line will result in an outage on all 5 distribution transformers. The placement of a breaker at FMC will reduce MW-Mile exposure from 1130 to 644, a 43.0% reduction, resulting in only 57% as many customers losing power during a given fault. Diagram 1 include in Appendix A depicts the configuration for the Lansdowne 614 to Loudon Avenue 614 69 kV line.

This project was initially opened for $100k during October 2016 to conduct preliminary engineering in an effort to better estimate the total funding needed to complete the project with the understanding that the cost of the full project would be presented for approval once those estimates were completed. The total cost of this project will be $1,350k in 2017. The 2017 BP included $850k for this project with $100k in 2016 and $750k in 2017. The budgeted amount was estimated based on similar projects that have been previously completed and has been updated based on the preliminary engineering performed. The funding needed above the budgeted amount in 2016 was addressed by the RAC during 2016. The funding needed above the budget in 2017 ($600k) was approved by the RAC in the 6+6 forecast. The estimated total project figure includes a 10% contingency. This contingency is expected to cover uncertainty with the contract labor costs based upon variances that have been noticed on past similar projects.

Background
The Lansdowne 614 to Loudon Avenue 614 69 kV line has some of the greatest MW-Mile exposure of any line in the Transmission system. This breaker will reduce the mileage exposure by roughly half for all of the customers served by this line as FMC is located in the approximate middle of the line. Therefore, for a given fault, fewer customers will go out in the case with the breaker, as compared to the case without the breaker. This will also speed up restoration in that the line requiring patrol will also be cut in half.

The following graph shows the number of relay events since 2010 and their associated cause codes.



- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $1,474k
     It is recommended that a breaker be installed on the Lansdowne 614 to Loudon Avenue 614 69 kV line to limit the exposure of customers on a line that has historically had SAIDI issues. This recommendation assists Transmission in achieving the SAIDI targets established as part of the Transmission Reliability Plan (TRP), as well as reduces the number of customers that would otherwise experience a power outage during an event. In addition, this recommendation provides additional relay data to aid in restoring service quickly that includes information to help determine the cause and location of the event.

2. Alternative #1: NPVRR: ($000s) $1,525k
   The next best alternative is to install the breaker within the existing substation which would require the relocation of the existing cap bank along with assocaited equipment. This would potentially require a longer outage duration, as well as limit any future expansion projects at the station due to the revised layout.

3. Do Nothing: NPVRR: N/A
   This option is not advisable as this circuit has ranked in the top ten of MW-Mile (customer outage) exposure and the current state of the line puts Transmission at risk of not being able to accomplish SAIDI targets established as part of the Transmission Reliability Plan which assumed the completion of this project.

Project Description

- **Project Scope and Timeline**

Description	Date
Project Initially Approved for preliminary engineering	October, 2016
Materials Ordered	November, 2016
Materials Received	April, 2017
Project Approved for Full Funding	July, 2017
Below Grade Work Begins	September, 2017
Below Grade Work Completed	October, 2017
Above Grade Work Begins	September, 2017
Above Grade Work Completed	October, 2017
Project Complete	December, 2017

- **Project Cost**
  This project was initially opened for $100k during October 2016 to conduct preliminary engineering in an effort to better estimate the total funding needed to complete the project with the understanding that the cost of the full project would be presented for approval once those estimates were completed. The total cost of this project will be $1,350k in 2017. The 2017 BP included $850k for this project with $100k in 2016 and $750k in 2017. The budgeted amount was estimated based on similar projects that have been previously completed and has been updated based on the preliminary engineering performed. The funding needed above the budgeted amount in 2016 was addressed by the RAC during 2016. The funding needed above the budget in 2017 ($600k) was approved by the RAC in the 6+6 forecast. The estimated total project figure includes a 10% contingency. This contingency is expected to cover uncertainty with the contract labor costs based upon variances that have been noticed on past similar projects.

Economic Analysis and Risks

- **Bid Summary**

Previously established blanket contract agreements will be utilized for related materials. Bids for any other necessary materials, as well as the below and above grade construction, will be sent out soon after project approval.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	-	1,345	-	-	1,345
2. Cost of Removal Proposed	-	5	-	-	5
3. Total Capital and Removal Proposed (1+2)	-	1,350	-	-	1,350
4. Capital Investment 2017 BP	100	750	-	-	850
5. Cost of Removal 2017 BP	-	-	-	-	-
6. Total Capital and Removal 2017 BP (4+5)	100	750	-	-	850
7. Capital Investment variance to BP (4-1)	100	(595)	-	-	(495)
8. Cost of Removal variance to BP (5-2)	-	(5)	-	-	(5)
9. Total Capital and Removal variance to BP (6-3)	100	(600)	-	-	(500)

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2017 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.5%
Capital Breakdown:	
Company Labor:	$70k
Contract Labor:	$591k
Materials:	$395k
Other:	$0k
Local Engineering:	$92K
Burdens:	$81k
Contingency:	$121k
Net Capital Expenditure:	$1,350k

- **Assumptions**
  - Suppliers and contractors will meet reasonable and customary delivery dates for materials and services.
  - The testing and validation for the operation of the new breaker is completed in the time frame scheduled for the project and not delayed due to the availability of resources. Delays could require additional mobilization costs for construction removal and cut-over to the new system.
  - Telecommunications will install a new radio communications at the site to provide communication for the new breaker.
  - Construction costs are estimated and not based on bid pricing.

- **Environmental**
  This project likely does not require permitting for the substation expansion, and there are no known issues regarding air, water, waste, lead, or asbestos.

- **Risks**
  - Completing the project involves risk related to construction work within an operating substation. This project involves installing new underground conduits, reconfiguring the existing system, expanding the substation including grading, and making transmission line modifications into the expanded substation.
  - If the breaker is not added, Transmission will continue to see negative SAIDI impacts associated with this line.

Conclusions and Recommendation
It is recommended that Management approve the FMC Breaker Addition project for $1,350k to enhance the reliability of the Transmission system.

CONFIDENTIAL INFORMATION REDACTED

Appendix A

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DIAGRAM 1

Capital Investment Proposal

Investment Proposal for Investment Committee Meeting on: N/A

Project Name: REL-Stanford 604 Breaker Add

Total Expenditures: $983k (Including $89k of Contingency)

Project Number(s): 144636

Business Unit/Line of Business: Transmission Reliability Performance & Standards

Prepared/Presented By: Keith Yocum – Manager Reliability Performance & Standards

Executive Summary

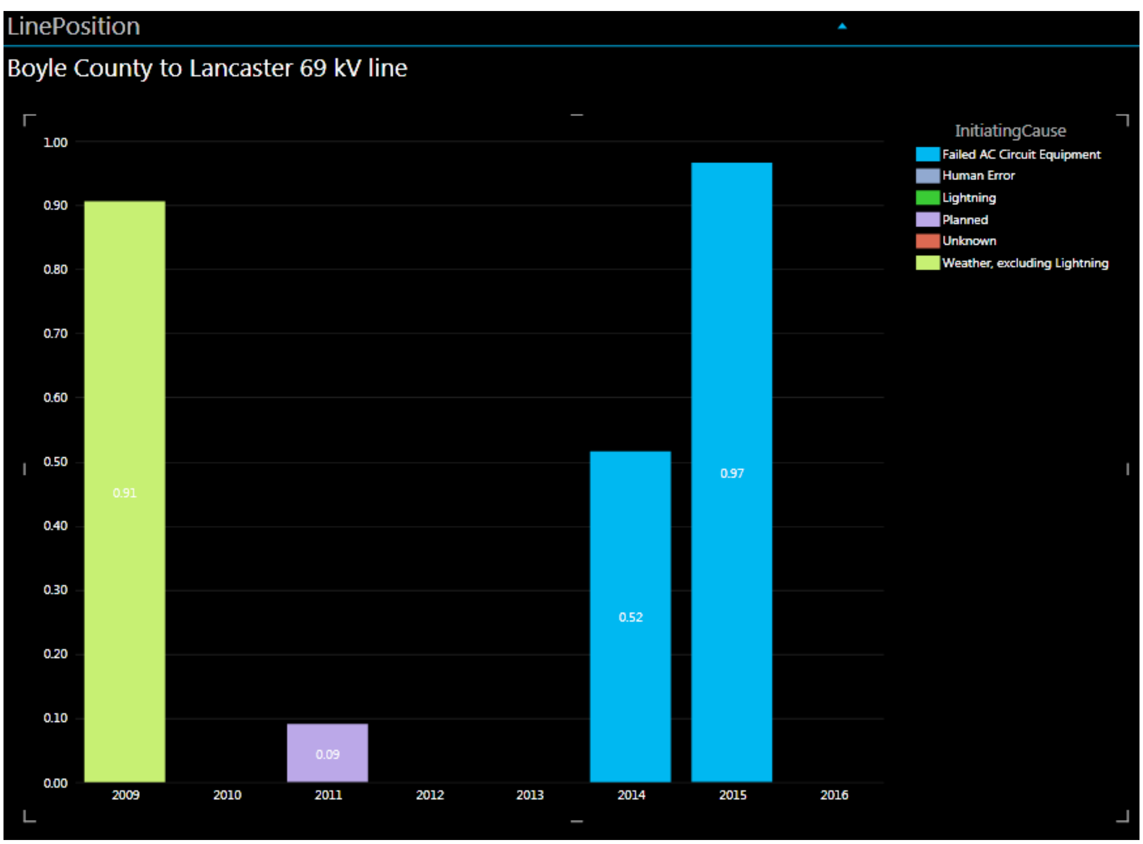
The Transmission Reliability Performance and Standards group identified the need for a breaker at the Stanford substation to reduce the System Average Interruption Duration Index (SAIDI) and the MegaWatt-Mile (MW-Mile is calculated by multiplying total miles of line exposure times the MWs served from the line) exposure on the Boyle County to Lancaster 69 kV line. This line has significant MW-Mile exposure and has been a significant SAIDI contributor for Transmission.

The Boyle County to Lancaster 69 kV line is 22.95 miles long and has 6 distribution transfomers tapped off of it which serve around 8,957 customers and 51.90 MW of load. A fault anywhere along this line will result in an outage on all 6 distribution stations. The placement of a breaker at Stanford will reduce MW-Mile exposure from 1191 to 610, a 48.8% reduction, resulting in only 51% as many customers losing power during a given fault. Diagram 1 include in Appendix A depicts the configuration for the Boyle County to Lancaster 69 kV line.

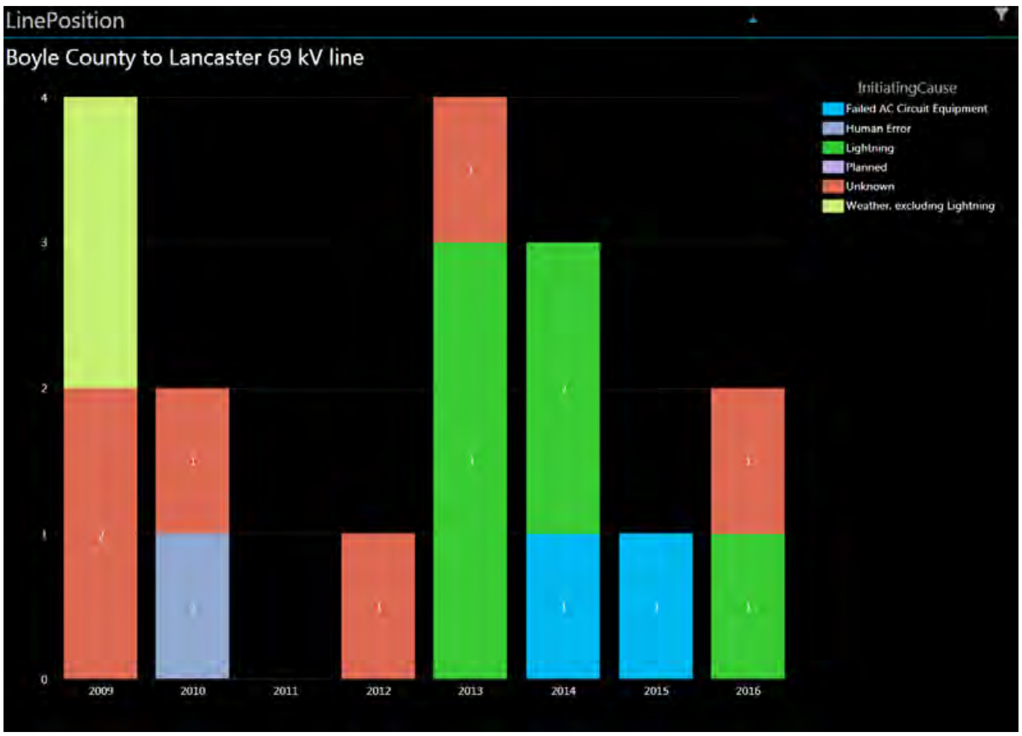
This project was initially opened for $250k to conduct preliminary engineering in an effort to better estimate the total funding needed to complete the project with the understanding that the cost of the full project would be presented for approval once those estimates were completed. The total cost of this project will be $983k with $44k in 2016 and $939k in 2017. The 2017 BP included $850k for this project with $100k in 2016 and $750k in 2017. The budgeted amount was estimated based on similar projects that have been previously completed and has been updated based on the preliminary engineering performed. The funding needed above the budgeted amount in 2016 was addressed by the RAC during 2016. The funding needed above the budget in 2017 ($133k) was partially approved by the RAC in the 3+9 Forecast ($130k) and the remainder ($3k) will be funded by a reduction in project KRTU-17. The estimated total project figure includes a 10% contingency. This contingency is expected to cover uncertainty with the contract labor costs based upon variances that have been noticed on past similar projects.

Background
The Boyle County to Lancaster 69 kV line has been a consistent high contributor to Transmission's SAIDI metric. This breaker will reduce the mileage exposure by half for all of the customers served by this line as Stanford is located in the approximate middle of the line. Therefore, for a given fault, only half as many customers will go out in the case with the breaker, as compared to the case without the breaker. This will also speed up restoration in that the line requiring patrol will also be cut in half.

The chart below shows the historical SAIDI/SAIFI (including MED) for this line:



The following graph shows the number of relay events since 2010 and their associated cause codes.



- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $1,080k
     It is recommended that a breaker be installed on the Boyle County to Lancaster 69 kV line to limit the exposure of customers on a line that has historically had SAIDI issues. This recommendation assists Transmission in achieving the SAIDI targets established as part of the Transmission Reliability Plan (TRP), as well as reduces the number of customers that would otherwise experience a power outage during an event. In addition, this recommendation provides additional relay data to aid in restoring service quickly that includes information to help determine the cause and location of the event.

  2. Alternative #1: NPVRR: ($000s) $615k
     The next best alternative is to add an automated motor operated switch in the steel on the Shelby City side of the Stanford tap. (There is already a project to add a motor to the switch on the Stanford North side of the tap.) This switch would sectionalize the

line and improve the restoration process, however, all customers on this line will continue to experience a power outage during an event. This option is not advisable as this circuit has ranked in the top ten of MW-Mile (customer outage) exposure. These switches also will not provide the additional relaying event data that the breaker option will provide which helps in determining the cause and location of an outage. This option, although not the lowest cost alternative, is not recommended because it does not achieve all of the objectives of the project.

3. Do Nothing: NPVRR: N/A
This option is not advisable as this circuit has ranked in the top ten of MW-Mile (customer outage) exposure and the current state of the line puts Transmission at risk of not being able to accomplish SAIDI targets established as part of the Transmission Reliability Plan which assumed the completion of this project.

Project Description

- **Project Scope and Timeline**

Description	Date
Project Initially Approved for preliminary engineering	September, 2016
Materials Ordered	November, 2016
Materials Received	May, 2017
Project Approved for Full Funding	April, 2017
Below Grade Work Begins	May, 2017
Below Grade Work Completed	May, 2017
Above Grade Work Begins	May, 2017
Above Grade Work Completed	June, 2017
Project Complete	August, 2017

- **Project Cost**
This project was initially opened for $250k to conduct preliminary engineering in an effort to better estimate the total funding needed to complete the project with the understanding that the cost of the full project would be presented for approval once those estimates were completed. The total cost of this project will be $983k with $44k in 2016 and $939k in 2017. The 2017 BP included $850k for this project with $100k in 2016 and $750k in 2017. The budgeted amount was estimated based on similar projects that have been previously completed and has been updated based on the preliminary engineering performed. The funding needed above the budgeted amount in 2016 was addressed by the RAC during 2016. The funding needed above the budget in 2017 ($133k) was partially approved by the RAC in the 3+9 Forecast ($130k) and the remainder ($3k) will be funded by a reduction in project KRTU-17. The estimated total project figure includes a 10% contingency. This contingency is expected to cover uncertainty with the contract labor costs based upon variances that have been noticed on past similar projects.

Economic Analysis and Risks

- **Bid Summary**
  Previously established blanket contract agreements will be utilized for related materials. Bids for any other necessary materials, as well as the below and above grade construction, will be sent out soon after project approval.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	44	939	-	-	983
2. Cost of Removal Proposed			-	-	-
3. Total Capital and Removal Proposed (1+2)	44	939	-	-	983
4. Capital Investment 2017 BP	100	750	-	-	850
5. Cost of Removal 2017 BP	-	-	-	-	-
6. Total Capital and Removal 2017 BP (4+5)	100	750	-	-	850
7. Capital Investment variance to BP (4-1)	56	(189)	-	-	(133)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	56	(189)	-	-	(133)

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2017 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):
Discount Rate: 6.5%
Capital Breakdown:
Labor: $45k
Contract Labor: $405k
Materials: $337k
Other: $0k
Local Engineering: $60k
Burdens: $47k
Contingency: $89k
Net Capital Expenditure: $983k

- **Assumptions**
  - Suppliers and contractors will meet reasonable and customary delivery dates for materials and services.
  - The testing and validation for the operation of the new breaker is completed in the time frame scheduled for the project and not delayed due to the availability of resources. Delays

could require additional mobilization costs for construction removal and cut-over to the new system.
    - Telecommunications will install a new radio communications at the site to provide communication for the new breaker.
    - Construction costs are estimated and not based on bid pricing.

- **Environmental**
  This project does not require permitting and there are no known issues regarding air, water, waste, lead, or asbestos.

- **Risks**
    - Completing the project involves risk related to construction work within an operating substation. This project involves installing new underground conduits and reconfiguring the existing system.
    - If the breaker is not added, Transmission will continue to see negative SAIDI impacts associated with this line.

Conclusions and Recommendation
It is recommended that Management approve the Stanford Breaker Addition project for $983k to enhance the reliability of the Transmission system.

CONFIDENTIAL INFORMATION REDACTED

Appendix A

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DIAGRAM 1

Investment Proposal 146982 Ghent-Blackwell Pole Replacement

Investment Proposal for Investment Committee Meeting on: April 27, 2016

Project Name: Ghent-Blackwell Pole Replacement

Total Expenditures: $2,093k
Total Contingency: $190k (10%)

Project Number(s): 146982

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Terry Snow/Adam Smith

Executive Summary
The proposed project is to replace twenty-three (23) wood structures on the Ghent-Blackwell 138kV line with steel based on the results of a routine line inspection. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

The alternative of replacing poles upon failure will result in much higher long term replacement costs due to mobilization of crews back to the site each time one fails and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability.

This project is included in the 2016 BP for $567k. The original scope of work included the replacement of fifteen (15) structures identified through inspections. Subsequent to the 2014 inspection, an additional eight (8) structures were identified to be in need of replacement. Also, due to the difficulty of obtaining an extended outage, the estimated cost to complete the project energized was added to the project cost. The current total project cost is $2,093k and was approved by the RAC in the 3+9 forecast.

Background
Above ground pole inspections are performed by the company at defined intervals in order to discover problems that may impact the integrity and reliability of the Transmission System. During a routine climbing inspection of the Ghent-Blackwell 138kV line in 2014, fifteen (15) structures were identified as priority poles. Subsequent to the 2014 inspection, an additional eight (8) structures were found and determined to be in need of replacement. All twenty three (23) structures need to be replaced in order to ensure the integrity and reliability of this line. There are 155 total structures along this 23.61 mile line. In addition to the (23) structures to be replaced on this project, there will be three (3) replaced concurrently on the Ghent-Blackwell NRP project (146983). These structures are located at various points along the entire length of the line.

- **Alternatives Considered (1 –Recommendation, 2 –Do nothing, 3 –Next Best Alt)**
  1. Recommendation: NPVRR: ($000s) $2,848k
     The recommendation is to replace the structures energized due to the difficulty in obtaining an extended outage. If the opportunity to complete the project de-energized would occur, we would pursue this option and it would reduce the NPVRR by $607k.
  2. Do Nothing: NPVRR: ($000s) $4,100k
     The alternative of do nothing would result in replacing poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on reliability.
     Next Best Alternative(s): NPVRR: ($000s) $3,652k
  3. The next best alternative would be to replace the poles with wood structures. The manufacturer's recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended life span of 90 years. This option assumes replacement of wood structures in 30 years and an escalation factor of 4% which is in line with market cost increases over the last 15 years.

Project Description

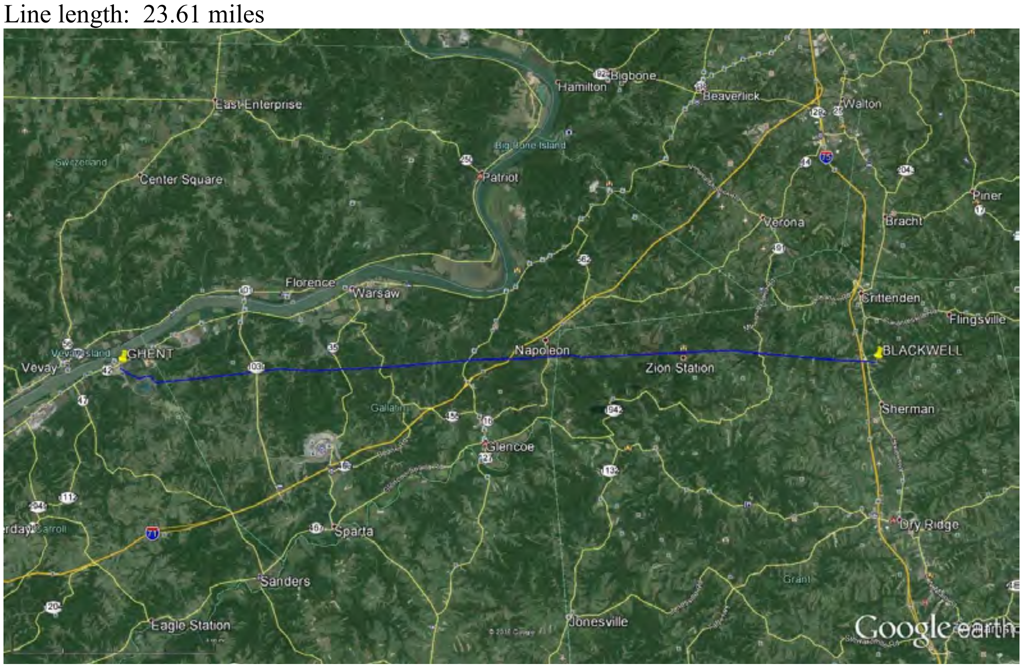
- **Project Scope and Timeline**
  The scope of work will consist of installing twenty-one (21) standard steel H-frame structures, one (1) 3-pole dead end structure, and 1 (1) 3-pole running corner and associated hardware and material, and the removal of (23) wood structures and associated hardware and material. The line construction will be based on continuing contracts from our line contractors. B&B, Elliot, Groves and Pike are the four contractors awarded the T&D Overhead Construction and Maintenance contract from the October 2011 Investment Committee meeting. The contract extension was re-approved by the IC in July of 2014. Construction is scheduled to begin in August of 2016 and to be completed in November of 2016.

  The construction milestones for this project are provided below:

Construction Milestones	
March 2016	Engineering and Design

April 2016	Steel Poles Ordered
July 2016	Steel Poles Received
August 2016	Line Construction Begins
November 2016	Line Construction Completed

A facility map of the Ghent-Blackwell 138kV line is shown below:
Line length: 23.61 miles



- **Project Cost**
  This project is included in the 2016 BP for $567k. The current total project cost is $2,093k and was approved by the RAC in the 3+9 forecast. Historical and existing contract and purchasing agreements were used to estimate the cost of material and contract labor. Due to the difficulty of obtaining an extended outage, the estimated cost to complete the project energized was added to the original project cost. This project includes 10% contingency to cover unexpected increases in cost due to weather, rocky soil, outage delays, reclamation, etc. 10% contingency is a standard assumption used across all of our projects and is calculated as a percentage of total burdened costs.

Economic Analysis and Risks

- **Bid Summary**
  Based on preliminary engineering, Transmission Lines has estimated the material packages for construction of this project to be $569k. This project will utilize standard and custom

steel structures. Hardware will be purchased through Brownstown Electrical Supply. The line construction will be based on continuing contracts with our line contractors. Davis H. Elliot, Pike Electric, B&B Electric and William E. Groves are the four main contractors which have been awarded the T&D Overhead Construction and Maintenance contracts.

Transmission Lines Material Cost Breakdown	
Material	**Cost**
Steel Poles	$490k
Hardware	$79k
Total	$569k

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	**2016**	**2017**	**2018**	**Post 2018**	**Total**
1. Capital Investment Proposed	1,844	-	-	-	1,844
2. Cost of Removal Proposed	250	-	-	-	250
3. Total Capital and Removal Proposed (1+2)	2,093	-	-	-	2,093
4. Capital Investment 2016 BP	450	-	-	-	450
5. Cost of Removal 2016 BP	117	-	-	-	117
6. Total Capital and Removal 2016 BP (4+5)	567	-	-	-	567
7. Capital Investment variance to BP (4-1)	(1,394)	-	-	-	(1,394)
8. Cost of Removal variance to BP (5-2)	(133)	-	-	-	(133)
9. Total Capital and Removal variance to BP (6-3)	(1,526)	-	-	-	(1,526)

Financial Detail by Year - O&M ($000s)	**2016**	**2017**	**2018**	**Post 2018**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2016 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):
Discount Rate: 6.49%
Capital Breakdown:
Labor: $96k
Contract Labor: $987k
Materials: $569k
Local Engineering: $140k
Burdens: $111k
Contingency: $190k
Reimbursements: ($0)
Net Capital Expenditure: $2,093k

Financial Analysis - Project Summary ($000)	**2016**	**2017**	**2018**	**2019**	**2020**	**Life of Project**
Project Net Income	$10	$48	$98	$93	$89	$1,904
Project ROE	1.9%	4.5%	9.8%	9.8%	9.8%	9.3%

- **Assumptions**

  Recommendation – The cost of this alternative assumes that the line outage will not be available and the structure replacements will need to be completed with the 138kV line energized.

  Do nothing alternative – The cost of this alternative would be approximately 60% higher due to overtime labor charges and the cost to mobilize and demobilize the construction crews. These poles would fail and require replacement within the next four years.

  Next best alternative - The cost of this alternative assumes the cost of the wood poles is 51% of the cost of the steel poles, and that the wood poles would be replaced again in 30 years.

- **Environmental**
  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

- **Risks**
  Without the proposed replacement of the priority poles on the Ghent-Blackwell 138kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays. Schedule delays may also occur if the requested outage is not obtained to complete the scheduled work.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the Ghent-Blackwell Pole Replacement project for $2,093k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Investment Proposal for Investment Committee Meeting on: June 29, 2016

Project Name: Mill Creek 4503 & 4503-33 Tie Breaker Replacements

Total Approved Expenditures: $920k

Total Revised Expenditures: $1,128k

Project Number(s): 147118

Business Unit/Line of Business: Transmission Substation Construction

Prepared/Presented By: Chris Talley – Manager Transmission Substation Construction

Reason for Revision

This project was originally approved in June 2015 for $920k to replace (2) 345kV circuit breakers at Mill Creek. The breakers that were changed out are tie breakers MC-4503 and MC-4503-33. Tie breakers are designed to tie different circuits together to enable one circuit to be fed off of another circuit's main breaker. These breakers needed replacement as several parts were needed, but the parts are no longer available because the manufacturer is no longer in business. The breakers were also in need of replacement due to leaking SF6 gas. This project must be revised to the amount of $1,128k ($208k increase). The original estimate for this project was based on similar work completed at the Mill Creek substation. The primary driver of the increased cost was the additional contract and company installation labor required due to the amount of conduit and control wiring. The physical configuration of the circuit breakers and the location of the control cabinets was different than what was assumed in the estimate which led to costs greater than what was anticipated in the estimate. The Corporate RAC approved the increase in the June 2016 meeting.

Financial Summary

Financial Summary ($000s):	Approved	Revised	Explanation
Discount Rate:	6.5%	6.5%	
Capital Breakdown:			
Labor:	$ 34	$ 77	
Contract Labor:	$ 190	$ 349	Cost of conduit and control wiring greater than anticipated
Materials:	$ 476	$ 502	
Other:	$ -	$ 6	
Local Engineering:	$ 87	$ 118	
Burdens:	$ 49	$ 76	
Contingency:	$ 84	$ -	
Reimbursements:	$ -	$ -	
Net Capital Expenditure:	$ 920	$ 1,128	
NPVRR:	$ 1,136	$ 1,389	

Financial Detail by Year - Capital ($000s)	2015	2016	2017	Post 2017	Total
1. Capital Investment Proposed	580	539	-	-	1,119
2. Cost of Removal Proposed	(3)	11	-	-	8
3. Total Capital and Removal Proposed (1+2)	578	550	-	-	1,128
4. Capital Investment 2016 BP	496	424	-	-	920
5. Cost of Removal 2016 BP	-	12	-	-	12
6. Total Capital and Removal 2016 BP (4+5)	496	436	-	-	932
7. Capital Investment variance to BP (4-1)	(85)	(115)	-	-	(199)
8. Cost of Removal variance to BP (5-2)	3	2	-	-	4
9. Total Capital and Removal variance to BP (6-3)	(82)	(113)	-	-	(195)

Financial Detail by Year - O&M ($000s)	2015	2016	2017	Post 2017	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2016 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Conclusions and Recommendation
It is recommended that the Investment Committee approve the Mill Creek 4503 & 4503-33 TIE Breaker Replacements project for $1,128k to enhance the reliability of the Transmission system.

Approval Confirmation for Capital Projects Greater Than or Equal to $1 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	Victor A. Staffieri Chairman, CEO and President

Investment Proposal

Investment Proposal for Investment Committee Meeting on: N/A

Project Name: Mill Creek 4503 & 4503-33 TIE Breaker Replacements

Total Expenditures: $920k ($84k of Contingency)

Project Number(s): 147118

Business Unit/Line of Business: Transmission Substation Construction

Prepared/Presented By: Chris Talley – Manager Transmission Substation Construction

Executive Summary

The scope of this project includes the replacement of (2) 345kV circuit breakers at Mill Creek. The breakers that will be changed out are MC-4503 and MC-4503-33. These breakers must be replaced as several parts are needing replacement, but the parts are no longer available because the manufacturer is no longer in business. The breakers are also in need of replacement due to leaking SF6 gas.

