KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information Dated January 8, 2021

Case No. 2020-00349

Question No. 62

Responding Witness: Adrien M. McKenzie

Q-62. Refer to the McKenzie Testimony, page 9 lines 3–25 and 16–19.

a. Current stock market indices have all recovered from the COVID-19 shock and are at or near all-time highs. Explain how this is indicative of a "fundamental shift in investors' risk perceptions.

b. Explain how overall market volatility has increased from prior to the COVID-19 shock and post-COVID-19 market low.

c. Since the stock market indices are at or near all-time highs, explain how the dramatic increase in market value from the market lows from the COVID-19 shock is indicative of an increased perception of risk.

d. Provide evidence that current monetary policy and interest rate environment is going to shift such that the "artificial" nature of the interest rate environment will cease and interest rates will increase to "normal" levels.

e. Explain whether the Federal Reserve has given any indication that it is going to change its current policy path.

A-62.

a. As discussed at page 17 of Mr. McKenzie's testimony, while the broader equity market has recovered from the lows reached in March 2020, utility stocks remain significantly below their previous highs. Coupled with ongoing market volatility, as evidenced by levels of the Chicago Board Options Exchange Volatility Index ("VIX") that remain well above pre-pandemic levels, and the significant increase in utility beta values, this supports Mr. McKenzie's statement that there has been a fundamental shift in investors' risk perceptions.

b. As discussed at page 16 of Mr. McKenzie's testimony, the VIX is a key measure of expectations of near-term volatility and market sentiment recognized in the investment community. The graph below shows the trend in the VIX since January 2019:

As illustrated above, while the VIX has declined significantly since the peak coinciding with the market's precipitous decline in March 2020, expectations of continued volatility remain well above levels prior to the pandemic.

c. See the response to part a.

d. The most recent published projections of the Federal Open Market Committee indicate that the majority of its members expect that the midpoint level of the target range for the federal funds rate will increase from 0.125% to 2.5% over the longer term, which is considered to be five to six years. This twentyfold increase indicates that the Federal Reserve expects to significantly alter monetary policies going forward. As documented at page 60 of Mr. McKenzie's testimony, projections from widely recognized forecasters also support a finding that interest rates are expected to increase substantially from current levels over the near-term.

e. See the response to part d.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 63

Responding Witness: Adrien M. McKenzie / Daniel K. Arbough

Q-63. Refer to the McKenzie Testimony, page 16 lines 25–26 through 18 lines1–7. The stock markets appear to have recovered from the COVID-19 induced sell off and are currently at or near all-time highs.

a. Provide the S&P Global Ratings publications since June 2020.

b. Provide the State Regulatory Evaluations, RRA Regulatory Focus issues published October through December 2020.

A-63.

a. S&P Global Ratings is one of the largest providers of investment information worldwide and publishes an enormous volume of reports on a multitude of topics. Thus, without further specificity KU is unable to respond to this question.

b. Attached is the RRA Regulatory Focus: Major Rate Case Decisions - January - September 2020, which RRA published on October 20, 2020. The Companies will supplement this response and provide the RRA report covering awarded returns on equity for the fourth quarter of 2020 and year-end 2020 when the report is available.

S&P Global
Market Intelligence

October 20, 2020
spglobal.com/marketintelligence

RRA Regulatory Focus
Major Rate Case Decisions - January - September 2020

For Detailed Data
Click here to see supporting data tables.

The equity returns authorized electric and gas utilities nationwide edged downward in the first nine months of 2020, which saw less activity than might otherwise have been the case. Several rate case decisions have been postponed until later this year and beyond due to the health and economic crisis triggered by the COVID-19 pandemic that brought the U.S. economy to a near halt. Based on data gathered by Regulatory Research Associates, a group within S&P Global Market Intelligence, the average return on equity authorized electric utilities was 9.50% in all rate cases decided in the first three quarters of 2020, below the 9.65% average for cases in full-year 2019. There were 38 electric ROE determinations in the first three quarters of 2020, versus 47 in full-year 2019.

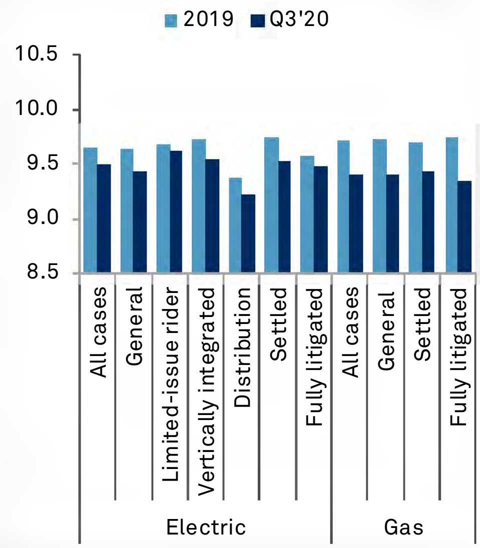
The average ROE authorized gas utilities was 9.45% in cases decided during the first nine months of 2020 versus 9.71% in full-year 2019. There were 20 gas cases that included an ROE determination in the first nine months of 2020 versus 32 in full-year 2019.

Included in electric ROE average is a decision by the Maine Public Utilities Commission in which the commission reduced Central Maine Power Co.'s ROE by 100 basis points to 8.25% due to imprudence associated with a new billing system. The adjustment is to be lifted when the utility meets all performance benchmarks for all service quality metrics for at least 18 consecutive months after March 1, 2020, and formally demonstrates to the commission that the problems have been resolved. Excluding the 100-basis point penalty would result in a 9.52% average ROE for the first three quarters of 2020.

In addition, the electric ROE average through the third quarter of this year was also weighed down by an 8.20% ROE authorized Green Mountain Power, as calculated under the company's multiyear regulation plan which employs a formulaic approach tied to U.S. Treasuries.

This data includes several limited-issue rider cases. Excluding these cases, the average authorized ROE was 9.44% in electric rate cases decided in the first nine months of 2020, versus 9.64% observed in full-year 2019. The difference between the ROE averages including rider cases and those excluding the rider cases is driven by ROE premiums allowed in Virginia for riders that address recovery of specific generation projects.

Average authorized return on equity (%)
Dashboard



Electric average	2019	Q3'20	
All cases	9.65	9.50	▼
General rate cases	9.64	9.44	▼
Limited-issue rider cases	9.68	9.62	▼
Vertically integrated cases	9.73	9.54	▼
Distribution cases	9.37	9.22	▼
Settled cases	9.75	9.52	▼
Fully litigated cases	9.58	9.48	▼
Gas average	**2019**	**Q3'20**	
All cases	9.71	9.45	▼
General rate cases	9.72	9.45	▼
Settled cases	9.70	9.53	▼
Fully litigated cases	9.74	9.33	▼
U.S. Treasury	**2019**	**Q3'20**	
30-year bond yield	2.58	1.54	▼

Data compiled Oct. 15, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

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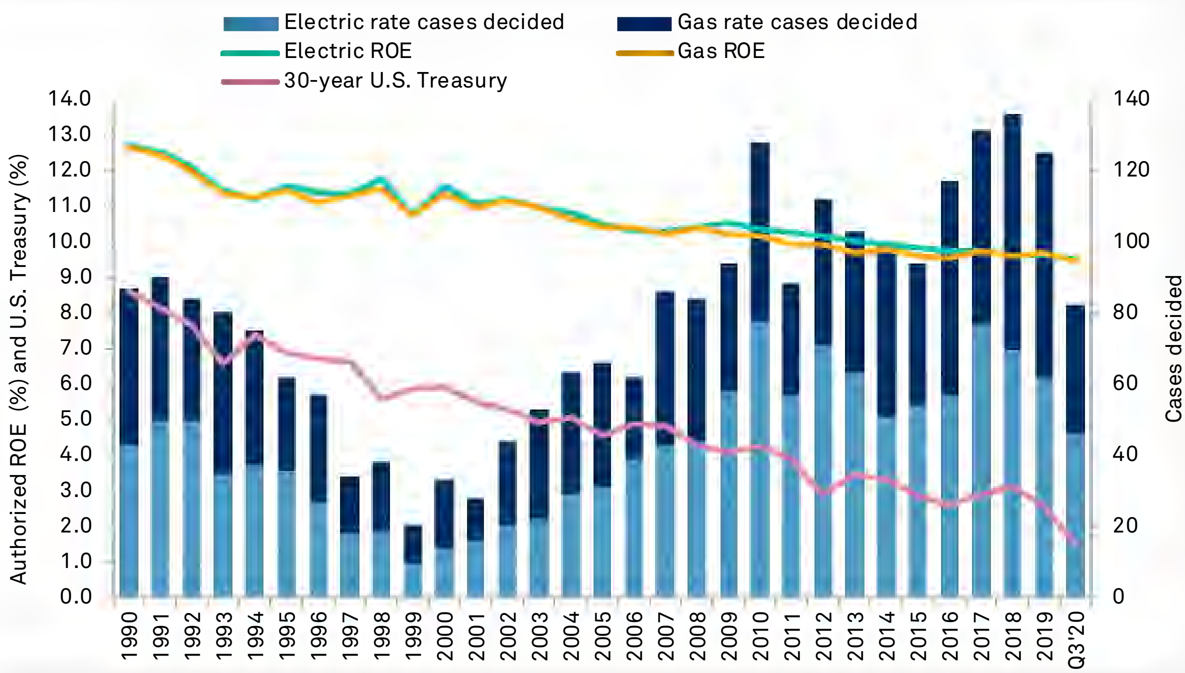
In the first nine months of 2020, the median ROE authorized in all electric utility rate cases was 9.44%, versus 9.60% in full-year 2019; for gas utilities, the metric was 9.42% in the first nine months of 2020, versus 9.70% in full-year 2019.

The averages for the first nine months of 2020 are at the lowest levels ever witnessed in the industry, and with the recent interest rate cuts by the U.S. Federal Reserve and current pandemic-induced recession, even lower authorized returns may be on the horizon.

From a longer-term perspective, interest rates, as measured by the 30-year U.S. Treasury bond yield, fell almost steadily from the early 1980s until 2015 or so, placing downward pressure on authorized ROEs. Even though the decline has been less dramatic in the period since 1990, average authorized ROEs fell below 10% for gas utilities in 2011 and for electric utilities in 2014.

Average electric and gas authorized ROEs and number of rate cases decided



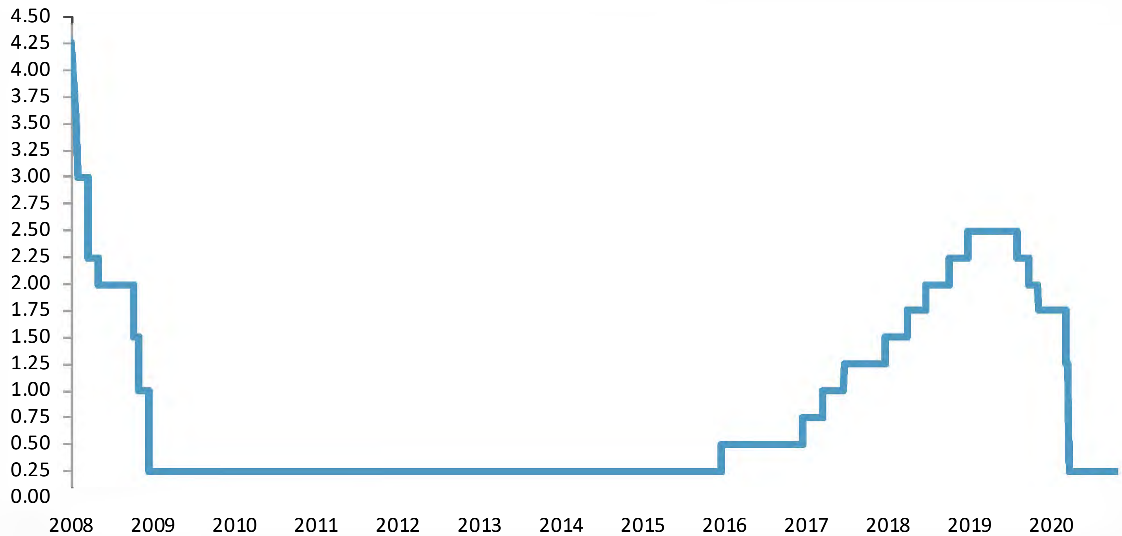
Data compiled Oct. 15, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Since 2010, rate case activity has been robust, with 100 or more cases adjudicated in eight of the last 10 calendar years. This count includes electric and gas cases where no ROEs have been specified; however, withdrawn cases are not included. After reaching an almost 30-year high in 2018, when almost 140 cases were decided, rate case activity moderated somewhat in 2019, with about 125 electric and gas cases resolved. Through Sept. 30, 2020, excluding cases that were withdrawn, there were 82 cases decided. Currently, there are about 90 rate cases pending; however, since the onset of COVID-19, some utilities have postponed rate case filings that were planned for this year. This backlog, coupled with the need to address COVID-19 pandemic-related costs and lost revenue, may usher in an even more robust level of rate case activity in 2021 and beyond.

Absent the pandemic, increased costs associated with environmental compliance, generation and delivery infrastructure upgrades and expansion, renewable generation mandates, storm and disaster recovery, cybersecurity and employee benefits have contributed to an active rate case agenda over the last decade.

Rising interest rates over the past several years also likely contributed to the increased rate case activity. After holding rates near zero for several years, the Federal Reserve began raising the federal funds rate in 2015. Before the pandemic hit, the Fed, after more than a decade without a cut, lowered rates three times in 2019, due to signs of a slowing economy. Earlier this year, amid the economic fallout from the coronavirus outbreak, the Fed delivered two rate cuts, the first in early March, which cut rates by 50 basis points to 1.00% from 1.25%, and a second mid-March, which slashed rates another 100 basis points to the current range of 0%-0.25%. To facilitate economic recovery, Fed policymakers have indicated that rates will remain near zero through 2023.

Federal funds target rate, upper limit %



Data compiled Oct. 15, 2020.
Source: Federal Reserve

While changes in the federal funds rate do not move in lockstep with longer-term treasuries and authorized ROEs do not move in lockstep with interest rates, the expectation is that as interest rates change, authorized ROEs would also change in a similar fashion. However, several factors impact the timing and magnitude of such a shift. Normal regulatory lag, i.e., the amount of time it takes for a utility to put together a rate case filing and tender it to the commission and then for the commission to process the case, would without any other influences delay a change in average authorized ROEs relative to interest rates.

It is also worth noting that while both interest rates and authorized ROEs have generally been declining since 1990, the gap between authorized ROEs and interest rates widened somewhat over this period, largely as a result of an often-unstated understanding by regulators that the drop in interest rates caused by Federal Reserve intervention was unusual.

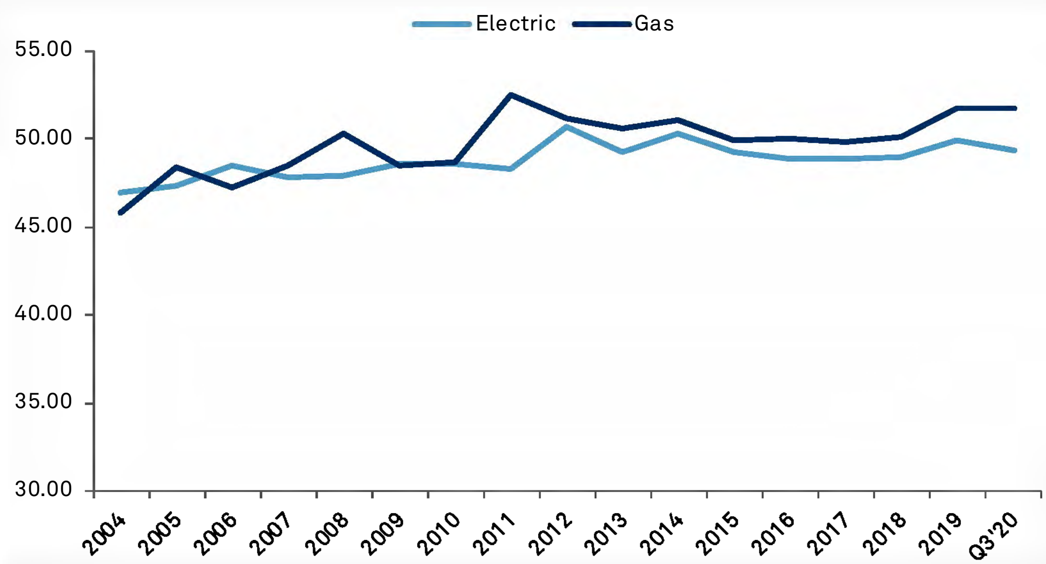
However, given the focus on customers' ability to pay and the need to maintain universal service as the pandemic drags on, regulators may be more apt to further lower authorized ROEs to mitigate the level of bill increases that result from recovery of pandemic-related costs. These considerations could be further complicated if a new administration seeks to roll-back the 2017 corporate tax reform initiatives.