The total cost of this project will be $920k and was approved by the 2015 5+7 RAC. No funding was included in the 2015 BP for this project. The estimated total project figure includes a 10% contingency.

Background
Inspection of the breakers identified several parts needing replacement as well as severe SF6 gas leaks; however, parts are no longer available because the manufacturer is no longer in business. It is critical that the remaining breakers be replaced to improve the reliability of Mill Creek Unit 2 and reduce the risk of damage to the unit from a breaker failure.

- **Alternatives Considered (1 –Recommendation, 2 – Next Best Alt, 3 – Do Nothing)**
  Recommendation – It is recommended to replace the MC-4503 and MC-4503-33 circuit breakers at Mill Creek. Parts from the breakers that are retired will be used to support other similar breakers that are still in service on the system.
  NPVRR: ($000s) $1,136k

  Next Best Alternative(s) – Replacing only one Mill Creek breaker at this time and replacing the other at a later date. This would result in continued SF6 leakage from the delayed breaker as well as the inherent risk of having Mill Creek Unit 2 connected to the transmission system by only one breaker for the duration of the second breaker's replacement.
  NPVRR: ($000s) $1,150k

  Do Nothing – This option is not advisable as the breakers currently in-service at Mill Creek have a significant history of maintenance issues and the parts necessary to alleviate these issues are no longer available. These breakers are also leaking SF6 gas, which requires additional maintenance activities as well.
  NPVRR: ($000s) ($52k)

Project Description

- **Project Scope and Timeline**

Description	Date
Project Approved	June, 2015
Materials Ordered	June, 2015
Materials Received	February, 2016
Below Grade Work Begins	March, 2016
Below Grade Work Completed	March, 2016
Above Grade Work Begins	April, 2016
Above Grade Work Completed	April, 2016
Project Complete	April, 2016

- **Project Cost**
  The total cost of this project will be $920k and was approved by the 2015 5+7 RAC. No funding was included in the 2015 BP for this project. The estimated total project figure includes a 10% contingency.

Economic Analysis and Risks

- **Bid Summary**
  The 345kV breakers will be purchased under the existing breaker purchasing agreement. Bids for any other necessary materials as well as the civil, below, and above grade work will be sent out in the fall of 2015.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2015	2016	2017	Post 2017	Total
1. Capital Investment Proposed	496	412	-	-	908
2. Cost of Removal Proposed	-	12	-	-	12
3. Total Capital and Removal Proposed (1+2)	496	424	-	-	920
4. Capital Investment 2015 BP	-	-	-	-	-
5. Cost of Removal 2015 BP	-	-	-	-	-
6. Total Capital and Removal 2015 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(496)	(412)	-	-	(908)
8. Cost of Removal variance to BP (5-2)	-	(12)	-	-	(12)
9. Total Capital and Removal variance to BP (6-3)	(496)	(424)	-	-	(920)

Financial Detail by Year - O&M ($000s)	2015	2016	2017	Post 2017	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2015 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):
Discount Rate: 6.5%
Capital Breakdown:
Labor: $34k
Contract Labor: $190k
Materials: $476k
Other: $0k
Local Engineering: $87k
Burdens: $49k
Contingency: $84k
Reimbursements: ($0k)
Net Capital Expenditure: $920k

Financial Analysis - Project Summary ($000)	2015	2016	2017	2018	2019	Life of Project
Project Net Income	$ (6)	$ (7)	$ 13	$ 21	$ 47	$ 993
Project ROE	-4.40%	-2.00%	2.70%	4.90%	11.20%	10.20%

- **Assumptions**
  - There is no Transmission Lines work associated with this project
  - There will be no 4533 line relay upgrades associated with this project
  - The reaquested outages for construction will be granted. The labor estimate assumes 4 day/week, 10 hour/day work week with no special construction considerations to minimize the required outage window.
  - Costs to expand the ground grid or lightning protection in the entire station to meet current standards or codes are not included in this estimate. The existing ground grid impedance to remote ground along with the touch and step potential is assumed to be adequate. New ground grid is only installed in the affected substation expansion area for touch and step potential upgrade.
  - Suppliers and contractors will meet reasonable and customary delivery dates for materials and services.

- **Environmental**
  This project does not require permitting and there are no known issues regarding air, water, waste, lead, or asbestos.

- **Risks**
  Completing the project involves risk related to high voltage substation construction work. Not completing the project decreases the reliability of the Mill Creek Unit 3 generator. Project schedule assumes that the planned maintenance outage on Mill Creek Unit 3 will take place between 4/16/16 and 6/10/16 per the current schedule. Once we start this work, the unit will not be able to go online without at least one of the two breakers in service. If only one of the two breakers is available when the unit is brought back online, then it is possible that an inadvertent trip of either the 345kV BUS SEC B or or the 4532 Blue Lick line could cause Unit 3 to trip offline depending on which of the two breakers is in-service. This is due to the fact that it will lose connection with the Transmission System.

Conclusions and Recommendation
It is recommended that the project Mill Creek 4503 & 4503-33 TIE Breaker Replacements be approved for $920k to enhance the reliability of the Transmission system.

Investment Proposal 147313 Bardstown-Elizabethtown Pole Replacement

Investment Proposal for Investment Committee Meeting on: July 27, 2016

Project Name: Bardstown-Elizabethtown Pole Replacement

Total Expenditures: $2,896k
Total Contingency: $263k (10%)

Project Number(s): 147313

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Nate Mullins/Adam Smith

Executive Summary
The proposed project is to replace eighty-seven (87) wood structures on the Bardstown-Elizabethtown 69kV line with steel, during a routine outage, based on the results of a routine line inspection.

This proposal is to proactively replace the structures over the course of the next year, prior to failure, to ensure the integrity and reliability of this line, and to prevent outages resulting from such failures. The alternative of replacing poles upon failure will result in much higher long term replacement costs due to mobilization of crews back to the site each time one fails and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability.

The total project cost is $2,896k and was included in the 2016 Business Plan for $2,002k in 2017. The original scope of work included replacement of eighty-nine (89) structures identified through inspections based on an average structure cost. Subsequent to the plan, we identified the need to replace an existing line switch on a structure identified for replacement and updated the scope to include replacement of eighty-seven (87) structures. In addition, we accelerated the project to 2016 due to the condition of the structures. The updated estimate also included project specific costs related to access and terrain not included in the original estimate. This project was approved by the RAC in the 6+6 forecast.

Background
Above ground pole inspections are performed by the company at defined intervals in order to discover problems that may impact the integrity and reliability of the Transmission System. During routine climbing inspections of the Bardstown-Elizabethtown 69kV line, eighty-seven (87) structures were identified as priority poles and determined to be in need of replacement in order to ensure the integrity and reliability of this line. There are 556 total structures along this 38.93 mile line.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $3,940k
     The recommendation is to replace all eighty-seven (87) structures, and one (1) existing switch during a scheduled outage.
  2. Alternative #1: NPVRR: ($000s) $5,674k
     The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on reliability.
  3. Alternative #2: NPVRR: ($000s) $4,269k
     The next best alternative would be to replace the poles with wood structures. The manufacturer's recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended life span of 90 years. This option also assumes replacement of wood structures in 30 years and an escalation rate of 4% which is in line with market cost increases over the last 15 years.

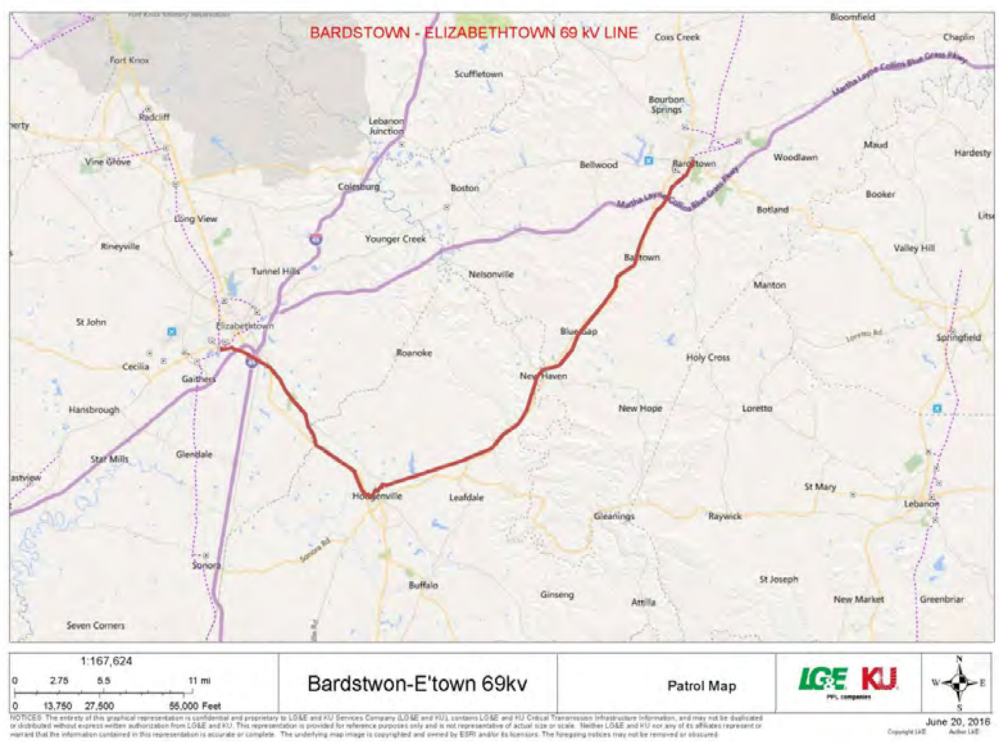
Project Description

- **Project Scope and Timeline**
  The scope of work will consist of installing sixty-two (62) single pole steel structures, twenty-one (21) standard steel H-frames, (2) steel 3 pole running corners, (1) steel 2 pole dead-end, (1) steel 3 pole dead end, one (1) in line one way switch, and associated hardware and material, and the removal of eighty-seven (87) wood structures, and associated hardware and material. The line construction will be based on continuing contracts from our line contractors. B&B, Elliot, Groves and Pike are the four contractors awarded the T&D Overhead Construction and Maintenance contract from the October 2011 Investment Committee meeting. The contract extension was re-approved by the IC in July of 2014. Construction is scheduled to begin in September of 2016 and be completed in December of 2016.

  The construction milestones for this project are provided below:

Construction Milestones	
April 2016	Engineering and Design
August 2016	Steel Poles Issued
September 2016	Line Construction Begins
December 2016	Line Construction Completed

A facility map of the Bardstown-Elizabethtown 69kV line is shown below:
Line length: 38.93 miles



- **Project Cost**
  The total project cost is $2,896k and was included in the 2016 Business Plan for $2,002k in 2017. This project was approved by the RAC in the 6+6 forecast. Historical and existing contract and purchasing agreements were used to estimate the cost of material and contract labor. This project includes a 10% contingency which is reasonable based on the level of detailed engineering, confidence in the cost of material and contractors, and potential unknown risks such as weather delays, rocky terrain, outage delays, reclamation, and structure access.

Economic Analysis and Risks

- **Bid Summary**
  Based on preliminary engineering, Transmission lines has estimated the material packages for construction to be $767k. This project will utilize stock steel structures, and associated hardware and material. The line construction will be based on continuing contracts with our line contractors. Davis H. Elliot, Pike Electric, B&B Electric and William E. Groves are the

four main contractors which have been awarded the T&D Overhead Construction and Maintenance contracts.

Transmission Lines Material Cost Breakdown	
Material	**Cost**
Steel Poles	$721k
Hardware	$46k
Total	$767k

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	**2016**	**2017**	**2018**	**Post 2018**	**Total**
1. Capital Investment Proposed	2,261	-	-	-	2,261
2. Cost of Removal Proposed	635	-	-	-	635
3. Total Capital and Removal Proposed (1+2)	2,896	-	-	-	2,896
4. Capital Investment 2016 BP	-	1,885	-	-	1,885
5. Cost of Removal 2016 BP	-	117	-	-	117
6. Total Capital and Removal 2016 BP (4+5)	-	2,002	-	-	2,002
7. Capital Investment variance to BP (4-1)	(2,261)	1,885	-	-	(376)
8. Cost of Removal variance to BP (5-2)	(635)	117	-	-	(518)
9. Total Capital and Removal variance to BP (6-3)	(2,896)	2,002	-	-	(894)

Financial Detail by Year - O&M ($000s)	**2016**	**2017**	**2018**	**Post 2018**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2016 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):
Discount Rate: 6.49%
Capital Breakdown:
Labor: $86k
Contract Labor: $1,350
Materials: $767k
Local Engineering: $197k
Burdens: $233k
Contingency: $263k
Reimbursements: ($0)
Net Capital Expenditure: $2,896k

Financial Analysis - Project Summary ($000)	2016	2017	2018	2019	2020	Life of Project
Project Net Income	$7	$65	$135	$129	$123	$2,633
Project ROE	0.9%	2.7%	7.2%	10.0%	10.0%	9.3%

- **Assumptions**
  Recommendation - This alternative assumes that the line outage will be available and that all eighty-seven (87) structures, and one (1) switch will be replaced during this timeframe.

  Do Nothing alternative – The cost of this alternative would be approximately 60% higher due to overtime labor charges and the cost to mobilize and demobilize construction crews. These poles would fail and require replacement within the next four years.

  Next Best alternative – The cost of this alternative assumes the cost of the wood poles is 24% the cost of the steel poles, and that the wood poles would be replaced again in 30 years.

- **Environmental**
  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

- **Risks**
  Without the proposed replacement of the priority poles on the Bardstown-Elizabethtown 69kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays. Schedule delays may also occur if the requested outage is not obtained to complete the scheduled work.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the Bardstown-Elizabethtown pole replacement project for $2,896k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $1 million</u>:

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	Victor A. Staffieri Chairman, CEO and President

Investment Proposal for Investment Committee Meeting on: March 30, 2016

Project Name: Trimble County-Centerfield Pole Replacement

Total Expenditures: $2,259k
Total Contingency: $169k (8%)

Project Number(s): 147328

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: John Doll/Adam Smith

Executive Summary

The proposed project is to replace thirty-five (35) wood structures on the Trimble County-Centerfield 138kV line with steel based on the results of a routine line inspection. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

The alternative of replacing poles upon failure will result in much higher long term replacement costs due to mobilization of crews back to the site each time one fails and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability.

This project is included in the 2016 BP for $1,360k. The original project cost estimate was based on a formula which did not include energized pricing. Once detailed engineering analysis was completed, a decision was made to complete the work energized due to the risk of not being able to obtain an extended outage to complete the work. The current total project cost is $2,259k and was approved by the RAC in the 2+10 forecast.

Background
Above ground pole inspections are performed by the company at defined intervals in order to discover problems that may impact the integrity and reliability of the Transmission System. During a routine climbing inspection of the Trimble County-Centerfield 138kV line in 2015, thirty-five (35) structures were identified as priority poles and determined to be in need of replacement in order to ensure the integrity and reliability of this line. There are 117 total structures along this 15.7 mile line.

- **Alternatives Considered (1 –Recommendation, 2 –Do nothing, 3 –Next Best Alt)**
  1. Recommendation: NPVRR: ($000s) $3,068k
     The recommendation is to replace the structures energized due to the difficulty in obtaining an extended outage. If the opportunity to complete the project de-energized would occur, we would pursue this option and it would reduce the NPVRR by $557k.
  2. Do Nothing: NPVRR: ($000s) $4,410k
     The alternative of do nothing would result in replacing poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on reliability.
  3. Next Best Alternative(s): NPVRR: ($000s) $3,477k
     The next best alternative would be to replace the poles with wood structures. The manufacturer's recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended life span of 90 years. This option assumes replacement of wood structures in 30 years and an escalation factor of 4% which is in line with market cost increases over the last 15 years.

Project Description

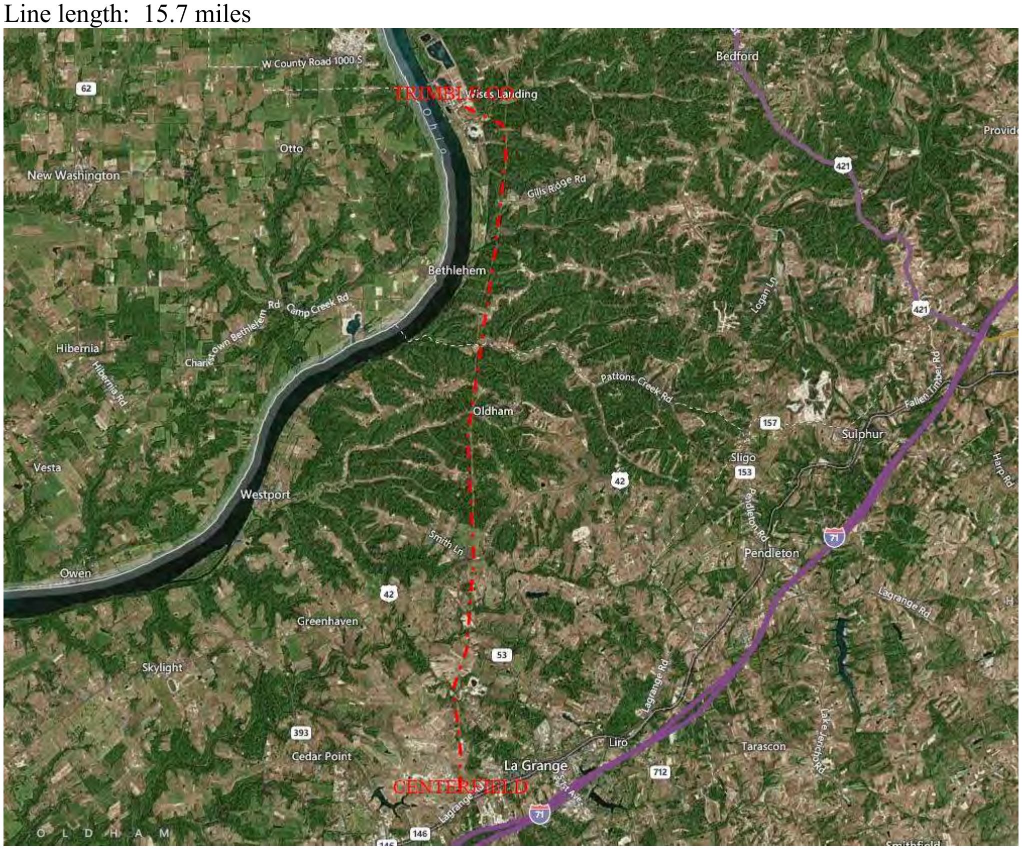
- **Project Scope and Timeline**
  The scope of work will consist of installing twenty-seven (27) standard steel H-frame structures and eight (8) 3-pole structures, and associated hardware and material, and the removal of (27) wood H-frame and (8) 5-pole wood structures, and associated hardware and material. The line construction will be based on continuing contracts from our line contractors. B&B, Elliot, Groves, and Pike are the four contractors awarded the T&D Overhead Construction and Maintenance contract from the October 2011 Investment Committee meeting. The contract extension was re-approved by the IC in July of 2014. Construction is scheduled to begin in May of 2016 and to be completed in July of 2016.

  The construction milestones for this project are provided below:

Construction Milestones	
January 2016	Engineering and Design
April 2016	Steel Poles Ordered
May 2016	Steel Poles Received

Construction Milestones	
May 2016	Line Construction Begins
July 2016	Line Construction Completed

A facility map of the Trimble County-Centerfield 138kV line is shown below:
Line length: 15.7 miles



- **Project Cost**
  This project is included in the 2016 BP for $1,360k. The current total project cost is $2,259k and was approved by the RAC in the 2+10 forecast. Historical and existing contract and purchasing agreements were used to estimate the cost of material and contract labor.

Economic Analysis and Risks

- **Bid Summary**
  Based on preliminary engineering, Transmission Lines has estimated the material packages for construction of this project to be $731k. This project will utilize standard steel structures. Hardware will be purchased through Brownstown Electrical Supply. The line construction

will be based on continuing contracts with our line contractors. Davis H. Elliot, Pike Electric, B&B Electric and William E. Groves are the four main contractors which have been awarded the T&D Overhead Construction and Maintenance contracts.

Transmission Lines Material Cost Breakdown	
Material	**Cost**
Steel Poles	$676k
Hardware	$55k
Total	$731k

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	**2016**	**2017**	**2018**	**Post 2018**	**Total**
1. Capital Investment Proposed	1,826	-	-	-	1,826
2. Cost of Removal Proposed	433	-	-	-	433
3. Total Capital and Removal Proposed (1+2)	2,259	-	-	-	2,259
4. Capital Investment 2016 BP	1,213	-	-	-	1,213
5. Cost of Removal 2016 BP	147	-	-	-	147
6. Total Capital and Removal 2016 BP (4+5)	1,360	-	-	-	1,360
7. Capital Investment variance to BP (4-1)	(613)	-	-	-	(613)
8. Cost of Removal variance to BP (5-2)	(286)	-	-	-	(286)
9. Total Capital and Removal variance to BP (6-3)	(899)	-	-	-	(899)

Financial Detail by Year - O&M ($000s)	**2015**	**2016**	**2017**	**Post 2017**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2016 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):
Discount Rate: 6.49%
Capital Breakdown:
Labor: $46k
Contract Labor: $1,005k
Materials: $731k
Local Engineering: $236k
Burdens: $72k
Contingency: $169k
Reimbursements: ($0k)
Net Capital Expenditure: $2,259k

Financial Analysis - Project Summary ($000)	2016	2017	2018	2019	2020	Life of Project
Project Net Income	$102	$94	$104	$99	$94	$1,751
Project ROE	17.5%	8.3%	9.7%	9.7%	9.7%	9.8%

- **Assumptions**

  Recommendation – The cost of this alternative assumes that the line outage will not be available and the structure replacements will need to be completed with the 138kV line energized.

  Do nothing alternative – The cost of this alternative would be approximately 60% higher due to overtime labor charges and the cost to mobilize and demobilize the construction crews. These poles would fail and require replacement within the next four years.

  Next best alternative - The cost of this alternative assumes the cost of the wood poles is 51% of the cost of the steel poles, and that the wood poles would be replaced again in 30 years.

- **Environmental**
  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

- **Risks**
  Without the proposed replacement of the priority poles on the Trimble County-Centerfield 138kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays. Schedule delays may also occur if the requested outage is not obtained to complete the scheduled work.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the Trimble County-Centerfield Pole Replacement project for $2,259k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Investment Proposal Project 147334 London-Sweet Hollow Pole Replacement

Investment Proposal for Investment Committee Meeting on: April 27, 2016

Project Name: London-Sweet Hollow Pole Replacement

Total Expenditures: $3,987k
Total Contingency: $345k (9%)

Project Number(s): 147334

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Nick Poston/Adam Smith

Executive Summary

The proposed project is to replace sixty-five (65) wood structures on the London-Sweet Hollow 69kV line with steel based on the results of a routine line inspection. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

The alternative of replacing poles upon failure will result in much higher long term replacement costs due to mobilization of crews back to the site each time one fails and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability.

This project is included in the 2016 BP for $2,720k. The original scope of work included the replacement of sixty-five (65) structures with wood and steel during a scheduled outage. Through coordination with distribution, we have worked out a solution for the distribution underbuild to attach to the steel poles. As a result, the decision was made to replace all sixty five (65) structures with steel. Also, due to the difficulty of obtaining an extended outage, the cost to complete the project energized was added. The current total project cost is $3,987k and was approved by the RAC in the 3+9 forecast.

Background

Above ground pole inspections are performed by the company at defined intervals in order to discover problems that may impact the integrity and reliability of the Transmission System. During a routine climbing inspection of the London-Sweet Hollow 69kV line in 2012, sixty-five (65) structures were identified as priority poles and determined to be in need of replacement in order to ensure the integrity and reliability of this line. There are 106 total structures along this 11.21 mile line.

- **Alternatives Considered (1 –Recommendation, 2 –Do nothing, 3 –Next Best Alt)**
    1. Recommendation: NPVRR: ($000s) $5,499k
    The recommendation is to replace the structures energized due to the difficulty in obtaining an extended outage. If the opportunity to complete the project de-energized would occur, we would pursue this option and it would reduce the NPVRR by $1,116k.
    2. Do Nothing: NPVRR: ($000s) $7,885k
    The alternative of do nothing would result in replacing poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on reliability.
    3. Next Best Alternative(s): NPVRR: ($000s) $4,377k
    The next best alternative would be to replace all 65 poles with wood structures. The manufacturer's recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended life span of 90 years. This option assumes replacement of wood structures in 30 years and an escalation factor of 4% which is in line with market cost increases over the last 15 years.

Project Description

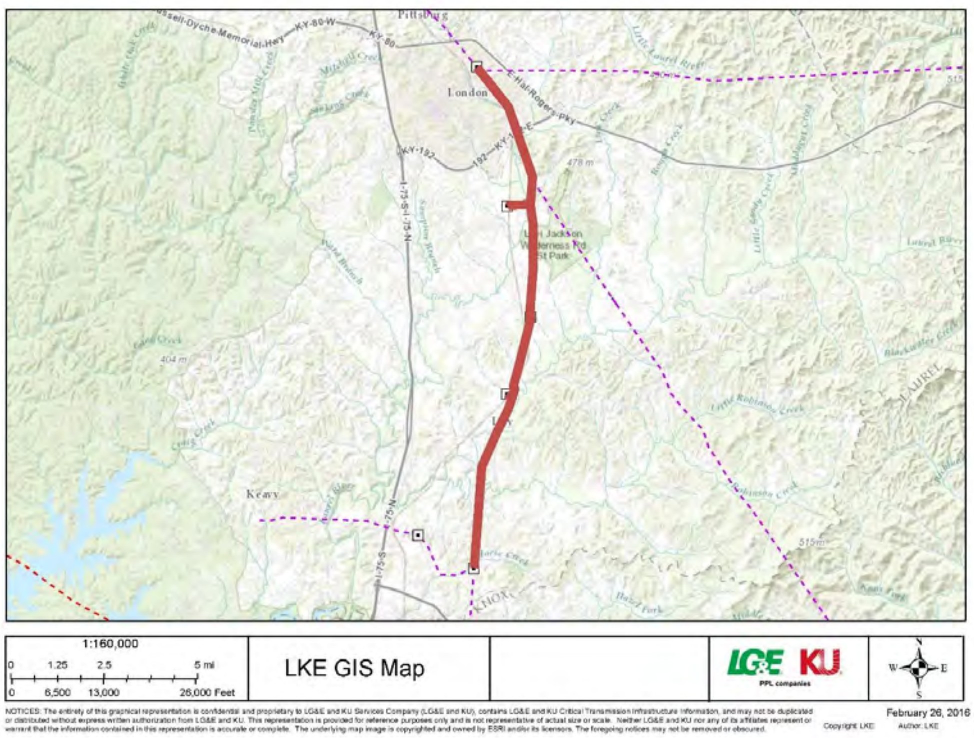
- **Project Scope and Timeline**
The scope of work will consist of installing fifty-eight (58) standard steel H-frame structures, one (1) custom steel H-frame structure, one (1) steel custom switch and platform structure, four (4) custom steel running corners, one (1) standard steel z-frame structure, and associated hardware and material, and the removal of (65) wood structures, and associated hardware and material. The line construction will be based on continuing contracts from our line contractors. B&B, Elliot, Groves and Pike are the four contractors awarded the T&D Overhead Construction and Maintenance contract from the October 2011 Investment Committee meeting. The contract extension was re-approved by the IC in July of 2014. Construction is scheduled to begin in June of 2016 and to be completed in July of 2016.

The construction milestones for this project are provided below:

Construction Milestones	
April 2016	Engineering and Design
April 2016	Steel Poles Ordered
June 2016	Steel Poles Received
June 2016	Line Construction Begins

July 2016	Line Construction Completed

A facility map of the London-Sweet Hollow 69kV line is shown below:
Line length: 11.21 miles



- **Project Cost**
  This project is included in the 2016 BP for $2,720k. The current total project cost is $3,987k and was approved by the RAC in the 3+9 forecast. Historical and existing contract labor and purchasing agreements were used to estimate the cost of the material and contract labor. This project includes 9% contingency to cover unexpected increases in cost due to weather, rocky soil, outage delays, reclamation, etc. 10% contingency is a standard assumption used across all of our projects and is calculated as a percentage of total burdened costs. The 9% contingency on this project resulted from late estimate changes.

Economic Analysis and Risks

- **Bid Summary**
  Based on preliminary engineering, Transmission Lines has estimated the material packages for construction of this project to be $1,131k. This project will utilize standard and custom steel structures. Hardware will be purchased through Brownstown Electrical Supply. The line construction will be based on continuing contracts with our line contractors. Davis H.

Elliot, Pike Electric, B&B Electric and William E. Groves are the four main contractors which have been awarded the T&D Overhead Construction and Maintenance contracts.

Transmission Lines Material Cost Breakdown	
Material	**Cost**
Steel Poles	$1,096k
Hardware	$35k
Total	$1,131k

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	3,794	-	-	-	3,794
2. Cost of Removal Proposed	193	-	-	-	193
3. Total Capital and Removal Proposed (1+2)	3,987	-	-	-	3,987
4. Capital Investment 2016 BP	2,289	-	-	-	2,289
5. Cost of Removal 2016 BP	431	-	-	-	431
6. Total Capital and Removal 2016 BP (4+5)	2,720	-	-	-	2,720
7. Capital Investment variance to BP (4-1)	(1,505)	-	-	-	(1,505)
8. Cost of Removal variance to BP (5-2)	238	-	-	-	238
9. Total Capital and Removal variance to BP (6-3)	(1,267)	-	-	-	(1,267)

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2016 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):
Discount Rate: 6.49%
Capital Breakdown:
Labor: $123k
Contract Labor: $1,811k
Materials: $1,131k
Local Engineering: $265k
Burdens: $312k
Contingency: $345k
Reimbursements: ($0)
Net Capital Expenditure: $3,987k

Financial Analysis - Project Summary ($000)	2016	2017	2018	2019	2020	Life of Project
Project Net Income	$152	$149	$186	$177	$168	$2,654
Project ROE	14.8%	7.4%	9.7%	9.0%	9.7%	9.6%

- **Assumptions**

  Recommendation – The cost of this alternative assumes that the line outage will not be available and the structures will need to be replaced with the 69kV line energized. This alternative also assumes that all required permitting will be received timely.

  Do nothing alternative – The cost of this alternative would be approximately 60% higher due to overtime labor charges and the cost to mobilize and demobilize the construction crews. These poles would fail and require replacement within the next four years.

  Next best alternative - The cost of this alternative assumes the cost of the wood poles is 24% of the cost of the steel poles, and that the wood poles would be replaced again in 30 years.