Capital structure trends

To offset the negative cash flow impact of 2017 federal tax reform, many utilities sought higher common equity ratios, and the average authorized equity ratios adopted by utility commissions in 2019 were modestly higher than the levels observed in 2018 and 2017. In cases decided the first nine months of 2020, the average authorized equity ratio for electric utilities was 49.37%. For full-years 2019, 2018 and 2017, the average equity ratios authorized in electric utility cases were 49.94%, 49.02% and 48.90%, respectively. The average allowed equity ratio for gas utilities nationwide in cases decided in the first nine months of 2020 was 51.74%. For full-years 2019, 2018 and 2017, the average was 51.75%, 50.12% and 49.88%, respectively.

Taking a longer-term view, equity ratios have generally increased over the last several years — the average equity ratio approved in electric rate cases decided during 2004 was 46.96%, while the average for gas utilities was 45.81%. Many commissions began approving more equity-rich capital structures in the wake of the 2008 financial crisis.

Average authorized capital structures (%)



Data compiled Oct. 15, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

By contrast, RRA has observed that the actual financial equity ratios of the major utility holding companies in the team's Financial Focus coverage universe fell during the first six months of 2020. See the article Average utility equity ratio declines in 2020 amid COVID-19 pandemic.

A more granular look at ROE trends

The discussion thus far has looked broadly at trends in authorized ROEs; the sections that follow provide a more granular view based upon the types of proceedings/decisions in which these ROEs were established.

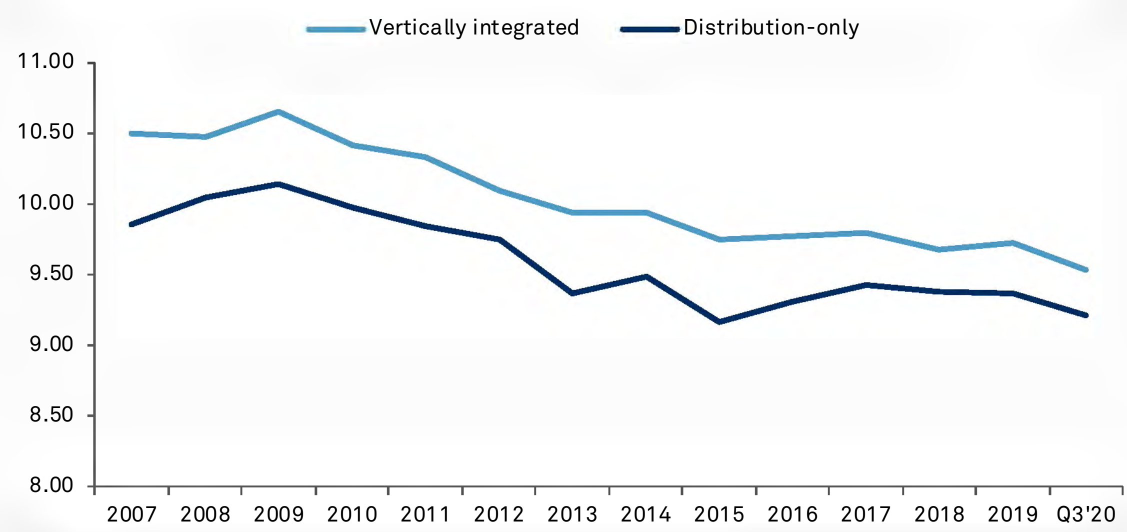
RRA has observed that there can be significant differences between the average ROEs from one subcategory of cases to another.

As a result of electric industry restructuring, certain states unbundled electric rates and implemented retail competition for generation. Commissions in those states now have jurisdiction only over the revenue requirement and return parameters for delivery operations.

Comparing electric vertically integrated cases versus delivery-only proceedings over the past several years, RRA finds that the annual average authorized ROEs in vertically integrated cases typically are about 30 to 65 basis points higher than in delivery-only cases, arguably reflecting the increased risk associated with ownership and operation of generation assets.

The industry average ROE for vertically integrated electric utilities was 9.54% in cases decided during the first nine months of 2020, versus the 9.73% average level posted in full-year 2019. For electric distribution-only utilities, the industry average ROE authorized in the first nine months of 2020 was 9.22%, versus 9.37% in full-year 2019. Included within the distribution returns for the first nine months of 2020 is the previously mentioned penalty ordered by the Maine PUC for Central Maine Power. Absent that 100 basis point penalty, the average ROE approved for distribution utilities in the first nine months of 2020 would have been 9.34%.

Average authorized electric ROEs (%)

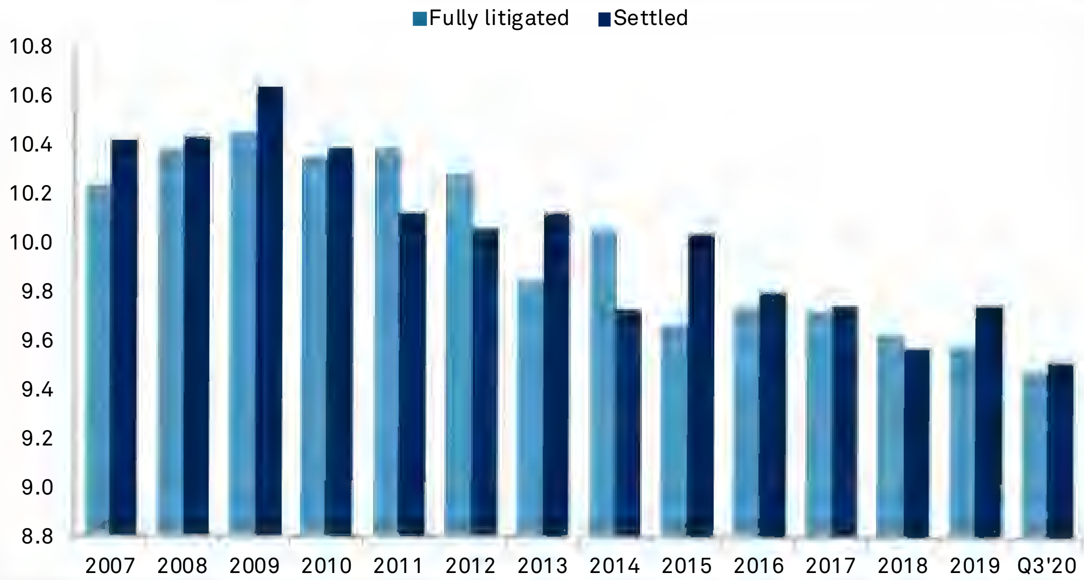


Data compiled Oct. 15, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Settlements have frequently been used to resolve rate cases over the last several years, and in many cases, these settlements are "black box" in nature and do not specify the ROE and other typical rate case parameters underlying the stipulated rate change. However, some states preclude this type of treatment, and settlements must specify these values, if not the specific adjustments from which these values were derived.

For both electric and gas cases, RRA has found no discernible pattern in the average authorized ROEs in cases that were settled versus those that were fully litigated. In some years, the average authorized ROE was higher for fully litigated cases, in others, it was higher for settled cases, and in a handful of years, the authorized ROE was similar for both fully litigated and settled cases.

Average authorized electric ROEs, settled vs. fully litigated cases (%)



Data compiled Oct. 15, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Average authorized gas ROEs, settled vs. fully litigated cases (%)

Data compiled Oct. 15, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

For several years, the annual average authorized ROEs in electric cases that involve limited-issue riders were meaningfully higher than those approved in general rate cases, driven primarily by the ROE premiums authorized in generation-related limited-issue rider proceedings in Virginia. However, these premiums were approved for limited durations and have since begun to expire. As a result, the gap between the average ROE observed in the rider cases and that observed in general rate cases has narrowed. Limited-issue rider cases in which a separate ROE is determined have had limited use in the gas industry, as most of the gas riders rely on ROEs approved in a previous base rate case.

The following discussion focuses on the corresponding tables available here.

Table 1 shows the average ROE authorized in major electric and gas rate decisions annually since 1990 and by quarter since 2016, followed by the number of observations in each period. Table 2 indicates the composite electric and gas industry data for all major cases, summarized annually since 2004 and by quarter for the past seven quarters.

Tables 3 and 4 provide comparisons since 2007 of average authorized ROEs for settled versus fully litigated cases, general rate cases versus limited-issue rider proceedings and vertically integrated cases versus delivery-only cases for electric and gas utilities, respectively.

The individual electric and gas cases decided in 2020 are listed in Table 5, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return, the ROE and the percentage of common equity in the adopted capital structure. Next, RRA indicates the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time decisions were rendered. Fuel adjustment clause rate changes are not reflected in this study.

The simple mean is utilized for the return averages. In addition, the average equity returns indicated in this report reflect the ROEs approved in cases that were decided during the specified time periods and are not necessarily representative of either the average currently authorized ROEs for utilities industrywide or the returns actually earned by the utilities.

Please note: In an effort to align data presented in this report with data available in S&P Global Market Intelligence's online database, earlier historical data provided in previous reports may not match historical data in this report due to certain differences in presentation, including the treatment of cases that were withdrawn or dismissed.

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Table 1: ROEs authorized January 1990-September 2020

		Electric utilities			Gas utilities		
Year	**Period**	**Average ROE (%)**	**Median ROE (%)**	**Number of observations**	**Average ROE (%)**	**Median ROE (%)**	**Number of observations**
1990	Full year	12.70	12.77	38	12.68	12.75	33
1991	Full year	12.54	12.50	42	12.45	12.50	31
1992	Full year	12.09	12.00	45	12.02	12.00	28
1993	Full year	11.46	11.50	28	11.37	11.50	40
1994	Full year	11.21	11.13	28	11.24	11.27	24
1995	Full year	11.58	11.45	28	11.44	11.30	13
1996	Full year	11.40	11.25	18	11.12	11.25	17
1997	Full year	11.33	11.58	10	11.30	11.25	12
1998	Full year	11.77	12.00	10	11.51	11.40	10
1999	Full year	10.72	10.75	6	10.74	10.65	6
2000	Full year	11.58	11.50	9	11.34	11.16	13
2001	Full year	11.07	11.00	15	10.96	11.00	5
2002	Full year	11.21	11.28	14	11.17	11.00	19
2003	Full year	10.96	10.75	20	10.99	11.00	25
2004	Full year	10.81	10.70	21	10.63	10.50	22
2005	Full year	10.51	10.35	24	10.41	10.40	26
2006	Full year	10.32	10.23	26	10.40	10.50	15
2007	Full year	10.30	10.20	38	10.22	10.20	35
2008	Full year	10.41	10.30	37	10.39	10.45	32
2009	Full year	10.52	10.50	40	10.22	10.26	30
2010	Full year	10.37	10.30	61	10.15	10.10	39
2011	Full year	10.29	10.17	42	9.92	10.03	16
2012	Full year	10.17	10.08	58	9.94	10.00	35
2013	Full year	10.03	9.95	49	9.68	9.72	21
2014	Full year	9.91	9.78	38	9.78	9.78	26
2015	Full year	9.84	9.60	31	9.60	9.68	16
	1st quarter	10.29	10.50	9	9.48	9.50	6
	2nd quarter	9.60	9.60	7	9.42	9.52	6
	3rd quarter	9.76	9.80	8	9.47	9.50	4
	4th quarter	9.57	9.58	18	9.68	9.73	10
2016	**Full year**	**9.77**	**9.75**	**42**	**9.54**	**9.50**	**26**
	1st quarter	9.87	9.60	15	9.60	9.25	3
	2nd quarter	9.63	9.50	14	9.47	9.60	7
	3rd quarter	9.66	9.60	5	10.14	9.90	6
	4th quarter	9.74	9.60	19	9.68	9.55	8
2017	**Full year**	**9.74**	**9.60**	**53**	**9.72**	**9.60**	**24**
	1st quarter	9.75	9.90	13	9.68	9.80	6
	2nd quarter	9.54	9.50	13	9.43	9.50	7
	3rd quarter	9.67	9.70	11	9.69	9.60	13
	4th quarter	9.42	9.50	11	9.53	9.60	14
2018	**Full year**	**9.60**	**9.58**	**48**	**9.59**	**9.60**	**40**
	1st quarter	9.73	9.70	12	9.55	9.70	4
	2nd quarter	9.58	9.50	12	9.73	9.73	3
	3rd quarter	9.55	9.60	7	9.80	9.90	3
	4th quarter	9.70	9.68	16	9.73	9.70	22
2019	**Full year**	**9.65**	**9.60**	**47**	**9.71**	**9.70**	**32**
	1st quarter	9.58	9.50	19	9.35	9.40	9
	2nd quarter	9.55	9.45	9	9.55	9.65	3
	3rd quarter	**9.30**	**9.33**	**10**	**9.52**	**9.45**	**8**
2020	Year-to-date	9.50	9.44	38	9.45	9.42	20

Data compiled Oct. 15, 2020.

Year-to-date through Sept. 30, 2020.

Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

S&P Global
Market Intelligence

Table 2: Electric and gas utilities summary

Electric utilities

Year	Period	ROR (%)	Number of observations	ROE (%)	Number of observations	Common equity to total capital (%)	Number of observations	Rate change amount ($M)	Number of observations
2004	Full year	8.71	20	10.81	21	46.96	19	1,806.3	29
2005	Full year	8.44	23	10.51	24	47.34	23	936.1	31
2006	Full year	8.32	26	10.32	26	48.54	25	1,318.1	39
2007	Full year	8.18	37	10.30	38	47.88	36	1,405.7	43
2008	Full year	8.21	39	10.41	37	47.94	36	2,823.2	44
2009	Full year	8.24	40	10.52	40	48.57	39	4,191.7	58
2010	Full year	8.01	62	10.37	61	48.63	57	4,921.9	78
2011	Full year	8.00	43	10.29	42	48.26	42	2,595.1	56
2012	Full year	7.95	51	10.17	58	50.69	52	3,080.7	69
2013	Full year	7.66	45	10.03	49	49.25	43	3,328.6	61
2014	Full year	7.60	32	9.91	38	50.28	35	2,053.7	51
2015	Full year	7.35	36	9.84	31	49.23	31	1,963.2	53
2016	Full year	7.28	41	9.77	42	48.91	41	2,326.1	58
2017	Full year	7.18	48	9.74	53	48.90	48	2,695.6	77
2018	Full year	6.90	49	9.60	48	49.02	49	1,880.4	67
	1st quarter	7.03	12	9.73	12	49.51	10	67.5	16
	2nd quarter	6.91	9	9.58	12	50.95	7	62.9	16
	3rd quarter	7.24	7	9.55	7	51.41	7	262.7	10
	4th quarter	6.85	16	9.70	16	49.12	16	1,268.1	20
2019	Full year	6.97	44	9.65	47	49.94	40	1,661.2	62
	1st quarter	6.82	20	9.58	19	48.72	21	700.9	22
	2nd quarter	6.82	8	9.55	9	48.64	8	452.3	12
	3rd quarter	7.03	10	9.30	10	51.33	10	188.5	12
2020	Year-to-date	6.88	38	9.50	38	49.37	39	1,341.7	46