- **Environmental**
  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

- **Risks**
  Without the proposed replacement of the priority poles on the London-Sweet Hollow 69kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays. Schedule delays may also occur if the required permitting is not received, or the requested outage is not obtained to complete the scheduled work.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the London-Sweet Hollow pole replacement project for $3,987k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Investment Proposal Project 147335 Green River Plant-Morganfield Pole Replacement

Investment Proposal for Investment Committee Meeting on: June 29, 2016

Project Name: Green River Plant-Morganfield Pole Replacement

Total Expenditures: $2,517k
Total Contingency: $229k (10%)

Project Number(s): 147335

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Nate Mullins/Adam Smith

Executive Summary

The proposed project is to replace forty-two (42) existing wood structures with forty (40) steel and two (2) wood structures on the Green River Plant-Morganfield 161kV line based on the results of a routine line inspection. The forty structures being replaced with steel will be completed during a scheduled outage. The two structures being replaced with wood will be completed energized due to their location in a double circuit section wherein operational restrictions require that one of the circuits remain energized during construction. Wood is being utilized for these two structures as a safety precaution.

This proposal is to proactively replace the structures over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures. The alternative of replacing poles upon failure will result in much higher long term replacement costs due to mobilization of crews back to the site each time one fails and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability.

This project is included in the 2016 BP for $1,511k. The original estimate was based on an average per structure replacement cost. Once the engineering analysis was completed, the project estimate was revised to be in line with the scope of work required. the proposed estimate includes $42k to replace two of the structures energized. The current total project cost is $2,517k and was approved by the RAC in the 5+7 forecast.

Background
Above ground pole inspections are performed by the company at defined intervals in order to discover problems that may impact the integrity and reliability of the Transmission System. During a routine climbing inspection of the Green River Plant-Morganfield 161kV line in 2014, forty-two (42) structures were identified as priority poles and determined to be in need of replacement in order to ensure the integrity and reliability of this line. There are 442 total structures along this 52.52 mile line. In addition to the 42 structures to be replaced on this project, there will be 25 replaced concurrently on the Green River Plant-Morganfield NRP project (147478). These structures are located at various points along the entire length of the line. The proposed estimate accounts for the unique delta configuration within a 7.75 mile 161kV/69kV double circuit section of the line.

- **Alternatives Considered (1 –Recommendation, 2 –Do nothing, 3 –Next Best Alt)**
  1. Recommendation: NPVRR: ($000s) $3,425k
     The recommendation is to replace forty (40) wood structures with steel during a scheduled outage and two (2) wood structures with wood. The wood structures will be replaced while one of the circuits within a double circuit section is energized. The additional cost of completing the energized work is $42k. These two structures must be completed energized. There is no option to complete de-energized due to the delta configuration.
  2. Do Nothing: NPVRR: ($000s) $4,930k
     The alternative of do nothing would result in replacing poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.
  3. Next Best Alternative(s): NPVRR: ($000s) $3,709k
     The next best alternative would be to replace 40 of the 42 structures identified for steel replacement with wood. The manufacturer's recommended lifespan of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of the wood structures in 30 years and an escalation factor of 4%, which is in line with market cost increases over the last 15 years.

Project Description

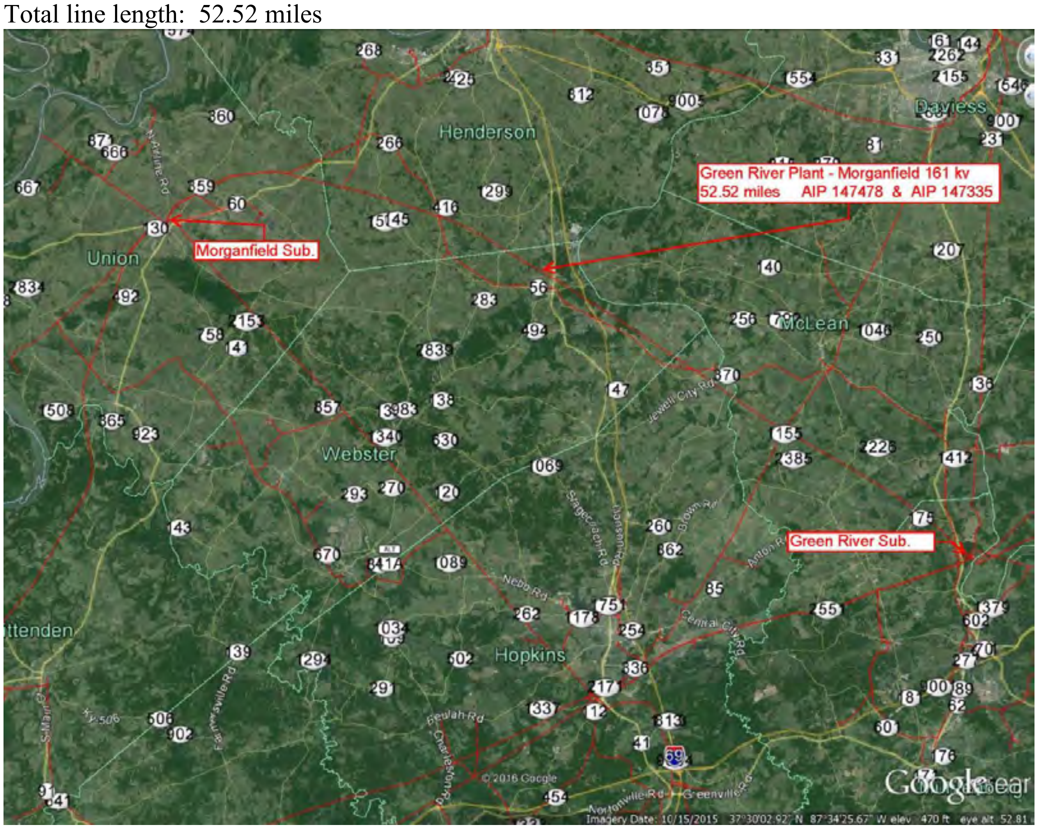
- **Project Scope and Timeline**
  The scope of work will consist of installing forty-two (40) steel H-frame structures, two (2) wood structures, and associated hardware and material, and the removal of 42 wood structures, associated hardware and material. The project will utilize standard steel and wood structures and associated hardware. The line construction will be based on continuing contracts from our line contractors. B&B, Elliot, Groves and Pike are the four contractors awarded the T&D Overhead Construction and Maintenance contract from the October 2011 Investment

Committee meeting. The contract extension was re-approved by the IC in July of 2014. Construction is scheduled to begin in August of 2016 and be completed in October of 2016.

The construction milestones for this project are provided below:

Construction Milestones	
July 2016	Engineering and Design
August 2016	Line Construction Begins
October 2016	Line Construction Completed

A facility map of the Green River Plant-Morganfield 161kV line is shown below:
Total line length: 52.52 miles



- **Project Cost**
  This project is included in the 2016 BP for $1,511k. The current total project cost is $2,517k and was approved by the RAC in the 5+7 forecast. Historical and existing contract and purchasing agreements were used to estimate the cost of material and contract labor. This project includes 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, and potential outage restrictions.

Economic Analysis and Risks

- **Bid Summary**
  Based on preliminary engineering, Transmission Lines has estimated the material packages for construction for this project to be $723k. This project will utilize standard steel and wood structures and associated hardware. The line construction will be based on continuing contracts with our line contractors. Davis H. Elliot, Pike Electric, B&B Electric and William E. Groves are the four main contractors which have been awarded the T&D Overhead Construction and Maintenance contracts.

Transmission Lines Material Cost Breakdown	
Material	Cost
Steel Poles	$678k
Wood Poles	$16k
Hardware	$29k
Total	$723k

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	**2016**	**2017**	**2018**	**Post 2018**	**Total**
1. Capital Investment Proposed	2,175	-	-	-	2,175
2. Cost of Removal Proposed	343	-	-	-	343
3. Total Capital and Removal Proposed (1+2)	2,517	-	-	-	2,517
4. Capital Investment 2016 BP	1,406	-	-	-	1,406
5. Cost of Removal 2016 BP	105	-	-	-	105
6. Total Capital and Removal 2016 BP (4+5)	1,511	-	-	-	1,511
7. Capital Investment variance to BP (4-1)	(769)	-	-	-	(769)
8. Cost of Removal variance to BP (5-2)	(238)	-	-	-	(238)
9. Total Capital and Removal variance to BP (6-3)	(1,006)	-	-	-	(1,006)

Financial Detail by Year - O&M ($000s)	**2016**	**2017**	**2018**	**Post 2018**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2016 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):
Discount Rate: 6.49%
Capital Breakdown:
Labor: $61k
Contract Labor: $1,132
Materials: $723k

Local Engineering:	$167k
Burdens:	$205k
Contingency:	$229k
Reimbursements:	($0)
Net Capital Expenditure:	$2,517k

Financial Analysis - Project Summary ($000)	2016	2017	2018	2019	2020	Life of Project
Project Net Income	$11	$57	$118	$112	$107	$2,289
Project ROE	1.8%	4.5%	9.8%	9.8%	9.8%	9.3%

- **Assumptions**
  Recommendation – The cost of this alternative assumes that forty (40) structures will be completed during a scheduled outage, and two (2) structures will be completed with one circuit within a double circuit section energized.

  Do nothing alternative – The cost of this alternative would be approximately 60% higher due to overtime labor charges and the cost to mobilize and demobilize the construction crews. These poles would fail and require replacement within the next four years.

  Next best alternative – The cost of this alternative assumes that the cost of the wood poles to replace the 40 structres identified for steel replacement is 36% the cost of the steel poles. The manufacturer's recommended lifespan of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of the wood structures in 30 years and an escalation factor of 4%, which is in line with market cost increases over the last 15 years.

- **Environmental**
  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

- **Risks**
  Without the proposed replacement of the priority poles on the Green River Plant-Morganfield 161kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays. Schedule delays may also occur if the requested outage is not obtained to complete the scheduled work.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Green River Plant-Morganfield Pole Replacement project for $2,517k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than or Equal to $1 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	Victor A. Staffieri Chairman, CEO and President

Investment Proposal Project 147999 Earlington North-Nebo Static Replacement

Investment Proposal

Project Name: Earlington North-Nebo Static Replacement

Total Expenditures: $1,601k
Total Contingency: $146k (10%)

Project Number(s): 147999

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Gary King/Adam Smith

Executive Summary
The 13.18 mile section of 69kV line between Earlington North and Nebo contains 9.01 miles of the original 3/8" high strength (HS) static wire, and 4.17 miles of 7#8 alumoweld. The 9.01 miles of 3/8" HS wire dates back to 1927 and has had multiple failures in recent years. The 4.17 miles of 7#8 alumoweld will also be removed to accommodate the replacement of all 13.18 miles in this section with Optical Ground Wire (OPGW).

Telecom has requested to replace this static wire with OPGW in lieu of a standard shield wire. While there is no immediate benefit, the long-term strategic benefits of this project make it worthwhile for Telecom to request OPGW be included with this project. These benefits include utilizing OPGW from Earlington North-Nebo-Morganfield which will eventually offset expensive leased line costs for the Call Center when the route is complete. In addition, network communications could potentially be provided for Distribution Automation, and other use cases for 5 additional substations. This project will cover the installation of 13.18 miles of OPGW (starting at Earlington North), with the remainder of OPGW to be installed from Nebo-Morganfield in a subsequent year (Project 148854 currently budgeted in 2021).

This project was included in the 2017 BP for $846k based on preliminary estimates for replacing 9.01 miles of 3/8" HS static wire with standard shield wire on the existing lattice towers. Telecom's request to replace the existing static wire with OPGW increased the amount of wire needing to be replaced to 13.18 miles. Detailed engineering along with complete scope development increased the planned work for this project. This project now includes a complete below grade inspection of all tower legs, replacement of five (5) lattice towers with steel poles, and the installation of OPGW. These changes increased the cost by $755k. The entire project cost of $1,601k was approved by the RAC in the 3+9 forecast.

Background
Aerial patrol inspections of this line revealed that the existing 3/8" HS static wire is in poor mechanical condition and has reached the end of its useful life. Due to the conditions of this line, there is a risk of additional failures that will expose the transmission network to further unscheduled outages. The goal is to replace the remainder of the static wire between Nebo and Morganfield (same vintage) in subsequent years.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $2,039k
     The recommendation is to replace 13.18 miles of static wire with new OPGW. The additional expense is a prudent strategic investment in this one time opportunity to be able to gain a company-owned fiber path along this route.
  2. Alternative #1-Splice Failed Sections As Needed: NPVRR: ($000s) $1,676k
     Without the proposed replacement of the existing static wire in the Earlington North-Nebo 69kV line, the company risks increased exposure to line outages. If the existing static wire is not replaced, the company risks having to make repairs with an unplanned outage which would add increased costs due to overtime labor. Repairs would involve splicing the failed static wire back together. Although this alternative has a lower cost, it would not allow the company-owned fiber path along this route to be extended.
  3. Alternative #2:-Replace With Standard 7#8 alumoweld NPVRR: ($000s) $1,229k
     The next best alternative would be to replace the existing 9.01 miles of existing 3/8" HS static wire with conventional 7#8 alumoweld, instead of the requested OPGW. The line outages related to static wire failures will be reduced, however the communications link will not be provided to Telecom. (Please see the background section for details regarding the communications aspect of this project).

Project Description

- **Project Scope and Timeline**
  The scope of work will consist of installing 13.18 miles of OPGW and related hardware. Five (5) new steel poles, twelve (12) steel lattice tower cage extensions, and forty-three (43) steel static peaks (tower steel) will also be required. A thorough ground-line, tower steel corrosion inspection will also be performed on these aging towers.

  The steel poles will be purchased through our steel pole alliance partner, Trinity-Meyer. The tower steel will be purchased through our steel tower alliance partner, SAE Tower. The OPGW will be bid between past proven providers, Prysmian and AFL. The line construction will be based on continuing contracts from our line contractors. B&B Electric, Davis H. Elliot, William E. Groves and Pike Electric are the four contractors awarded the T&D Overhead Construction and Maintenance contract from the October 2011 Investment Committee (IC) meeting. The contract extension was re-approved by the IC in July of 2014. Construction is scheduled to begin in June of 2017 and to be completed in December of 2017.

Construction Milestones	
May 2017	Project Approved
May 2017	Lattice Tower Steel, OPGW & Hardware Ordered
June 2017	Lattice Tower Steel, OPGW & Hardware Delivered
June 2017	Line Construction Begins
December 2017	Line Construction Completed

Below is a map of the 13.18 mile section of the Earlington North-Nebo line:

- **Project Cost**
  This project was included in the 2017 BP for $846k with preliminary estimates for replacing 9.01 miles of 3/8" HS static wire with standard shield wire on the existing lattice towers. Telecom's request to replace the existing static wire with OPGW increased the amount of wire needing to be replaced to 13.18 miles. Detailed engineering along with complete scope development increased the planned work for this project. , a complete below grade inspections of all tower legs, replacement of five (5) lattice towers with steel poles, and the

installation of OPGW. These changes increased the cost by $755k. The entire project cost of $1,601k was approved by the RAC in the 3+9 forecast.

Economic Analysis and Risks

- **Bid Summary**
  Based on detailed engineering, Transmission Lines has estimated the material package for this project to be $259k. The project will utilize OPGW, standard steel structures, and material. The OPGW will be bid between Prysmian and AFL. The line construction will be based on continuing contracts with our line contractors. B&B Electric, Davis H. Elliot, William E. Groves and Pike Electric are the four contractors which have been awarded the T&D Overhead Construction Maintenance contracts.

Transmission Lines Material Cost Breakdown	
Material	Cost
Steel Poles	$65k
Tower Steel	$26k
OPGW	$100k
Hardware	$68k
Total	$259k

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	**2017**	**2018**	**2019**	**Post 2019**	**Total**
1. Capital Investment Proposed	1,487	-	-	-	1,487
2. Cost of Removal Proposed	115	-	-	-	115
3. Total Capital and Removal Proposed (1+2)	1,601	-	-	-	1,601
4. Capital Investment 2017 BP	846	-	-	-	846
5. Cost of Removal 2017 BP	-	-	-	-	-
6. Total Capital and Removal 2017 BP (4+5)	846	-	-	-	846
7. Capital Investment variance to BP (4-1)	(641)	-	-	-	(641)
8. Cost of Removal variance to BP (5-2)	(115)	-	-	-	(115)
9. Total Capital and Removal variance to BP (6-3)	(755)	-	-	-	(755)

Financial Detail by Year - O&M ($000s)	**2017**	**2018**	**2019**	**Post 2019**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2017 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.49%
Capital Breakdown:	
Labor:	$47k
Contract Labor:	$981k
Materials:	$259k
Local Engineering:	$99k
Burdens:	$69k
Contingency:	$146k
Net Capital Expenditure:	$1,601k

- **Assumptions**

  Recommendation - This assumes that the 13.18 miles of existing static wire will be replaced with OPGW. An outage must be obtained to replace the existing static wire and is scheduled for summer of 2017. This also assumes that all highway and railroad crossing permits will be granted by the Kentucky Transportation Cabinet (KYTC), and associated railroads.

  Alternative #1 - This assumes that the existing static wire would be replaced in 2026 and the company will have to make any necessary repairs in the meantime during unplanned outages.

  Alternative #2 - This assumes that the existing 9.01 miles of existing 3/8" HS static wire will be replaced with 7#8 alumoweld rather than the requested OPGW. If 7#8 is used, the communications link will not be provided to Telecom. This also assumes that all highway and railroad crossing permits will be granted by the KYTC, and associated railroads.

- **Environmental**
  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

- **Risks**
  Without the proposed replacement of the existing static wire in the Earlington North-Nebo 69kV line, the company risks increased exposure to line outages. The wire along the 9.01 miles has deteriorated and corroded over time. It has become brittle and does not have its original design strength. Unplanned outages are often time-consuming and costly when it comes to repairs. If the line outage cannot be obtained, the proposed static replacement project cannot be performed safely within the budget constraints. Construction delays may be encountered due to possible severe weather events. If the appropriate crossing permits are not granted, it could result in the project being delayed.

Conclusions and Recommendation
It is recommended that Management approve the Earlington North-Nebo static replacement project for $1,601k to improve the reliability of the electric transmission system.

Capital Investment Proposal

Investment Proposal for Investment Committee Meeting on: N/A
Project Name: REL-Hoover 604 Breaker Add
Total Expenditures: $967k (Including $88k of Contingency)
Project Number(s): 148370
Business Unit/Line of Business: Transmission Reliability Performance & Standards
Prepared/Presented By: Keith Yocum – Manager Reliability Performance & Standards

Executive Summary
The Transmission Reliability Performance and Standards group identified the need for a breaker at the Hoover substation to reduce the System Average Interruption Duration Index (SAIDI) and the MegaWatt-Mile (MW-Mile is calculated by multiplying total miles of line exposure times the MWs served from the line) exposure on the Adams to Haefling 69 kV line. This line has significant MW-Mile exposure and has been a significant SAIDI contributor for Transmission.

The Adams to Haefling 69 kV line is 12.07 miles long and has 7 distribution transformers in 5 distribution stations tapped off of it which serve around 10,689 customers and 82.95 MW of load. A fault anywhere along this line will result in an outage on all 5 distribution stations. The placement of a breaker at Hoover will reduce MW-Mile exposure from 1001 to 305, a 69.5% reduction, resulting in only 30% as many customers losing power during a given fault. Diagram 1 include in Appendix A depicts the configuration for the Adams to Haefling 69 kV line.

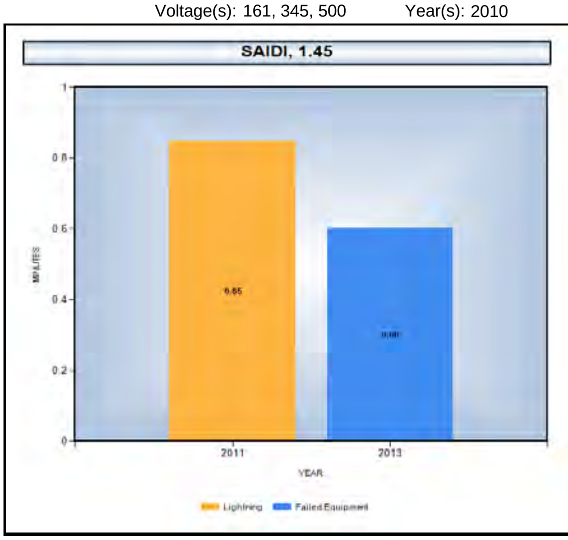
This project was initially opened for $100k to conduct preliminary engineering in an effort to better estimate the total funding needed to complete the project with the understanding that the cost of the full project would be presented for approval once those estimates were completed. The total cost of this project will be $967k with $134k in 2016 and $834k in 2017. The 2017 BP included $850k for this project with $100k in 2016 and $750k in 2017. The budgeted amount was estimated based on similar projects that have been previously completed and has been updated based on the preliminary engineering performed. The funding needed above the budgeted amount in 2016 was addressed by the RAC during 2016. The funding needed above the budget in 2017 ($84k) will be funded by a reduction in project #152141 (PBR-Lynch 69kV Brkr Rpl). The estimated total project figure includes a 10% contingency. This contingency is expected to cover uncertainty with the contract labor costs based upon variances that have been noticed on past similar projects.

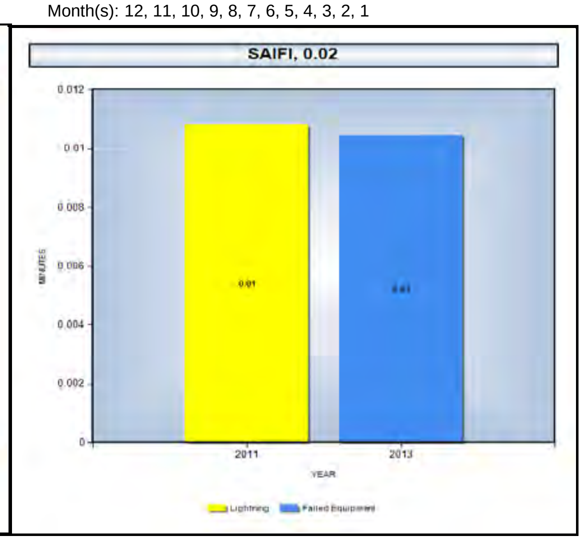
Background
The Adams to Haefling 69 kV line has been a consistent high contributor to Transmission's SAIDI metric. This breaker will reduce the mileage exposure by half for all of the customers served by this line as Hoover is located in the approximate middle of the line. Therefore, for a given fault, only half as many customers will go out in the case with the breaker, as compared to the case without the breaker. This will also speed up restoration in that the line requiring patrol will also be cut in half.

The chart below shows the historical SAIDI/SAIFI (including MED) for this line:

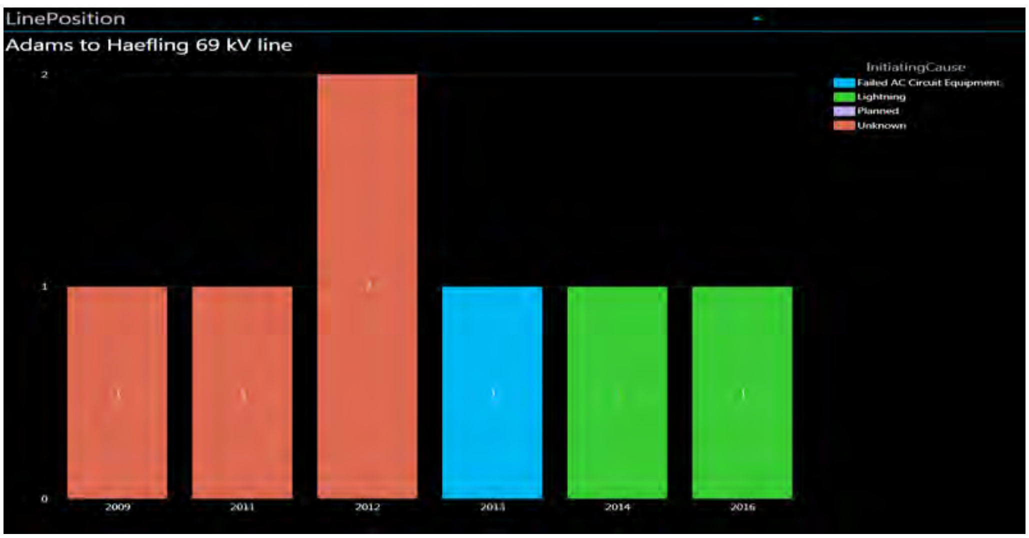
Adams to Haefling 69 kV line

Voltage(s): 23, 34, 69, 138, 161, 345, 500   Year(s): 2016, 2015, 2014, 2013, 2012, 2011, 2010   Month(s): 12, 11, 10, 9, 8, 7, 6, 5, 4, 3, 2, 1





The following graph shows the number of relay events since 2010 and their associated cause codes.



- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $1,057k
     It is recommended that a breaker be installed on the Adams to Haefling 69 kV line to limit the exposure of customers on a line that has historically had SAIDI issues. This recommendation assists Transmission in achieving the SAIDI targets established as part of the Transmission Reliability Plan (TRP), as well as reduces the number of customers that would otherwise experience a power outage during an event. In addition, this recommendation provides additional relay data to aid in restoring service quickly that includes information to help determine the cause and location of the event.

  2. Alternative #1: NPVRR: ($000s) $615k
     The next best alternative is to add an automated motor operated switch instead of a breaker at the Hoover tap. The automated switch at the Hoover tap would sectionalize the line and improve the restoration process, however, all customers on this line will continue to experience a power outage during an event. This option is not advisable as this circuit has ranked in the top ten of MW-Mile (customer outage) exposure. These switches also will not provide the additional relaying event data that the breaker option will provide which helps in determining the cause and location of an outage. This option, although not the lowest cost alternative, is not recommended because it does not achieve all of the objectives of the project.

3. Do Nothing: NPVRR: N/A
   This option is not advisable as this circuit has ranked in the top ten of MW-Mile (customer outage) exposure and the current state of the line puts Transmission at risk of not being able to accomplish SAIDI targets established as part of the Transmission Reliability Plan which assumed the completion of this project.

Project Description

- **Project Scope and Timeline**

Description	Date
Project Initially Approved for preliminary engineering	September, 2016
Materials Ordered	November, 2016
Materials Received	January, 2017
Project Approved for Full Funding	January, 2017
Below Grade Work Begins	February, 2017
Below Grade Work Completed	February, 2017
Above Grade Work Begins	March, 2017
Above Grade Work Completed	March, 2017
Project Complete	April, 2017

- **Project Cost**
  This project was initially opened for $100k to conduct preliminary engineering in an effort to better estimate the total funding needed to complete the project with the understanding that the cost of the full project would be presented for approval once those estimates were completed. The total cost of this project is $967k with $134k in 2016 and $834k in 2017. The 2017 BP included $850k for this project with $100k in 2016 and $750k in 2017. The budgeted amount was estimated based on similar projects that have been previously completed and has been updated based on the preliminary engineering performed. The funding needed above the budgeted amount in 2016 was addressed by the RAC during 2016. The funding needed above the budget in 2017 ($84k) will be funded by a reduction in project #152141 (PBR-Lynch 69kV Brkr Rpl). The estimated total project figure includes a 10% contingency. This contingency is expected to cover uncertainty with the contract labor costs based upon variances that have been noticed on past similar projects.

Economic Analysis and Risks

- **Bid Summary**
  Previously established blanket contract agreements will be utilized for related materials. Bids for any other necessary materials, as well as the below and above grade construction, will be sent out soon after project approval.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	134	834	-	-	967
2. Cost of Removal Proposed			-	-	-
3. Total Capital and Removal Proposed (1+2)	134	834	-	-	967
4. Capital Investment 2017 BP	100	750	-	-	850
5. Cost of Removal 2017 BP	-	-	-	-	-
6. Total Capital and Removal 2017 BP (4+5)	100	750	-	-	850
7. Capital Investment variance to BP (4-1)	(34)	(84)	-	-	(117)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(34)	(84)	-	-	(117)

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2017 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):
Discount Rate: 6.5%
Capital Breakdown:
Labor: $57k
Contract Labor: $445k
Materials: $261k
Other: $0k
Local Engineering: $59k
Burdens: $57k
Contingency: $88k
Net Capital Expenditure: $967k

Spend (000's)	Construction	P&C	Telecom	Total
Company Labor	$ 32	$ 20	$ 5	**$ 57**
Contract Labor	$ 320	$ 121	$ 4	**$ 445**
Materials	$ 131	$ 125	$ 5	**$ 261**
Burdens	$ 72	$ 39	$ 5	**$ 116**
Contingency	$ 56	$ 31	$ 2	**$ 88**
Total	**$ 611**	**$ 336**	**$ 21**	**$ 967**

- **Assumptions**
  - Suppliers and contractors will meet reasonable and customary delivery dates for materials and services.
  - The testing and validation for the operation of the new breaker is completed in the time frame scheduled for the project and not delayed due to the availability of resources. Delays could require additional mobilization costs for construction removal and cut-over to the new system.

- Telecommunications will install a new radio communications at the site to provide communication for the new breaker.
- Construction costs are estimated and not based on bid pricing.

- **Environmental**
  This project does not require permitting and there are no known issues regarding air, water, waste, lead, or asbestos.

- **Risks**
  - Completing the project involves risk related to construction work within an operating substation. This project involves installing new underground conduits and reconfiguring the existing system.
  - If the breaker is not added, Transmission will continue to see negative SAIDI impacts associated with this line.

Conclusions and Recommendation

It is recommended that Management approve the Hoover Breaker Addition project for $967k to enhance the reliability of the Transmission system.

CONFIDENTIAL INFORMATION REDACTED

Appendix A

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DIAGRAM 1

Capital Investment Proposal

Investment Proposal N/A
Project Name: REL-Earlington 604 Breaker Add
Total Expenditures: $1,245k (Including $113k of Contingency)
Project Number(s): 148371
Business Unit/Line of Business: Transmission Reliability Performance & Standards
Prepared/Presented By: Keith Yocum – Manager Reliability Performance & Standards

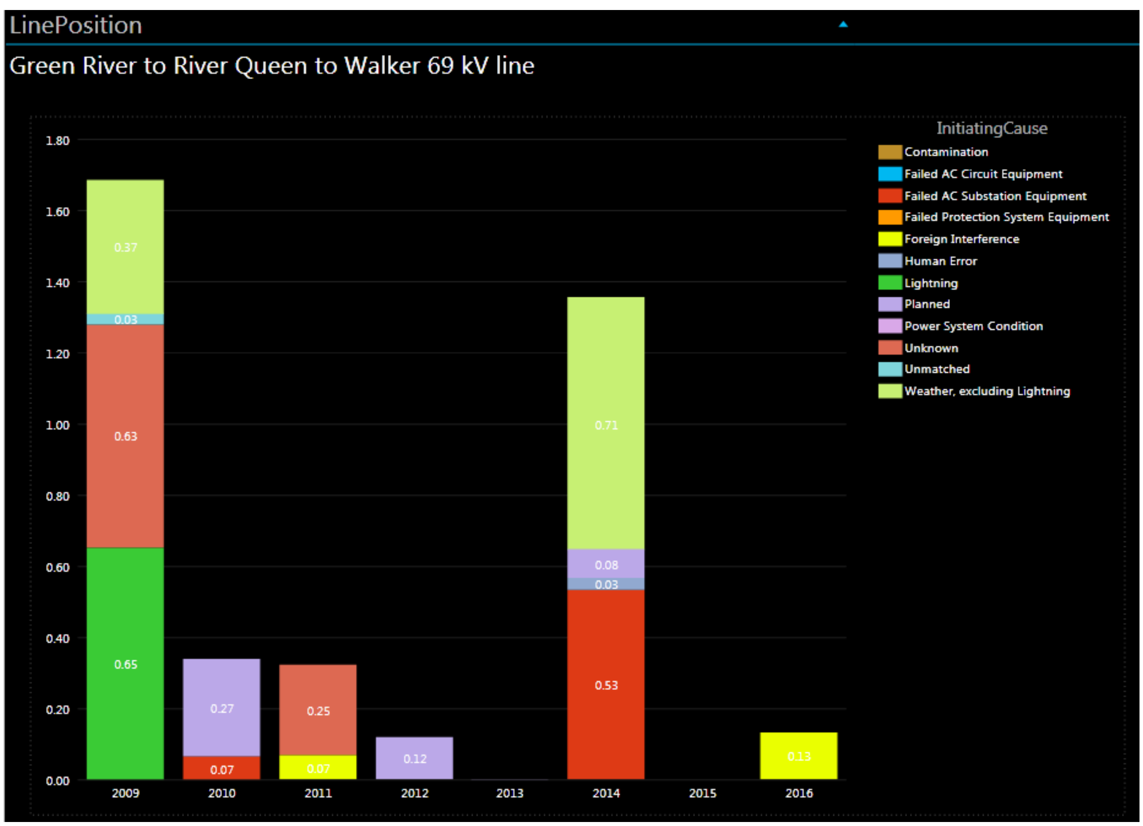
Executive Summary
The Transmission Reliability Performance and Standards group identified the need for a breaker at the Earlington Substation to reduce the System Average Interruption Duration Index (SAIDI) and the MegaWatt-Mile (MW-Mile is calculated by multiplying total miles of line exposure times the MWs served from the line) exposure on the Green River to River Queen to Walker 69 kV line. This line has significant MW-Mile exposure and has been a significant SAIDI contributor for Transmission.

The Green River to River Queen to Walker 69 kV line is 32.51 miles long and has 11 distribution transfomers tapped off of it which serve around 3,955 customers and 29.50 MW of load. A fault anywhere along this line will result in an outage on all 11 distribution stations. The placement of a breaker at Earlington will reduce MW-Mile exposure from 959 to 580, a 39.5% reduction, resulting in only 60% as many customers losing power during a given fault. Diagram 1 included in Appendix A depicts the configuration for the Green River to River Queen to Walker 69 kV line.

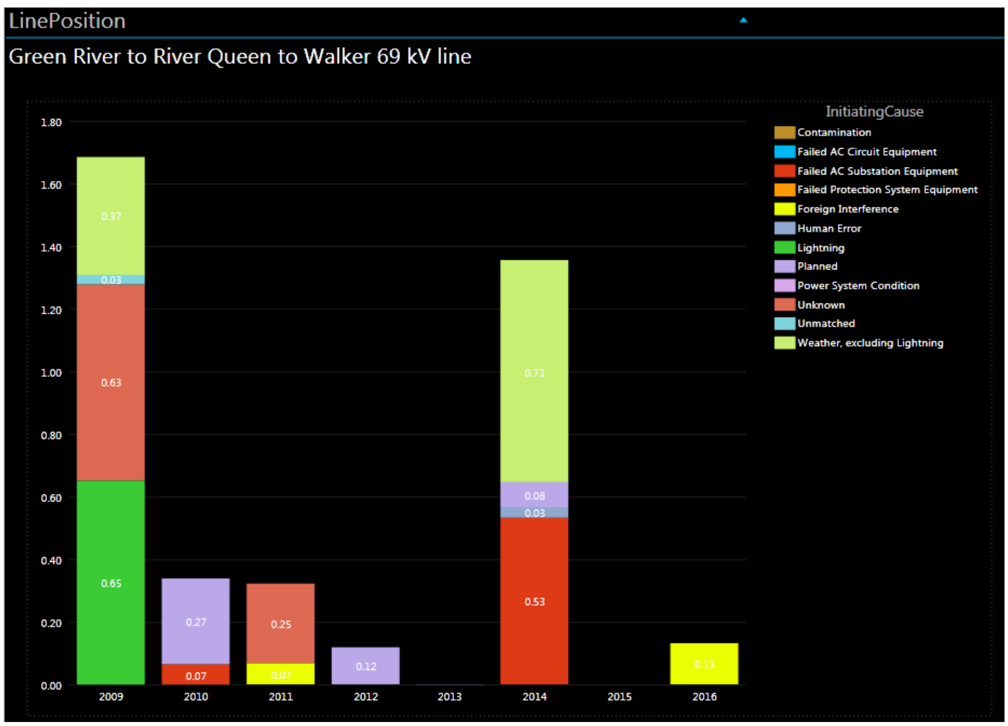
This project was initially opened for $100k to conduct preliminary engineering in an effort to better estimate the total funding needed to complete the project with the understanding that the cost of the full project would be presented for approval once those estimates were completed. The total cost of this project will be $1,245k with $43k in 2016 and $1,202k in 2017. The 2017 BP included $850k for this project with $100k in 2016 and $750k in 2017. The budgeted amount was estimated based on similar projects that have been previously completed and has been updated based on the preliminary engineering performed. The funding needed above the budgeted amount in 2016 was addressed by the RAC during 2016. The funding needed above the budget in 2017 ($451k) was partially funded by the RAC in the 3+9 forecast ($85k) and partially funded by a reduction in project KRTU-17 ($366k). The estimated total project figure includes a 10% contingency. This contingency is expected to cover uncertainty with the contract labor costs based upon variances that have been noticed on past similar projects.

Background
The Green River to River Queen to Walker 69 kV line has been a consistent high contributor to Transmission's SAIDI metric. This breaker will reduce the mileage exposure for all of the customers served by this line as Earlington is located in the approximate middle of the line. Therefore, for a given fault, only 40-60% (depending on which side of the breaker the fault is on) as many customers will go out in the case with the breaker, as compared to the case without the breaker. This will also speed up restoration in that the line requiring patrol will also be reduced.

The chart below shows the historical SAIDI/SAIFI (including MED) for this line:



The following graph shows the number of relay events since 2010 and their associated cause codes.



- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $1,367k
     It is recommended that a breaker be installed on the Green River to River Queen to Walker 69 kV line to limit the exposure of customers on a line that has historically had chronic SAIDI issues. This recommendation assists Transmission in achieving the SAIDI targets established as part of the Transmission Reliability Plan (TRP), as well as reduces the number of customers that would otherwise experience a power outage during an event. In addition, this recommendation provides additional relay data to aid in restoring service quickly that includes information to help determine the cause and location of the event.

2. Alternative #1: NPVRR: ($000s) $615k
The next best alternative is to add an automated motor operated switch in the steel at Earlington. This switch would sectionalize the line and improve the restoration process, however, all customers on this line will continue to experience a power outage during an event. This option is not advisable as this circuit has ranked in the top ten of MW-Mile (customer outage) exposure. These switches also will not provide the additional relaying event data that the breaker option will provide which helps in determining the cause and location of an outage. This option, although not the lowest cost alternative, is not recommended because it does not achieve all of the objectives of the project.

3. Do Nothing: NPVRR: N/A
This option is not advisable as this circuit has ranked in the top ten of MW-Mile (customer outage) exposure and the current state of the line puts Transmission at risk of not being able to accomplish SAIDI targets established as part of the Transmission Reliability Plan which assumed the completion of this project.

Project Description

- **Project Scope and Timeline**

Description	Date
Project Initially Approved for preliminary engineering	September, 2016
Materials Ordered	November, 2016
Materials Received	March and July, 2017
Project Approved for Full Funding	April, 2017
Below Grade Work Begins	June, 2017
Below Grade Work Completed	July, 2017
Above Grade Work Begins	August, 2017
Above Grade Work Completed	October, 2017
Project Complete	November, 2017

- **Project Cost**
This project was initially opened for $100k to conduct preliminary engineering in an effort to better estimate the total funding needed to complete the project with the understanding that the cost of the full project would be presented for approval once those estimates were completed. . The total cost of this project will be $1,245k with $43k in 2016 and $1,202k in 2017. The 2017 BP included $850k for this project with $100k in 2016 and $750k in 2017. The budgeted amount was estimated based on similar projects that have been previously completed and has been updated based on the preliminary engineering performed. The funding needed above the budgeted amount in 2016 was addressed by the RAC during 2016. The funding needed above the budget in 2017 ($451k) was partially funded by the RAC in the 3+9 forecast ($85k) and partially funded by a reduction in project KRTU-17 ($366k). The estimated total project figure includes a 10% contingency. This contingency is expected to cover uncertainty with the contract labor costs based upon variances that have been noticed on past similar projects.

Economic Analysis and Risks

- **Bid Summary**
  Previously established blanket contract agreements will be utilized for related materials. Bids for any other necessary materials, as well as the below and above grade construction, will be sent out soon after project approval.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	43	1,190	-	-	1,233
2. Cost of Removal Proposed	-	12	-	-	12
3. Total Capital and Removal Proposed (1+2)	43	1,202	-	-	1,245
4. Capital Investment 2017 BP	100	750	-	-	850
5. Cost of Removal 2017 BP	-	-	-	-	-
6. Total Capital and Removal 2017 BP (4+5)	100	750	-	-	850
7. Capital Investment variance to BP (4-1)	57	(440)	-	-	(383)
8. Cost of Removal variance to BP (5-2)	-	(12)	-	-	(12)
9. Total Capital and Removal variance to BP (6-3)	57	(452)	-	-	(395)

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2017 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):
Discount Rate: 6.5%
Capital Breakdown:
Labor: $94k
Contract Labor: $580k
Materials: $271k
Other: $0k
Local Engineering: $67k
Burdens: $120k
Contingency: $113k
Net Capital Expenditure: $1,245k

- **Assumptions**
  - Suppliers and contractors will meet reasonable and customary delivery dates for materials and services.
  - The testing and validation for the operation of the new breaker is completed in the time frame scheduled for the project and not delayed due to the availability of resources. Delays could require additional mobilization costs for construction removal and cut-over to the new system.

  - Telecommunications will install fiber communications at the site to provide communication for the new breaker which includes four splice locations.
  - Construction costs are estimated and not based on bid pricing.

- **Environmental**
  This project likely does not require permitting and there are no known issues regarding air, water, waste, lead, or asbestos. Mudboat access across wet vegetated area is required and all environmental protection measures will be utitlized as necessary.

- **Risks**
  - Completing the project involves risk related to construction work within an operating substation. This project involves installing new underground conduits and reconfiguring the existing system.
  - If the breaker is not added, Transmission will continue to see negative SAIDI impacts associated with this line.

Conclusions and Recommendation
It is recommended that Management approve the Earlington Breaker Addition project for $1,245k to enhance the reliability of the Transmission system.

CONFIDENTIAL INFORMATION REDACTED

Appendix A

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DIAGRAM 1

Investment Proposal Project 148821 Floyd-Seminole Static Replacement

Investment Proposal

Project Name: SR Floyd-Seminole

Total Expenditures: $1,829k
Total Contingency: $167k (10%)

Project Number(s): Transmission Lines - 148821
Distribution Operations - 157696

Business Unit/Line of Business: Transmission Lines/Distribution Operations

Prepared/Presented By: John Doll/Adam Smith

Executive Summary
The proposed project is to replace 1.75 miles of overhead transmission static that is over 49 years old and beyond its expected useful life. Performance of this line has diminished, with the most recent wire failure occurring in 2011 from a failed static. This project will improve reliability, maintain system integrity, and reduce the risk of failures and unplanned transmission interruptions to the University of Louisville, Wilder Park, Bradley, and Louisville Fairground areas.

A Transmission System Improvement Plan was submitted as support in the 2016 Rate Case, outlining programs and projects aimed at reducing the risk of failure, avoiding extended sustained outages, and limiting costly emergency repairs. The programs submitted with the plan were selected to ensure long-term system integrity and modernize the transmission system to avoid degradation of performance over time due to aging infrastructure. Replacement of overhead wires beyond or approaching their expected useful life was included as part of the Transmission System Improvement Plan to replace aging infrastructure.

Transmission Lines plans to replace the 1.75 miles of 69kV static between the Floyd-Seminole substations with optical ground wire (OPGW). In addition, thirty-one (31) wood structures will be replaced with new steel structures. Distribution Operations will transfer distribution equipment along this route from the existing to new transmission structures.

The total project cost is $1,829k ($1,665k Transmission Lines, $164k Distribution Operations). This project was included in the 2018 Business Plan (BP) for $1,500k, with estimated spend of $200k in 2018, and $1,300k in 2019. As the scope, timing, and certainty of work has evolved, the estimates have been further refined. The current total project cost is $1,829k, with estimated spend of $247k in 2018, and $1,582k in 2019. The 2018 spend was approved by the RAC in the 7+5 forecast. The 2019 spend is consistent with the proposed 2019 BP.

Background
The existing 1.75 mile section of 69kV line between Floyd and Seminole contains aging 5/16" copperweld which dates back to 1969 and has experienced diminishing performance in recent years. Furthermore, static failures have occurred in recent years, causing significant damage to the already brittle and aged wire, with the most recent event occurring in 2011.

Due to the condition of this line, there is risk for additional failures that will expose the transmission network to further unscheduled outages. The following picture is representative of the static on sections of this line.

The aging static will be replaced with OPGW. In addition, new steel structures will be installed in place of existing wood structures.

In March of 2018, the transmission project was opened to support preliminary engineering and project scope development. Preliminary engineering included design development, structure design and selection, and the development of the construction plan. The transmission line design was provided to all departments involved for review.

One additional anchor easement will be required along the route at the Seminole substation. This easement will eliminate an intermediate structure, which will allow entry into the face of steel at a more direct angle. The Real Estate and Right of Way department indicates the easement acquisition is feasible and likely. The existing structures are horizontal post construction with porcelain insulators. This configuration will be replaced with steel poles on horizontal post construction with polymer insulators which allows for increased capacity of the structure.

This project also includes a supporting project from Distribution Operations. Distribution Operations plans to transfer distribution equipment from the existing to new transmission structures.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $2,152
     The recommendation is to replace 1.75 miles of overhead static with new OPGW. In addition, thirty-one (31) wood structures will be replaced with new steel structures.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   This option is not advisable as this line is nearing the end of its useful life and puts Transmission at risk of not being able to accomplish the objectives established as part of the Transmission System Improvement Plan that was filed as support in the 2016 Rate Case and assumed the completion of this project. These objectives include reducing the risk of failure, avoiding an extended sustained outage, and costly emergency repairs.
3. Alternative #2: Construct Alternate Route NPVRR: ($000s) $3,705
   The Next Best Alternative would be to construct a new 1.2 mile transmission line along Crittenden Drive. Constructing a new route would require the purchase of 1.2 miles of new right of way that customers may not be willing to sell. Selecting a new route for this alternative would likely cause project delays and result in community concerns and opposition over the new route.

Project Description
Floyd-Seminole Static Replacement Facility Map

- **Project Scope and Timeline**
  Transmission Lines Project Description – Project 148821

The Transmission Lines project involves the upgrade of 1.75 miles of existing static wire with OPGW between Floyd and Seminole 69kV line. This project also involves the replacement of thirty-one (31) existing wood structures with new steel structures.

Transmission Lines Project Scope and Timeline

Design Start	March 2018
Design Complete	June 2018
Space reserved for steel pole production with manufacturer	July 2018
Materials Delivered	January 2019
Construction Start	February 2019
Facility In-Service	July 2019
Project Completion	August 2019

Distribution Operations Project Description – Project 157696
Distribution Operations plans to transfer distribution equipment to the new transmission structures. In addition, Distribution Operations plans to replace existing cross-arms, LB switches, transformers and capacitor banks.

Distribution Operations Project Scope and Timeline

Design Start	February 2018
Design Complete	4th Quarter 2018
Materials Ordered	January 2019
Materials Delivered	February 2019
Construction Start	March 2019
Construction Finish	December 2019

- **Project Cost**

	Transmission Lines	Distribution Operations	Total
Total 2018	$247k	$0k	$247k
Total 2019	$1,418k	$164k	$1,582k
Project Total	$1,665k	$164k	$1,829k
Contingency	10%	10%	

Economic Analysis and Risks

- **Bid Summary**
  Transmission Lines
  Based on detailed engineering, Transmission Lines has estimated the material package for this project to be $215k. The project will utilize OPGW, custom steel structures, standard steel structures, and material. The OPGW will be purchased through AFL. The line construction will be based on continuing contracts with our line contractors. B&B Electric,

Davis H. Elliot, William E. Groves and Pike Electric are the four contractors which have been awarded the T&D Overhead Construction Maintenance contracts.

Distribution Operations:
Distribution Operations line relocation will be performed by company labor (no bids required).

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	247	1,418	-	-	1,665
2. Cost of Removal Proposed	-	165	-	-	165
3. Total Capital and Removal Proposed (1+2)	247	1,582	-	-	1,829
4. Capital Investment 2018 BP	200	1,300	-	-	1,500
5. Cost of Removal 2018 BP	-	-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	200	1,300	-	-	1,500
7. Capital Investment variance to BP (4-1)	(47)	(118)	-	-	(164)
8. Cost of Removal variance to BP (5-2)	-	(165)	-	-	(165)
9. Total Capital and Removal variance to BP (6-3)	(47)	(282)	-	-	(329)

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2018 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Discount Rate: 6.59%
Capital Breakdown:

	148857 Trans Lines	157697 Dist Ops	Total
Labor	$60k	$0k	$60k
Contract Labor	$926k	$109k	$1,035k
Materials	$215k	$25k	$240k
Local Engineering	$234k	$11k	$245k
Burdens	$79k	$4k	$83k
Contingency	$151k	$15k	$166k
Reimbursements	$0	$0	$0
Net Capital Expenditure	$1,665k	$164k	$1,829k

- **Assumptions**
  Recommendation - This assumes that the 1.75 miles of existing static will be replaced with OPGW. An outage must be obtained to complete the project and is scheduled for 2019. This also assumes that all permits will be granted by Louisville Metro Public Works. It is anticipated that no customers will be out of service for the duration of this work.

  Alternative #1 – Do Nothing - This option is not advisable as this line is nearing the end of its useful life and puts Transmission at risk of not being able to accomplish the objectives established as part of the Transmission System Improvement Plan, that was filed as support in the 2016 Rate Case, which assumed the completion of this project. These objectives include reducing the risk of failure, avoiding and extended sustained outage, and costly emergency repairs.

  Alternative #2 – Next Best Alternative – This alternative assumes that a new 1.2 mile transmission line would be constructed. This option would require additional funding due to the need to purchase 1.2 miles of new right of way, in which the property owners may not be willing to sell. The impacts associated with this option would be more disruptive and have a larger negative impact on the community during construction.

- **Environmental**
  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

- **Customer Experience**
  A communication plan is being developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the community and businesses along the route.

- **Risks**
  - Without the proposed replacement of the existing wire in the Floyd-Seminole 69kV line, the company risks increased exposure to line outages. The wire along the 1.75 miles has deteriorated over time, and is beyond its expected useful life. Unplanned outages are often time-consuming and costly when it comes to repairs.
  - The Louisville Metro Department of Public Works requires permits for lane closures and flagging. The permit application will be submitted prior to construction. Lane closure permits are typically obtained in a timely manner from this agency to support our projects.
  - This project requires an easement acquisition from a private property owner. This easement has been informally agreed upon and is currently being processed for formal execution.
  - The local community may react negatively to the work and potential inconvenience of the project. A communication plan is being developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the community and businesses.

Conclusions and Recommendation
It is recommended that Management approve the Floyd-Seminole Static Replacement project for $1,829k to improve reliability of the electric transmission system.

Investment Proposal Project 148823 CR Earlington North-Green River Steel

Investment Proposal for Investment Committee Meeting on: July 31, 2018

Project Name: Earlington North-Green River Steel Conductor Replacement

Total Expenditures: $25,925k
Total Contingency: $2,351k (10%)

Project Number(s): Transmission Lines - 148823
Distribution Operations – 157839

Business Unit/Line of Business: Transmission Lines/Distribution Operations

Prepared/Presented By: Joe Dionisio/Adam Smith

Executive Summary
The proposed project is to replace 35.73 miles of overhead transmission line containing conductor that is over 75 years old and beyond its expected useful life. Performance of this line has diminished, with the most recent failure occurring in 2018 from a failed conductor. Over 1,870 customers with a peak load over 18 MVA are served by the facilities being replaced. Substations directly served by this line include Green River Steel, Rumsey, East Diamond, Earlington, and Earlington North. This project will improve reliability, maintain system integrity, and reduce the risk of failures and unplanned transmission interruptions in the Owensboro, Earlington, and Calhoun areas.

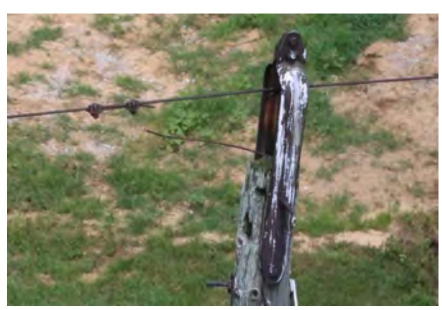
A Transmission System Improvement Plan was submitted as support in the 2016 Rate Case, outlining programs and projects aimed at reducing the risk of failure, avoiding extended sustained outages, and limiting costly emergency repairs. The programs submitted with the plan were selected to ensure long-term system integrity and modernize the transmission system to avoid degradation of performance over time due to aging infrastructure. Replacement of overhead wires beyond or approaching their expected useful life was included as part of the Transmission System Improvement Plan to replace aging infrastructure.

Transmission Lines plans to replace 35.73 miles of 69kV line between the Earlington North and Green River Steel substations. The proposed project utilizes a new design which optimizes the structure placement, removing one hundred seventy-two (172) structures, minimizing our footprint on local farmlands. In addition, reliability of the circuit will be improved by replacing existing wood structures with new steel structures. Finally, the addition of steel towers at critical points will add system resiliency by preventing a future cascading line failure. Distribution Operations will provide the layout work and transfer of underbuilt distribution conductors where needed.

The total project cost is $25,925k ($25,847k Transmission Lines, $78k Distribution Operations). This project was included in the 2018 Business Plan (BP) for $32,000k, including estimated spend of $300k in 2018, $2,260k in 2019, $9,176k in 2020, and $20,264k in years 2021-2023. As the scope, timing and certainty of work has evolved, the estimates have been further refined. The current total project cost is $25,925k, with estimated spend of $2,981k in 2018, $8,502k in 2019, and $14,442k in 2020. 2018 spend was approved by the RAC in the 6+6 forecast. The 2019 and 2020 spend is consistent with the proposed 2019 BP for the Transmission project. The 2019 and 2020 spend for the Distribution project will be identified through the 2019 Forecasting and RAC process.

Background

The existing 35.73 mile sections of 69kV line between Earlington North and Green River Steel contains aging 1F copper conductor, which dates back to 1942 and has experienced diminishing performance in recent years. This aging conductor is obsolete, no longer commonly used in the industry, and is difficult to obtain for needed repairs. Inspections revealed that the existing 1F copper conductor and 3/8" steel static wire showed signs of corrosion and are in fair to poor condition. Similar copper conductors with 75+ years of service life often have sections with broken conductor strands and significant corrosion at the clamps where the conductor attaches to the structure. This line has experienced six (6) conductor failures over the last five years, with the most recent failure occurring in 2018. Along with the conductor failure events, this line has experienced numerous equipment failures over the past five years. The primary cause for these forced outages has been cross arms failures. This circuit ranks 7th for highest number of events and ranks in the top 30 in terms of worst SAIDI performers over the past five years on the LGE-KU transmission system. Due to the conditions of this line, there is a risk of additional failures that will expose the transmission network to further unscheduled outages. The following pictures are representative of the condition of this line.



The picture on the left highlites a broken conductor strand and corrosion, which is representative of the wire condition. The picture on the right shows one of many broken grounding wires, corrosion to the static wire and ridge iron, and general degradation of the wood pole that has occurred over the asset's service life. Left unrepaired these conditions leave the system vulnerable to future unplanned outages.

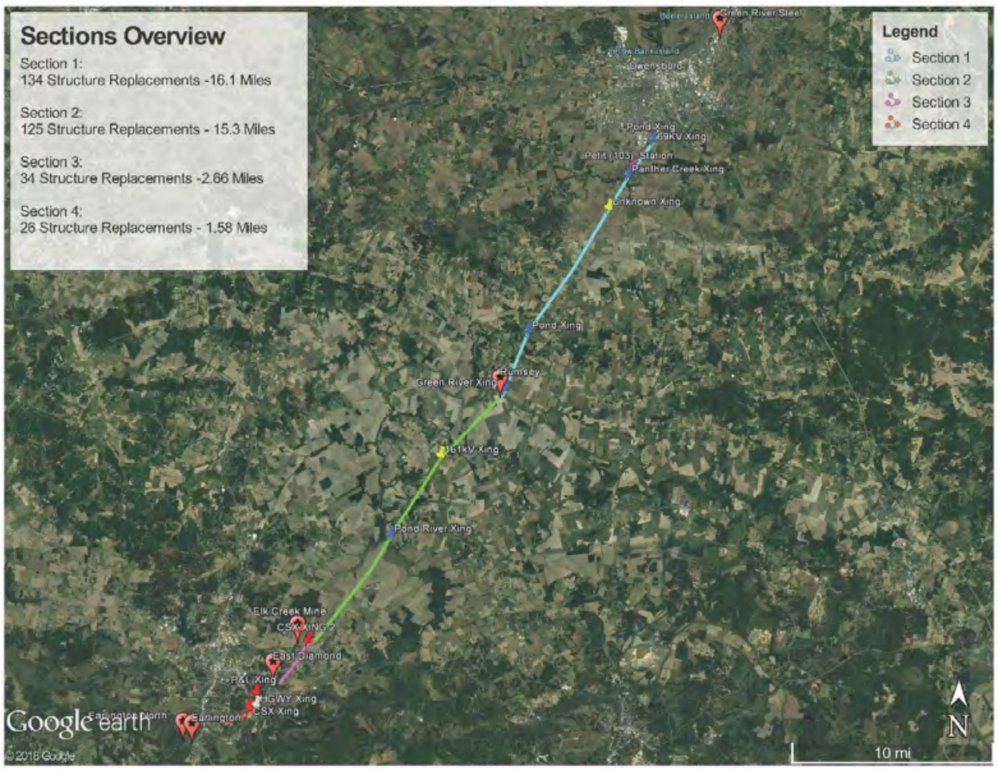
This aging conductor will be replaced with aluminum conductor steel-reinforced (ACSR) conductor and the deteriorating 3/8" steel static wire will be replaced with optical ground wire (OPGW) and new steel structures will be installed in place of existing wood structures. In addition to the performance history of this line, a routine inspection of the wood structures on the line was completed in 2017. From this inspection, eighty six (86) structures were found to be in need of replacement, of which seventy-three (73) structures will be addressed as a part of this project. The remaining 13 structures are in different sections of this line that do not have copper conductor targeted for replacement and will be replaced under a separate project.

In May 2018, the transmission project was opened to support preliminary engineering and project scope development. Preliminary engineering included design development, structure design and selection, and development of the construction sequence. This project will upgrade the identified 35.73 miles of 69kV transmission line in three (3) phases. Phase I will upgrade 16.11 miles of 69kV line between Green River Steel and Rumsey substations, replacing two hundred twenty-six (226) existing wood structures with one hundred thirty-one (131) new steel structures, and three (3) new lattice steel towers. Phase II will upgrade 17.94 miles of 69kV line between Rumsey and East Diamond substations, replacing two hundred thirty-six (236) existing wood structures with one hundred fifty-six (156) new steel structures, and three (3) new lattice steel towers. Phase III will upgrade 1.68 miles of 69kV line between East Diamond and Earlington Substations, and will replace twenty-four (24) existing wood structures with twenty-seven (27) new steel structures.

This project also includes a supporting project from Distribution Operations. The Distribution Operations project will provide the layout work and transfer of underbuilt distribution conductors where needed.

- **Alternatives Considered**
    1. Recommendation: NPVRR: ($000s) $29,748
       The recommendation is to replace 35.73 miles containing 1F copper conductor with new ACSR, and the existing 3/8" static wire with new OPGW. In addition, 486 wood structures will be replaced with 314 new steel structures, which includes the installation of six (6) new lattice steel towers.
    2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
       This option is not advisable as this line is nearing the end of its useful life and puts Transmission at risk of not being able to accomplish the objectives established as part of the Transmission System Improvement Plan that was filed as support in the 2016 Rate Case and assumed the completion of this project. These objectives include reducing the risk of failure, avoiding an extended sustained outage, and costly emergency repairs.
    3. Alternative #2 – 1 for 1 Structure Replacement: NPVRR: ($000s) $39,446
       The Next Best Alternative would be to perform a 1 for 1 structure replacement on the entire 35.73 miles. Still replacing the 1F copper conductor with ACSR and the 3/8" static wire with new OPGW. This option would require the replacement of 172 additional structures and would increase the overall project cost.

Project Description
Earlington North-Green River Steel Conductor Replacement Facility Map



- **Project Scope and Timeline**
  Transmission Lines Project Description – Project 148851
  The Transmission Lines project involves the upgrade of 35.73 miles of existing conductor with ACSR and existing static wire with OPGW between the Earlington North, Rumsey, and Green River Steel substations on the Earlington North-Green River Steel 69kV line. This project also involves the replacement of 486 existing wood structures with 314 new steel structures, and the installation of six (6) new steel lattice towers.

  Transmission Lines Project Scope and Timeline

Design Start	October 2017
Design Complete	July 2018
Space reserved for steel pole production with manufacturer	November 2018
Materials Delivered	December 2018
Construction Start	January 2019
Construction Finish	September 2020

Distribution Operations Project Description – Project 157839
The Distribution Operations project will layout and transfer underbuilt distribution conductor, along with the removal and installation distribution framing materials.

Distribution Operations Project Scope and Timeline

Design Start	April 2018
Design Complete	June 2018
Materials Ordered (Section #2)	February 2019
Materials Delivered (Section #2)	July 2019
Materials Ordered (Section #4)	January 2020
Materials Delivered (Section #4)	April 2020
Construction Start	September 2018
Construction Finish	September 2020

- **Project Cost**

	Transmission Lines 148823	Distribution Operations 157839	Total
Total 2018	$2,981k	$0k	$2,981k
Total 2019	$8,472k	$30k	$8,502k
Total 2020	$14,394k	$48k	$14,442k
Total Project	$25,847k	$78k	$25,925k
Contingency	10%	10%	

Economic Analysis and Risks

- **Bid Summary**
  Transmission Lines
  Based on detailed engineering, Transmission Lines has estimated the material package for this project to be $7,446k. The project will utilize OPGW, standard and custom steel structures, and material. The OPGW will be purchased through an existing contract with AFL. The conductor will be competitively bid through normal Supply chain processes. The line construction will be based on continuing contracts with our line contractors. B&B Electric, Davis H. Elliot, William E. Groves and Pike Electric are the four contractors which have been awarded the Transmission Overhead Construction Maintenance contracts.