Gas utilities

Year	Period	ROR (%)	Number of observations	ROE (%)	Number of observations	Common equity to total capital (%)	Number of observations	Rate change amount ($M)	Number of observations
2004	Full year	8.51	23	10.63	22	45.81	22	306.0	33
2005	Full year	8.24	29	10.41	26	48.40	24	465.4	35
2006	Full year	8.44	17	10.40	15	47.24	16	392.5	23
2007	Full year	8.11	31	10.22	35	48.47	28	645.3	43
2008	Full year	8.49	33	10.39	32	50.35	32	700.0	40
2009	Full year	8.15	29	10.22	30	48.49	29	438.6	36
2010	Full year	7.99	40	10.15	39	48.70	40	776.5	50
2011	Full year	8.09	18	9.92	16	52.49	14	367.0	31
2012	Full year	7.98	30	9.94	35	51.13	32	264.0	41
2013	Full year	7.43	21	9.68	21	50.60	20	498.7	40
2014	Full year	7.65	27	9.78	26	51.11	28	544.2	48
2015	Full year	7.34	16	9.60	16	49.93	16	494.1	40
2016	Full year	7.08	28	9.54	26	50.06	26	1,263.8	59
2017	Full year	7.26	24	9.72	24	49.88	24	410.7	54
2018	Full year	7.00	45	9.59	40	50.12	44	939.1	66
	1st quarter	7.37	4	9.55	4	51.40	4	90.4	9
	2nd quarter	7.75	3	9.73	3	58.87	3	48.3	10
	3rd quarter	6.52	5	9.80	3	43.86	4	619.5	16
	4th quarter	7.22	22	9.73	22	52.33	20	697.2	28
2019	Full year	7.18	34	9.71	32	51.75	31	1,455.3	63
	1st quarter	7.22	9	9.35	9	52.25	9	124.4	11
	2nd quarter	7.28	3	9.55	3	55.74	3	22.0	8
	3rd quarter	6.80	9	9.52	8	49.67	8	384.6	17
2020	Year-to-date	7.05	21	9.45	20	51.74	20	531.1	36

Data compiled Oct. 15, 2020.
Year-to-date through Sept. 30, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

S&P Global
Market Intelligence

Table 3: Electric authorized ROEs: 2007-Q3'20

Settled versus fully litigated cases

	All cases			Settled cases			Fully litigated cases		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2007	10.30	10.20	38	10.42	10.33	14	10.23	10.15	24
2008	10.41	10.30	37	10.43	10.25	17	10.39	10.54	20
2009	10.52	10.50	40	10.64	10.62	16	10.45	10.50	24
2010	10.37	10.30	61	10.39	10.30	34	10.35	10.10	27
2011	10.29	10.17	42	10.12	10.07	16	10.39	10.25	26
2012	10.17	10.08	58	10.06	10.00	29	10.28	10.25	29
2013	10.03	9.95	49	10.12	9.98	32	9.85	9.75	17
2014	9.91	9.78	38	9.73	9.75	17	10.05	9.83	21
2015	9.84	9.60	31	10.04	9.60	15	9.66	9.62	16
2016	9.77	9.75	42	9.80	9.85	17	9.74	9.60	25
2017	9.74	9.60	53	9.75	9.60	29	9.73	9.56	24
2018	9.60	9.58	48	9.57	9.63	26	9.63	9.53	22
2019	9.65	9.60	47	9.75	9.73	20	9.58	9.50	27
2020 YTD	9.50	9.44	38	9.52	9.45	15	9.48	9.40	23

General rate cases versus limited-issue riders

	All cases			General rate cases			Limited-issue riders		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2007	10.30	10.20	38	10.32	10.23	36	9.90	9.90	1
2008	10.41	10.30	37	10.37	10.30	35	11.11	11.11	2
2009	10.52	10.50	40	10.52	10.50	38	10.55	10.55	2
2010	10.37	10.30	61	10.29	10.26	58	11.87	12.30	3
2011	10.29	10.17	42	10.19	10.14	40	12.30	12.30	2
2012	10.17	10.08	58	10.02	10.00	51	11.57	11.40	6
2013	10.03	9.95	49	9.82	9.82	40	11.34	11.40	7
2014	9.91	9.78	38	9.76	9.75	32	10.96	11.00	5
2015	9.84	9.60	31	9.60	9.53	23	10.87	11.00	6
2016	9.77	9.75	42	9.60	9.60	32	10.31	10.55	10
2017	9.74	9.60	53	9.68	9.60	42	10.01	9.95	10
2018	9.60	9.58	48	9.56	9.58	38	9.74	9.70	10
2019	9.65	9.60	47	9.64	9.65	33	9.68	9.31	14
2020 YTD	9.50	9.44	38	9.44	9.45	25	9.62	9.20	13

Vertically integrated cases vs. distribution-only cases

	All cases			Vertically integrated cases			Distribution-only cases		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2007	10.30	10.20	38	10.50	10.45	26	9.86	9.98	10
2008	10.41	10.30	37	10.48	10.47	26	10.04	10.25	9
2009	10.52	10.50	40	10.66	10.66	28	10.15	10.30	10
2010	10.37	10.30	61	10.42	10.40	41	9.98	10.00	17
2011	10.29	10.17	42	10.33	10.20	28	9.85	10.00	12
2012	10.17	10.08	58	10.10	10.20	39	9.75	9.73	12
2013	10.03	9.95	49	9.95	10.00	31	9.37	9.36	9
2014	9.91	9.78	38	9.94	9.90	19	9.49	9.55	13
2015	9.84	9.60	31	9.75	9.70	17	9.17	9.07	6
2016	9.77	9.75	42	9.77	9.78	20	9.31	9.33	12
2017	9.74	9.60	53	9.80	9.65	28	9.43	9.55	14
2018	9.60	9.58	48	9.68	9.73	23	9.38	9.50	15
2019	9.65	9.60	47	9.73	9.73	25	9.37	9.60	8
2020 YTD	9.50	9.44	38	9.54	9.50	17	9.22	9.40	8

Data compiled Oct. 15, 2020.
Year-to-date through Sept. 30, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

S&P Global
Market Intelligence

Table 4: Gas authorized ROEs: 2007-2020 Q3

Settled versus fully litigated cases

	All cases			Settled cases			Fully litigated cases		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2007	10.22	10.20	35	10.24	10.18	22	10.20	10.40	13
2008	10.39	10.45	32	10.34	10.28	20	10.47	10.68	12
2009	10.22	10.26	30	10.43	10.40	13	10.05	10.15	17
2010	10.15	10.10	39	10.30	10.15	12	10.08	10.10	27
2011	9.92	10.03	16	10.08	10.08	8	9.76	9.80	8
2012	9.94	10.00	35	9.99	10.00	14	9.92	9.90	21
2013	9.68	9.72	21	9.80	9.80	9	9.59	9.60	12
2014	9.78	9.78	26	9.51	9.50	11	9.98	10.10	15
2015	9.60	9.68	16	9.60	9.60	11	9.58	9.80	5
2016	9.54	9.50	26	9.50	9.50	16	9.61	9.58	10
2017	9.72	9.60	24	9.68	9.60	17	9.82	9.50	7
2018	9.59	9.60	40	9.59	9.60	23	9.59	9.50	17
2019	9.71	9.70	32	9.70	9.70	20	9.74	9.72	12
2020 YTD	9.45	9.42	20	9.53	9.55	12	9.33	9.33	8

General rate cases versus limited-issue riders

	All cases			General rate cases			Limited-issue riders		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2007	10.22	10.20	35	10.22	10.20	35	—	—	0
2008	10.39	10.45	32	10.39	10.45	32	—	—	0
2009	10.22	10.26	30	10.22	10.26	30	—	—	0
2010	10.15	10.10	39	10.15	10.10	39	—	—	0
2011	9.92	10.03	16	9.91	10.05	15	10.00	10.00	1
2012	9.94	10.00	35	9.93	10.00	34	10.40	10.40	1
2013	9.68	9.72	21	9.68	9.72	21	—	—	0
2014	9.78	9.78	26	9.78	9.78	26	—	—	0
2015	9.60	9.68	16	9.60	9.68	16	—	—	0
2016	9.54	9.50	26	9.53	9.50	25	9.70	9.70	1
2017	9.72	9.60	24	9.73	9.60	23	9.50	9.50	1
2018	9.59	9.60	40	9.59	9.60	39	9.50	9.50	1
2019	9.71	9.70	32	9.72	9.72	30	9.60	9.60	2
2020 YTD	9.45	9.42	20	9.45	9.42	20	—	—	0

Data compiled Oct. 15, 2020.
Year-to-date through Sept. 30, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

S&P Global
Market Intelligence

Table 5: Electric and gas utility decisions

Electric utility decisions

Date	Company	State	ROR (%)	ROE (%)	Common equity as % of capital	Test year	Rate base	Rate change amount ($)	Footnotes
1/8/20	Interstate Power and Light Co.	IA	7.23	10.02	51.00	12/20	Average	127.0	B, I
1/16/20	Consolidated Edison Co. of New York, Inc.	NY	6.61	8.80	48.00	12/20	Average	113.3	B, D, Z
1/22/20	Rockland Electric Co.	NJ	7.11	9.50	48.32	9/19	Year-end	12.0	B, D
1/23/20	Indiana Michigan Power Co.	MI	6.08	9.86	46.56	12/20	Average	36.4	B,*
2/3/20	Virginia Electric and Power Co.	VA	6.84	9.20	51.17	3/21	Average	-6.3	LIR,1
2/3/20	Virginia Electric and Power Co.	VA	6.84	9.20	51.17	3/21	Average	11.4	LIR,2
2/3/20	Virginia Electric and Power Co.	VA	7.35	10.20	51.17	3/21	Average	-20.3	LIR,3
2/3/20	Virginia Electric and Power Co.	VA	7.35	10.20	51.17	3/21	Average	0.7	LIR,4
2/6/20	PacifiCorp	CA	—	10.00	51.96	12/19	Average	-5.8	
2/11/20	Public Service Co. of Colorado	CO	6.97	9.30	55.61	8/19	Average	292.7	5,6
2/14/20	CenterPoint Energy Houston Electric, LLC	TX	6.51	9.40	42.50	12/18	Year-end	55.9	B, D,Hy
2/18/20	Virginia Electric and Power Co.	VA	7.35	10.20	51.17	3/21	Average	-13.0	LIR,7
2/19/20	Central Maine Power Co.	ME	6.30	8.25	50.00	6/18	Average	17.4	D,Hy,8
2/24/20	Virginia Electric and Power Co.	NC	7.20	9.75	52.00	12/18	Year-end	5.0	B, I,Hy,9
2/25/20	Appalachian Power Co.	VA	7.74	10.42	50.78	4/21	Average	-6.3	LIR,10
2/27/20	AEP Texas Inc.	TX	6.45	9.40	42.50	12/18	Year-end	0.7	B, D,Hy
2/28/20	Oklahoma Gas and Electric Co.	AR	5.33	—	37.92	3/20	Year-end	5.2	B,11,*
3/11/20	Indiana Michigan Power Co.	IN	5.61	9.70	37.55	12/20	Year-end	77.1	Z,*
3/17/20	Mississippi Power Co.	MS	7.57	—	53.00	12/20	Year-end	-16.7	B
3/18/20	Union Electric Co.	MO	—	—	—	12/18	—	-32.0	B,12
3/20/20	Virginia Electric and Power Co.	VA	6.84	9.20	51.17	5/21	Average	18.0	LIR,13
3/25/20	Avista Corp.	WA	7.21	9.40	48.50	12/18	—	28.5	B
2020	**1st quarter: averages/total**		**6.82**	**9.58**	**48.72**			**700.9**	
	Observations		**20**	**19**	**21**			**22**	
4/6/20	Kentucky Utilities Co.	VA	—	—	—	12/18	—	9.0	B
4/7/20	Northern States Power Co. - MN	MN	—	—	—	—	—	—	14
4/13/20	Virginia Electric and Power Co.	VA	6.84	9.20	51.17	5/20	Average	7.4	LIR,15
4/17/20	Fitchburg Gas and Electric Light Co.	MA	7.99	9.70	52.45	12/18	Year-end	1.1	B, D
4/27/20	Duke Energy Kentucky, Inc.	KY	6.41	9.25	48.23	3/21	Average	24.1	
5/8/20	DTE Electric Co.	MI	5.46	9.90	38.32	4/21	Average	188.3	*
5/20/20	Southern Indiana Gas and Electric Co.	IN	—	—	—	10/19	Year-end	7.4	LIR,16
5/20/20	Southwestern Public Service Co.	NM	7.19	9.45	54.77	3/19	Year-end	31.0	B
5/21/20	Appalachian Power Co.	VA	—	9.42	—	6/21	Year-end	4.0	LIR,17
6/23/20	Virginia Electric and Power Co.	VA	7.35	10.20	51.17	8/21	Average	-20.1	B, LIR,18
6/26/20	Appalachian Power Co.	WV	—	—	—	12/19	—	50.1	B, LIR
6/29/20	Duke Energy Indiana, LLC	IN	5.71	9.70	40.98	12/20	Year-end	145.9	Z,*
6/30/20	Liberty Utilities (Granite State Electric) Corp.	NH	7.60	9.10	52.00	12/18	Year-end	4.2	B, D, Z, I
	2nd quarter: averages/total		**6.82**	**9.55**	**48.64**			**452.3**	
	Observations		**8**	**9**	**8**			**12**	
7/1/20	Empire District Electric Co.	MO	6.77	9.25	46.00	3/19	—	1.0	B
7/1/20	Virginia Electric and Power Co.	VA	6.84	9.20	51.17	8/21	Average	-5.2	LIR,19
7/8/20	Puget Sound Energy, Inc.	WA	7.39	9.40	48.50	12/18	Year-end	59.6	
7/14/20	Delmarva Power & Light Co.	MD	6.84	9.60	50.53	8/19	Average	11.7	D
7/28/20	Hawaii Electric Light Co., Inc.	HI	7.52	9.50	56.83	12/19	Average	0.0	B, I
7/30/20	Virginia Electric and Power Co.	VA	6.84	9.20	51.17	8/21	Average	10.6	LIR,20
8/27/20	Green Mountain Power Corp.	VT	6.43	8.20	49.87	9/21	Average	0.0	21
8/27/20	Liberty Utilities (CalPeco Electric) LLC	CA	7.63	10.00	52.50	12/19	Average	1.4	
8/27/20	Southwestern Public Service Co.	TX	7.13	9.45	54.62	6/19	Year-end	88.0	B, I
9/4/20	Virginia Electric and Power Co.	VA	6.88	9.20	52.07	10/20	Average	-19.4	LIR,22
9/23/20	Massachusetts Electric Co.	MA	—	—	—	—	—	46.1	D,23
9/24/20	Lone Star Transmission, LLC	TX	—	—	—	—	—	-5.3	B,24
	3rd quarter: averages/total		**7.03**	**9.30**	**51.33**			**188.5**	
	Observations		**10**	**10**	**10**			**12**	
2020	**YTD: averages/total**		**6.88**	**9.50**	**49.37**			**1,341.7**	
	Observations		**38**	**38**	**39**			**46**	

Gas utility decisions

Date	Company	State	ROR (%)	ROE (%)	Common equity as % of capital	Test year	Rate base	Rate change amount ($)	Footnotes
1/15/20	MDU Resources Group Inc.	WY	7.08	9.35	51.25	12/18	Year-end	0.8	B
1/16/20	Consolidated Edison Co. of New York, Inc.	NY	6.61	8.80	48.00	12/20	Average	83.9	B,Z
1/24/20	Roanoke Gas Co.	VA	7.28	9.44	59.64	12/17	Average	7.3	I
1/29/20	Indiana Gas Co., Inc.	IN	—	—	—	6/19	Year-end	1.8	LIR,16
1/29/20	Southern Indiana Gas and Electric Co.	IN	—	—	—	6/19	Year-end	2.2	LIR,16
2/3/20	Cascade Natural Gas Corp.	WA	7.24	9.40	49.10	12/18	—	6.5	B
2/24/20	Atmos Energy Corp.	KS	7.03	9.10	56.32	3/19	Year-end	3.1	
2/25/20	Questar Gas Co.	UT	7.18	9.50	55.00	12/20	Average	2.7	Z
2/28/20	Fitchburg Gas and Electric Light Co.	MA	7.99	9.70	52.45	12/18	Year-end	4.6	B,Z
2/28/20	Liberty Utilities (EnergyNorth Natural Gas) Corp.	NH	—	—	—	—	—	—	14
3/25/20	Avista Corp.	WA	7.21	9.40	48.50	12/18	—	8.0	B
3/26/20	Northern Utilities, Inc.	ME	7.34	9.48	50.00	12/18	Year-end	3.6	Hy
2020	**1st quarter: averages/total**		**7.22**	**9.35**	**52.25**			**124.4**	
	Observations		**9**	**9**	**9**			**11**	
4/21/20	Atmos Energy Corp.	TX	7.71	9.80	60.12	—	—	-0.3	B
4/28/20	Delta Natural Gas Co., Inc.	KY	—	—	—	12/19	Year-end	3.4	LIR,25
5/13/20	Missouri Gas Energy	MO	—	—	—	2/20	—	5.6	B, LIR,26
5/13/20	Spire Missouri Inc.	MO	—	—	—	2/20	—	5.5	B, LIR,26
5/19/20	Black Hills Colorado Gas, Inc.	CO	6.76	9.20	50.15	6/18	Average	-2.3	
6/16/20	CenterPoint Energy Resources Corp.	TX	7.38	9.65	56.95	6/19	Year-end	4.0	B
6/23/20	Black Hills Kansas Gas Utility Co., LLC	KS	—	—	—	1/20	Year-end	1.6	LIR,27
6/24/20	Northern Indiana Public Service Co.	IN	—	—	—	12/19	Year-end	4.5	LIR,16
	2nd quarter: averages/total		**7.28**	**9.55**	**55.74**			**22.0**	
	Observations		**3**	**3**	**3**			**8**	