  Distribution Operations:
  Distribution Operations is working on detailed engineering and has provided a basis for the Distribution lines estimate and design. Bids for materials will be sent out once the detailed engineering has been finalized.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	2,981	7,840	10,838	-	21,659
2. Cost of Removal Proposed	-	662	3,604	-	4,266
3. Total Capital and Removal Proposed (1+2)	2,981	8,502	14,442	-	25,925
4. Capital Investment 2018 BP	300	2,260	9,176	20,264	32,000
5. Cost of Removal 2018 BP	-	-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	300	2,260	9,176	20,264	32,000
7. Capital Investment variance to BP (4-1)	(2,681)	(5,580)	(1,662)	20,264	10,341
8. Cost of Removal variance to BP (5-2)	-	(662)	(3,604)	-	(4,266)
9. Total Capital and Removal variance to BP (6-3)	(2,681)	(6,242)	(5,266)	20,264	6,075

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2018 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Discount Rate: 6.59%

Capital Breakdown:

	148857 Trans Lines	157389 Dist Ops	Total
Labor	$582k	$0k	$582k
Contract Labor	$12,002k	$54k	$12,056k
Materials	$7,446k	$13k	$7,459k
Other	$5k	$0k	$5k
Local Engineering	$1,658k	$8k	$1,666k
Burdens	$1,803k	$3k	$1,806k
Contingency	$2,351k	$0k	$2,351k
Reimbursements	$0k	$0k	$0k
Net Capital Expenditure	$25,847k	$78k	$25,925k

- **Assumptions**
  Recommendation - This assumes that the 35.73 miles of existing conductor will be replaced with ACSR and the existing static wire will be replaced with OPGW.

  Alternative #1 – Do Nothing - This option is not advisable as this line is nearing the end of its useful life and puts Transmission at risk of not being able to accomplish the objectives established as part of the Transmission System Improvement Plan, that was filed as support in the 2016 Rate Case, which assumed the completion of this project. These objectives include reducing the risk of failure, avoiding an extended sustained outage, and costly emergency repairs.

Alternative #2 – This alternative assumes that all four hundred eighty-six structures would be replaced on all 35.73 miles of line, the 1F copper conductor would be replaced with ACSR, and the 3/8" static wire with new OPGW. This option would require the replacement of 172 additional structures which would increase the cost of the overall project.

- **Environmental**
  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project. All permitting, including the Army Corps of Engineers, the Kentucky Division of Water, and CSX Railroad are in process.

- **Customer Experience**
  A communication plan is being developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the community, businesses, and farmers along the project route.

- **Risks**
  - Without the proposed replacement of existing wire in the Earlington North to Green River Steel 69kV line, the company risks increased exposure to line outages. The wire along the 35.73 mile route has deteriorated and corroded over time, and is beyond its expected useful life. There have been notable failures in the conductor's 75+ year service life. Unplanned outages are often time-consuming and costly when it comes to repairs.
  - A single overhead transmission failure would impact over 1,870 customers, reducing their reliability until the repairs are complete.
  - An Army Corps of Engineers environmental permit is required for the Green River crossing. Through coordination with environmental affairs, this permit application is being processed.
  - A Storm Water Pollution Prevention Plan (SWPPP) is being developed for the Kentucky Division of Water. All required permitting will be obtained prior to construction.
  - The local community and farmers may react negatively to the work and potential inconvenience of the project. A communication plan is being developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the community, businesses, and agricultural operations.

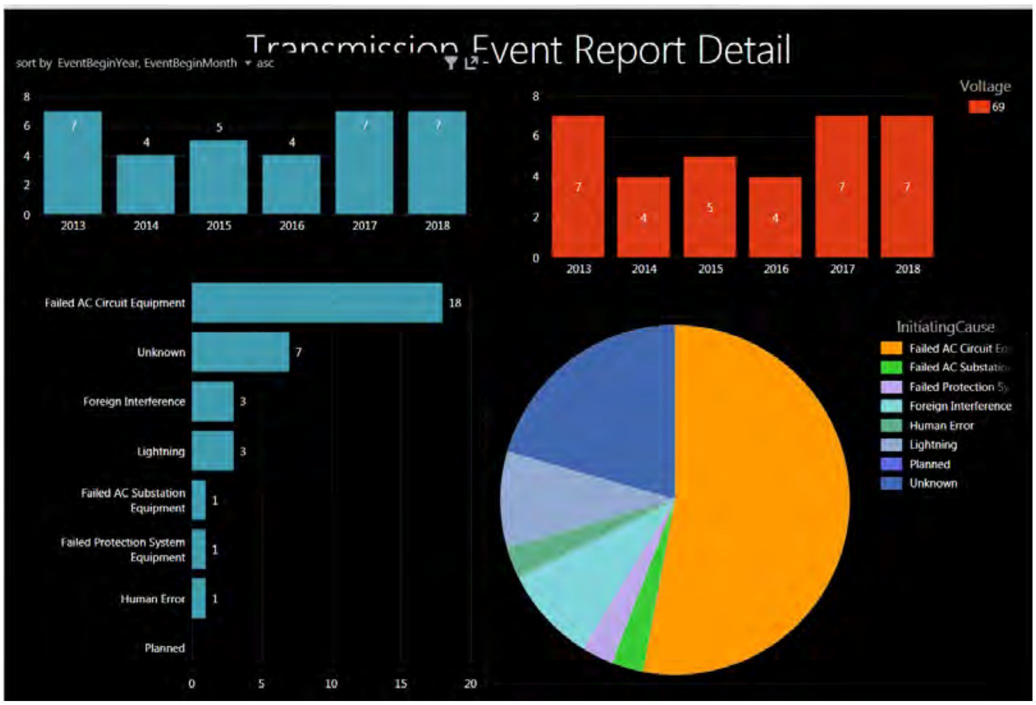
Conclusions and Recommendation
It is recommended that the Investment Committee approve the Earlington North-Green River Steel Conductor replacement project for $25,925k to improve the reliability of the electric transmission system.

Approval Confirmation for Capital Projects Greater Than $2 million:

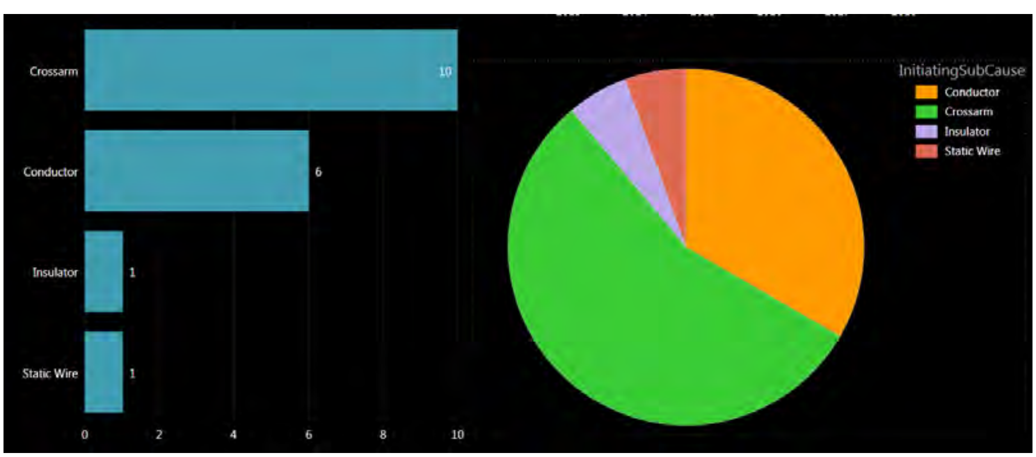
The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

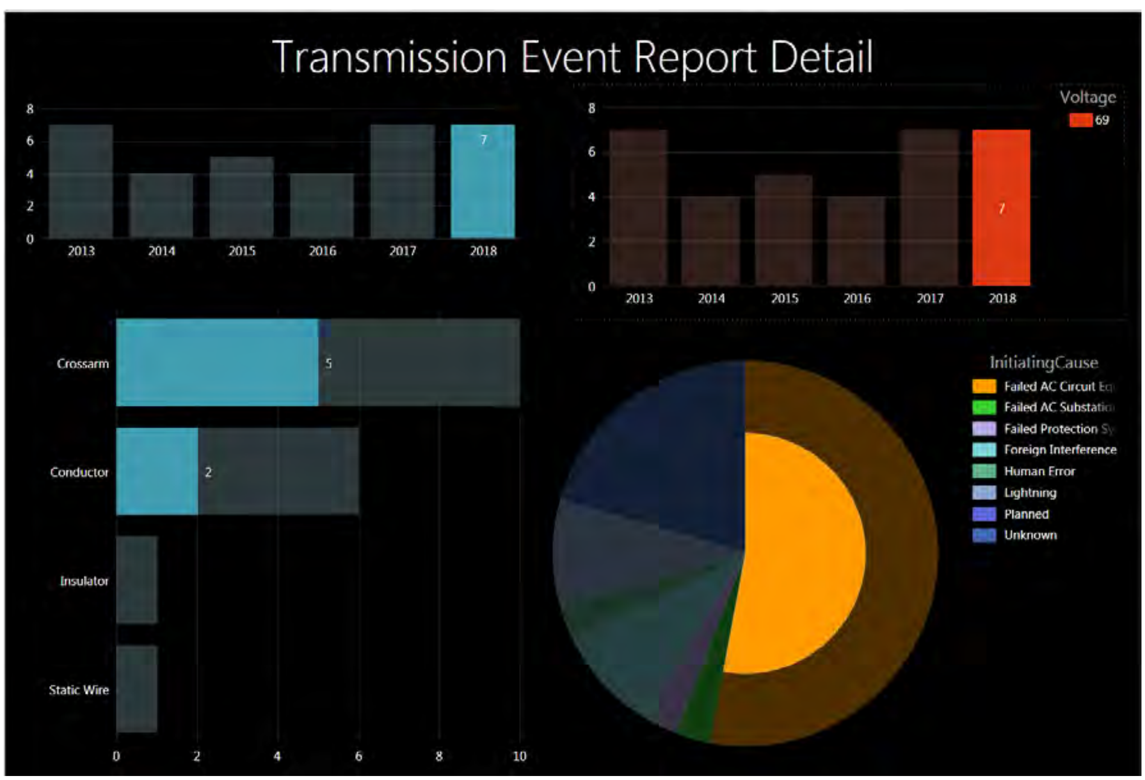
Transmission Reliability Outage Data System (TRODS) 5 Year DATA



TRODS 5 Year DATA of failed AC Circuit Equipment for Earlington North-Green River Steel



TRODS 2018 DATA for Earlington North-Green River Steel



Investment Proposal Project 148851 CR Morganfield-Overland North

Investment Proposal for Investment Committee Meeting on: June 27, 2018
Project Name: Morganfield-Overland North Conductor Replacement
Total Expenditures: $5,337k Total Contingency: $477k (10%)
Project Number(s): Transmission Lines - 148851 Transmission Substation – 157437
Business Unit/Line of Business: Transmission Lines/Transmission Substation
Prepared/Presented By: Ronnie Bradford/Adam Smith

Executive Summary
The proposed project is to replace 9.1 miles of overhead transmission line containing conductor that is over 90 years old and beyond its expected useful life. Performance of this line has diminished, with the most recent failure occurring in 2016 from a failed conductor. Over 750 customers with a peak load over 30 MVA are served by the facilities being replaced. These customers include Alliance Coal, the City of Uniontown, the Uniontown sewer facility, and the Morganfield water department. This project will improve reliability, maintain system integrity, and reduce the risk of failures and unplanned transmission interruptions to the Morganfield area.

A Transmission System Improvement Plan was submitted as support in the 2016 Rate Case, outlining programs and projects aimed at reducing the risk of failure, avoiding extended sustained outages, and limiting costly emergency repairs. The programs submitted with the plan were selected to ensure long-term system integrity and modernize the transmission system to avoid degradation of performance over time due to aging infrastructure. Replacement of overhead wires beyond or approaching their expected useful life was included as part of the Transmission System Improvement Plan to replace aging infrastructure.

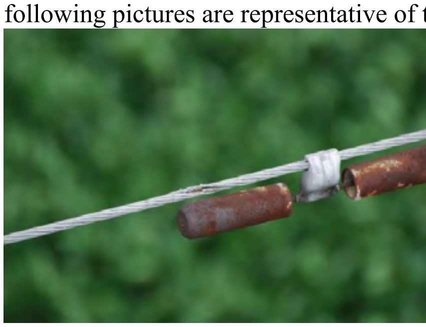
Transmission Lines plans to replace the 9.1 mile section of 69kV line between the Morganfield and Uniontown substations. Transmission Substation plans to remove a breaker from service at the Morganfield substation and modify the relays to ensure protection for the Riverview Coal, Uniontown, and Overland North substations during construction. Telecom also plans to install OPGW (optical ground wire) along the transmission route providing connectivity to the Uniontown substation.

The total project cost is $5,337k ($5,172k Transmission Lines, $165k Transmission Substation). This project was included in the 2018 Business Plan (BP) for $8,500k, including estimated spend of $4,250k in 2018, and $4,250k in 2019. The original scope also included replacement of the 2 mile section of conductor between Uniontown-Overland North. As the scope, timing and certainty of work has evolved, the estimates have been further refined to only include the 9.1 mile section between Morganfield and Uniontown substations. Distribution Planning is evaluating options to provide distribution service at Overland North in lieu of rebuilding the additional 2 mile section of transmission line between the Uniontown and Overland North substations. This analysis will be utilized to determine the recommended alternative for a future project.

The current total project cost is $5,337k, with actuals of $26k in 2017, estimated spend of $3,514k in 2018, $1,124k in 2019, and $673k in 2020. 2018 spend was approved by the RAC in the 4+8 forecast.

Background

The existing 9.1 mile section of 69kV line between Morganfield and Uniontown contains aging 3/0 conductor which dates back to 1927 and has experienced diminishing performance in recent years. Non-destructive inspections were performed to measure the remaining cross sectional area of steel and to detect the presence of pits and flaws due to corrosion in the steel core wires of ferrous conductors and static wires. These inspections revealed that the existing 3/0 conductor and 3/8" HS static wire showed signs of corrosion and are in fair to poor condition. In addition, there have been recent failures in 2014 and 2016 of the 90+ year old conductor. This line has also experienced lightning arrestor failures and a number of momentary events due to lightning. Over the past five years, this circuit ranks in the top 50 in terms of worst SAIDI performers and is in the top 20 for highest number of events. Due to the conditions of this line, there is a risk of additional failures that will expose the transmission network to further unscheduled outages. The following pictures are representative of the 3/0 conductor condition on sections of this line.



The picture on the left shows broken strands on the existing conductor and signs of corrosion on the steel core. The picture on the right highlights evidence of damage to the existing conductor, and hardware age.

This aging conductor will be replaced with aluminum conductor steel-reinforced (ACSR) conductor (with multiple outer layers of aluminum strands) and the deteriorating 3/8" HS static wire will be replaced with OPGW. There is currently 2.1 miles of the existing line without a static wire which is needed for lightning protection, this project will install OPGW along the entire 9.1 mile route. In addition, new steel structures will be installed in place of existing wood structures and a complete below grade inspection and coating for twenty-five (25) existing steel lattice towers will be completed. A PSC inspection was completed on this line in 2017. From this inspection, twenty-five (25) structures were found to be in need of replacement. The twenty-five (25) structures found during inspection will be addressed as a part of this project.

In October 2017, the transmission line engineering phase of this project was approved and initiated. The engineering phase consisted of development of a project plan, determination of the preferred line route modifications, structure design and selection, and development of the construction sequence. This project will upgrade the identified 9.1 miles of 69kV transmission line in two phases. Phase I will upgrade 8.0 miles of 69kV line between the Morganfield and Riverview Coal substations in 2018. Forty-nine (49) existing wood structures will be replaced with new steel structures, and a complete below grade inspection and coating on twenty-five (25) lattice steel towers will be performed. Phase II will upgrade 1.1 miles of 69kV line between the Riverview Coal and Uniontown substations in 2019. This phase will replace sixteen (16) existing wood structures with new steel structures.

Alliance Coal has provided KU with a new easement for the section of line deviating from the existing route. This newly acquired easement will provide better access to facilitate future construction and maintenance to this line. In addition, the easement should accommodate the future development plans of Alliance Coal and eliminate the need for additional relocations. All environmental permits associated with this new route have been acquired.

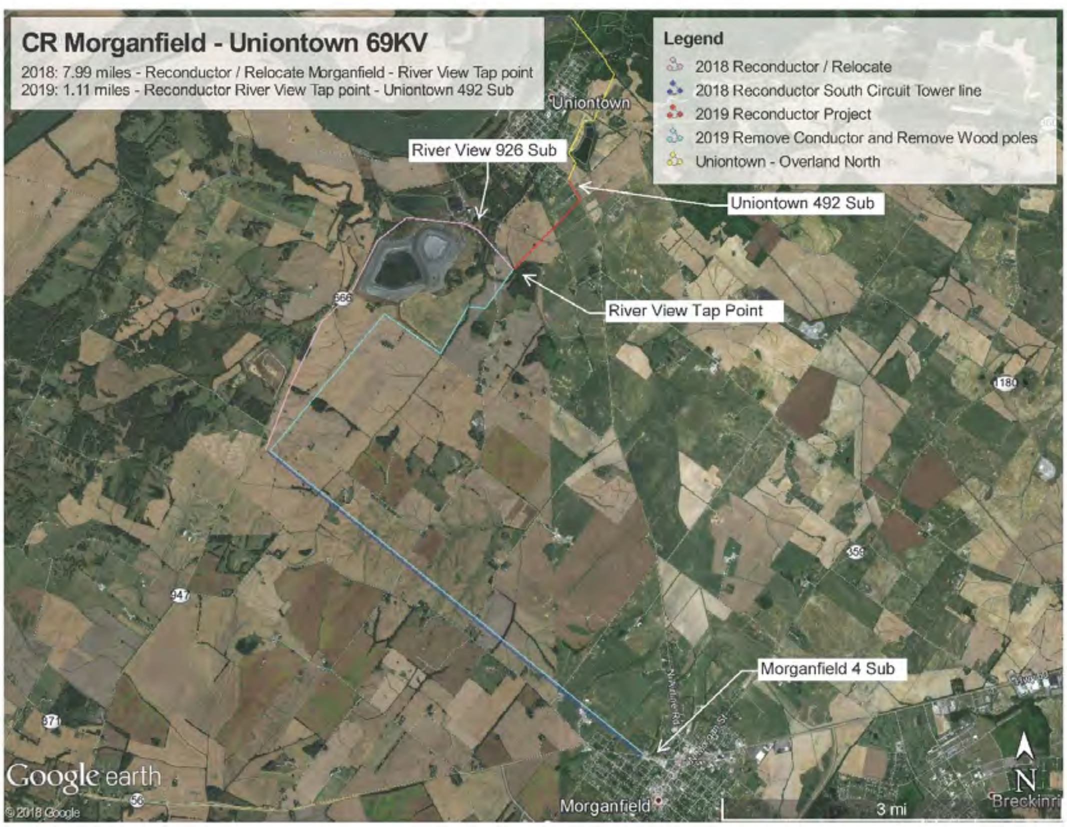
This project also includes a supporting project from Transmission Substation. The Transmission Substation project will involve modifications of Morganfield Substation steel structures to accommodate transmission line reconfiguration and installation of protection and control devices at the relay panels that will provide improved telemetry to Transmission Control Center. Also, Protection & Control will review the current relay settings and adjust them, if necessary, during construction phases.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $6,206
     The recommendation is to replace 9.1 miles containing 3/0 conductor with new ACSR, and existing 3/8" static wire with new OPGW. In addition, sixty five (65) wood structures will be replaced with new steel structures, and a thorough ground-line, tower steel corrosion inspection will also be performed on twenty-five (25) lattice steel towers.
  2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
     This option is not advisable as this line is nearing the end of its useful life and puts Transmission at risk of not being able to accomplish the objectives established as part of the Transmission System Improvement Plan that was filed as support in the 2016 Rate Case and assumed the completion of this project. These objectives include reducing the risk of failure, avoiding an extended sustained outage, and costly emergency repairs.
  3. Alternative #2 – Construct Alternate Route: NPVRR: (000s) $8,246
     The Next Best Alternative would be to construct a new 5.3 mile transmission line which would provide an alternate route beginning at the Morganfield 4 Substation,

and would parallel the Morganfield - Green River Plant 161kV line. Constructing a new route would require the purchase of 4.7 miles of new right of way that customers may not be willing to sell. This could cause potential project delays that may result in additional expenses and customer challenges. In addition, an alternate route would not provide Alliance Coal the option to expand future operations. This alternative would also require an additional 1.5 miles of existing 69kV line to the Riverview Tap to be re-built in order to complete the alternate route. The 1.5 miles to the Riverview Tap is located on existing right of way.

Project Description

Recommendation - Morganfield-Overland North Conductor Replacement Facility Map



- **Project Scope and Timeline**

  Transmission Lines Project Description – Project 148851
  The Transmission Lines project involves the upgrade of 9.1 miles of existing conductor with ACSR and existing static wire with OPGW between the Morganfield-Uniontown section on the Morganfield-Overland North 69kV line. This project also involves the replacement of

sixty-five (65) existing wood structures with new steel structures, and a ground-line tower steel corrosion inspection on twenty-five lattice steel towers.

Transmission Lines Project Scope and Timeline

Design Start	November 2017
Design Complete	January 2018
Space reserved for steel pole production with manufacturer	February 2018
Materials Delivered	August 2018
Construction Start	September 2018
Construction Finish	July 2019
Clean up and Permit Close Out	January 2020

Transmission Substation Project Description – Project 157437
The Transmission Substation project will involve modifications of Morganfield Substation steel structures to accommodate transmission line reconfiguration and installation of protection and control devices at the relay panels that will provide improved telemetry to Transmission Control Center. Also, Protection & Control will review the current relay settings and adjust them, if necessary, during construction phases.

Transmission Substation Project Scope and Timeline

Design Start	July 2018
Design Complete	July 2018
Materials Ordered	July 2018
Materials Delivered	August 2018
Construction Start	September 2018
Construction Finish	April 2019

- **Project Cost**

	Transmission Lines	Transmission Substation	Total
Total 2017	$26k	$0k	$26k
Total 2018	$3,354k	$160k	$3,514k
Total 2019	$1,119k	$5k	$1,124k
Total 2020	$673k	$0k	$673k
Contingency	10%	6%	

Economic Analysis and Risks

- **Bid Summary**
  Transmission Lines

Based on detailed engineering, Transmission Lines has estimated the material package for this project to be $930k. The project will utilize OPGW, standard steel structures, and material. The OPGW will be purchased through an existing contract with AFL. The line construction will be based on continuing contracts with our line contractors. B&B Electric, Davis H. Elliot, William E. Groves and Pike Electric are the four contractors which have been awarded the T&D Overhead Construction Maintenance contracts.

Transmission Substation:
Based on detailed engineering, Transmission Substation has provided a solid basis for the substation estimate and design. Bids for materials, as well as the below grade and above grade construction, will be sent out once the detailed engineering has been finalized.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	26	3,440	997	673	5,136
2. Cost of Removal Proposed	-	74	127	-	201
3. Total Capital and Removal Proposed (1+2)	26	3,514	1,124	673	5,337
4. Capital Investment 2018 BP		4,016	3,899		7,916
5. Cost of Removal 2018 BP		234	351		584
6. Total Capital and Removal 2018 BP (4+5)	-	4,250	4,250	-	8,500
7. Capital Investment variance to BP (4-1)	(26)	576	2,902	(673)	2,779
8. Cost of Removal variance to BP (5-2)	-	160	223	-	383
9. Total Capital and Removal variance to BP (6-3)	(26)	736	3,126	(673)	3,163

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2018 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

	148851 Trans Lines	157437 Trans Substation	Total
Discount Rate:	6.59%	6.59%	6.59%
Capital Breakdown:			
Labor	$167k	$14k	$181k
Contract Labor	$2,861k	$82k	$2,943k
Materials	$930k	$33k	$963k

Other	$79k	$0k	$79k
Local Engineering	$360k	$11k	$371k
Burdens	$307k	$16k	$323k
Contingency	$468k	$9k	$477k
Reimbursements	$0	$0	$0
Net Capital Expenditure	$5,172k	$165k	$5,337k

- **Assumptions**
  Recommendation - This assumes that the 9.1 miles of existing conductor will be replaced with ACSR and the existing static wire will be replaced with OPGW. Temporary transmission line work and a portable substation will be needed to limit service interruptions at the Uniontown substation. Short planned outages to the Riverview Coal substation will be needed to support this project. These outages will be coordinated with the customer to limit impacts.

  Alternative #1 – Do Nothing - This option is not advisable as this line is nearing the end of its useful life and puts Transmission at risk of not being able to accomplish the objectives established as part of the Transmission System Improvement Plan, that was filed as support in the 2016 Rate Case, which assumed the completion of this project. These objectives include reducing the risk of failure, avoiding an extended sustained outage, and costly emergency repairs.

  Alternative #2 – Next Best Alternative – This alternative assumes that a new 5.3 mile transmission line would be constructed, and an additional 1.5 miles would need to be re-built. This option would also require additional funding due to the need to purchase 4.7 miles of new right of way, in which the property owners may not be willing to sell. The impacts associated with this option would be more disruptive and have a larger negative impact on the community during construction. The remaining 2.1 miles is located on existing right of way.

- **Environmental**
  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project. All environmental permitting, including the Army Corps of Engineers, and Department of Environmental Protection have been acquired.

- **Customer Experience**
  A communication plan is being developed in coordination with the project proponents, corporate communications, external affairs, customer experience and major accounts, and the local business office. This plan will be executed to limit the impacts to the community, businesses, and farmers.

- **Risks**
  - Without the proposed replacement of existing wire in the Morganfield-Overland North 69kV line, the company risks increased exposure to line outages. The wire along the 9.1 miles has deteriorated and corroded over time, and is beyond its expected useful life. There have been notable failures in the conductor's 90+ year service life. Unplanned outages are often time-consuming and costly when it comes to repairs.
  - A single overhead transmission failure would impact over 750 customers, with limited options to restore their service until the repairs are complete. This would be especially concerning for many key customers, including Alliance Coal, the City of Uniontown, and the Morganfield water department.
  - The construction sequence for this project has been communicated and coordinated with Alliance Coal to minimize impacts to their operations.
  - Easements have been acquired for Alliance Coal and one private property owner. An additional easement is required from a second private property owner which has been formally agreed upon and is currently being processed for formal execution.
  - An Army Corps of Engineers environmental permit is required for a line segment being constructed near a wetland on Alliance Coal's property. Through coordination with environmental affairs, this permit has been obtained for the proposed plan.
  - The local community and farmers may react negatively to the work and potential inconvenience of the project. A communication plan is being developed in coordination with the project proponents, corporate communications, external affairs, customer experience, major accounts, and the local business office. This plan will be executed to limit the impacts to the community and businesses.
  - To limit customer impacts and maintain service continuity at Uniontown, a temporary transmission line and portable substation will be installed near the existing Uniontown substation. The temporary service will utilize an existing Alliance Coal 69kV line and the metering adjusted to ensure billing integrity is maintained.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the Morganfield-Overland North Conductor replacement project for $5,337k to improve the reliability of the electric transmission system.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

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	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal Project 148857 Oxmoor Underground Replacement

Investment Proposal for Investment Committee Meeting on: October 26, 2016

Project Name: Oxmoor Underground Replacement

Total Expenditures: $1,681k (2016-$50k) (2017-$1,631k)
Total Contingency: $140k (9%)

Project Number(s): 148857

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Chris Wheeldon/Adam Smith

Executive Summary

The proposed project is to replace the underground segment (600 feet) of two (2) 69kV transmission feeds into the Oxmoor substation, Oxmoor-Aiken (circuit 6650), and Oxmoor-Breckenridge (circuit 6653). This project will include a new duct bank underneath Shelbyville Road (US 60), 3,600 feet of underground cable, and two (2) new steel risers to replace the existing wood riser poles.

The total project cost is $1,681k and was included in the 2016 Business Plan for $1,890k in 2019. The original estimate was created with the assumptions that anchor bolt foundation structures would be required to replace the existing wood pole risers. Subsequent to the 2016 Business Plan, a more detailed engineering analysis was completed which resulted in eliminating the need for large foundation structures. This project was accelerated in the 2017 Business Plan for construction in 2016-2017 due to reliability issues with the condition of the existing cable. This project was approved by the RAC in the 9+3 forecast.

Background
The termination for the underground feed on the Oxmoor-Aiken (circuit 6650) 69kV line at the Oxmoor Substation failed in 2015 and damaged a portion of the cable. The original cable was installed in 1975 and has been in service for 41 years. The Oxmoor Substation currently serves 6,304 customers. As part of the commissioning of the cable, High Voltage Maintenance (HVM) was contracted to do acceptance testing for the repair. The cable testing identified concerns with phase C because the resistance results fell outside of the National Electrical Testing Association (NETA) specifications due to corrosion of the shield wire. The termination was installed at a lower height due to the need to remove the damaged portion of cable requiring installation of a temporary barrier to ensure compliance with the National Electric Safety Code (NESC) clearances for personnel safety. In addition, the riser pole for circuit 6650 was identified to be replaced from a recent inspection. The Oxmoor-Breckenridge (circuit 6653) underground segment will be replaced concurrently with the Oxmoor to Aiken underground segment due to the age of existing cable, and its inclusion in the existing duct bank that will be replaced as part of the proposed project.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $2,149k
     The recommendation is to replace 600 feet of two (2) underground transmission feeds into the Oxmoor substation during a scheduled outage.
  2. Alternative #1-Do Nothing: NPVRR: ($000s) $2,928k
     This NPVRR for this alternative is based on an estimated termination failure in 2018 and cable failure in 2020. The do nothing alternative is not recommended as the underground conductor is deteriorated, there has been a recent failure, and proactive replacement will avoid in service failures affecting 6,304 customers served from the Oxmoor Substation.
  3. Alternative #2-Next Best Alternative: NPVRR: ($000s) $2,308k
     The next best alternative would be to construct 600 feet of new overhead transmission line, which would require acquisition of easement rights to build overhead. This option would also require full unbalanced terminal structures on the line side of Shelbyville Road, and A-Frames in the substation. The original underground construction was driven at least in part by aesthetics and community acceptance of the substation which is adjacent to the Oxmoor shopping mall. Converting to overhead construction and acquisition of required easements would be opposed by the community and local businesses.

Project Description

- **Project Scope and Timeline**
  The scope of work will consist of the replacement of 1 existing duct bank, six (6) existing cables (three on each circuit), and the replacement of two (2) existing wood riser poles with new steel poles. The construction will be based on continuing contracts from our line contractors. B&B, Elliot, Groves and Pike are the four contractors awarded the T&D Overhead Construction and Maintenance contract from the October 2011 Investment Committee meeting. The contract extension was re-approved by the IC in July of 2014. Preliminary

engineering is scheduled to begin in December of 2016. Construction is scheduled to begin in March of 2017 and be completed in June of 2017.