S&P Global
Market Intelligence

Table 5: Electric and gas utility decisions

Electric utility decisions

Date	Company	State	ROR (%)	ROE (%)	Common equity as % of capital	Test year	Rate base	Rate change amount ($)	Footnotes
7/8/20	Oklahoma Natural Gas Co.	OK	—	—	—	12/19	—	9.7	B,23
7/8/20	Puget Sound Energy, Inc.	WA	7.39	9.40	48.50	12/18	Year-end	42.9	
7/14/20	CenterPoint Energy Resources Corp.	OK	—	—	—	12/19	—	-2.5	B,23
7/22/20	Indiana Gas Co., Inc.	IN	—	—	—	12/19	Year-end	2.8	LIR,16
7/22/20	Southern Indiana Gas and Electric Co.	IN	—	—	—	12/19	Year-end	0.7	LIR,16
8/4/20	Texas Gas Service Co., Inc.	TX	7.46	9.50	59.00	6/19	—	10.3	B
8/14/20	Summit Natural Gas of Missouri, Inc.	MO	—	—	—	—	—	—	14
8/20/20	DTE Gas Co.	MI	—	9.90	—	9/21	Average	110.0	B
8/21/20	Questar Gas Co.	WY	7.11	9.35	55.00	12/19	Year-end	1.5	B
8/27/20	Virginia Natural Gas, Inc.	VA	—	—	—	10/21	Average	3.0	LIR,28
9/10/20	Consumers Energy Co.	MI	—	9.90	—	9/21	Average	144.0	B
9/11/20	Roanoke Gas Co.	VA	7.30	—	—	9/21	Average	2.3	LIR,28
9/14/20	Chattanooga Gas Co.	TN	7.12	—	49.23	12/19	Average	4.8	B,29
9/23/20	South Jersey Gas Co.	NJ	6.90	9.60	54.00	6/20	Year-end	39.5	B
9/25/20	Southwest Gas Corp.	NV	6.75	9.25	49.26	—	—	0.6	
9/25/20	Southwest Gas Corp.	NV	6.52	9.25	49.26	—	—	22.7	
9/28/20	CenterPoint Energy Resources Corp.	AR	4.62	—	33.07	9/21	Year-end	-12.1	*,11
9/30/20	Atmos Energy Corp.	KY	—	—	—	9/21	Year-end	4.5	LIR,30
	3rd quarter: averages/total		**6.80**	**9.52**	**49.67**			**384.6**	
	Observations		**9**	**8**	**8**			**17**	
2020	**YTD: averages/total**		**7.05**	**9.45**	**51.74**			**531.1**	
	Observations		**21**	**20**	**20**			**36**	

Data compiled Oct. 15, 2020.
Year-to-date through Sept. 30, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Footnotes

A- *Average.*
B- *Order followed stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.*
D- *Applies to electric delivery only.*
Hy *Hypothetical capital structure adopted.*

I- *Interim rates implemented prior to the issuance of final order, normally under bond and subject to refund.*
LIR *Limited-issue rider proceeding.*
NA *Not available at the time of publication.*
Z- *Rate change implemented in multiple steps.*

* *Capital structure includes cost-free items or tax credit balances at the overall rate of return.*

1 *Rate change was approved under Rider B, which is the mechanism through which the company recovers the costs associated with the conversion of the Altavista, Hopewell and Southampton power s*
2 *Rate change was approved under Rider GV, which is the mechanism through which the company recovers its investment in the Greensville County generation facility.*
3 *Rate change was approved under Rider S, which is the mechanism through which the company recovers its investment in the Virginia City Hybrid Energy Center.*
4 *Rate change was approved under Rider W, which is the mechanism through which the company recovers its investment in the Warren County generation facility.*
5 *While the specified 2/11/20 date coincides with the date of the PUC's written order, the authorized base rate change coincides with a compliance filing submitted by the company on 2/18/20 and imple*
6 *The company petitioned the PUC for a rehearing on 3/2/20. On 7/14/20, the PUC issued an order granting in part and denying in part reconsideration motions filed by the company, as well as other intervenors in the proceeding.*
7 *Rate change was approved under Rider R, which is the mechanism through which the company recovers its investment in the Bear Garden power plant.*
8 *Decision reflects date of written order issued on Feb. 19, 2020. The ROE authorized reflects a 100 basis point downward adjustment for poor service. The PUC ordered that this ROE disallowance be lifted when the utility meets all performance benchmarks for all service equality metrics for at least 18 consecutive months beginning March 1, 2020, and formally demonstrates to the commission that problems have been solved.*
9 *Company seeks reconsideration regarding coal ash cost recovery.*
10 *This case addresses the company's investment in the Dresden Generating Plant.*
11 *Rate change pursuant to company's formula rate plan.*
12 *The approved partial settlements were largely silent regarding traditional rate case parameters, including capital structure and rate base, but notes that the stipulated return on equity is in a range of 9.*
13 *Reflects recovery of two utility-scale solar generation facilities, the 142-MW Colonial Trail West Solar Facility and the 98-MW AC Spring Grove 1 Solar Facility.*
14 *Case withdrawn or closed.*
15 Rate change approved under US-4, which is the mechanism through which the company will recover its investment in the roughly 100 megawatt utility-scale solar generation facility, Sadler Solar Facil
16 Case established the rates to be charged to customers under the company's compliance and system improvement adjustment mechanism, which includes both federally mandated pipeline-safety initiatives and projects that are permitted under the state's "transmission, distribution, and storage system improvement charge" statute.
17 Rate change authorized under company's energy efficiency rider.
18 Rate change approved under Rider BW, which is the mechanism through which the company recovers its investment in the 1358 MW natural gas-fired combined-cycle Brunswick County Power Statio
19 Rate change approved under Rider US-2, which is the mechanism through which the company recovers its investment in three utility-scale solar facilities: Scott Solar; Whitehouse Solar; and, Woodla
20 Rate change under Rider DSM, which is a consolidation of three riders that reflect costs associated with the company's demand-side management and energy conservation program.
21 Reflects authorization under company's multi-year alternative regulation plan.
22 Rate change approved under Rider E, which allows for recovery of costs incurred to comply with the U.S. Environmental Protection Agency and Virginia Waste Management Board regulations related
23 Rate change under performance-based regulation plan.
24 Transmission rate case.
25 Rate change authorized under the company's pipe replacement program rider.
26 Rate change authorized under the company's infrastructure system replacement surcharge rider.
27 Case involves company's gas system reliability surcharge.
28 Rate change was approved under company's rider pertaining to investment made under Virginia Steps to Advance Virginia Energy infrastructure program.
29 Rate change under company's annual rate mechanism.
30 Rate change approved under company's pipeline replacement program rider.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 64

Responding Witness: Adrien M. McKenzie

Q-64. Refer to the McKenzie Testimony, page 45 lines 7–11 and Exhibit No. 4. As quoted in the FERC Opinion, if the purpose of the outlier test is "to exclude from the proxy group those companies whose Return On Equity (ROE) estimated are below the average bond yield or above the average bond yield, but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt," explain why it would be either appropriate to:

a. Exclude those companies from the proxy group whose ROEs were excluded from the DCF analysis; or

b. Include all the observations, excluding none, since there are at least two additional ROE estimates derived from other sources.

A-64.

a. In applying tests of low-end values, FERC eliminates results for those companies in the proxy group that fall outside the established threshold. Thus, the cost of equity estimate for that company is not considered in evaluating the overall result for the proxy group. FERC performs this test based on the results of each method independently, so that a proxy firm that is excluded from consideration because its DCF estimate falls below the low-end threshold would still be included in evaluating the CAPM results, so long as its CAPM cost of equity estimate exceeded the threshold. This methodology appropriately excludes only those values which are determined to fall below the threshold test of reasonableness, while retaining all estimates that exceed the test.

b. See the response to part a.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 65

Responding Witness: Adrien M. McKenzie

Q-65. Refer to the McKenzie Testimony, Exhibit No. 4.

a. Explain why PPL Corporation is not listed in the Proxy Group.

b. Explain whether any of the companies in the Proxy Group have had a credit downgrade or put on notice of the potential of a downgrade as a result of carbon transition risk.

c. Explain whether any of the companies listed in the Proxy Group assign a high, moderate, or low probability of carbon regulation in their long-range resource plans.

A-65.

a. PPL Corporation was excluded from the proxy group due to its planned sale of its utility operations in the United Kingdom.

b. Mr. McKenzie has not conducted any research studies to determine whether the utilities included in his proxy group have been downgraded over some past period or for what reasons; nor was such a study necessary to support the conclusions and recommendations contained in his testimony.

c. Mr. McKenzie has not reviewed the long-range resource plans for the utilities included in his proxy group; nor was this necessary to support the conclusions and recommendations contained in his testimony.

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Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 66

Responding Witness: Adrien M. McKenzie

Q-66. Refer to the McKenzie Testimony, Exhibit No. 4. Many of the companies in the Proxy Group have extensive unregulated and or foreign operations while LG&E and KU do not.

a. Explain why these outside influences on the parent holding companies' financial operations should not be minimized within if not eliminated from the Proxy Group.

b. For each company in the Proxy Group, provide the percent of revenue derived from U.S. electric and gas (not storage or interstate transportation) operations regulated

A-66.

a. Mr. McKenzie's direct testimony at pages 24-32 contains an extensive discussion of the relative risk pertaining to his proxy group of utilities. As Mr. McKenzie explains, his identification of a proxy group of risk-comparable utilities focuses primarily on credit ratings, which provide an objective indicator of investment risk that considers the key risk factors relevant to investors, including quantitative and qualitative factors. As the Managing Director for Moody's Global Regulatory Affairs noted in comments to the Securities and Exchange Commission:

> To meet market needs over time, credit ratings have developed important attributes including insightful, robust and independent analysis, symbols that succinctly communicate opinions, and broad coverage across markets, industries and asset classes. These attributes have enabled credit ratings to serve as a point of reference and common language of credit that is used by financial market professionals worldwide to compare credit risk across jurisdictions, industries and asset

> classes, thereby facilitating the efficient flow of capital worldwide.[13]

A comparison of credit ratings is widely accepted as a means of evaluating the relative risks of utilities for purposes of identifying a proxy group in the context of estimating the cost of equity. For example, the Federal Energy Regulatory Commission has concluded that "corporate credit ratings are a reasonable measure to use to screen for investment risk," and that "[c]redit ratings are a key consideration in developing a proxy group that is risk-comparable."[14] FERC has also ruled that the measure of comparable risks afforded a credit rating screen alone is a sufficient test of comparable investment risks.[15]

In addition to credit ratings, Mr. McKenzie also examines a number of key metrics (i.e., beta, Value Line Safety Rank, Value Line Financial Strength Rating) that are widely recognized as independent guides to the investment risks associated with common stocks. Moreover, these measures incorporate the impact of a broad spectrum of risks, including business and financial position, relative size, and exposure to company-specific factors. As Mr. McKenzie indicated at page 42 of his direct testimony, these objective measures indicate that the overall investment risks for LGE/KU are generally comparable to those of the firms in his proxy group. In other words, "extensive unregulated and or foreign operations" do not differentiate the risks of the proxy group from those of LGE/KU.

The Supreme Court has recognized that the degree of risk, not the nature of the business, is relevant in evaluating an allowed ROE for a utility.[16] The cost of capital is based on the returns that investors could realize by putting their money in other alternatives, and the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment. The simple observation that a firm operates in non-utility businesses says nothing at all about the overall investment risks perceived by investors, which is the very basis for a fair rate of return. Similarly, gas distribution operations are regulated by the states in the same manner as electric operations, and there is no basis to distinguish between revenues from electric and gas utility

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[13] Farisa Zarin, *Letter Re: Credit Rating Standardization Study – Release No. 34-63573*; File No. 4-622 (Feb. 18, 2011). Available at (link follows):
https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=5&cad=rja&uact=8&ved=0ahUKEwjM7uicuMrbAhUGRqwKHeY0BGkQFghJMAQ&url=https%3A%2F%2Fwww.sec.gov%2Fcomments%2F4-622%2F4622-15.pdf&usg=AOvVaw3Lsgo0DWInU17QdvxEuw9v (last visited Jan. 16, 2021).
[14] *Potomac-Appalachian Transmission Highline, L.L.C.*, 133 FERC ¶ 61,152, at P 63 (2010).
[15] *N. Pass Transmission LLC*, 134 FERC ¶ 61,095 at P 52 & n.70 (2011).
[16] *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923) ("A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time . . . on investments in other business undertakings which are attended by corresponding risks and uncertainties . . .").

operations. Regulatory standards governing a fair ROE are based on comparable risk, not the nature of the business.

In fact, as Mr. McKenzie's testimony explains at pages 72-76, returns in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criterion in establishing a meaningful proxy group to estimate investors' required return is relative risk, not the source of the revenue stream or the nature of the asset base. Moreover, due to differences in business segment definition and reporting between utilities, it is often impossible to accurately apportion financial measures, such as revenues and total assets, between regulated (*e.g.*, electric and gas) and non-regulated sources. As a result, even if one were to ignore the fact that there is no clear link between the nature of a utility's revenues or assets and investors' risk perceptions, it is generally not possible to accurately and consistently apply asset or revenue-based criteria. In fact, FERC has specifically rejected arguments that utilities "should be excluded from the proxy group given the risk factors associated with its unregulated, non-utility business operations."[17]

b. Mr. McKenzie did not calculate the requested statistic in the course of preparing his testimony; nor was it necessary to support his analyses and conclusions. To the extent the information necessary to perform these calculation is publicly available, it can be obtained from the Form 10-K reports for each of the proxy companies, which can be obtained at https://www.sec.gov/edgar/searchedgar/legacy/companysearch.html.

[17] *Bangor Hydro-Elec. Co.*, 117 FERC ¶ 61,129 at PP 19, 26 (2006).

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Response to Commission Staff's Second Request for Information
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Question No. 67

Responding Witness: Adrien M. McKenzie

Q-67. Refer to the McKenzie Testimony, Table 2, page 46. Provide an update to the table using the most current available from IHS Global Insight and the Energy Information Administration and the current Baa - Aa yield spread. Include in the response the monthly observations for the Baa and Aa yields.

A-67. Mr. McKenzie does not have a more recent forecast from IHS Global Insight. The Energy Information Administration publishes an annual forecast, with the next long-term forecast being scheduled for release on February 3, 2021 and publicly available at https://www.eia.gov/outlooks/aeo/.

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Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 68

Responding Witness: Adrien M. McKenzie

Q-68. Refer to the McKenzie Testimony, page 50, lines 8–13.

a. Explain why the individual firm's dividend yield and growth rate are weighted by its proportionate share of total market value.

b. Explain why a similar procedure would not be appropriate for the DCF analysis in Exhibit No. 4.

A-68.

a. The S&P 500, which is a widely cited proxy for the market as a whole, is a market-weighted stock index. Thus, to estimate the market rate of return based on the dividend-paying firms in the S&P 500, it is necessary to weight the individual firm's dividend yield and growth rate by its proportionate share of total market value.

b. Application of the DCF model and other methodologies (e.g., CAPM) to firms in the electric utility industry does not involve the use of a market value weighted stock index as a proxy. Rather, financial models such as the DCF are applied directly to a group of firms that have been determined to be risk comparable. As a result, once illogical values have been eliminated, each observation represents a valid estimate of investors' required rate of return and there is no basis to give greater weight to any single result.

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Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 69

Responding Witness: Adrien M. McKenzie

Q-69. Refer to the McKenzie Testimony, page 51, lines 2–20 through page 52, lines 1–4. Provide a list of state regulatory commissions that Mr. McKenzie has appeared before that have rejected and accepted his size adjustment in the last five years.

A-69. Mr. McKenzie did not conduct any research studies of regulatory orders in other state jurisdictions regarding treatment of the size adjustment in past proceedings to support the size adjustment used in his application of the CAPM and ECAPM methods; rather, it was predicated on the results of financial research indicating that beta does not fully account for the impact of firm size on investors' required returns. Moreover, in Mr. McKenzie's experience, regulatory agencies generally do not rule on specific details underlying the results of financial models or even indicate precisely which results were relied on specifically in arriving at their authorized ROE.

The size adjustment methodology used by Mr. McKenzie is identical to that approved by the Federal Regulatory Commission, which has concluded that "[t]his type of size adjustment is a generally accepted approach to CAPM analyses."[18] Similarly, a recent publication available from the National Association of Certified Valuators and Analysts documented the relevance of the size adjustment in applying the CAPM:

> [A] beta-adjusted size premium is also an indication of the relative market performance of small-cap versus large-cap stocks, but is typically used for a very specific purpose: as a "size" adjustment within the context of the capital asset pricing model (CAPM) when developing cost of equity capital estimates. A size adjustment is typically applied to the CAPM to make up for the fact that the betas of smaller companies do not fully explain their observed returns. Because the CAPM already includes a beta input in its textbook specification, the size premium is then "beta adjusted" to remove the portion of realized excess return that is attributable to beta, thereby isolating the size effect's contribution to

[18] Coakley v. Bangor Hydro-Elec. Co., Opinion No. 531-B, 150 FERC ¶ 61,165 P 117 (2015).

> realized excess return and avoiding double counting the impact of each factor.
>
> Another way of saying this is that within the context of the CAPM, the betas of small-cap companies do not fully account for (or explain) their actual returns. Because the amount of this difference (what actually happened versus what CAPM predicted) varies with "size" (in this case, as measured by market capitalization) we call it a "size premium".[19]

This article went on to conclude that "valuation professionals typically add a 'size premium' to the base CAPM equation. . ." A copy of the article is attached.

[19] National Association of Certified Valuators and Analysts, "Using a Non-Beta-Adjusted Size Premium in the Context of the CAPM Will Likely Overstate Risk and Understate Value" (Jan. 30, 2019).

Using a Non-Beta-Adjusted Size Premium in the Context of the CAPM Will Likely Overstate Risk and Understate Value

QR quickreadbuzz.com/2019/01/30/business-valuation-grabowski-harringtonsing-a-non-beta-adjusted-size-

National Association of Certified Valuators and Analysts January 31, 2019

Measuring the Relative Performance of Small Stock vs. Large Stock and the Cost of Equity

Roger Ibbotson and James Harrington discuss two different ways of measuring the relative performance of small stocks versus large stocks in this article: (i) the “small stock premium” and (ii) the “beta-adjusted size premium”. Ibbotson and Harrington demonstrate why using a non-beta-adjusted size premium within the context of the capital asset pricing model (CAPM) to estimate cost of equity capital will likely “double count” beta risk, and therefore overstate risk and understate value. The authors also demonstrate that a non-beta-adjusted size premium used in conjunction with “build-up” methods that employ an industry risk premium would be equally inappropriate.

Roger Ibbotson and James Harrington discuss two different ways of measuring the relative performance of small stocks versus large stocks in this article: (i) the “small stock premium” and (ii) the “beta-adjusted size premium”. Ibbotson and Harrington demonstrate why using a non-beta-adjusted size premium within the context of the capital asset pricing model (CAPM) to estimate cost of equity capital will likely “double count” beta risk, and therefore

overstate risk and understate value. The authors also demonstrate that a non-beta-adjusted size premium used in conjunction with "build-up" methods that employ an industry risk premium would be equally inappropriate.[1],[2]

The "Small Stock Premium" and the "Beta-Adjusted Size Premium" Are Different Things, and are Used for Different Purposes

The "small stock premium" and a "beta-adjusted size premium" are both informative about the performance of small company stocks relative to large company stocks. However, they are different things, and are used for different purposes.

The small stock premium is the difference between the returns of small capitalization (small-cap) stocks and large capitalization (large-cap) stocks. This difference can be used in a top-down review of market performance and general discussions of whether small-cap stocks perform better than large-cap stocks over time and can also be used to develop long-term inputs for use in mean-variance optimization (MVO) analyses or wealth forecasting.[3]

Alternatively, a beta-adjusted size premium is also an indication of the relative market performance of small-cap versus large-cap stocks, but is typically used for a very specific purpose: as a "size" adjustment within the context of the capital asset pricing model (CAPM) when developing cost of equity capital estimates.[4] A size adjustment is typically applied to the CAPM to make up for the fact that the betas of smaller companies do not fully explain their observed returns. Because the CAPM already includes a beta input in its textbook specification, the size premium is then "beta adjusted" to remove the portion of realized excess return that is attributable to beta, thereby isolating the size effect's contribution to realized excess return and avoiding double counting the impact of each factor.

Calculating the Small Stock Premium

The "small stock premium" can be defined as the simple difference between small-cap stock total returns (as measured by the Ibbotson Associates Small Company Stock total return index) and large-cap stock total returns (as measured by the Ibbotson Associates Large Company Stock total return index).[5],[6] The small-stock premium is given by:[7],[8]

Small Stock Premium = (Small Stock Total Return – Large Stock Total Return)

In Exhibit 1, the small stock premium is calculated on an annual basis from 2010 through 2017.

Exhibit 1: Annual Small Stock Premium (2010–2017)

	Large Stock Total Return	Small Stock Total Return	Small Stock Premium
2010	15.06%	31.26%	16.20%
2011	2.11%	-3.26%	-5.37%
2012	16.00%	18.24%	2.23%
2013	32.39%	45.07%	12.68%
2014	13.69%	2.92%	-10.77%
2015	1.38%	-3.60%	-4.98%
2016	11.96%	25.65%	13.69%
2017	21.83%	11.19%	-10.64%

Source of underlying data in Exhibit 1: Stocks, Bonds, Bills, and Inflation® (SBBI®) return series from the Morningstar *Direct* database. Series used: (i) Large Company Stocks (IA SBBI® US Large Stock TR USD Ext). The "SBBI ® US Large Stock" return series is essentially the S&P 500 index. (ii) Small Company Stocks (IA SBBI® US Small Stock TR USD). Used with permission. All rights reserved. Calculations performed by Duff & Phelps, LLC.

For example, in calendar year 2010, small-cap stocks had a total return of 31.26%, and large-cap stocks (as measured by the S&P 500 total return index) had a total return of 15.06%. The small stock premium for 2010 was therefore 31.26% – 15.06%, or 16.20%. Note that the small stock premium is not always positive, especially over shorter periods of time.[9]

The small stock premium can also be calculated over longer periods of time. For example, the average annual return of large-cap stocks (as measured by the S&P 500 total return index) from 1926 through 2017 was 12.06%, and the average annual return of small-cap stocks (as measured by the Ibbotson Associates Small Company Stock total return index) over the same period was 16.52%, implying a small stock premium of 4.46% (16.52% – 12.06%).[10]

Calculating a Beta-Adjusted Size Premium

In the Duff & Phelps online Cost of Capital Navigator (dpcostofcapital.com) there are two different valuation data sets, each of which includes beta-adjusted size premia that can be used as inputs when estimating the cost of equity capital: (i) the CRSP Size Premia Study, and (ii) the Risk Premium Report Study.[11] The size premia presented in both the studies are "beta-adjusted", and are calculated using the *same* methodological framework.[12] For simplicity, in this article we employ data from the CRSP Deciles Size Study in the examples presented.

Size premia are calculated here as the difference in historical portfolio excess returns (i.e., what *did happen*), and the excess returns that CAPM would have *predicted*. Excess returns are defined here as returns over and above the risk-free asset's returns. This is the same way that the size premia were calculated in the Ibbotson Associates/Morningstar *SBBI Valuation Yearbook* (1999–2013), the *Valuation Handbook—U.S. Guide to Cost of Capital* (2014–2017), and now in the online Cost of Capital Navigator (2018 and subsequent years).

First, let's examine the base (i.e., "textbook") CAPM equation to see what is meant by "excess returns that CAPM would have predicted". The base CAPM equation can be expressed as follows:[13]

Cost of equity = Risk-free Rate + (Beta x Equity Risk Premium)

Or notationally as:

$K_e = R_f + (ß \times RP_m)$

"Excess returns" are defined here as returns over and above the risk-free asset's returns. Anything added to the risk-free rate ("R_f" in the equation above) is by definition "over and above" the risk-free rate. In the base CAPM equation, "excess returns" is therefore represented by beta multiplied by the equity risk premium (in the equation this is "$ß \times RP_m$"):

$$K_e = R_f + \boxed{(ß \times RP_m)} \quad \text{excess return}$$

A problem with the base CAPM equation is that it is not very reliable in predicting the realized excess returns of small-cap companies. To demonstrate this, we can use the CAPM equation to decompose the average annual return of CRSP decile 10 (comprised of the smallest companies, as measured by market capitalization).[14]

In Exhibit 2, the average annual returns of CRSP NYSE/NYSE MKT/NASDAQ deciles 1–10 over the period 1926–2017 period for are shown. As size (in this case, as measured by market cap) decreases, the realized return tends to increase. For example, the average annual return of decile 1 (the largest-cap companies) was 11.19% over the 1926–2017 period, while the annual arithmetic mean returns of decile 10 (the smallest-cap companies) was 20.19%.

Note that this increased return comes at a price: risk (as measured by standard deviation) increases from 18.86% for decile 1 to 42.22% for decile 10. The increase in standard deviation of returns is correlated with the increase in the decile betas. The relationship between risk and return is a fundamental principle of finance and the framework to estimate cost of capital.

Exhibit 2: Summary Statistics of Annual Returns (CRSP NYSE/NYSE MKT/NASDAQ Deciles)

1926–2017

Decile	Beta	Arithmetic Mean (%)	Standard Deviation (%)
1-Largest	0.92	11.19%	18.86%
2	1.04	12.89%	21.37%
3	1.11	13.67%	23.24%
4	1.13	13.84%	25.42%
5	1.17	14.62%	26.03%
6	1.17	14.89%	26.97%
7	1.25	15.41%	28.87%
8	1.30	16.08%	32.84%
9	1.34	16.94%	36.97%
10-Smallest	1.39	20.19%	42.22%

Source of underlying data: CRSP U.S. Stock Database and CRSP U.S. Indices Database © 2018 Center for Research in Security Prices (CRSP®), University of Chicago Booth School of Business. CRSP NYSE/NYSE MKT/NASDAQ deciles 1–10. Used with permission. All rights reserved. Calculations performed by Duff & Phelps, LLC. To learn more about CRSP, visit crsp.com.

The predicted excess returns of CRSP decile 10 using the base CAPM equation can be calculated in the following fashion. Again, the base CAPM equation is:

Cost of equity = Risk-free Rate + (Beta x Equity Risk Premium), or

$K_e = R_f + (ß \times RP_m)$

To calculate the excess return of CRSP decile 10 using the base CAPM equation, we need a beta (*ß*) and an equity risk premium (RP_m):

- The beta (*ß*) of CRSP Decile 10 is 1.39
- The "historical" average annual long-term equity risk premium (RP_m) is 7.07%, calculated as the difference between the average annual total return of the S&P 500 total index (12.06%) and the average annual income return (4.99%) of a long-term (i.e., 20-year) U.S. Treasury bond (the "risk-free" asset).

The "excess return" ("$ß \times RP_m$" in the textbook CAPM equation) of CRSP decile 10 is therefore 9.84%:

Excess Return of CRSP Decile 10 = $ß \times RP_m = 1.39 \times 7.07\% = 9.84\%$ *(difference due to rounding)*[15]

To gauge how well the base CAPM equation did at predicting the excess returns of CRSP decile 10, we can compare the textbook CAPM equation estimate of what "should have happened" with what "actually happened".

Looking to Exhibit 2, the actual average annual return of CRSP decile 10 over the 1926–2017 period was 20.19%, and the average annual income return of a long-term (i.e., 20-year) U.S. Treasury bond (the "risk-free" asset) was 4.99%.

- The actual excess return of CRSP decile 10 is therefore 15.20% (20.19% –99%).
- The textbook CAPM equation estimate of excess returns for CRSP Decile 10 was 9.84%.

The textbook CAPM equation did not do a very good job of predicting the excess returns of CRSP decile 10, which is comprised of the smallest companies. The textbook CAPM equation estimate of what "should have happened" fell 5.37% (15.20% – 9.84%) short of what "actually happened".[16]

This analysis demonstrates why valuation professionals typically add a "size premium" to the base CAPM equation: the betas of small-cap companies do not fully account for the actual excess returns that are typically seen with small-cap companies. The 5.37% that the textbook CAPM equation fell short is assumed to be a function of "size", and is therefore added as a "beta-adjusted" size premium in the "modified" CAPM equation (MCAPM), which includes an adjustment for size:

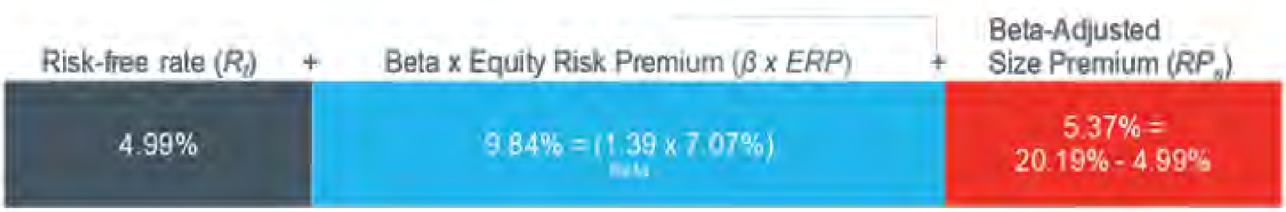
Cost of equity = Risk-free Rate + (Beta x Equity Risk Premium) + Size Premium, or

$$K_e = R_f + (ß \times RP_m) + \boxed{RP_s} \quad \textit{beta-adjusted size premium}$$

The average annual return of CRSP Decile 10 is thus decomposed into three components using the modified CAPM: (i) the risk-free rate (4.99%), (ii) the excess returns predicted by the systematic risks measured by beta and the equity risk premium (9.84%), and (iii) the return in excess of what the textbook CAPM predicted (5.37%), also known as a beta-adjusted size premium. This decomposition is illustrated in Exhibit 3.