Construction Milestones	
October 2016	Preliminary Engineering
November 2016	Material Ordered
March 2017	Material Received
March 2017	Construction Begins
June 2017	Construction Completed

A facility map of the Oxmoor-Aiken (circuit 6650) and Oxmoor-Breckenridge (circuit 6653) 69kV lines is shown below:
Line length: Circuit 6650=5.14 miles/Circuit 6653=6.61 miles

- **Project Cost**
The total project cost is $1,681k, with estimates of $50k in 2016 and $1,631k in 2017. This project is included in the 2016 Business Plan for $1,890k in 2019. Subsequent to the 2016 Business Plan, a more detailed engineering analysis was completed which resulted in eliminating the need for large foundation structures. This project was approved by the RAC in the 9+3 forecast. Historical and existing contract and purchasing agreements were used to

estimate the cost of material and contract labor. This project includes a 9% contingency which is reasonable based on the level of detailed engineering, confidence in the cost of materials and contractors, and potential unknown risks such as weather delays, outage delays, reclamation, and site access.

Economic Analysis and Risks

- **Bid Summary**
  Based on preliminary engineering, Transmission Lines has estimated the material package for construction to be $364k. This project will utilize standard steel structures, and associated hardware and material. The terminators will be purchased through Raychem. The current estimate for the 69kV underground cable is based on historical pricing. Bids for the 69kV underground cable will be sent out shortly after project approval. The underground line construction will be competitively bid. The overhead line construction will be based on continuing contracts with our line contractors. Davis H. Elliot, Pike Electric, B&B Electric and William E. Groves are the four main contractors which have been awarded the T&D Overhead Construction and Maintenance contracts.

Transmission Lines Material Cost Breakdown	
Material	**Cost**
Duct Bank	$15k
Terminators	$15k
Underground Cable	$280k
Steel Poles	$46k
Hardware	$8k
Total	$364k

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	50	1,472	-	-	1,522
2. Cost of Removal Proposed	-	159	-	-	159
3. Total Capital and Removal Proposed (1+2)	50	1,631	-	-	1,681
4. Capital Investment 2016 BP	-	-	-	1,743	1,743
5. Cost of Removal 2016 BP	-	-	-	147	147
6. Total Capital and Removal 2016 BP (4+5)	-	-	-	1,890	1,890
7. Capital Investment variance to BP (4-1)	(50)	(1,472)	-	1,743	221
8. Cost of Removal variance to BP (5-2)	-	(159)	-	147	(12)
9. Total Capital and Removal variance to BP (6-3)	(50)	(1,631)	-	1,890	209

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2016 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Proposed spending is consistent with the 2017 BP

Financial Summary ($000s):
Discount Rate: 6.49%
Capital Breakdown:
Labor: $54k
Contract Labor: $917k
Materials: $364k
Local Engineering: $131k
Burdens: $75k
Contingency: $140k
Reimbursements: ($0)
Net Capital Expenditure: $1,681k

Financial Analysis - Project Summary ($000)	2016	2017	2018	2019	2020	Life of Project
Project Net Income	$0	$55	$82	$78	$74	$1,294
Project ROE	0.0%	6.2%	8.1%	10.0%	10.0%	9.7%

- **Assumptions**
  Recommendation – This alternative assumes that the line outage will be available and that the work will be completed during this timeframe. This alternative also assumes that the Kentucky Transportation Cabinet (KYTC) will approve a traffic control plan which will allow for lane closure during construction.

  Alternative #1-Do Nothing – This alternative assumes a termination failure would occur in year three, and a cable failure would occur in year five. Estimated failure years are based on the initial testing date of 2015.

  Alternative #2 – Next Best Alternative – The cost if this alternative assumes that all required easement rights would be purchased at a reasonable cost without condemnation in order to complete construction of the overhead line.

- **Environmental**
  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

- **Risks**
  Without completion of the proposed project, the company risks unplanned outages and increased cost of repairs in emergency situations. Schedule delays may occur if the requested outage is not obtained to complete the scheduled work. Schedule delays may also occur if the KYTC does not approve the recommended traffic control plan.

  The local community and businesses may react negatively to the work and potential inconvenience of the traffic plan. The Customer Experience process will be used to mitigate this risk proactively.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the Oxmoor Underground Replacement project for $1,681k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than or Equal to $1 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	Victor A. Staffieri Chairman, CEO and President

Investment Proposal

Investment Proposal for Investment Committee Meeting on: N/A
Project Name: Middlesboro (5) 69kV Breaker Replacements
Total Expenditures: $782k (Including $35k of Contingency)
Project Number(s): 150636
Business Unit/Line of Business: Transmission Substation Construction & Maintenance
Prepared/Presented By: Corbin Williams – Electrical Engineer

Executive Summary

The proposed project consists of replacing (5) 69kV oil breakers with new SF6 gas breakers at the Middlesboro substation. The breakers that will be replaced are 602, 614, 624, 634, and 644. Breakers 602 and 644 are the primary breakers of concern and are a concern to mitigating an oil release into navigable water. These breakers are in close proximity to a stream and any failure would cause a release. 614, 624 and 634 are older breakers that lack the spare parts available to continue maintaining this equipment. It is expected that the new breakers will have fewer maintenance issues and increase system reliability due to the fact that they will have a lower likelihood of operating incorrectly.

The total cost of this project will be $782k and was approved by the 2016 1+11 RAC. $0k was included in the 2016 BP for this project. These breakers were flagged with a spill prevention compliance issues after inspections done by a third party engineering firm last year. Transmission had 54 non-compliant sites and Middlesboro was not reviewed until the end of the year, after the BP was prepared. Containing these breakers only created maintenance issues and still left sizable risk of oil releasing into navigable water. Transmission Substation Construction felt a better solution was to replace 602 & 644 with SF6 breakers. It made sense to add the remaining breakers to this project due to their age and operating performance while on site to replace 602 and 604. The estimated total project figure includes a 5% contingency.

Background
Replacement of the 602 and 644 breakers with new SF6 breakers is recommended. The breakers currently in-service are late 1970's vintage McGraw-Edison, type CGR (20kA) and could be used to replace older 1950's vintage breakers in other parts of the system. The remaining three breakers (614, 624, and 634) are vintage 1950's General Electric models that need to be replaced to alleviate issues with ageing parts and to reduce breaker operations and maintenance costs.

- **Alternatives Considered (1 –Recommendation, 2 –Do nothing, 3 –Next Best Alt)**
  Recommendation – It is recommended that (5) 69kV breakers at Middlesboro substation be replaced. This will enhance the reliability of the Transmission system in the area.
  NPVRR: ($000s) $981k

  Do Nothing – Do nothing and accept risk of breaker failures. Emergency replacement can become costly and is inevitable with older breakers such as these. Cost savings can be achieved and greater reliability of the Transmission System can be gained by replacing all five under one project. The CEM assumes a failure every other year beginning in 2016.
  NPVRR: ($000s) $1,377k

  Next Best Alternative – Build secondary containment to mitigate an oil release from the 602 and 644 breakers and refurbish the 614, 624, and 634 breakers by replacing bushings, performing interrupter maintenance, fixing oils leaks and fabricating and replacing mechanized parts to increase the life of this asset by an estimated 10-15 years. This option is not advisable as installing secondary containment would be costly due to existing substation layout and it does not alleviate operational issues these breakers have previously experienced. Any means to contain these breakers would be invasive and impact future response times to maintain or repair these breakers. Additionally, a complete overhaul of the breakers currently in-service is not possible due to obsolete parts for key breaker assemblies.
  NPVRR: ($000s) $1,194k

Project Description

- **Project Scope and Timeline**

Description	Date
Project Approved	March, 2016
Materials Ordered	April, 2016
Materials Received	July, 2016
Below Grade Work Begins	August, 2016
Below Grade Work Completed	September, 2016
Above Grade Work Begins	September, 2016
Above Grade Work Completed	October, 2016
Project Complete	December, 2016

- **Project Cost**

The total cost of this project will be $782k and was approved by the 2016 1+11 RAC. $0k was included in the 2016 BP for this project. The estimated total project figure includes a 5% contingency.

Economic Analysis and Risks

- **Bid Summary**
  The 69kV breakers will be purchased under the existing breaker purchasing agreement. Bids for any other necessary materials as well as the civil, below, and above grade work will be sent out early in March, 2016.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	693	-	-	-	693
2. Cost of Removal Proposed	88	-	-	-	88
3. Total Capital and Removal Proposed (1+2)	782	-	-	-	782
4. Capital Investment 2016 BP	-	-	-	-	-
5. Cost of Removal 2016 BP	-	-	-	-	-
6. Total Capital and Removal 2016 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(693)	-	-	-	(693)
8. Cost of Removal variance to BP (5-2)	(88)	-	-	-	(88)
9. Total Capital and Removal variance to BP (6-3)	(782)	-	-	-	(782)

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2016 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):
Discount Rate: 6.5%
Capital Breakdown:
Labor: $107k
Contract Labor: $248k
Materials: $243k
Other: $0k
Local Engineering: $60
Burdens: $89
Contingency: $35
Reimbursements: ($0k)
Net Capital Expenditure: $782

Financial Analysis - Project Summary ($000)	2016	2017	2018	2019	2020	Life of Project
Project Net Income	$ 16	$ 24	$ 37	$ 35	$ 33	$ 831
Project ROE	8.0%	6.2%	9.8%	9.8%	9.8%	9.6%

- **Assumptions**
  - Assumes internal project management.
  - Assumes contract labor for construction.
  - Assumes use of LG&E/KU relay techs for commissioning and breaker testing.
  - Assumes no site or geo-technical work required for this project.
  - Below grade is suitable to accommodate standard 69kV breaker foundation.
  - Same contractor will be used for above and below grade work
  - New breakers will be purchased that will match the existing breaker's requirements for CT ratios and accuracies. No changes to relays or relay settings will be required.
  - Special equipment, outages or outage coordination were not needed to remove the existing breaker and install the replacement.
  - Normal work schedule can be used with no expedited construction schedule or overtime required.
  - RTU points available to accommodate new spring discharge points. Otherwise alarms will be parallel.
  - Onsite disposal of excess soil obtained during foundation installation.
  - Rock will not be encountered during installation of the foundations.
  - Doble test connectors will not be installed on the breaker.
  - Breaker testing will be completed by contractor.
  - New AC and DC power feeders for the spring charge motor is required and there is adequate AC and DC power infrastructure to support these changes. It was also assumed that the existing cable trench and conduits leaving the control house has adequate space for the new conductors. It was assume all other existing control cable could be reused up to the new junction box.

- **Environmental**
  This project does not require permitting and there are no known issues regarding air, water, waste, lead, or asbestos.

- **Risks**
  If action is not taken, there will continue to be challenges associated with keeping these breakers in good working order. There is also an increased probability of failure, reduction of system reliability through the occurrence of system outages and possible collateral damage in the event of a catastrophic failure.

Conclusions and Recommendation

It is recommended that the Middlesboro (5) 69kV Breaker Replacements project for $782k be approved to enhance the reliability of the transmission system by removing equipment that can no longer be maintained.

Investment Proposal Project 150646 Livingston-South Paducah Pole Replacement

Investment Proposal for Investment Committee Meeting on: N/A

Project Name: Livingston-South Paducah Pole Replacement

Total Expenditures: $1,091k
Total Contingency: $92k (9%)

Project Number(s): 150646

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Nate Mullins/Adam Smith

Executive Summary

The proposed project is to replace twenty-seven (27) wood structures on the Livingston-South Paducah 161kV line based on the results of a routine line inspection. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

The alternative of replacing poles upon failure will result in much higher long term replacement costs due to mobilization of crews back to the site each time one fails and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability.

This project is being accelerated to align with the Livingston-South Paducah NRP project (147465). Completing both projects together will allow for resource efficiencies and limit the impacts to property owners. The total project cost is $1,091k and was not included in the 2016 Business Plan, however was approved by the RAC in the 3+9 forecast.

Background
Above ground pole inspections are performed by the company at defined intervals in order to discover problems that may impact the integrity and reliability of the Transmission System. During a routine climbing inspection of the Livingston-South Paducah 161kV line in 2013, twenty-seven (27) structures were identified as priority poles and determined to be in need of replacement in order to ensure the integrity and reliability of this line. There are 160 total structures along this 21.52 mile line. In addition to the 27 structures to be replaced on this project, there will be 20 replaced concurrently on the Livingston-South Paducah NRP project (147465). These structures are located at various points along the entire length of the line.

The transmission industry has been consistent in utilizing standard wood pole equivalent steel structures for many single pole applications. The industry has yet to align on wood pole equivalent steel structures for multi pole structures and typically approaches these as custom/unique design. Based on the quantity of wood H-frames on the transmission system and the anticipated replacement of these structure types, the company developed a library of standard steel H-frames with our alliance partner Trinity-Meyer in 2014. These structures have proved advantageous and to be a good addition to our replacement strategy. Wood was selected for these projects as the design parameters of these structures allows for wood replacements. Specifically, many of these structures identified for replacement were original vintage and there was limited wood pecker issues observed in this area. This project will be able to utilize wood poles from current inventory to avoid lead time issues in materials delivery.

- **Alternatives Considered (1 –Recommendation, 2 –Do nothing, 3 –Next Best Alt)**
    1. Recommendation: NPVRR: ($000s) $1,485k
       The recommendation is to replace 27 wood structures with new wood H-frames during a scheduled outage. Given the average lifespan of wood, these structures would likely need replacement again in 30 years. The NPVRR of replacing now and in 30 years would be $2,132k, however the second replacement in 30 years is not being requested at this time.
    2. Do Nothing: NPVRR: ($000s) $2,138k
       The alternative of do nothing would result in replacing poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.
    3. Next Best Alternative(s): NPVRR: ($000s) $1,837k
       The next best alternative would be to replace the poles with steel structures. Although the lifespan of steel is generally three times longer than wood and would eliminate the need for additional wood replacements in 30 years (as noted above, replacing with wood now and in 30 years would have an NPVRR of $2,132k), based on the design of these structures being good candidates for wood replacements, the immediate inventory availability of wood, the synergies to be gained by completing this project concurrently with the Livingston-South Paducah NRP project, and the

opportunity to help manage wood structure inventory levels with this project as we transition more fully to steel, we are recommending wood replacements in this case.

Project Description

- **Project Scope and Timeline**
  The scope of work will consist of installing twenty-seven (27) wood H-frame structures and associated hardware and material, and the removal of 27 wood H-frame structures, and associated hardware and material. The project will utilize standard wood structures and associated hardware. The line construction will be based on continuing contracts from our line contractors. B&B, Elliot, Groves and Pike are the four contractors awarded the T&D Overhead Construction and Maintenance contract from the October 2011 Investment Committee meeting. The contract extension was re-approved by the IC in July of 2014. Construction is scheduled to begin in May of 2016 and be completed in June of 2016.

The construction milestones for this project are provided below:

Construction Milestones	
April 2016	Engineering and Design
May 2016	Line Construction Begins
June 2016	Line Construction Completed

A facility map of the Livingston-South Paducah 161kV line is shown below:
Total line length: 21.52 miles

- **Project Cost**
  The total project cost is $1,091k and is not included in the 2016 Business Plan. Historical and existing contract and purchasing agreements were used to estimate the cost of material and contract labor. This project includes 9% contingency to cover unexpected increases in cost due to weather, rocky soil, outage delays, reclamation, etc. 10% contingency is a standard assumption used across all of our projects and is calculated as a percentage of total burdened costs. The 9% contingency on this project resulted from late estimate changes.

Economic Analysis and Risks

- **Bid Summary**
  Based on preliminary engineering, Transmission Lines has estimated the material packages for construction for this project to be $161k. This project will utilize standard wood structures and associated hardware. The line construction will be based on continuing contracts with our line contractors. Davis H. Elliot, Pike Electric, B&B Electric and William E. Groves are the four main contractors which have been awarded the T&D Overhead Construction and Maintenance contracts.

Transmission Lines Material Cost Breakdown

Material	Cost
Wood Poles	$96k
Hardware	$65k
Total	$161k

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	863	-	-	-	863
2. Cost of Removal Proposed	228	-	-	-	228
3. Total Capital and Removal Proposed (1+2)	1,091	-	-	-	1,091
4. Capital Investment 2016 BP	-	-	-	-	-
5. Cost of Removal 2016 BP	-	-	-	-	-
6. Total Capital and Removal 2016 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(863)	-	-	-	(863)
8. Cost of Removal variance to BP (5-2)	(228)	-	-	-	(228)
9. Total Capital and Removal variance to BP (6-3)	(1,091)	-	-	-	(1,091)

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2016 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):
Discount Rate: 6.49%
Capital Breakdown:
Labor: $42k
Contract Labor: $650k
Materials: $161k
Local Engineering: $73k
Burdens: $73k
Contingency: $92k
Reimbursements: ($0)
Net Capital Expenditure: $1,091k

Financial Analysis - Project Summary ($000)	2016	2017	2018	2019	2020	Life of Project
Project Net Income	$63	$54	$51	$49	$46	$1,079
Project ROE	22.3%	9.7%	9.8%	9.8%	9.8%	10.1%

- **Assumptions**

Recommendation – The cost of this alternative assumes that the line outage will be available and the structure replacements will be completed during this timeframe.

Do nothing alternative – The cost of this alternative would be approximately 60% higher due to overtime labor charges and the cost to mobilize and demobilize the construction crews. These poles would fail and require replacement within the next four years.

- Next best alternative – Utilizing steel poles would not allow for this project to be worked concurrently with the Livingston-South Paducah NRP project due to the limited availability and lead time required to obtain the steel structures.

- **Environmental**
  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

- **Risks**
  Without the proposed replacement of the priority poles on the Livingston-South Paducah 161kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays. Schedule delays may also occur if the requested outage is not obtained to complete the scheduled work.

Conclusions and Recommendation
It is recommended that the Livingston-South Paducah pole replacement project be approved in the amount of $1,091k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Investment Proposal for Investment Committee Meeting on: April 27, 2016

Project Name: Blackwell-Kenton Pole Replacement

Total Expenditures: $3,495k
Total Contingency: $318k (10%)

Project Number(s): 150652

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Terry Snow/Adam Smith

Executive Summary

The proposed project is to replace forty-two (42) wood structures on the Blackwell-Kenton 138kV line with steel based on the results of a routine line inspection. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

The alternative of replacing poles upon failure will result in much higher long term replacement costs due to mobilization of crews back to the site each time one fails and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability.

This project is being accelerated to align with the Blackwell-Kenton NRP project (146984). Completing both projects together will allow for resource efficiencies and limit the impacts to property owners. The total project cost is $3,495k and was not included in the 2016 BP, however was approved by the RAC in the 3+9 forecast.

Background

Above ground pole inspections are performed by the company at defined intervals in order to discover problems that may impact the integrity and reliability of the Transmission System. During a routine climbing inspection of the Blackwell-Kenton 138kV line in 2014, forty-two (42) structures were identified as priority poles and determined to be in need of replacement in order to ensure the integrity and reliability of this line. There are 290 total structures along this 46.47 mile line. In addition to the (42) structures to be replaced on this project, there will be seven (7) replaced concurrently on the Blackwell-Kenton NRP project (146984). These structures are located at various points along the entire length of the line.

- **Alternatives Considered (1 –Recommendation, 2 –Do nothing, 3 –Next Best Alt)**
  1. Recommendation: NPVRR: ($000s) $4,756k
     The recommendation is to replace the structures energized due to the difficulty in obtaining an extended outage. If the opportunity to complete the project de-energized would occur, we would pursue this option and it would reduce the NPVRR by $1,088k.
  2. Do Nothing: NPVRR: ($000s) $6,847k
     The alternative of do nothing would result in replacing poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on reliability.
  3. Next Best Alternative(s): NPVRR: ($000s) $6,033k
     The next best alternative would be to replace the poles with wood structures. The manufacturer's recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended life span of 90 years. This option assumes replacement of wood structures in 30 years and an escalation factor of 4% which is in line with market cost increases over the last 15 years.

Project Description

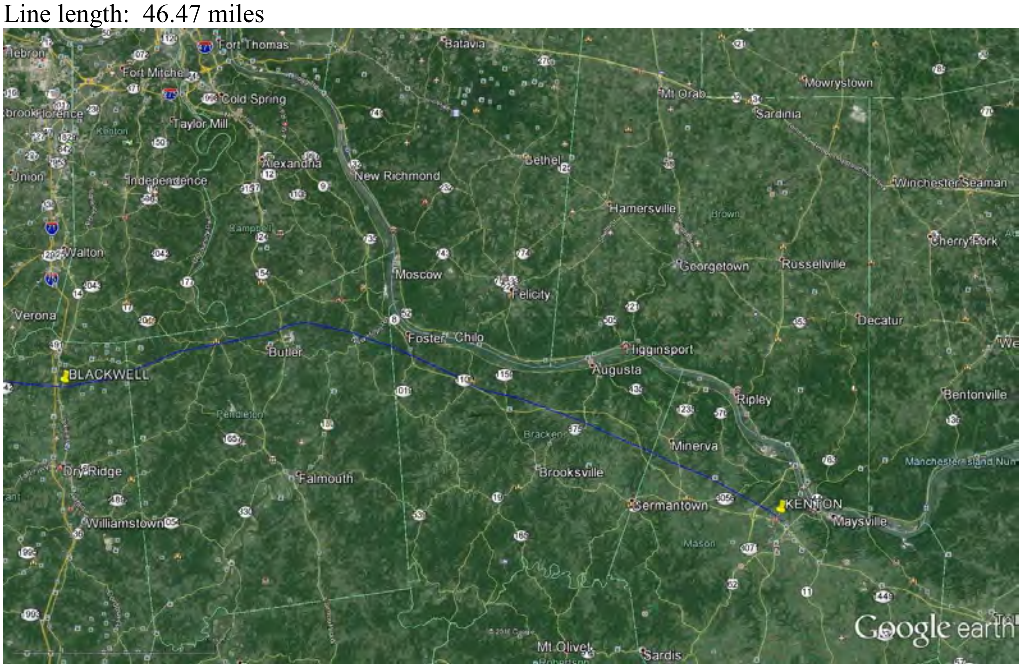
- **Project Scope and Timeline**
  The scope of work will consist of installing thirty-eight (38) standard steel H-frame structures, two (2) 3-pole running corners, one (1) running corner, and one (1) 3-pole dead end with tap and associated hardware and material, and the removal of (42) wood structures and associated hardware and material. The line construction will be based on continuing contracts from our line contractors. B&B, Elliot, Groves and Pike are the four contractors awarded the T&D Overhead Construction and Maintenance contract from the October 2011 Investment Committee meeting. The contract extension was re-approved by the IC in July of 2014. Construction is scheduled to begin in August of 2016 and be completed in November of 2016.

  The construction milestones for this project are provided below:

Construction Milestones	
March 2016	Engineering and Design

April 2016	Steel Poles Ordered
July 2016	Steel Poles Received
August 2016	Line Construction Begins
November 2016	Line Construction Completed

A facility map of the Blackwell-Kenton 138kV line is shown below:
Line length: 46.47 miles



- **Project Cost**
  This project is not included in the 2016 BP, however was approved by the RAC in the 3+9 forecast. Historical and existing contract and purchasing agreements were used to estimate the cost of material and contract labor. This project includes 10% contingency to cover unexpected increases in cost due to weather, rocky soil, outage delays, reclamation, etc. 10% contingency is a standard assumption used across all of our projects and is calculated as a percentage of total burdened costs.

Economic Analysis and Risks

- **Bid Summary**
  Based on preliminary engineering, Transmission Lines has estimated the material packages for construction of this project to be $1,022k. This project will utilize standard and custom steel structures. Hardware will be purchased through Brownstown Electrical Supply. The line construction will be based on continuing contracts with our line contractors. Davis H.

Elliot, Pike Electric, B&B Electric and William E. Groves are the four main contractors which have been awarded the T&D Overhead Construction and Maintenance contracts.

Transmission Lines Material Cost Breakdown	
Material	**Cost**
Steel Poles	$858k
Hardware	$164k
Total	$1,022k

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	**2016**	**2017**	**2018**	**Post 2018**	**Total**
1. Capital Investment Proposed	3,025	-	-	-	3,025
2. Cost of Removal Proposed	470	-	-	-	470
3. Total Capital and Removal Proposed (1+2)	3,495	-	-	-	3,495
4. Capital Investment 2016 BP	-	-	-	-	-
5. Cost of Removal 2016 BP	-	-	-	-	-
6. Total Capital and Removal 2016 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(3,025)	-	-	-	(3,025)
8. Cost of Removal variance to BP (5-2)	(470)	-	-	-	(470)
9. Total Capital and Removal variance to BP (6-3)	(3,495)	-	-	-	(3,495)

Financial Detail by Year - O&M ($000s)	**2016**	**2017**	**2018**	**Post 2018**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2016 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):
Discount Rate: 6.49%
Capital Breakdown:
Labor: $141k
Contract Labor: $1,601k
Materials: $1,022k
Local Engineering: $236k
Burdens: $177k
Contingency: $318k
Reimbursements: ($0)
Net Capital Expenditure: $3,495k

Financial Analysis - Project Summary ($000)	2016	2017	2018	2019	2020	Life of Project
Project Net Income	$16	$79	$163	$155	$148	$3,179
Project ROE	1.8%	4.5%	9.8%	9.8%	9.8%	9.3%

- **Assumptions**

  Recommendation – The cost of this alternative assumes that the line outage will not be available and the structure replacements will need to be completed with the 138kV line energized.

  Do nothing alternative – The cost of this alternative would be approximately 60% higher due to overtime labor charges and the cost to mobilize and demobilize the construction crews. These poles would fail and require replacement within the next four years.

  Next best alternative - The cost of this alternative assumes the cost of the wood poles is 49% of the cost of the steel poles, and that the wood poles would be replaced again in 30 years.

- **Environmental**
  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

- **Risks**
  Without the proposed replacement of the priority poles on the Blackwell-Kenton 138kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays. Schedule delays may also occur if the requested outage is not obtained to complete the scheduled work.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the Blackwell-Kenton Pole Replacement project for $3,495k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Investment Proposal for Investment Committee Meeting on: March 30, 2016

Project Name: Pocket-Pennington Gap Pole Replacement

Total Expenditures: $1,572k
Total Contingency: $ 143k (10%)

Project Number(s): 150687

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Nick Poston/Adam Smith

Executive Summary

The proposed project is to replace seven (7) wood structures on the Pocket-Pennington Gap 69kV line with steel based on the results of a routine line inspection. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

The alternative of replacing poles upon failure will result in much higher long term replacement costs due to mobilization of crews back to the site each time one fails and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability.

The initial estimate to complete this work was less than $500k, so a portion of the work was charged to a task under the Priority Pole Replacement blanket (project K9-2013) in accordance with the Capital Policy. As inspections began, limited accessability to the structures and extremely rough terrain required additional project planning. Because of this limited access, a helicopter will now be used to facilitate the installation of the conductor. Replacement of these poles will require a section of this tap to be constructed parallel to the existing line, while the existing line remains energized. Once the new line is constructed, the load will be transferred from the existing line to the new line and the existing original line will be removed. There are no alternate means for distribution to maintain power to the affected customers. An extended transmission outage is not feasible to complete this work. Approximately 2,200 customers are serviced from this line. Due to this scope change, the total cost of the project will exceed $500k. The proposed project is being submitted in order to move the existing costs from the Priority Pole Replacement blanket (project K9-2013) and to facilitate completion of the project.

The total project cost is $1,572k of which $559k was spent previously under the K9-2013 Pole Replacement blanket before terrain issues were discovered and will be moved to this project once approved. This project was not included in the 2016 Business Plan, however was approved by the RAC in the 2+10 forecast.

Background
Above ground pole inspections are performed by the company at defined intervals in order to discover problems that may impact the integrity and reliability of the Transmission System. During a routine climbing inspection of the Pocket-Pennington Gap 69kV line, six (6) structures were identified as priority poles and determined to be in need of replacement in order to ensure the integrity and reliability of this line. There are 23 total structures along this 1.71 mile line.

Work began during December 2013 with company labor and tree clearing. Tree clearing continued into 2014, steel structures and other material was purchased, and contract labor to survey, move material and equipment, to inspect site conditions and to construct access roads began. During 2015, additional survey work was performed and construction of access work was completed. During January 2016, additional materials were purchased and contract labor to move material and equipment continued. To date, approximately $559k has been spent, which includes $151k for material, $45k for preliminary survey, $30k for tree clearing, $200k to move material and equipment, $2k for employee vehicle and meal expense, and $131k to construct access roads. The additional cost to complete the the project includes the remaining cost of construction, which includes energized pricing as well as facilitaton by helicopter to install the conductor. Once this project is approved, that spending will be transferred to this project.

- **Alternatives Considered (1 –Recommendation, 2 –Do nothing, 3 –Next Best Alt)**
  1. Recommendation: NPVRR: ($000s) $2,139k
     The recommendation is to replace the six wood H-frames and one wood running corner with steel structures parallel to the existing line and to remove the existing line.
  2. Do Nothing: NPVRR: ($000s) $3,079k
     The alternative of do nothing would result in replacing poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.
  3. Next Best Alternative(s): NPVRR: ($000s) $5,239k
     The next best alternative would be to construct a permanent new line from Pocket to Pennington Gap.

Project Description

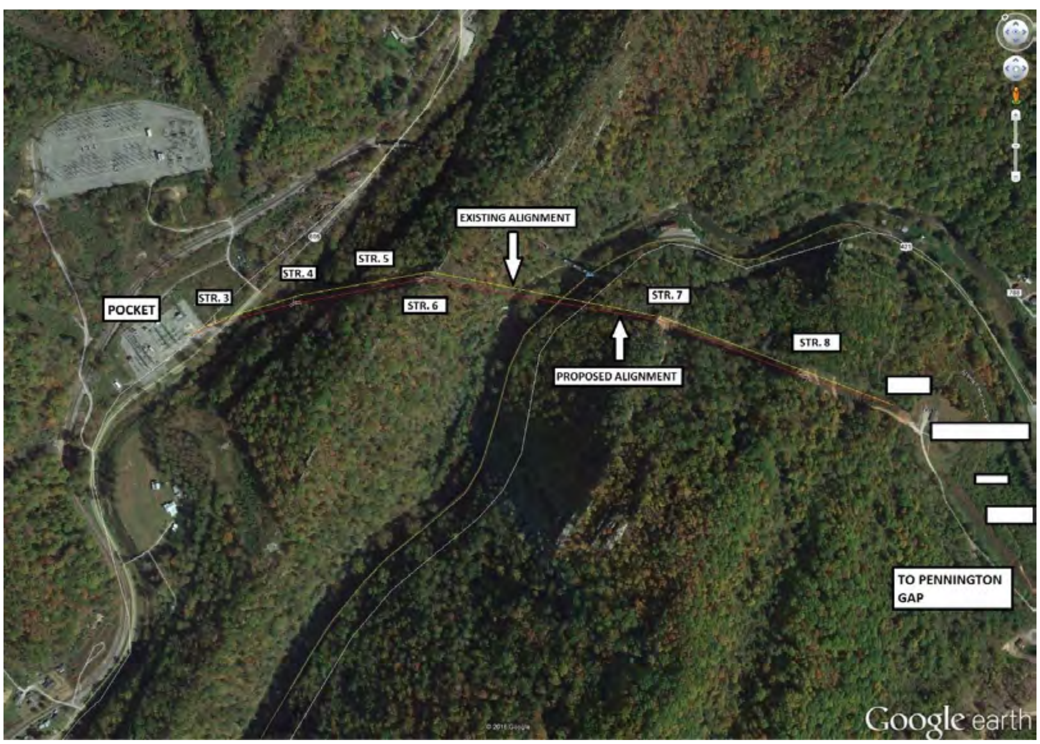
- **Project Scope and Timeline**
  The scope of the work will consist of installing six (6) standard steel H-frames and one (1) single steel structure, and associated hardware and material, as well as the removal of 7 wood structures and associated hardware and material. The line construction will be based on continuing contracts from our line contractors. B&B, Elliot, Groves, and Pike are the four contractors awarded the T&D Overhead Construction and Maintenance contract from the October 2011 Investment Committee meeting. The contract extension was re-approved by the

IC in July of 2014. Construction is scheduled to begin in April of 2016 and to be completed in May of 2016.