Exhibit 3: Decomposition of CRSP Decile 10 Average Annual Returns Using the Modified CAPM Equation

1926–2017

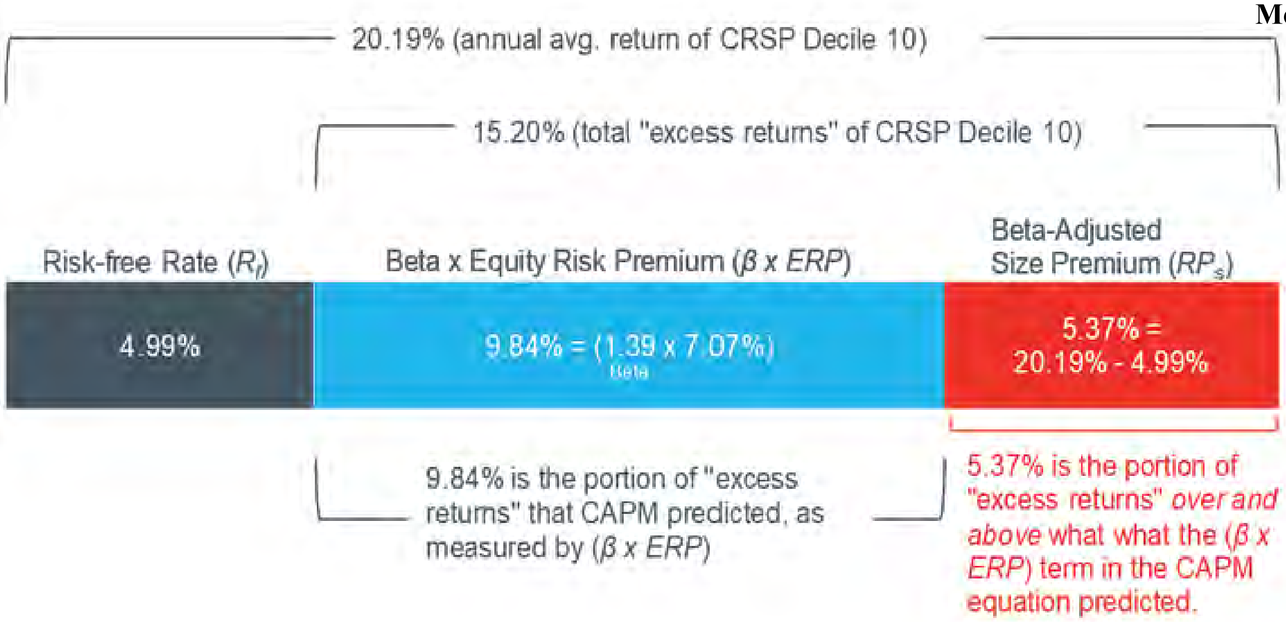


What Does "Beta-Adjusted" Mean?

A "beta-adjusted" size premium has been adjusted to remove the portion of excess return that is attributable to beta (within the context of the CAPM), therefore isolating the size effect's contribution to excess return. But what exactly does this mean? When we say we are "adjusting" (i.e., "controlling") for something, what we mean is that we want to exclude the influence of something from a calculation.

In Exhibit 4, the predicted excess return for CRSP decile 10 (9.84%) is calculated in the textbook CAPM equation by the beta multiplied by the equity risk premium (*β x ERP*). It follows that anything over and above what the base CAPM predicts (in this case, 5.37%) is (by definition) not the result of the risks embodied by the beta and equity risk premium. We can thus say that the 5.37% portion of excess returns is "beta-adjusted" within the framework of the CAPM equation.

Exhibit 4: CAPM Decomposition of the Annual Average Return of CRSP Decile 10 (20.19%) Over the Time Period 1926–2017



Why the Portion of Excess Returns Over and Above What CAPM Predicts is Attributed to "Size"

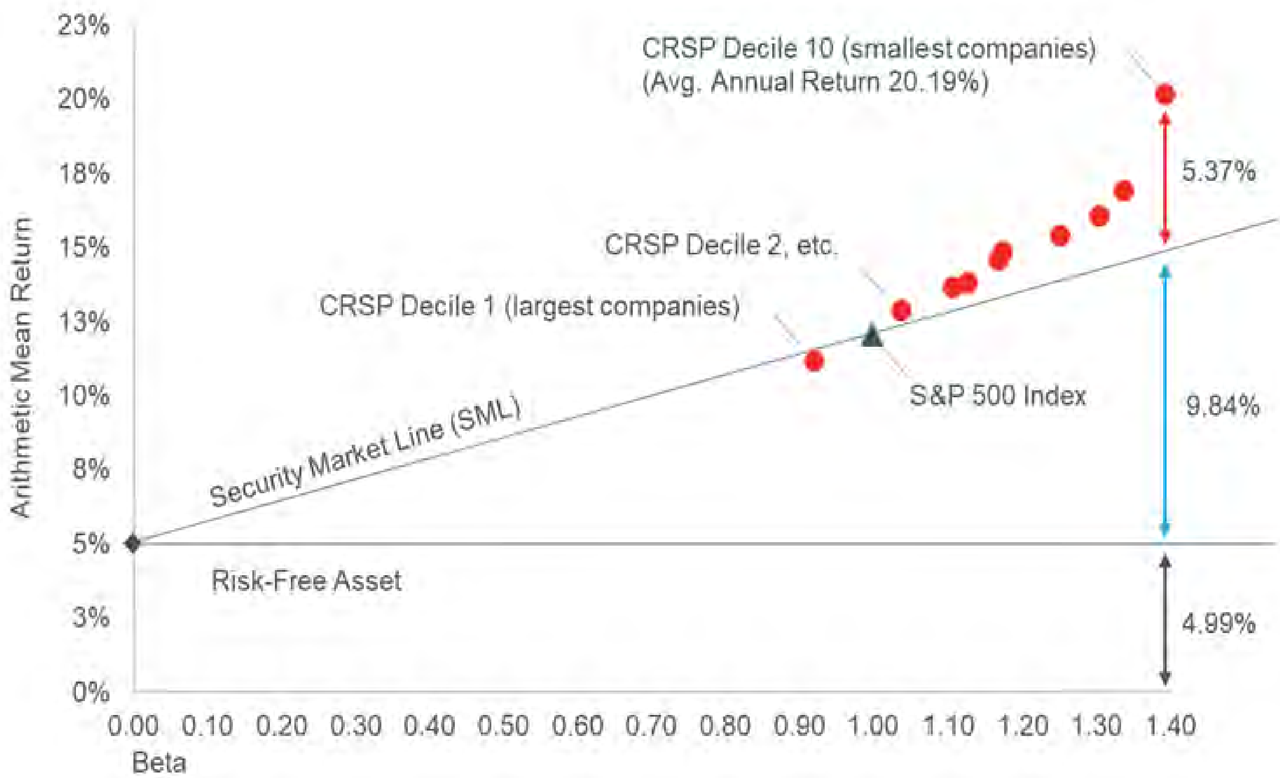
Exhibit 2 displays the betas, arithmetic average (i.e., "mean") annual return, and standard deviation of CRSP deciles 1–10, measured over 1926–2017. We noted in the discussion of Exhibit 2 that as size (in this case, as measured by market cap) decreases, return tends to increase.

Exhibit 5 depicts a "scatterplot" graph of the betas (horizontal axis) and average annual returns (vertical axis) from Exhibit 2 of each of the CRSP deciles 1–10. In the graph, the ten red dots represent CRSP deciles 1 (comprised of the largest companies) through CRSP decile 10 (comprised of the smallest companies), and the dark gray triangle is the "market" benchmark (the S&P 500 Index; beta = 1.00).

The security market line (SML) in Exhibit 5 represents what the textbook CAPM equation (without an adjustment for size) predicts as the excess return for each of the CRSP deciles, dependent on the respective levels of systematic risk (beta) for each. Note that the textbook CAPM equation does not do a very good job of predicting the realized excess return of the deciles, which fall increasingly above the security market line as size decreases. This indicates that these deciles have returns in excess of what their systematic risk implies. Another way of saying this is that within the context of the CAPM, the betas of small-cap companies do not fully account for (or explain) their actual returns. Because the amount of this difference (what actually happened versus what CAPM predicted) varies with "size" (in this case, as measured by market capitalization) we call it a "size premium". It is not clear, however, whether this is due to size itself, or to other factors closely related to or correlated with size. [17]

We previously used the CAPM equation to decompose the average annual return of CRSP decile 10 from 1926 through 2017 (20.19%) into (i) the return on a risk-free asset (4.99%), (ii) the excess returns predicted by the textbook CAPM (9.84%), and (iii) excess return over and above what CAPM predicted (5.37%), which represents the "beta-adjusted size premium" for Decile 10 as of December 31, 2017. For a different perspective (and aid in understanding this concept), these values (4.99%, 9.84%, 5.37%) have been included in Exhibit 5.

Exhibit 5: Security Market Line versus CRSP Deciles 1–10; 1926–2017



The Potential Danger of Using a *Non-Beta-Adjusted* Size Premium in the Context of the CAPM to Estimate Cost of Equity Capital

To answer this question, revisit the earlier discussion about the calculation of the "small stock premium". The small stock premium is related to the beta-adjusted size premium, insofar as each contains information about the relative performance of small-cap versus large-cap stocks. However, they are not interchangeable as far as usage.

As previously discussed, for forward-looking long-term forecasting purposes, the small stock premium is typically calculated as the simple difference in the average annual returns of small stocks and large stocks.

Earlier in this article we calculated a small stock premium in this fashion using the Ibbotson Associates "Large Company Stocks" series (which is essentially the S&P 500 index) and "Small Company Stocks" series that have traditionally been used in the Ibbotson

Associates/Morningstar *SBBI Yearbook* for such calculations.[18] In the following section, an equivalent calculation of a long-term “small stock premium” for forecasting purposes can be accomplished using the S&P 500 index as the market benchmark, but this time with CRSP decile 10 as the proxy for “small stocks”. [19],[20]

Calculating a Small Stock Premium (i.e., a Non-Beta-Adjusted Size Premium) Using CRSP

Decile 10

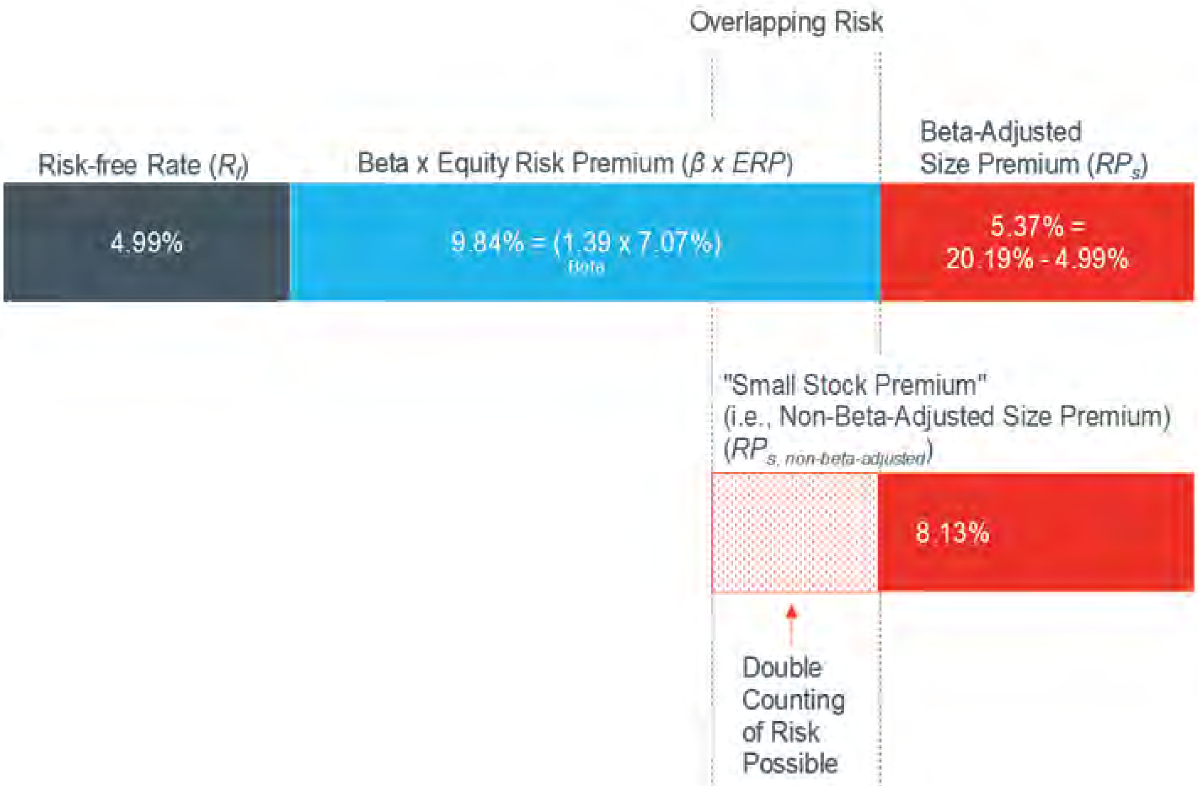
A small stock premium for CRSP decile 10 can be calculated as the simple difference between the average annual return of the market benchmark (in this case, the S&P 500 index) from 1926–2017, and the average annual return of CRSP Decile 10 over the same time period. The average annual return of large stocks (as measured by the S&P 500 total return index) from 1926 through 2017 was 12.06%, and the average annual return of small stocks (as measured by CRSP decile 10) over the same period was 20.19%, implying a “small stock premium” of 8.13% (20.19% – 12.06%).

The result of this calculation is effectively a “non-beta-adjusted” size premium.

Potential of Double Counting Risk

Compare this non-beta-adjusted size premium result (8.13%) to the beta-adjusted size premium result (5.37%) previously developed for CRSP decile 10. The non-beta-adjusted size premia for CRSP decile 10 is larger than the beta-adjusted size premia by 2.76% (8.13% – 5.37%). This is likely because some risks being measured in the small stock premium *overlap* with systematic risks already being measured within the context of the CAPM in the term where beta is multiplied by the equity risk premium (β *x ERP*). This “double counting” of risk is illustrated in Exhibit 6.

Exhibit 6: CAPM Decomposition of the Annual Average Return of CRSP Decile 10 (1926–2017)



As illustrated in Exhibit 6, using the small stock premium (i.e., a non-beta-adjusted size premium) in the context of the CAPM to estimate cost of equity capital will likely overstate risk, and thus understate value.

In pre-1995 versions of the Ibbotson Associates *Stocks, Bonds, Bills, and Inflation® (SBBI®) "Classic" Yearbook*, the book actually did suggest that the "small stock premium" could be added to the CAPM as a size adjustment to the CAPM. That changed in the 1995 version of that book, when Ibbotson Associates began "beta-adjusting" the size premia they published, stating, "The size premia given here (...) are adjusted for beta. That is, small stocks do have higher betas than large stocks; the return, above what might be expected because of the higher betas, is the size premia. These size premia increase as the capitalization of the company decreases."[21]

In 1999, Ibbotson Associates used the single chapter dedicated to valuation issues in the *SBBI® "Classic" Yearbook* and used it as the basis for a new "yearbook" dedicated solely to valuation issues, the *Stocks, Bonds, Bills, and Inflation® (SBBI®) "Valuation" Yearboo*k. That book provided significantly expanded commentary and analysis of valuation issues, plus "Key Variables in Estimating the Cost of Capital", which included size premia and other valuation inputs.

Can a Non-Beta-Adjusted Size Premium Be used With the Build-Up Method?

Thus far the discussion has been focused on the use of beta-adjusted size premia within the context of the modified CAPM (MCAPM), and the potential for double-counting risk if the "small stock premium" (i.e., a non-beta-adjusted size premium) is used.

A non-beta-adjusted size premium should not be used in "build-up" methods of estimating cost of capital that employ an industry risk premium and a size premium together in the same equation. The reason is that the MCAPM equation and the equation of a build-up method that employs an industry risk premium and a size premium are exactly equivalent. In other words, this formulation of the build-up method is merely the MCAPM with the terms re-arranged.

To understand why, it is important to appreciate that an industry risk premium is simply a beta that has been modified so that it can be added as a simple "up or down" adjustment in a build-up method of estimating cost of equity capital (i.e., an additive risk adjustment in the equation). Industry risk premia are calculated as follows:

Industry Risk Premium = RP_i = (Beta x Equity Risk Premium) – Equity Risk Premium, or

$RP_i = (ß \times RP_m) - RP_m$

One of the variations of the build-up method can be expressed as the following equation:

$K_e = R_f + RP_m + RP_i + RP_s$

To demonstrating algebraically that the MCAPM and this formulation of the build-up method are equivalent, we can substitute the Industry Risk Premium equation (above) into the build-up equation for the term "RP_i", and we obtain the following:

$K_e = R_f + RP_m + (ß \times RP_m - RP_m) + RP_s$

We can then simplify the equation further, as the positive and negative RP_m factors cancel out:

$K_e = R_f + RP_m + (ß * RP_m - RP_m) + RP_s$

Which simplifies to the MCAPM equation:

$K_e = R_f + ß * RP_m + RP_s$

Because a build-up equation that employs an industry risk premium and a size premium is the exact equivalent of the MCAPM equation, a beta-adjusted size premium must also be used in conjunction with this formulation of the build-up method. If a non-beta-adjusted size premium is used, it will likely embody risks that overlap with systematic risks already being measured within the context of the build-up (just as in the MCAPM), and thus "double-count" these risks.

Conclusion

The small stock premium *is* related to the beta-adjusted size premium, insofar as each contains information about the relative performance of small-cap versus large-cap stocks. However, they are *not* interchangeable as far as usage. Using a non-beta-adjusted size premium in the context of the MCAPM (or a build-up method that includes an industry risk premium) to estimate cost of equity capital will likely *overstate* risk and *understate* value. As elegantly summarized in the inaugural Ibbotson Associates *Stocks, Bonds, Bills, and Inflation® (SBBI®) "Valuation" Yearboo*k in 1999:

"The non-beta-adjusted size premia already account for the added return generally attributed to the higher betas of small companies. Again, the non-beta-adjusted size premium makes the assumption that the beta of the company is the same as the small stock portfolio. If the non-beta-adjusted size premium is used in the context of the modified CAPM equation…the effect of beta on return will essentially be counted double. Multiplying the equity risk premium by another measure of beta (either the company beta or industry beta) introduces to the same equation a duplicate, though possibly different, measure of systematic risk."

– Roger Ibbotson, *1999 Stocks, Bonds, Bills, and Inflation® (SBBI®) Valuation Yearboo*k (Ibbotson Associates, Chicago), page 23.

[1] Roger Ibbotson is Chairman and Chief Investment Officer of Zebra Capital Management (www.zebracapm.com), Professor in the Practice Emeritus of Finance at Yale School of Management, and former Chairman of Ibbotson Associates and Ibbotson Associates Advisors, LLC until both were acquired by Morningstar Inc. in March 2006. He has written numerous books and articles including *Stocks, Bonds, Bills, and Inflation* with Rex Sinquefield (updated annually) which serves as a standard reference for information on capital market returns. He has published The *Equity Risk Premium* with William Goetzmann and *Lifetime Financial Advice* with Milevsky, Chen, and Zhu. He has also co-authored two books with Gary Brinson, *Global Investing and Investment Markets*. In addition, he has co-authored a textbook with Jack Clark Francis, *Investments: A Global Approach*. He is the recipient of many awards including Graham and Dodd Scrolls in 1979, 1982, 1984, 2001, 2004, 2007, 2011, 2012, and best *Financial Analysts Journal* article of 2013. He received the Harry M. Markowitz Award for "Momentum, Acceleration, and Reversal", the 2015 best paper in the *Journal of Investment Management*. Most recently (2019), Ibbotson and colleagues Thomas M. Idzorek, CFA, Paul D. Kaplan, CFA, and James X. Xiong, CFA published a new Chartered Financial Analyst® (CFA) Institute Research Foundation monograph entitled "Popularity: A Bridge Between Classical and Behavioral Finance" (available for download at https://www.cfainstitute.org/en/research/foundation/2018/popularity-bridge-between-classical-and-behavioral-finance). Professor Ibbotson served on numerous boards, and currently serves as a disinterested director, Chairman of the Audit Committee and member of the Nominating Committee of Dimensional Investment Group Inc. (DIG) and DFA

Investment Dimensions Group Inc. (DFAIDG), registered investment companies for which Dimensional Fund Advisors Inc. serves as investment adviser. He frequently speaks at universities, conferences, and other forums. He received his bachelor degree in mathematics from Purdue University, his MBA from Indiana University, and his PhD from the University of Chicago where he taught for more than ten years and served as Executive Director of the Center for Research in Security Prices.

[2] James P. Harrington is a Director at Duff & Phelps. James is a leading contributor to Duff & Phelps' efforts in the development of studies, surveys, online content and tools, firm-wide valuation models, data distribution platforms, and published thought leadership. James is a co-author of the Duff & Phelps "Valuation Handbook" series and a developer of the online "Cost of Capital Navigator" platform (dpcostofcapital.com), along with colleagues Roger Grabowski and Carla Nunes.

[3] For a detailed discussion, see the *2018 Stocks, Bonds, Bills, and Inflation® (SBBI®) Yearbook*, Chapter 10, "Using Historical Data in Wealth Forecasting and Portfolio Optimization". To learn more about or purchase the *SBBI® Yearbook*, visit: duffandphelps.onfastspring.com/books.

[4] The base (i.e., "textbook") CAPM equation is Cost of Equity = (Risk-free Rate) + (Beta) x (Equity Risk Premium), or notationally expressed as $K_e = R_f + ß \times RP_m$. When a size adjustment is added, this becomes Cost of Equity = (Risk-free Rate) + (Beta) x (Equity Risk Premium) + (Size Premium), or notationally expressed as $K_e = R_f + ß \times RP_m + RP_s$. This modified CAPM equation is often referred to as "modified CAPM" or MCAPM.

[5] Morningstar previously published two "Ibbotson SBBI®" yearbooks: (i) The *SBBI® "Classic" Yearbook*, which is now produced by Duff & Phelps as the "SBBI® Yearbook" starting in 2016 (the word "Classic" was dropped from the title), and (ii) the *SBBI® "Valuation"* Yearbook, which was discontinued by Morningstar in 2013. The former Ibbotson Associates/Morningstar *SBBI® Valuation Yearbook* was replaced by the Duff & Phelps *Valuation Handbook—U.S. Guide to Cost of Capital* in 2014, which was published annually as a hardcover book through 2017. Starting in 2018, Duff & Phelps does not publish a physical version of the *Valuation Handbook—U.S. Guide to Cost of Capital;* the essential valuation data from the data exhibits are available *only* in the Cost of Capital Navigator online platform at dpcostofcapital.com. The major difference between the *SBBI Yearbook* (the former "Classic" yearbook) and other Duff & Phelps data resources (e.g., the online Cost of Capital Navigator) is that Duff & Phelps' other data resources provide U.S. and international equity risk premia, risk-free rates, size premia, industry risk premia, betas, industry multiples and other statistics, etc., for use in valuation models, while the *SBBI® Yearbook* is (i) a history of the asset class returns of U.S. capital markets (thus the name, "Stocks, Bonds, Bills, and Inflation®," or "SBBI®") from 1926 to the present, and (ii) an analysis of the relative performance of U.S. asset classes. The *SBBI® Yearbook* does not provide extensive valuation data or methodology. To learn more about or purchase the *Stocks, Bonds, Bills, and Inflation®*

(SBBI®) Yearbook, visit: duffandphelps.onfastspring.com/books.

[6] In the *2018 SBBI® Yearbook*, the Ibbotson Associates SBBI U.S. Small Stock total return series (i.e., "IA SBBI US Small Stock TR USD") is represented by: (i) the DFA U.S. Micro Cap Portfolio from April 2001 through December 2017, (ii) the DFA U.S. 9–10 Small Company Portfolio from January 1982 through March 2001, and (iii) the NYSE Fifth Quintile Returns from 1926 through 1981. The Ibbotson Associates SBBI U.S. Large Stock total return series (i.e., "IA SBBI US Large Stock TR USD Ext") is based upon the S&P Composite Index. This index is a readily available, carefully constructed, market-capitalization-weighted benchmark of large-cap stock performance. Market-capitalization-weighted means that the weight of each stock in the index, for a given month, is proportionate to its market capitalization (price times the number of shares outstanding) at the beginning of that month. Currently, the S&P Composite includes 500 of the largest stocks (in terms of stock market value) in the U.S.; prior to March 1957 it consisted of 90 of the largest stocks. From February 1970 to the present, the large-cap stock total return is provided by S&P Dow Jones Indices, which calculates the total return based on the daily reinvestment of dividends on the ex-dividend date. S&P uses closing pricing from stock exchanges in its calculation. Prior to February 1970, the total return for a given month was calculated by summing the capital appreciation return and the income return The capital appreciation component of the large-cap stock total return is the change in the S&P 500 index as reported by S&P Dow Jones Indices from March 1928 to December 2017, and in Standard & Poor's *Trade and Securities Statistics* from January 1926 to February 1928. From February 1970 to December 2017, the income return was calculated as the difference between the total return and the capital appreciation return. From January 1926 to January 1970, quarterly dividends were extracted from rolling yearly dividends reported quarterly in S&P's *Trade and Securities Statistics*, then allocated to months within each quarter using proportions taken from the 1974 actual distribution of monthly dividends within quarters.

[7] "Small Stock" in this context refers to a specific data series created by Ibbotson Associates to represent smaller market capitalization (i.e., small-cap) stocks. "Small-cap" stocks can be represented in a variety of ways, including the aforementioned Ibbotson Associates "small stock" series, or the CRSP 10th decile (as is done later in this article).

[8] The small stock premium is calculated arithmetically here. Arithmetic calculation of premia is typically done when developing forward-looking long-term inputs for MVO analyses, wealth forecasting, or discount rates. The small stock premium can also be calculated on a geometric basis as (1+Small Stock Total Return) ÷ (1+Large Stock Total Return) –1. See: *2018 Stocks, Bonds, Bills, and Inflation® (SBBI®) Yearbook*, Chapter 4, "Description of the Derived Series", page 4-2. To learn more about or purchase the *Stocks, Bonds, Bills, and Inflation® (SBBI®) Yearbook,* visit: duffandphelps.onfastspring.com/books.

[9] Small-cap companies do not always outperform large-cap companies. However, as the holding period is increased, small-cap companies tend to outperform large-cap companies to an increasingly greater degree. In other words, the *longer* small-cap companies are given to "race" against large-cap companies, the greater the chance that small-cap companies outpace their larger counterparts. For a detailed discussion of this concept, see the Cost of Capital Navigator "Resources" section, *2018 Valuation Handbook—U.S. Guide to Cost of Capital*, Chapter 4, "Basic Building Blocks of the Cost of Equity Capital – Size Premium". Duff & Phelps © 2018. Available at dpcostofcapital.com.

[10] The result of this calculation can vary dependent on the series selected to represent large-cap and small-cap stocks. For example, later in this article a small stock premium is calculated over the same time horizon (1926–2017) using the same measure of large-cap stocks (the S&P 500 total return index), but a different measure of small-cap stocks (the CRSP 10th decile). The result of that calculation yields a result of 8.13% (see section entitled "Calculating a Small Stock Premium (i.e., a Non-Beta-Adjusted Size Premium) Using CRSP Decile 10".

[11] "Premia" is the plural of "premium".

[12] For a detailed discussion of the CRSP Size Premia Study, and the Risk Premium Report Study, see the Cost of Capital Navigator "Resources" section, *2018 Valuation Handbook—U.S. Guide to Cost of Capital*, Chapter 7, "The CRSP Decile Studies and the Risk Premium Report Studies—A Comparison". Duff & Phelps © 2018. Available at dpcostofcapital.com.

[13] Finance professionals use the term equity risk premium interchangeably with market risk premium (MRP, or RP_m) and equity market risk premium (EMRP).

[14] The Center for Research in Securities Prices (CRSP) constructs 10 market-capitalization-weighted deciles that are then sorted by market cap. CRSP decile 1 is comprised of the largest companies, and CRSP decile 10 is comprised of the smallest companies. The CRSP deciles are comprised of publicly traded U.S. companies from the NYSE, the NYSE MKT, and the NASDAQ exchanges. To learn more about CRSP, visit www.CRSP.com. The CRSP standard market-capitalization-weighted deciles were used to calculate size premia in Ibbotson Associates/Morningstar *SBBI® Valuation Yearbook* (1999–2013), the Duff & Phelps *Valuation Handbook—U.S. Guide to Cost of Capital* (2014–2017), and now in the online Cost of Capital Navigator (2018 and subsequent years) at dpcostofcapital.com.

[15] Difference due to rounding. Using two decimals of precision (as shown here), the result is 9.83% (1.39 x 7.07%). However, using full precision (i.e., all decimals), this result is 9.84%. We note this because "9.84%" is the actual value used as of December 31, 2017 in these calculations as published in the Cost of Capital Navigator at dpcostofcapital.com.

[16] Difference due to rounding. Using two decimals of precision (as shown here), the difference is 5.36% (15.20% – 9.84%). However, using full precision (i.e., all decimals), the difference is 5.37%. We note this because "5.37%" is the actual size premia calculated for CRSP Decile 10 as of December 31, 2017, as published in the Cost of Capital Navigator at dpcostofcapital.com.

[17] See: Roger J. Grabowski (*2018*) The Size Effect Continues to Be Relevant When Estimating the Cost of Capital. *Business Valuation Review: Fall 2018*, Vol. 37, No. 3, pp. 93-109. See also: Roger G. Ibbotson and Daniel Y.-J. Kim, "Risk and Return within the Stock Market: What Works Best?" working paper, January 8, 2016. Available at www.zebracapital.com.

[18] The *SBBI® Yearbook* has been published for over 30 years. The *SBBI® Yearbook* does not provide extensive valuation data or methodology. The *SBBI® "Classic" Yearbook* was published by Morningstar, Inc. from 2007 through 2015, and by Ibbotson Associates in years prior to 2007. Starting with the 2016 edition, the *Stocks, Bonds, Bills, and Inflation® (SBBI®) Yearbook* has been produced by Duff & Phelps (the word "Classic" was dropped from the book's title). To learn more about or purchase the *Stocks, Bonds, Bills, and Inflation® (SBBI®) Yearbook,* visit: duffandphelps.onfastspring.com/books.

[19] Our previous discussion of the small stock premium was in the context of the traditional way this statistic has been calculated in the *Stocks, Bonds, Bills, and Inflation (SBBI) "Classic" Yearbook*, and so the Ibbotson Associates Small Company Stock total return index was used as the proxy for small-cap stocks for that calculation, as is done in that book. In this section, however, we are discussing the small stock premium and beta-adjusted size premia in the context of the CRSP deciles, and so a different proxy for small stocks is necessarily being used (CRSP decile 10).

[20] An equivalent calculation can be accomplished using any of the ten CRSP deciles; for the examples in this section we will develop a small stock premium for CRSP decile 10 to facilitate easy comparison to our earlier development of a beta-adjusted size premium for CRSP decile 10.

[21] Roger, G. Ibbotson, *1995 Stocks, Bonds, Bills, and Inflation® (SBBI®) Yearbook* (Ibbotson Associates, 1995), Chapter 8, "Estimating the Cost of Capital or Discount Rate", page 155.

Roger G. Ibbotson is Professor in the Practice Emeritus of Finance at Yale School of Management. He is also chairman and CIO of Zebra Capital Management, LLC, an equity investment and hedge fund manager. He is founder, advisor and former chairman of Ibbotson Associates, now a Morningstar Company. He has written numerous books and articles including Stocks Bonds Bills and Inflation with Rex Sinquefield (updated annually) which serves as a standard reference for information and capital market returns.

Professor Ibbotson conducts research on a broad range of financial topics, including popularity, *liquidity, investment returns, mutual funds, international markets, portfolio management, and valuation. He has recently published The Equity Risk Premium and Lifetime Financial Advice. He has also co-authored two books with Gary Brinson, Global Investing and Investment Markets. He is a regular contributor and editorial board member to both trade and academic journals.*

Professor Ibbotson serves on numerous boards including Dimensional Fund Advisors' funds. He frequently speaks at universities, conferences, and other forums. He received his bachelor's degree in mathematics from Purdue University, his MBA from Indiana University, and his PhD from the University of Chicago where he taught for more than ten years and served as executive director of the Center for Research in Security Prices.

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James P. Harrington is a Director at Duff & Phelps. He is a leading contributor to Duff & Phelps' efforts in the development of studies, surveys, online content and tools, firm-wide valuation models, data distribution platforms, and published thought leadership. Mr. Harrington is a co-author of the Duff & Phelps "Valuation Handbook" series and a developer of the online "Cost of Capital Navigator" platform (dpcostofcapital.com), along with colleagues Roger Grabowski and Carla Nunes.