The construction milestones for this project are provided below:

Construction Milestones	
January 2016	Engineering and Design
April 2016	Line Construction Begins
May 2016	Line Construction Completed

A facility map of the Pocket-Pennington Gap 69kV line is shown below:
Line length: 1.71 miles



- **Project Cost**
  The total project cost of $1,572k was not included in the 2016 Business Plan but has been approved by the RAC in the 2+10 Forecast. Historical and existing contract and purchasing agreements were used to estimate the cost of the material and contract labor.

Economic Analysis and Risks

- **Bid Summary**
  Based on preliminary engineering, Transmission Lines has estimated the material package for construction of this project to be $160k. Approximately $125K was spent on K9-2013 for the replacement structures and hardware. An additional $35k will be spent on material for the new line. This project will utilize standard steel structures and associated hardware and material. The line construction will be based on continuing contracts with our line contractors. Davis H. Elliot, Pike Electric, B&B Electric, and William E. Groves are the four main contractors which have been awarded the T&D Overhead Construction and Maintenance contracts.

Transmission Lines Material Cost Breakdown	
Material	**Cost**
Steel Poles	$118k
Hardware	$42k
Total	$160k

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	**2016**	**2017**	**2018**	**Post 2018**	**Total**
1. Capital Investment Proposed	1,251	-	-	-	1,251
2. Cost of Removal Proposed	321	-	-	-	321
3. Total Capital and Removal Proposed (1+2)	1,572	-	-	-	1,572
4. Capital Investment 2016 BP	-	-	-	-	-
5. Cost of Removal 2016 BP	-	-	-	-	-
6. Total Capital and Removal 2016 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(1,251)	-	-	-	(1,251)
8. Cost of Removal variance to BP (5-2)	(321)	-	-	-	(321)
9. Total Capital and Removal variance to BP (6-3)	(1,572)	-	-	-	(1,572)

Financial Detail by Year - O&M ($000s)	**2016**	**2017**	**2018**	**Post 2018**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2016 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):
Discount Rate: 6.49%
Capital Breakdown:
Labor: $16k
Contract Labor: $1,085k
Materials: $160k
Local Engineering: $124k
Burdens: $44k
Contingency: $143k
Reimbursements: ($0)
Net Capital Expenditure: $1,572k

Financial Analysis - Project Summary ($000)	2016	2017	2018	2019	2020	Life of Project
Project Net Income	$90	$77	$73	$70	$67	$1,555
Project ROE	22.3%	9.7%	9.8%	9.8%	9.8%	10.1%

- **Assumptions**

  Recommendation – This alternative assumes that all required permits will be received in order to complete construction.

  Do Nothing Alternative – The cost of this alternative would be approximately 60% higher due to overtime labor charges and the cost to mobilize and demobilize the construction crews. These poles would fail and require replacement within the next four years.

  Next Best Alternative – The cost of this alternative assumes that construction of a new line parallel to the existing Pocket-Pennington Gap 69kV line will be completed. This alternative also assumes that all required permits will be received in order to complete construction.

- **Environmental**
  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

- **Risks**
  Without the proposed replacement of the priority poles on the Pocket-Pennington Gap 69kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. In the event repairs would have to be made in an emergency situation, limited accessibility to the site combined with the rough terrain would result in extended unplanned outages. Inclement weather which affects site access and working conditions could increase project costs and cause schedule delays. Schedule delays may also occur if the requested outage and permits are not obtained to complete the scheduled work.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the Pocket-Pennington Gap pole replacement project for $1,572k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Investment Proposal

Investment Proposal for Investment Committee Meeting on: June 29, 2016
Project Name: Pineville Transmission 932 & 952 Breaker Replacements
Total Expenditures: $1,260k ($52k of Contingency)
Project Number(s): 150772
Business Unit/Line of Business: Transmission Substation Construction
Prepared/Presented By: Chris Talley – Manager Transmission Substation Construction

Executive Summary
The scope of this project includes the replacement of the Pineville 192-932 and 192-952 345kV circuit breakers. These breakers present challenges with ongoing maintenance due to a lack of available spare parts and field expertise to make the repairs. In addition, they have a history of leaking excessive amounts of Sulfur Hexaflouide (SF6) gas.

The total cost of this project will be $1,260k and was approved in the 2016 5+7 RAC Approved forecast. Funding for this project was included in the 2016 BP under the project KBR-18. Concerns with maintaining the reliable operation of the 345kV system prompted the need to replace these breakers in 2016. The estimated total project figure includes a 5% contingency. This contingency is expected to cover uncertainty with the contract labor costs based upon variances that have been noticed on past similar projects.

Background
LG&E/KU has seven vintage 1973-1982 dead tank, two pressure ITE type GA breakers in service. They employ complicated operating systems with two pressures blast valve systems for arc extinguishing, multi-breaker contacts, pre-insertion resistors and grading capacitors across the contacts which predisposes these types of breakers to many failure modes. These types of breakers hold up to 1,800 lbs. of gas compared to new style puffer breakers with around 340 lbs. and have infinitely more places to leak. These breakers have the highest gas leakage rates in our system. Since 2010 the combined leak total of these seven breakers averages 1,088.6 pounds per year; the combined total of all remaining gas in our 107 newer style puffer breakers is 451.8 pounds per year. There are no current environmental regulatory implications related to these gas leaks, however there are higher maintenance costs associated with refilling the breakers with new gas.

These breakers ceased being manufactured in the late 1980’s and are only marginally supported by the manufacturer at this point. There have been a combined 295 corrective maintenance orders since 2005. Parts for these breakers generally have to be made by third party machine shops. These two breakers were targeted for replacement based upon their maintenance history and SF6 leak rates. The remaining five breakers will be targeted for replacement prior to 2020.

Alternatives Considered:

(1 –Recommendation, 2 – Next Best Alternative, 3 – Do Nothing)

Recommendation – It is recommended to replace the 192-932 and 192-952 circuit breakers at Pineville Transmission. Parts from the breakers that are retired will be used to support other similar breakers that are still in service on the system.
NPVRR: ($000s) $1,581k

Next Best Alternative(s) – Replace one Pineville Transmission breaker at this time and replacing the other breaker in 2017. This would result in continued SF6 leakage from the delayed breaker. It is a more cost effective contracting strategy to coordinate the replacement of both breakers under the same scope of work. NPVRR: ($000s) $1,603k

Do Nothing – This option is not advisable as the breakers currently in-service at Pineville Transmission have a history of maintenance issues and the parts necessary to alleviate these issues are no longer available. These breakers are also leaking SF6 gas, which requires additional maintenance activities as well. The reduction in the number of similar breakers that are still in service makes it challenging to procure the expertise (internal or external) to maintain these assets.. These breakers historically have had high leak rates. SF6 released to the atsmosphere is currently being monitored by the EPA, but there are no compliance risks as of today.

It is assumed one breaker will fail within five years and both will fail within a ten year period. A failure could result from a defective a component within the breaker that cannot be replaced due to spare part availability. The current ongoing maintenance costs of the breakers in-service is approximately $3,500 a year. The new breakers will have an estimated $500 a year in maintenance costs. If one of these breakers fails at certain time of year, more serious consequences could occur within the system, including the loss of customers.
NPVRR: ($000s) $1,188k plus risk of potential loss of customers for undetermined period

Project Description

- **Project Scope and Timeline**

Description	Date
Project Approved	June, 2016
Materials Ordered	June, 2016
Materials Received	September, 2016
Below Grade Work Begins	August, 2016
Below Grade Work Completed	September, 2016
Above Grade Work Begins	October, 2016
Above Grade Work Completed	November, 2016
Project Complete	December, 2016

- **Project Cost**
  The total cost of this project will be $1,260k and was approved in the 2016 5+7 RAC Approved forecast. Project KBR-18 was included in the 2016 BP as a placeholder for breaker replacements and budgeted at $1,700k. The original estimate to complete this project was $950k and would have been funded by moving dollars out of the blanket project (KBR-18). The estimated total project figure includes a 5% contingency. This contingency is expected to cover uncertainty with the contract labor costs based upon variances that have been noticed on past similar projects.

Economic Analysis and Risks

- **Bid Summary**
  The 345kV breakers will be purchased under the existing breaker purchasing agreement. Bids for any other necessary materials, as well as the below and above grade construction, will be sent out late summer of 2016.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	1,247	-	-	-	1,247
2. Cost of Removal Proposed	13	-	-	-	13
3. Total Capital and Removal Proposed (1+2)	1,260	-	-	-	1,260
4. Capital Investment 2016 BP	1,700	-	-	-	1,700
5. Cost of Removal 2016 BP	-	-	-	-	-
6. Total Capital and Removal 2016 BP (4+5)	1,700	-	-	-	1,700
7. Capital Investment variance to BP (4-1)	453	-	-	-	453
8. Cost of Removal variance to BP (5-2)	(13)	-	-	-	(13)
9. Total Capital and Removal variance to BP (6-3)	440	-	-	-	440

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2016 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.5%
Capital Breakdown:	
Labor:	$87k
Contract Labor:	$404k
Materials:	$550k
Other:	$0k
Local Engineering:	$86k
Burdens:	$81k
Contingency:	$52k
Reimbursements:	($0k)
Net Capital Expenditure:	$1,260k

Financial Analysis - Project Summary ($000)	2016	2017	2018	2019	2020	Life of Project
Project Net Income	$ 20	$ 36	$ 59	$ 56	$ 54	$ 1,331
Project ROE	6.3%	5.7%	9.8%	9.8%	9.8%	9.5%

- **Assumptions**
    - There is no Transmission Lines work associated with this project.
    - There will be no relay upgrades associated with this project.
    - The requested outages for construction will be granted. The labor estimate assumes 4 day/week, 10 hour/day work week, with no special construction considerations to minimize the required outage window.
    - Suppliers and contractors will meet reasonable and expected delivery dates for materials and services

- **Environmental**
  This project does not require permitting and there are no known issues regarding air, water, waste, lead, or asbestos.

- **Risks**
  Completing the project involves risk related to high voltage substation construction work. Not completing the project decreases the reliability of the transmission system. To minimize potential risks to the transmission system, one breaker will be replaced at a time, in sequential outages. The project schedule assumes that the outages on each breaker will take place between during the Fall of 2016.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the Pineville Transmission 932 and 952 Breaker Replacements project for $1,260k to enhance the reliability of the Transmission system.

Approval Confirmation for Capital Projects Greater Than or Equal to $1 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	Victor A. Staffieri
Chief Financial Officer	Chairman, CEO and President

Investment Proposal Project 150841 Ghent-Scott County Pole Replacement

Investment Proposal for Investment Committee Meeting on: June 29, 2016

Project Name: Ghent-Scott County Pole Replacement

Total Expenditures: $9,759k (2016-$3,972k) (2017-$5,787k)
Total Contingency: $921k (10%)

Project Number(s): 150841

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Joe Mina/Adam Smith

Executive Summary

The proposed project is to replace one hundred fifty-five (155) wood structures on the Ghent-Scott County 138kV line with steel, while energized, based on the results of a routine line inspection. Due to the length of time required to receive custom steel structures, along with the limited availability of time remaining to complete the project, fifty (50) structures will be replaced in 2016 and one hundred five (105) structures will be replaced in 2017.

This proposal it to proactively replace the structures over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures. The alternative of replacing poles upon failure will result in much higher long term replacement costs due to mobilization of crews back to the site each time one fails and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability.

The total project cost is $9,759k and was not included in the 2016 Business Plan, however was approved by the RAC in the 5+7 forecast. While not specifically identified in the 2016 Business Plan, this project utilizes funding included for pole replacements in the plan. This project is being accelerated due to the severity and number of priority poles identified. The proposed estimate includes an energized cost of $315k to replace fifty (50) structures in 2016 and $1,152k to replace one hundred five (105) structures in 2017.

Background
Above ground pole inspections are performed by the company at defined intervals in order to discover problems that may impact the integrity and reliability of the Transmission System. A routine climbing inspection of the Ghent-Scott County 138kV line was completed in 2015, and a Comprehensive Visual Inspection (CVI) was completed in 2016. The inspection reports indicate that the majority of the structures were damaged by woodpeckers, and one hundred fifty-five (155) structures were identified as priority poles and determined to be in need of replacement in order to ensure the integrity and reliability of this line. There are 284 total structures along this 40.30 mile line.

- **Alternatives Considered (1 –Recommendation, 2 –Do nothing, 3 –Next Best Alt)**
  1. Recommendation: NPVRR: ($000s) $12,922k
     The recommendation is to replace the structures energized due to the difficulty in obtaining an extended outage. If the opportunity to complete the project de-energized would occur, we would pursue this option which would reduce the cost by $1,467k and NPVRR by $1,939k.
  2. Do Nothing: NPVRR: ($000s) $20,665k
     The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on reliability.
  3. Next Best Alternative(s): NPVRR: ($000s) $16,135
     The next best alternative would be to replace the poles with wood structures. The manufacturer's recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended life span of 90 years. This option assumes replacement of wood structures in 30 years and an escalation factor of 4% which is in line with market cost increases over the last 15 years.

Project Description

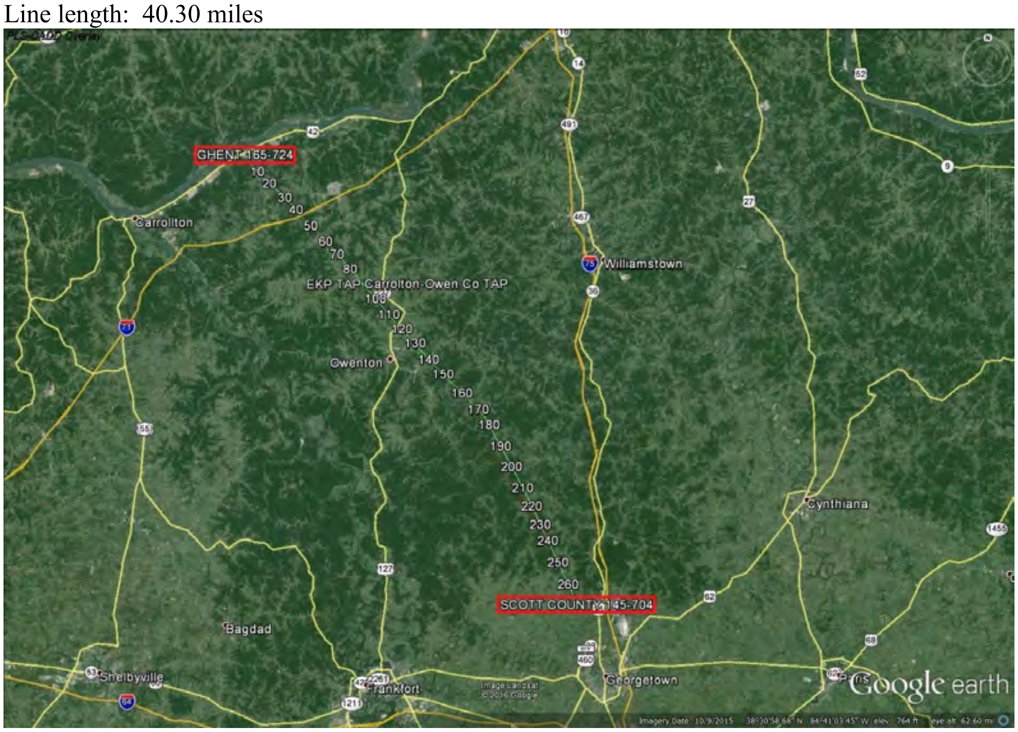
- **Project Scope and Timeline**
  The scope of work will consist of installing one hundred thirty-three (133) standard steel H-frame structures, nineteen (19) custom H-frames, two (2) custom steel 3-pole running corners, one (1) custom steel 3-pole dead end, and associated hardware and material, and the removal of 155 wood structures and associated hardware and material. The line construction will be based on continuing contracts from our line contractors. B&B, Elliot, Groves and Pike are the four contractors awarded the T&D Overhead Construction and Maintenance contract from the October 2011 Investment Committee meeting. The contract extension was re-approved by the IC in July of 2014. Construction is scheduled to begin in October of 2016 and be completed in June of 2017.

  The construction milestones for this project are provided below:

Construction Milestones	
May 2016	Engineering and Design
July 2016	Steel Poles Ordered

September 2016	Standard Steel H-frames Received
October 2016	Line Construction Begins
January 2017	Custom Steel Poles Received
June 2017	Line Construction Completed

A facility map of the Ghent-Scott 138kV line is shown below:
Line length: 40.30 miles



- **Project Cost**
  The total project cost is $9,759k and was not included in the 2016 Business Plan, however was approved by the RAC in the 4+8 forecast. Historical and existing contract and purchasing agreements were used to estimate the cost of material and contract labor. This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Economic Analysis and Risks

- **Bid Summary**
  Based on preliminary engineering, Transmission Lines has estimated the material packages for construction of this project to be $2,909k. This project will utilize standard and custom steel structures. The steel structures will be purchased through our steel pole alliance partner,

Trinity Meyer. Hardware will be purchased through Brownstown Electrical Supply. The line construction will be based on continuing contracts with our line contractors. Davis H. Elliot, Pike Electric, B&B Electric and William E. Groves are the four main contractors which have been awarded the T&D Overhead Construction and Maintenance contracts.

Transmission Lines Material Cost Breakdown	
Material	**Cost**
Steel Poles	$2,810k
Hardware	$99k
Total	$2,909k

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	**2016**	**2017**	**2018**	**Post 2018**	**Total**
1. Capital Investment Proposed	3,539	4,173			7,713
2. Cost of Removal Proposed	432	1,614			2,046
3. Total Capital and Removal Proposed (1+2)	3,972	5,787	-	-	9,759
4. Capital Investment 2016 BP	-	-	-	-	-
5. Cost of Removal 2016 BP	-	-	-	-	-
6. Total Capital and Removal 2016 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(3,539)	(4,173)	-	-	(7,713)
8. Cost of Removal variance to BP (5-2)	(432)	(1,614)	-	-	(2,046)
9. Total Capital and Removal variance to BP (6-3)	(3,972)	(5,787)	-	-	(9,759)

Financial Detail by Year - O&M ($000s)	**2016**	**2017**	**2018**	**Post 2018**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2016 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.49%
Capital Breakdown:	
Labor:	$339k
Contract Labor:	$4,455k
Materials:	$2,909k
Local Engineering:	$707k
Burdens:	$428k
Contingency:	$921k
Reimbursements:	($0)
Net Capital Expenditure:	$9,759k

Financial Analysis - Project Summary ($000)	2016	2017	2018	2019	2020	Life of Project
Project Net Income	$0	$303	$479	$456	$434	$9,392
Project ROE	0.0%	8.5%	9.7%	9.8%	9.8%	9.6%

- **Assumptions**

  Recommendation – The cost of this alternative assumes that the line outage will not be available and the structure replacements will need to be completed with the 138kV line energized.

  Do nothing alternative – The cost of this alternative would be approximately 60% higher due to overtime labor charges and the cost to mobilize and demobilize the construction crews. These poles would fail and require replacement within the next four years.

  Next best alternative - The cost of this alternative assumes the cost of the wood poles is 41% of the cost of the steel poles, and that the wood poles would be replaced again in 30 years.

- **Environmental**
  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

- **Risks**
  Without the proposed replacement of the priority poles on the Ghent-Scott 138kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the Ghent-Scott Pole Replacement project for $9,759k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than or Equal to $1 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.	Victor A. Staffieri
Chief Financial Officer	Chairman, CEO and President

Capital Investment Proposal

Investment Proposal for Investment Committee Meeting on: N/A
Project Name: Mill Creek 4533 Breaker Replacement
Total Expenditures: $784k (Including $59k of contingency)
Project Number(s): 151208
Business Unit/Line of Business: Transmission Substation Construction & Maintenance
Prepared/Presented By: Victor Payne – Electrical Engineer

Executive Summary
The scope of this project includes the replacement of (1) 345kV circuit breaker, free standing current transformers and associated equipment at the Mill Creek substation. This breaker is being replaced due to the lack of manufacturer support, readily available replacement parts and leaking SF6 gas. The breaker position that will be replaced is MC-4533.

The total cost of this project will be $784k and was approved by the 2016 5+7 RAC. Funding for this project was included in the 2016 BP under the project KBR-18, however it is being pulled forward due to the necessity of replacing this breaker and is being charged to a separate project since the detailed engineering estimate exceeds the $500k threshold to charge to the KBR blanket. The estimated total project figure includes a 8% contingency as the breaker to be installed is already owned (a replacement spare will be purchased). This contingency is expected to cover uncertainty with the contract labor costs based upon variances that have been noticed on past similar projects.

Background
The breaker being replaced is a live tank, 345kV, 1976, GE model ATB-362-7 circuit breaker. The live tank design has proven to be highly unreliable and prone to failure. This breaker is over the expected life expectancy and replacement parts are no longer available as the original manufacturer no long supports this breaker. The breaker is also in need of replacement due to leaking SF6 gas, which leads to considerably higher maintenance costs and the leaks can cause low SF6 gas pressure that may cause breaker failure or unplanned opening of the breaker. Live tank breakers leak around the same amount of gas as other similarly manufactured designs. Replacement of this breaker would increase reliability of the Mill Creek 345kV substation.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $984k
     It is recommended that MC-4533 be replaced at the Mill Creek substation.

  2. Alternative #1: NPVRR: ($000s) $185k
     The next best alternative is to remove the breaker and lock out-tag-out the breaker disconnects. This option is not recommended as this breaker provides significant additional electric system reliability. The function of this breaker (and every breaker in the LKE system) is to protect the transmission system and generation equipment from potential faults that can occur on the electric grid. This is a commonly accepted industry practice and is considered to be cost effective as well.

     Without the added reliability, transmission and generation power flow could be reduced during outage and fault condition events. This breaker also interrupts power flow to allow other system switching. Additionally, the existence of this breaker adds a supplemental connection between the two 345kV buses and the Mill Creek generation unit itself. This additional path helps reduce the risk of the generator quickly separating from the grid during a bus fault, which could damage the generation unit.

  3. Do Nothing: NPVRR: ($000s) $684k
     This option is not advisable as the breakers currently in-service at Pineville Transmission have a history of maintenance issues and the parts necessary to alleviate these issues are no longer available. These breakers are also leaking SF6 gas, which requires additional maintenance activities as well. Expertise to maintain assets in the field are lacking or are not currently available. These assets historically have had high leak rates. SF6 is currently being monitored by the EPA, but there are no compliance risks as of today. If this breaker were to fail, it could lead to an unplanned Mill Creek unit or line outage or impair a Unit’s ability to produce generation for the Louisville Gas & Electric and Kentucky Utility (LKE) system.

Project Description

- **Project Scope and Timeline**

Description	Date
Project Originally Approved	July, 2016

Materials Ordered	July, 2016
Materials Received	October, 2016
Construction Work Begins	November, 2016
Construction Work Completed	November, 2016
Project Complete	December, 2016

- **Project Cost**
  The total cost of this project will be $784k and was approved by the 2016 5+7 RAC. Funding for this project was included in the 2016 BP under the project KBR-18. The estimated total project figure includes a 8% contingency. This contingency is expected to cover uncertainty with the contract labor costs based upon variances that have been noticed on past similar projects.

Economic Analysis and Risks

- **Bid Summary**
  Previously established blanket contract agreements will be utilized for related materials. Bids for any other necessary materials, as well as the below and above grade construction, will be sent out soon after project approval. Materials priced below $50k will not be bid and instead purchased directly from various business partners who LKE has significant previous experience working with.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	700	-	-	-	700
2. Cost of Removal Proposed	84	-	-	-	84
3. Total Capital and Removal Proposed (1+2)	784	-	-	-	784
4. Capital Investment 2016 BP	-	-	-	-	-
5. Cost of Removal 2016 BP	-	-	-	-	-
6. Total Capital and Removal 2016 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(700)	-	-	-	(700)
8. Cost of Removal variance to BP (5-2)	(84)	-	-	-	(84)
9. Total Capital and Removal variance to BP (6-3)	(784)	-	-	-	(784)

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2016 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate: 6.5%

Capital Breakdown:

Labor:	$66k
Contract Labor:	$252k
Materials:	$270k
Other:	$0k
Local Engineering:	$82k
Burdens:	$55
Contingency:	$59k
Reimbursements:	($0k)
Net Capital Expenditure:	$784k

Financial Analysis - Project Summary ($000)	2016	2017	2018	2019	2020	Life of Project
Project Net Income	$ 3	$ 18	$ 37	$ 35	$ 33	$ 751
Project ROE	1.6%	4.5%	9.8%	9.8%	9.8%	9.3%

- **Assumptions**
  - There is no Transmission Lines work associated with this project.
  - The ABB spare breaker "BK000612" 380PMI63 will be used.
  - There will be no line relay upgrades associated with this project.
  - The requested outages for construction will be granted. The labor estimate assumes 4 day/week, 10 hour/day work week with no special construction considerations to minimize the required outage window.
  - Costs to expand the ground grid or lightning protection in the entire station to meet current standards or codes are not included in this estimate. The existing ground grid impedance to remote ground along with the touch and step potential is assumed to be adequate. New ground grid is only installed in the affected substation expansion area for touch and step potential upgrade.
  - Suppliers and contractors will meet reasonable and customary delivery dates for materials and services.

- **Environmental**
  This project does not require permitting and there are no known issues regarding air, water, waste, lead, or asbestos. There are no current environmental regulatory implications as related to SF6 gas.

- **Risks**
  If the recommended option is not accepted, there is an increased risk of a breaker failure which could lead to extended out of service time at the Mill Creek Generation facility. The duration of the outage would be dependent upon repairs or other maintenance as related to the failure. Such an outage would impair the generation unit's ability to produce power for the LKE system.

Conclusions and Recommendation
It is recommended that Management approve the Mill Creek 4533 Breaker Replacement project for $784k to enhance the reliability of the Transmission system.

Capital Investment Proposal

Investment Proposal for Investment Committee Meeting on: N/A

Project Name: Cane Run SW CT Add

Total Expenditures: $820k (Including $0k of Contingency)

Project Number(s): 151467

Business Unit/Line of Business: Transmission Substation Construction & Maintenance

Prepared/Presented By: Corbin Williams

Executive Summary

This project was originally opened during June 2016 for $334k to add new, higher capacity current transformers (CTs) at Cane Run Switching in order to reduce the chance of misoperations for faults on adjacent circuits. The project is being revised to include the replacement of (3) 138kV circuit breakers and associated equipment, and the installation of (30) 138kV surge arresters, in addition to the new CTs in order to increase overall reliability of the equipment at this station.

While installing the CTs, it was decided that the continued use of the existing breakers was not prudent. The age, reliability, availability of replacement parts, known operational issues, and higher maintenance costs were drivers for the decision. The replacement of this equipment will lead to fewer unplanned outages and therefore increased reliability within the Transmission grid system.

The total cost of this project will be $820k, of which $541k was spent during 2016 and $279k is forecasted for 2017. $344k of funding was included in the 2017 BP for this project, all of which was in 2016. The 2017 BP did not include any spending for 2017, however was approved by the RAC in the 2017 0+12 forecast. The estimated total project figure includes a no contingency as the project is in its final stages of completion and there is less risk associated with the remaining activities necessary for project completion.

Background
Based on historical data, most circuit breakers reach the end of useful life at 60 years. Appendix A, Diagram 1 outlines the age of the breakers that are currently in service in the LKE system. Failure to fund this project and others that are similar will contribute to the ongoing concern of an aging infrastructure with equipment in-service that has reached the end of its useful life and can no longer be properly maintained. The technology used for the construction of these breakers is antiquated and the high number of moving parts makes it challenging to keep all of the measurements within manufacturers specifications.

Project Description

- **Project Scope and Timeline**

The replaced breakers are CRS-3825-TR2, CRS-3808-24, and CRS-3822-33. The breakers that have an additional set of current transformers installed are CRS-3801-23 and CRS-3866-TR1. All (10) 138kV transmission lines associated with the substation's 138kV breakers have a set of surge arresters installed.

Description	Date
Project Originally Approved	June, 2016
Materials Ordered	July, 2016
Materials Received	October, 2016
Below Grade Work Begins	October, 2016
Below Grade Work Completed	October, 2016
Above Grade Work Begins	October, 2016
Above Grade Work Completed	November, 2016
Project Complete	May, 2017

Economic Analysis and Risks

- **Bid Summary**
  Previously established blanket contract agreements will be utilized for related materials. The below and above grade construction were sole sourced to Davis H. Elliot Construction Company, Inc. (DHE). The work was sole sourced since the priority of the work did not allow sufficient time to conduct a competitive bid by either internal or external sourcing resources. To gauge the prudency of the cost estimate provided by DHE, the estimate was compared to our internally created estimate for the scope of work. As the estimates were comparable, their estimate was determined to be reasonable. A fully executed Sole Source Authorization form was completed.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	527	262	-	-	789
2. Cost of Removal Proposed	14	17	-	-	31
3. Total Capital and Removal Proposed (1+2)	541	279	-	-	820
4. Capital Investment 2017 BP	344	-	-	-	344
5. Cost of Removal 2017 BP	-	-	-	-	-
6. Total Capital and Removal 2017 BP (4+5)	344	-	-	-	344
7. Capital Investment variance to BP (4-1)	(183)	(262)	-	-	(445)
8. Cost of Removal variance to BP (5-2)	(14)	(17)	-	-	(31)
9. Total Capital and Removal variance to BP (6-3)	(197)	(279)	-	-	(476)

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2017 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):
Discount Rate: 6.5%
Capital Breakdown:
Labor: $49k
Contract Labor: $313k
Materials: $308k
Other: $8k
Local Engineering: $96k
Burdens: $46k
Contingency: $0k
Net Capital Expenditure: $820k

- **Environmental**
This project does not require permitting and there are no known issues regarding air, water, waste, lead, or asbestos.

- **Risks**
Completing the project involves risk related to high voltage substation construction work. If action is not taken, there will continue to be challenges associated with keeping these breakers in good working order. There is also an increased probability of failure, reduction of system reliability through the occurrence of system outages and possible collateral damage in the event of a catastrophic failure.

Conclusions and Recommendation
It is recommended that the Cane Run SW CT Add revised project be approved for $820k to enhance the reliability of the Transmission system.

Appendix A

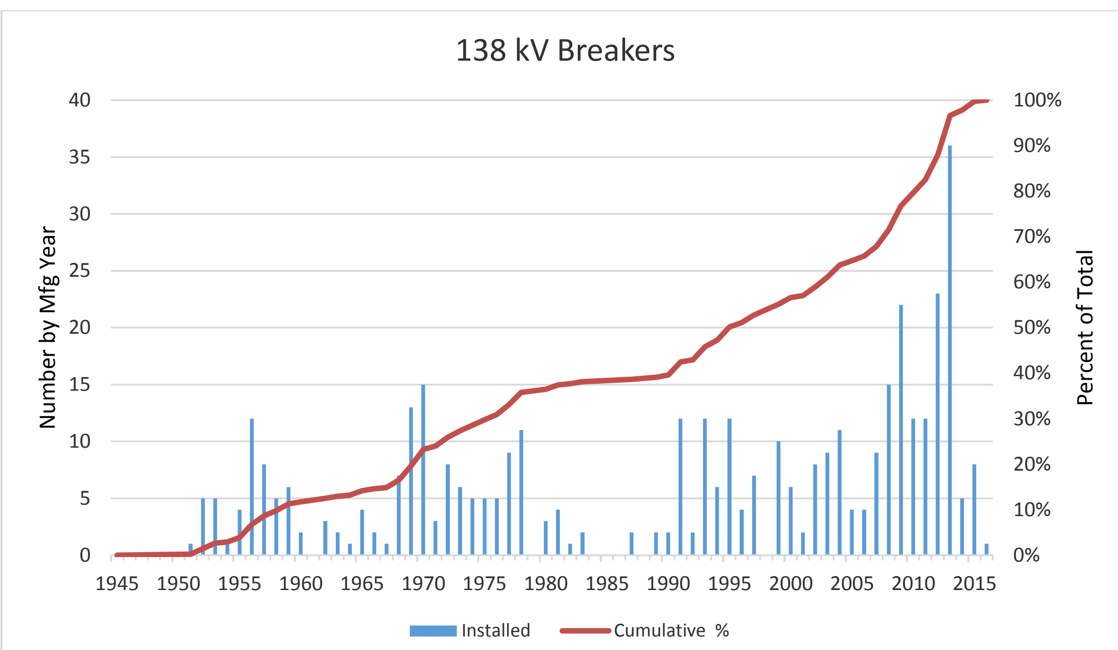


DIAGRAM 1

Investment Proposal 151554 Hardinsburg-Central Hardin EKPC Pole Replacement

Investment Proposal for Investment Committee Meeting on: July 27, 2016 Project Name: Hardinsburg-Central Hardin EKPC Pole Replacement Total Expenditures: $1,526k Total Contingency: $139k (10%) Project Number(s): 151554 Business Unit/Line of Business: Transmission Lines Prepared/Presented By: Kelly Mefford/Adam Smith

Executive Summary

The proposed project is to replace twenty-four (24) wood structures on the Hardinsburg-Central Hardin EKPC 138kV line with steel, during a routine outage, based on the results of a routine line inspection. Due to the length of time required to receive custom steel structures, along with the limited availability of time to complete the project, eleven (11) structures will be replaced in 2016, and thirteen (13) structures will be replaced in 2017.

This proposal is to proactively replace the structures over the course of the next year, prior to failure, to ensure the integrity and reliability of this line, and to prevent outages resulting from such failures. The alternative of replacing poles upon failure will result in much higher long term replacement costs due to mobilization of crews back to the site each time one fails and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability.

This project is being accelerated to align with the Hardinsburg-Central Hardin EKPC NRP project (147474). Completing both projects together will allow for resource efficiencies and limit the impacts to property owners. The total project cost is $1,526k and was not included in the 2016 Business Plan, however was approved by the RAC in the 6+6 forecast.

Background
Above ground pole inspections are performed by the company at defined intervals in order to discover problems that may impact the integrity and reliability of the Transmission System. During a routine climbing inspection of the Hardinsburg-Central Hardin EKPC 138kV line, twenty-four (24) structures were identified as priority poles and determined to be in need of replacement in order to ensure the integrity and reliability of this line. There are 228 total structures along this 31.55 mile line.

- **Alternatives Considered (1 –Recommendation, 2 –Do nothing, 3 –Next Best Alt)**
  1. Recommendation: NPVRR: ($000s) $2,066k
     The recommendation is to replace all twenty-four (24) structures during a scheduled outage.
  2. Do Nothing: NPVRR: ($000s) $3,002k
     The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on reliability.
  3. Next Best Alternative(s): NPVRR: ($000s) $2,395k
     The next best alternative would be to replace the poles with wood structures. The manufacturer's recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended life span of 90 years. This option also assumes replacement of wood structures in 30 years and an escalation rate of 4% which is in line with market cost increases over the last 15 years.

Project Description

- **Project Scope and Timeline**
  The scope of work will consist of installing nineteen (19) standard H-frames, four (4) custom H-frames, and one (1) 3-pole running corner, and associated hardware and material, and the removal of twenty-four (24) wood structures, and associated hardware and material. The line construction will be based on continuing contracts from our line contractors. B&B, Elliot, Groves and Pike are the four contractors awarded the T&D Overhead Construction and Maintenance contract from the October 2011 Investment Committee meeting. The contract extension was re-approved by the IC in July of 2014. Construction is scheduled to begin in September of 2016 and be completed in March of 2017.

  The construction milestones for this project are provided below:

Construction Milestones	
April 2016	Engineering and Design
July 2016	Steel Poles Ordered
September 2016	Steel Poles Delivered
September 2016	Line Construction Begins
March 2017	Line Construction Completed

A facility map of the Hardinsburg-Central Hardin EKPC 138kV line is shown below:
Line length: 31.55 miles

- **Project Cost**
  The total project cost is $1,526k and was not included in the 2016 Business Plan, however was approved by the RAC in the 6+6 forecast. Historical and existing contract and purchasing agreements were used to estimate the cost of material and contract labor. This project includes 10% contingency which is reasonable based on the level of detailed engineering, confidence in the cost of materials and contractors and potential unknown risks such as weather delays, rocky terrain, outage delays, reclamation, and structure access.

Economic Analysis and Risks

- **Bid Summary**
  Based on preliminary engineering, Transmission Lines has estimated the material packages for construction of this project to be $481k. This project will utilize standard and custom steel structures. The custom steel structures will be purchased through our steel pole alliance partner, Trinity Meyer. Hardware will be purchased through Brownstown Electrical Supply. The line construction will be based on continuing contracts with our line contractors. Davis H. Elliot, Pike Electric, B&B Electric and William E. Groves are the four main contractors which have been awarded the T&D Overhead Construction and Maintenance contracts.

Transmission Lines Material Cost Breakdown	
Material	**Cost**
Steel Poles	$403k
Hardware	$78k
Total	$481k

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	**2016**	**2017**	**2018**	**Post 2018**	**Total**
1. Capital Investment Proposed	935	393	-	-	1,328
2. Cost of Removal Proposed	90	108	-	-	198
3. Total Capital and Removal Proposed (1+2)	1,025	501	-	-	1,526
4. Capital Investment 2016 BP	-	-	-	-	-
5. Cost of Removal 2016 BP	-	-	-	-	-
6. Total Capital and Removal 2016 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(935)	(393)	-	-	(1,328)
8. Cost of Removal variance to BP (5-2)	(90)	(108)	-	-	(198)
9. Total Capital and Removal variance to BP (6-3)	(1,025)	(501)	-	-	(1,526)

Financial Detail by Year - O&M ($000s)	**2016**	**2017**	**2018**	**Post 2018**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2016 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):
Discount Rate: 6.49%
Capital Breakdown:
Labor: $32k
Contract Labor: $663k
Materials: $481k
Local Engineering: $101k
Burdens: $110k
Contingency: $139k
Reimbursements: ($0)
Net Capital Expenditure: $1,526k

Financial Analysis - By Year	2016	2017	2018	2019	2020	Life 2016-2069
Net Income, $000s	$0	$47	$75	$71	$68	$1,468
ROE	0.0%	3.6%	8.0%	10.0%	10.0%	9.4%

- **Assumptions**

Recommendation - This alternative assumes that the line outage will be available and that all twenty-four (24) structures will be replaced during this timeframe.

Do Nothing alternative – The cost of this alternative would be approximately 60% higher due to overtime labor charges and the cost to mobilize and demobilize construction crews. These poles would fail and require replacement within the next four years.

Next Best alternative – The cost of this alternative assumes the cost of the wood poles is 35% the cost of the steel poles, and that the wood poles would be replaced again in 30 years.

- **Environmental**
  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

- **Risks**
  Without the proposed replacement of the priority poles on the Hardinsburg-Central Hardin EKPC 138kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays. Schedule delays may also occur if the requested outage is not obtained to complete the scheduled work.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the Hardinsburg-Central Hardin EKPC pole replacement project for $1,526k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than or Equal to $1 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	Victor A. Staffieri Chairman, CEO and President

Capital Investment Proposal

Investment Proposal for Investment Committee Meeting on: N/A
Project Name: Fawkes Capacitor Bank Replacement & Firewall Installation
Total Expenditures: $840k (Including $76k of Contingency)
Project Number(s): 151761
Business Unit/Line of Business: Transmission Substation Construction & Maintenance
Prepared/Presented By: Victor Payne – Electrical Engineer

Executive Summary

This project includes installing a firewall between the two 138/69kV transformers and the control house at Fawkes Transmission Substation to reduce the risk of a failure of one transformer damaging the adjacent transformer or control house and the 69kV capacitor bank. The existing 69kV capacitor bank currently located between the two transformers will be relocated to allow installation of the firewall. The oil containment will need to be modified for both transformers. Due to a history of individual capacitor can failures on the existing bank at Fawkes, it will be redesigned and replaced upon its relocation. This project was initiated to follow the IEEE standard Std 979-2012.

The total cost of this project will be $840k. The 2016 spending was approved by the RAC in the 9+3 forecast. $101k will be spent in 2016 and $739k in 2017. No funding was included in the 2016 BP for this project as this capacitor bank has just recently been experiencing more serious equipment issues. This project is however included in the 2017 BP for $666k, with $284k included in 2016 and $383k included in 2017. The 2017 portion was not fully funded in the 2017 BP, so the additional amount above the budgeted amount ($357k) has been covered by a reduction in project #151764 (KU Fence Replacements). The estimated total project figure includes a 10% contingency.

Background
During the failure of a transformer, there is a possibility that the transformer itself could catch on fire. Due to the quantity of oil located within a transformer, a potential fire would be difficult to contain and could damage surrounding equipment. Adding a firewall between the transformers and redesigning the oil containment will greatly reduce the risk of damage to the adjacent equipment during this event. To install the firewall, the existing 69kV capacitor bank will need to be relocated to a new location. This capacitor bank has recently experienced serious operational issues and therefore will be redesigned and replaced upon its move. The new capacitor bank design will reduce the amount of operational issues and potential for future equipment failures. A specialized capacitor switcher that has been specifically designed for the capacitor bank will replace the existing breaker layout. Additionally, the design of the capacitor bank will be changed to a fuseless design in lieu of a fused capacitor type.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $1,001k
     It is recommended that the a firewall be installed and the capacitor bank redesigned and relocated to reduce the risk of damaging adjacent equipment during a potential transformer failure. This will increase the reliability of the transmission system.

  2. Alternative #1: NPVRR: ($000s) $1,456k
     Relocate of one of the existing transformers and the capacitor bank. This option is not recommended due to the additional outage requirements of the transformer, higher cost and risks associated with damaging the transformer during its relocation.

  3. Do Nothing: NPVRR: ($000s) $2,652k
     This option is not advisable because of the increased risk of an equipment failure damaging adjacent equipment and additional costs to cleanup and repair any possible damage. Additionally, losing any further equipment during a possible transformer failure would decrease the reliability of the transmission system. IEEE recommended standards to mitigate the risk to an acceptable level was followed. Such an event has a low probability of occurring based on consideration of past failures in our system.

Project Description

- **Project Scope and Timeline**

Description	Date
Project Originally Approved	Nov, 2016
Cap Bank Ordered	Nov, 2016
Other Major and Minor Material Ordered	Jan, 2016
Materials Received	June, 2017
Below Grade Work Begins	May, 2017
Below Grade Work Completed	June, 2017
Above Grade Work Begins	July, 2017
Above Grade Work Completed	Aug, 2017
Project Complete	Oct, 2017

- **Project Cost**

The total cost of this project will be $840k. The 2016 spending was approved by the RAC in the 9+3 forecast. $101k will be spent in 2016 and $739k in 2017. $0k of funding was included in the 2016 BP for this project as this capacitor bank has just recently been experiencing more serious equipment issues. This project is however included in the 2017 BP for $666k, with $284k included in 2016 and $383k included in 2017. The 2017 portion was not fully funded in the 2017 BP, so the additional amount above the budgeted amount ($357k) has been covered by a reduction in project #151764 (KU Fence Replacements). The estimated total project figure includes a 10% contingency.

Economic Analysis and Risks

- **Bid Summary**

  Previously established blanket contract agreements will be utilized for related materials. Bids for any other necessary materials, as well as the below and above grade construction, will be sent out soon after project approval.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	101	715	-	-	816
2. Cost of Removal Proposed	-	24	-	-	24
3. Total Capital and Removal Proposed (1+2)	101	739	-	-	840
4. Capital Investment 2016 BP	-	-	-	-	-
5. Cost of Removal 2016 BP	-	-	-	-	-
6. Total Capital and Removal 2016 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(101)	(715)	-	-	(816)
8. Cost of Removal variance to BP (5-2)	-	(24)	-	-	(24)
9. Total Capital and Removal variance to BP (6-3)	(101)	(739)	-	-	(840)

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2016 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):
Discount Rate: 6.5%
Capital Breakdown:
- Labor: $76k
- Contract Labor: $310k
- Materials: $262k
- Other: $0k
- Local Engineering: $47k
- Burdens: $69k
- Contingency: $76k
- Reimbursements: ($0k)
- Net Capital Expenditure: $840k

Financial Analysis - Project Summary ($000)	2016	2017	2018	2019	2020	Life of Project
Project Net Income	$ -	$ 25	$ 41	$ 39	$ 38	$ 917
Project ROE	0.0%	5.2%	7.9%	10.0%	10.0%	9.8%

- **Assumptions**
  - Assumes the required outages are obtainable with no extra overtime costs.
  - Assumes the individual capacitor bank cans can be reused.
  - Assumes the existing protection scheme and panel can be reused.

- **Environmental**
  This project does not require permitting and there are no known issues regarding air, water, waste, lead, or asbestos. The transformers oil containments will be revised to accommodate the installation of the wall. There is a standard procedure for oil containment that will be followed. Any final designs will be reviewed by th Environmental group.

- **Risks**
  If this project is not completed, there is risk of a transformer failure damaging adjacent equipment and additional significant costs to cleanup and repair any potential damage. Also, losing an additional transformer and/or capacitor bank during a transformer failure would decrease the reliability of the transmission system.

Conclusions and Recommendation
It is recommended that Management approve the Fawkes Capacitor Bank Replacement & Firewall Installation project for $840k to enhance the reliability of the Transmission system.

Revised Capital Investment Proposal

Investment Proposal for Investment Committee Meeting on: N/A

Project Name: Fawkes Capacitor Bank Replacement & Firewall Installation

Total Approved Expenditures: $840k (76k of Contingency) (Approved on 12/12/2016)

Total Revised Expenditures: $1,079k

Project Number(s): 151761

Business Unit/Line of Business: Transmission Substation Construction & Maintenance

Prepared/Presented By: Bill Williams

Reason for Revision
A large contributing factor would be scope changes and their corresponding material and construction costs. The original design for the project was to use a capacitor switcher with free standing current transformers in series with the capacitor bank, however the scope was changed to use a breaker with the capacitor switcher to protect the equipment. Another scope change necessitated the use of an RTU (Remote Terminal Unit). Due to outage reasons, both capacitor banks had to be in service at all times. Additionally, there wasn't enough space in the control house on the existing panels to add these controls, therefore a new system had to be designed and installed. Lastly, the original scope underestimated the total cost to protect the control house with the new firewalls.

Financial Summary

Financial Summary ($000s):	**Approved**	**Revised**	**Explanation**
Discount Rate:	6.5%	6.32%	
Capital Breakdown:			
Labor:	$76k	$29k	
Contract Labor:	$310k	$546k	Wall and RTU addition
Materials:	$262k	$334k	Additional Breaker & RTU
Other:	$ 0	$5k	
Local Engineering:	$47k	$81k	Additional Scope
Burdens:	$69k	$41k	
Contingency:	$76k	$43k	
Reimbursements:	($0k)	($0)	
Net Capital Expenditure:	$840k	$1,079k	

NPVRR: $1,001k $1,178k

Financial Detail by Year - Capital ($000s)	**Pre-2017**	**2017**	**2018**	**Post 2018**	**Total**
1. Capital Investment Proposed	7	1,038	-	-	1,045
2. Cost of Removal Proposed	-	1	-	-	1
3. Total Capital and Removal Proposed (1+2)	7	1,040	-	-	1,047
4. Capital Investment 2017 BP	284	358	-	-	641
5. Cost of Removal 2017 BP	-	25	-	-	25
6. Total Capital and Removal 2017 BP (4+5)	284	383	-	-	666
7. Capital Investment variance to BP (4-1)	277	(681)	-	-	(404)
8. Cost of Removal variance to BP (5-2)	-	24	-	-	24
9. Total Capital and Removal variance to BP (6-3)	277	(657)	-	-	(380)

Financial Detail by Year - O&M ($000s)	**Pre-2017**	**2017**	**2018**	**Post 2018**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M Pre-2017 BP	-	-	-	-	-
3. Total Project O&M Variance to BP (2-1)	-	-	-	-	-

Conclusions and Recommendation
It is recommended that Management approve the Fawkes Capacitor Bank Replacement & Firewall Installation project for $1,079k to allow for engineering, material and construction charges associated with the additional scope outlined above which will enhances the protection of the capacitor bank and safety of the control house.

Capital Investment Proposal

Investment Proposal for Investment Committee Meeting on: N/A

Project Name: PCH-Hillside Control House

Total Expenditures: $1,544k (Including $130k of contingency)

Project Number(s): 151775

Business Unit/Line of Business: Transmission Substation Engineering

Prepared/Presented By: Bill Goans-Director, Mesa Associates Inc.

Executive Summary
The Hillside Substation currently houses transmission protection and control (P&C) equipment that is aging past the date of reasonable repair. The existing control house also has size and security concerns. Maintenance of the existing equipment inside the control house is also becoming more difficult as replacement parts are difficult to find.

By installing a new, pre-fabricated control house inside the substation fenced area, with microprocessor relays, the obsolete, aging equipment will be replaced with reliable, digital protective relays while also enhancing safe and reliable performance of the Transmission protective system.

The total cost of this project will be $1,544k with $768k in 2018 and $776k in 2019. This project was included in the 2018 BP for $1,732k with $877k in 2018 and $855k in 2019. The current estimates are based on a more detailed level of engineering than was used to estimate the BP.

Background
The Hillside Substation contains a 69kV bus which connects three transmission lines. The equipment currently used for relaying and controls for the switchyard is located inside an aging control building with no climate control. This affects the lifespan of equipment as weather changes can damage sensitive electronics and battery cells. A new control house would provide a climate controlled environment and ensure that safe working conditions are provided for any individuals working inside.

The existing substation control house is small and has several security concerns. It is located at the corner of the property partially outside the fenced area. It houses transmission P&C equipment that is aging past the date of reasonable repair. Maintenance of said equipment is becoming more difficult as replacement parts are difficult to find. There is not sufficient room in the existing control house to replace the aging equipment.

The existing P&C equipment is composed of electromechanical relays. Replacing these with new microprocessor relays will provide an improvement to reliability along with an increase in functionality, including disturbance monitoring and event reporting. This will allow faults in the area to be studied in greater detail so they can be properly identified with a root-cause, allowing a more specified approach to improving the reliability of the transmission system overall.

- **Alternatives Considered**
    1. Recommendation: NPVRR: ($000s) $1,745k
    It is recommended that all P&C equipment located inside the existing control house be decommissioned and new, microprocessor based relays be installed in a new control house within the substation yard.

    2. Delay Project: NPVRR: ($000s) $1,808k
    This option would be to delay the control replacement by one year. Doing so would also necessitate replacing the existing fence. This not advisable as the possibility of misoperations will increase with time as well as the availability of replacement parts of the existing electromechanical relays will diminish as they become increasingly obsolete.

    3. Do Nothing: NPVRR: ($000s) N/A
    This option is not advisable as the failure of these relays will be imminent over a period of years, which will greatly increase the risk of misoperations. The scarcity of parts will surely increase and the existing control house condition will continue to deteriorate over many years.

Project Description

- **Project Scope and Timeline**

Description	Date
Order Materials	May, 2018
Receive Materials	December, 2018
Begin Below Grade Work	October, 2018

Complete Below Grade Work	January, 2019
Begin Above Grade Work	November, 2018
Complete Above Grade Work	April, 2019
Project Complete	June, 2019

- **Project Cost**
  The total cost of this project will be $1,544k with $768k in 2018 and $776k in 2019. This project was included in the 2018 BP for $1,732k with $877k in 2018 and $855k in 2019. The current estimates are based on a more detailed level of engineering than was used to estimate the BP. The estimated total project figure includes 9% contingency. This contingency is reasonable based on the level of detailed engineering and is expected to cover the uncertainty with the material and contract labor costs based upon variances that have been observed on past projects.

Economic Analysis and Risks

- **Bid Summary**
  Previously established blanket contract agreements will be utilized for related materials. Bids for any other necessary materials, as well as the below and above grade construction, will be sent out at the conclusion of detailed engineering.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	768	754	-	-	1,522
2. Cost of Removal Proposed	-	22	-	-	22
3. Total Capital and Removal Proposed (1+2)	768	776	-	-	1,544
4. Capital Investment 2018 BP	870	855	-	-	1,725
5. Cost of Removal 2018 BP	7	-	-	-	7
6. Total Capital and Removal 2018 BP (4+5)	877	855	-	-	1,732
7. Capital Investment variance to BP (4-1)	102	101	-	-	203
8. Cost of Removal variance to BP (5-2)	7	(22)	-	-	(15)
9. Total Capital and Removal variance to BP (6-3)	109	79	-	-	188

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2018 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.58%
Capital Breakdown:	
Labor:	$88
Contract Labor:	$504
Materials:	$570
Local Engineering:	$102
Burdens:	$150
Contingency:	$130
Reimbursements:	($-)
Net Capital Expenditure:	$1,544

- **Assumptions**
  Required outages are assumed to be able to be obtained within the requested timeframe. The control house is assumed to be placed in our initial location with no impact due to hard rocks underground. Weather is assumed to be fair enough to work on schedule with no delays to mobilization of contractors or delivery of material.

- **Environmental**
  This project does not require permitting and there are no know issues regarding air, water, waste, lead, or asbestos.

- **Risks**
  Completing the project involves risks related to high voltage substation construction work and coordination between projects. Not completing the project decreases the reliability of the LKE Transmission system and introduces the risks to the operation of the Hillside Substation. Outages may be delayed due to system loading requirements, weather, or other outages in the area.

Conclusions and Recommendation

It is recommended that Management approve the Hillside Control House Replacement project for $1,544k to enhance the reliability of the Transmission system.

Capital Investment Proposal

Investment Proposal N/A

Project Name: Finchville Control House Replacement

Total Expenditures: $1,478k (Including $130k of Contingency)

Project Number(s): 151777

Business Unit/Line of Business: Transmission Protection & Controls

Prepared/Presented By: Brent Birchell – Manager, Transmission Protection & Controls

Executive Summary

The Finchville Substation currently houses transmission protection and control (P&C) equipment that is aging past the date of reasonable repair. Much of this equipment was installed over fifty years ago and will begin to fail without proactive replacement of these assets. Maintenance of said equipment is also becoming more difficult as replacement parts are difficult to find.

By installing a new, pre-fabricated control house with microprocessor relays, the obsolete, aging equipment will be replaced with reliable, digital protective relays while also enhancing safe and reliable performance of the Transmission protection system. This project is part of the overall 2016 Transmission System Improvement Plan.

The total cost of this project will be $1,478k. $1,024k will be spent in 2017 with the remaining $454k to be spent in 2018. This project was included in the 2017 BP for $100k in 2016, $1,231k in 2017 and $425k in 2018. The proposed estimate is lower than the BP due to a more detailed estimate being completed. The additional funding needed in 2018 will be addressed in the 2018 BP.

Background

The Finchville Substation contains a 69kV bus which connects four transmission lines. The equipment currently used for relaying and controls for the switchyard is located inside an aging control building with no climate control. This affects the lifespan of equipment as weather changes can damage sensitive electronics and battery cells. A new control house would provide a climate controlled environment and ensure that safe working conditions are provided for any individuals working inside.

The existing P&C equipment is composed of electromechanical relays. Twelve of these relays are General Electric GCX type electromechanical relays which have been marked as a priority by the Transmission P&C department to replace, due to the age of these relays and a higher percentage of misoperations caused by these relays. New microprocessor relays will provide an improvement to reliability along with an increase in functionality, including disturbance monitoring and event reporting. This will allow faults in the area to be studied in greater detail so they can be properly identified with a root-cause, allowing a more specified approach to improving the reliability of the transmission system overall.

- **Alternatives Considered**
    1. Recommendation: NPVRR: ($000s) $1,732k
       It is recommended that all P&C equipment located inside the existing control house be decommissioned and new, microprocessor based relays be installed in a new control house within the substation yard. This control house is part of the 2016 Transmission Reliability Plan.

    2. Delay Project NPVRR: ($000s) 1,983k
       This option is not advisable as the possibility of misoperations will increase with time as well as the availability of replacement parts of the existing GCX relays will diminish as they become increasingly obsolete. This option assumes that one panel will fail prior to the house being replaced and will need to be replaced again as part of the house installation.

    3. Do Nothing: NPVRR: ($000s) N/A
       This option is not advisable as the failure of these relays will be imminent over a period of years, which will greatly increase the risk of misoperations. The scarcity of parts will surely increase and the existing control house condition will continue to deteriorate over many years. Additionally, choosing this option puts the company at risk of not being able to accomplish the objectives of the Transmission System Improvement Plan.

Project Description

- **Project Scope and Timeline**

Description	Date
Project Approval	April, 2017
Begin Engineering	April, 2017
Order Materials	June, 2017
Receive Materials	December, 2017
Begin Below Grade Work	October, 2017
Complete Below Grade Work	November, 2017
Begin Above Grade Work	November, 2017
Complete Above Grade Work	March, 2018
Project Complete	May, 2018

- **Project Cost**
  The total cost of this project will be $1,478k. $1,024k will be spent in 2017 with the remaining $454k to be spent in 2018. This project was included in the 2017 BP for $100k in 2016, $1,231k in 2017 and $425k in 2018. The proposed estimate is lower than the BP due to a more detailed estimate being completed. The additional funding needed in 2018 will be addressed in the 2018 BP. The estimated total project figure includes a 10% contingency. This contingency is expected to cover uncertainty with the contract labor costs based upon variances that have been noticed on past similar projects.

Economic Analysis and Risks

- **Bid Summary**
  Previously established blanket contract agreements will be utilized for related materials. Bids for any other necessary materials, as well as the below and above grade construction, will be sent out soon after project approval.

  Because of the expiration of funding of the LG&E and KU control house blanket, control houses were competitively bid and a vendor will be selected upon full funding of this project. Below is a summary table of the received bids for the control house.

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[redacted]

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	-	1,015	443	-	-	1,458
2. Cost of Removal Proposed	-	9	11	-	-	20
3. Total Capital and Removal Proposed (1+2)	-	1,024	454	-	-	1,478
4. Capital Investment 2017 BP	100	1,217	425	-	-	1,742
5. Cost of Removal 2017 BP	-	14	-	-	-	14
6. Total Capital and Removal 2017 BP (4+5)	100	1,231	425	-	-	1,755
7. Capital Investment variance to BP (4-1)	100	202	(18)	-	-	284
8. Cost of Removal variance to BP (5-2)	-	5	(11)	-	-	(7)
9. Total Capital and Removal variance to BP (6-3)	100	206	(29)	-	-	277

Financial Detail by Year - O&M ($000s)	2017	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed	-	-	-	-	-	-
2. Project O&M 2017 BP	-	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.5%
Capital Breakdown:	
Labor:	$80k
Contract Labor:	$497k
Materials:	$594k
Other:	$0
Local Engineering:	$98k
Burdens:	$79k
Contingency:	$130k
Reimbursements:	($0)
Net Capital Expenditure:	$1,478

- **Assumptions**
  Required outages are assumed to be able to be obtained within the requested timeframe. The control house is assumed to be placed in our initial location with no impact due to hard rocks underground. Weather is assumed to be fair enough to work on schedule with no delays to mobilization of contractors or delivery of material.

- **Environmental**
  This project does not require permitting and there are no known issues regarding air, water, waste, lead, or asbestos.

- **Risks**
  Poor reliability and potential misoperations is a risk of not doing this project. Weather may pose a risk as most construction work will be performed in the late fall of 2017 to spring of 2018. Outages may be delayed due to system loading requirements or other outages in the area.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Finchville Control House Replacement project for $1,478k to enhance the reliability of the Transmission system.

Capital Investment Proposal

Investment Proposal for Investment Committee Meeting on: N/A

Project Name: REL-Centerfield 604 Breaker Add

Total Expenditures: $906k (Including $84k of Contingency)

Project Number(s): 152108

Business Unit/Line of Business: Transmission Reliability Performance & Standards

Prepared/Presented By: Keith Yocum – Manager Reliability Performance & Standards

Executive Summary

The Transmission Reliability Performance and Standards group identified the need for a breaker at the Centerfield substation to reduce the MegaWatt-Mile (MW-Mile is calculated by multiplying total miles of line exposure times the MWs served from the line) exposure on the Middletown to Trimble County Switching 138 kV line to Centerfield 138/69 kV tran. This line has significant MW-Mile exposure and has had close to a minute of SAIDI since 2009 for Transmission.

Middletown to Trimble County Switching 138 kV line to Centerfield 138/69 kV tran is 28.02 miles long and has 1 distribution transfomer tapped off of it which serve around 4,978 customers and 28.02 MW of load. A fault anywhere along this line will result in an outage on all customers. The placement of a breaker at Centerfield will reduce MW-Mile exposure from 855 to 375, a 56% reduction. Diagram 1 include in Appendix A depicts the configuration for Middletown to Trimble County Switching 138 kV line to Centerfield 138/69 kV tran.

The total cost of this project is estimated at $906k with $149k in 2017, and the remaining $757k in 2018. The 2017 BP included $850k for this project in 2018. The budgeted amount was estimated based on similar projects that have been previously completed and has been updated based on the preliminary scope review and site visit performed. Of the proposed 2017 spending, $100k approved by the RAC in the 8+4 forecast and $49k is being funded by a reduction in project 153370.