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KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 70

Responding Witness: Adrien M. McKenzie

Q-70. Refer to McKenzie Testimony, Exhibit No. 8. Explain whether the average utility bond yields on page 3 of 4 are Baa rated utility bond yields and whether they are the same bonds as represented in Average Utility Bond Yields of 3.10 percent and 4.12 percent listed on pages 1 of 4 and 2 of 4 respectively. If not:

a. For page 1 of 4, show the calculation in footnote (b), and explain why it is reasonable to average the yield on all utility bonds and a specific subset for a current average utility bond yield of 3.01 percent, and why that difference can be applied to a different specific bond subset.

b. For page 2 of 4, show the calculation in footnote (b), and explain why it is reasonable to average the yield on all utility bonds and a specific subset for a forecasted average utility bond yield of 4.12 percent, and why that difference can be applied to a different specific bond subset.

c. For pages 1 of 4 and 2 of 4, explain why different bond subsets (Baa and A) were used in the calculations described in footnote (b).

d. Refer to McKenzie Testimony, Table 4, page 60. Explain whether the bond data listed in the table are the same as used in Exhibit No. 8, page 1 of 4 and page 2 of 4.

e. Provide a copy of the source documents for Table 4.

A-70.

a. Calculations underlying the average utility bond yield of 3.01% and the average yield on Baa utility bonds of 3.37% are contained at tab "Bond Yields" in the Excel File identified as " 2020_Att_KU_LGE_PSC_1-56_Exhibit_McKenzie_2-12.xlsm" which is provided in response to PSC 1-56. The average yield on all utility bonds was used as the basis for developing the adjusted risk premium because this measure best reflects the average ratings of the utility industry over the long historical horizon of the study period. To better reflect the average risks of this proxy group, the adjusted risk premium was combined with the current average yield on Baa-rated utility bonds to compute the estimated cost of equity.

b. Calculations underlying the average projected utility bond yield of 4.45% and the average projected yield on Baa utility bonds of 5.09% are contained at tab "Bond Yields" in the Excel File identified as " 2020_Att_KU_LGE_PSC_1-56_Exhibit_McKenzie_2-12.xlsm" which is provided in response to PSC 1-56. Please refer to the response to subpart (a) regarding the use of the average utility bond yields and Baa subset.

c. As indicated in footnote (b) to pages 1 and 2 of Exhibit No. 8, the bond yield averages refer to those for all utility bonds and Baa-rated utility bonds. Please refer to the response to subpart (a), which explains why different bond subsets were used in the calculations.

d. No. Table 4 presents average forecasted yields on 10-year and 30-year Treasury bonds, Aaa-rated corporate bonds, and Aa-rated utility bonds based on published projections from the cited sources. The bond yields referenced in Exhibit No. 8, page 1 of 4 are six-month average yields on public utility bonds rated Aa, A, and Baa, as well as six-month average yields on Baa-rated utility bonds. Page 2 of 4 of Exhibit No. 8 references projected yields over the 2021-2025 time period for public utility bonds rated Aa, A, and Baa, as well as Baa-rated utility bonds. The derivation of these projected yields is provided at tab "Bond Yields" in the Excel File identified as " 2020_Att_KU_LGE_PSC_1-56_Exhibit_McKenzie_2-12.xlsm" which is provided in response to PSC 1-56.

e. The source documents for Table 4 are provided as files "WP-31," "WP-32," "WP-34," and "WP-35," to Mr. McKenzie's workpapers, which are provided in response to PSC 2-61.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 71

Responding Witness: Adrien M. McKenzie

Q-71. Refer to McKenzie Testimony, Exhibit No. 8, page 3. Confirm that over the 45-year study period, the data in the Allowed ROE column is based upon state jurisdictional electric or electric and gas combination utilities only. If not, explain what other types of utilities are included in the data set.

A-71. Confirmed.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 72

Responding Witness: Adrien M. McKenzie

Q-72. Refer to McKenzie Testimony, page 62, lines 5–23, through page 63, lines 4–13.

a. Explain why the argument put forth in the testimony opposing the use of quarterly ROE observations is not also applicable to the use of annual average ROEs.

b. Confirm that each annual average observation used in Exhibit No. 8 is comprised of individual and, hence, quarterly awarded ROE observations.

A-72.

a. Mr. McKenzie's testimony at page 63, lines 4-13 addresses this issue. As explained there, consideration of the entire available data set over a 44-year horizon is not unduly influenced by the circumstances specific to an isolated statistic based on a single calendar quarter. In addition, the risk premium analyses presented in Exhibit No. 8 accounts for the impact of changes in capital market conditions by adjusting equity risk premiums for the empirical relationship with bond yields.

b. The annual average allowed ROEs reported in RRA Regulatory Focus are based on the ROEs allowed in individual rate proceedings during each calendar year. Quarterly average ROE observations are based on similar data, but limited to a specific quarterly period.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 73

Responding Witness: Adrien M. McKenzie

Q-73. Refer to McKenzie Testimony, page 67, lines 4–24, through page 68, lines 1–8.

a. Explain whether and how flotation costs are recovered such that investors who invest in nonregulated competitive industries have the opportunity to earn their required ROE.

b. Explain the extent to which investors' required ROEs for holding company stock are influenced by the nonregulated operations of holding companies, which include regulated utilities, such as LG&E and KU.

A-73.

a. Unlike regulated utilities, firms in the competitive sector are not regulated on the basis of the book value of their investment and are free to set their own prices, subject to market forces. As a result, the fact that a portion of stock proceeds is not reflected in rate base or otherwise accounted for in the revenue requirements used to establish prices has no direct relevance in the nonregulated sector.

b. While the firms included in Mr. McKenzie's proxy group are regarded by the investment community as primarily regulated utilities, investors' required ROEs for holding company stocks would consider the risks and expectations for both regulated and unregulated operations.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 74

Responding Witness: Christopher M. Garrett

Q-74. Refer to the Direct Testimony of Christopher M. Garrett (Garrett Testimony) page 23, lines 23–24, and page 24, line 1. For the uncollectable account percentages, explain how KU accounted for the moratorium on disconnections from Case No. 2020-00085.[20]

A-74. KU did not account for the moratorium on disconnections from Case No. 2020-00085 in the uncollectable account percentages for the forecasted test period.

As discussed in the Direct Testimony of Kent W. Blake (page 5, lines 17-21, and page 6, lines 1-6), KU and LG&E are using a 5-year historical average (2015-2019) which does not reflect the COVID-19 pandemic and resulting recession. This decision resulted in a reduction in the revenue requirements in this proceeding of $5.1 million (KU $2.2 million, LG&E Electric $2.4 million, and LG&E Gas $0.5 million). The Companies recognize there is uncertainty around the ultimate size of the expected increase in bad debts with the moratorium on disconnects having just been lifted last month. In the event the Companies ultimately experience any significant increase in bad debt expense resulting from restrictions put in place during the 2020 pandemic, the Companies would expect to file, and the Commission to fairly consider, a request for a regulatory asset for any expenses significantly beyond that embedded in base rates during these proceedings.

[20] Case No. 2020-00085, Electronic Emergency Docket Related to the Novel Coronavirus COVID-19, (Ky. PSC Mar. 16, 2020).

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 75

Responding Witness: Robert M. Conroy

Q-75. Refer to the Direct Testimony of Robert M. Conroy (Conroy Testimony), page 9, lines 21–23. LG&E proposed to make a post-case filing ten days prior to the effective date of the true-up charge or credit through the post-case filing.

a. Explain if KU would file the true-up through the Commission's electronic tariff filing system.

b. Explain why KU would not file at least 30 days prior given the proposed true up month is 90 days after the completion of the proposed surcredit.

A-75.

a. Consistent with other adjustment clause filings that do not require tariff updates to reflect the current billing factor (e.g., FAC, OSS, and ECR), KU proposes making a post-case filing in this proceeding in order to document the calculation of the true-up charge or credit.[21] Because the Commission has the opportunity to approve the methodology being used to calculate the true-up in this proceeding, this filing is simply an informational update to the Commission that provides the results of the true-up calculations.

b. Because KU does not consider this to require a tariff filing and other adjustment clause filings require KU to file supporting documentation for changes in billing factors at least 10 days prior to the effective date, KU proposes to follow the same filing requirement as its other adjustment clauses.[22] See also the response to Question No. 76.

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[21] *See* 807 KAR 5:056 Sec. 2(4) ("The monthly fuel adjustment shall be filed with the commission no later than ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustment."); Kentucky Utilities Company, P.S.C. No. 19, Original Sheet No. 88 ("The combined monthly FAC and OSS factor shall be filed with the Commission ten (10) days before it is scheduled to go into effect[.]"); KRS 278.183 ("The amount of the monthly environmental surcharge shall be filed with the commission ten (10) days before it is scheduled to go into effect[.]").

[16] *Id*.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 76

Responding Witness: Robert M. Conroy

Q-76. Refer to the Conroy Testimony, page 10, lines 5–7. Explain why KU choose the true-up period to occur in the 15th month, 90 days after the completion of the proposed surcredit.

A-76. The timing of the true-up calculation was determined based on when the billing cycle will be complete for the last month of the 12-month period during which the Economic Relief Surcredit will be effective. In other words, if the initial Economic Relief Surcredit terminates effective with services rendered July 1, 2022, customer billing cycles that overlap this time period must have time to complete before the last of the initial Economic Relief Surcredit is credited to customer bills (expected to be the end of August 2022, which is the 13th month). In the 14th month (expected to be September 2022), KU will then have access to all of the billing information needed to calculate the total amount of the initial Economic Relief Surcredit credited to customers and make the post-case filing 10 days prior to the effective date of the true-up charge or credit. The effective date coincides with the first day of the first billing cycle in the 15th month (expected to be October 2022).

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information Dated January 8, 2021

Case No. 2020-00349

Question No. 77

Responding Witness: Robert M. Conroy

Q-77. Refer to the Conroy Testimony, page 15, lines 9–21. For the proposed Environmental Cost Recovery (ECR) project eliminations, confirm that these projects would then receive rate recovery based upon the approved base rate WACC in this case, as opposed to the lowered WACC of limited rider mechanisms, and would no longer be subject to the true-up mechanism of the ECR tariff.

A-77. Confirmed. For clarity, if the question is referring to WACC with respect to the authorized return on equity for base rates compared to the authorized return on equity for ECR projects, it is important to note that the ECR projects proposed to be eliminated in this proceeding are currently authorized for the same return on equity as current base rates. Also of importance is that the WACC for ECR purposes changes periodically as a result of ECR review case proceedings. While the authorized return on equity does not change without Commission approval, the capital structure and cost of debt could vary in ECR review proceedings. Thus, the WACC used in the ECR tariff could be higher or lower than that used to establish base rates.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 78

Responding Witness: Robert M. Conroy

Q-78. Refer to the Conroy Testimony, page, 15–16, regarding ECR projects. Explain whether KU's proposal to remove the test-year ECR base rate revenue requirement from the ECR revenue requirement would effectively true-up KU's base rates until the next two-year review.

A-78. For the ECR projects proposed to be eliminated, the portion of ECR revenue requirement currently collected as a component of base rates (either in energy or demand depending on the rate class) as the result of prior ECR "roll-ins" from two-year ECR review proceedings is net neutral from a base rate perspective. The component of base rates previously assigned as ECR revenue will now be reflected solely as base rate revenue to offset the costs now included in the base rate revenue requirement and thus will not be subject to the true-up mechanism of the ECR tariff. For the ECR expense month filing coinciding with the change in base rates from this proceeding, the amount of the monthly ECR revenue requirement collected through base rates will be adjusted to reflect the ECR project eliminations in the same manner that occurred following the ECR project elimination in Case No. 2012-00221.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 79

Responding Witness: Robert M. Conroy / William Steven Seelye

Q-79. Refer to the Conroy Testimony, page 22, lines 3–6.

a. Provide support for adding an evening winter peak time to Rates RTOD-Demand and RTOD-Energy.

b. Provide a bill comparison of the average customer's energy bill portion.

A-79.

a. See pages 21 through 25 of Mr. Seelye's direct testimony.

b. The following table is derived from information found in the filing requirements Tab 66 Schedule M-2.3.

	Average Annual Customer Energy Revenue at Current Rates	Average Annual Customer Energy Revenue at Proposed Rates	Percent Change
KU RTOD-E On-Peak	$369.14	$446.61	21%
KU RTOD-E Off-Peak	$694.80	$741.33	7%
KU RTOD-E Total	$1,063.94	$1,187.94	12%
KU RTOD-D	$2,219.61	$2,282.33	3%

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 80

Responding Witness: Robert M. Conroy

Q-80. Refer to the Conroy Testimony, page 26, lines 4–8. Mr. Conroy states that under the proposed NMS-2, customer-generators who size their generating systems to align the generation with their own consumption will receive that same value for the energy consumed as if they were under Rider NMS-1. Provide support to this statement.

A-80. As long as a customer's consumption exceeds the customer's energy production at all times, the customer's value of energy will be the same under NMS-1 and NMS-2; namely, each kWh produced will offset a kWh the customer otherwise would have consumed and for which the customer would have paid the full retail rate. Only when the generation is greater than consumption does the value of energy differ between NMS-1 and NMS-2; excess generation offsets consumption in the same or future billing periods on a one-to-one kWh basis under NMS-1, whereas NMS-2 values excess generation at the SQF rate and provides a bill credit to the customer for that value.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 81

Responding Witness: Robert M. Conroy

Q-81. Refer to the Conroy Testimony, page 26. Explain whether KU considered allowing customers that take service under time-of-use rates to be compensated for production based on the time-differentiated rate set forth in Standard Rate Rider SQF.

A-81. For simplicity, the Company only considered compensation for energy fed back on the grid for net-metering customers at the non-time-differentiated rate under Rider SQF. The time periods under the time-differentiated rates for Rider SQF differ from the time periods used in the various time-of-use rate schedules.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 82

Responding Witness: Robert M. Conroy

Q-82. Refer to the Conroy Testimony, page 28, lines 11–18. Explain whether the Commission will still approve the Net Metering application.

A-82. Yes. As noted in the testimony, the Companies will continue to file any changes to the net metering application forms with the Commission under the administrative case concerning net metering guidelines. The existing application form removed from the tariff has not been modified from previous Commission approval.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 83

Responding Witness: Eileen L. Saunders

Q-83. Refer to the Conroy Testimony, page 30, line 10. For the contracts for Rate PS, state at whose discretion the initial term is assigned.

A-83. Customer Services, specifically the Business Service Center and/or Major Accounts team.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 84

Responding Witness: Eileen L. Saunders

Q-84. Refer to the Conroy Testimony, page 30, lines 5–10, which discusses the revision to Rate PS to remove the mandatory requirement for a contract, thus allowing KU to require a contract for an initial term at their discretion. Explain how KU would decide whether or not to require a contract for an initial term to a prospective Rate PS customer.

A-84. The Business Service Center and/or Major Accounts team determines when a PS customer needs to sign an initial contract. Such contracts are required only if the customer's electric service requires additional facilities or other ancillary services, such as those under the excess facilities or redundant capacity riders. This contract functions to assist the Customer Services representative and the customer to see the whole picture in terms of all components of the customer's bill.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 85

Responding Witness: Robert M. Conroy

Q-85. Refer to the Conroy Testimony, page 33, lines 14–23, and page 34, lines 1–7.

a. Regarding the legacy customers in Rates GS and PS, confirm this does not remove all legacy customers.

b. As KU's proposed tariff has been suspended up to and including June 30, 2021, state the usage period that will be examined to determine whether legacy customers meet the applicable availability requirements of Rates GS and PS.

A-85.

a. Confirmed. This approach will not remove all legacy customers.

b. The Companies will use data for the 12 months ending January 31, 2020, to avoid the effects of COVID on customers' usage data.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
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Case No. 2020-00349

Question No. 86

Responding Witness: John K. Wolfe

Q-86. Refer to the Conroy Testimony, page 35, lines 5–9, which discusses removal costs being incorporated into the Restricted Lighting Service Tariff (Rate RLS) and the circumstances under which a Rate RLS customer who requests removal of an existing Rate RLS lighting system may be required to pay a conversion fee. Explain the circumstances under which a Rate RLS customer who requests removal of a Rate RLS lighting system and subsequently requests installation of an LED replacement would not be required to pay the conversion fee.

A-86. This provision is intended to prevent customers from requesting removal of an RLS fixture and subsequently requesting installation of an LS fixture for the sole purpose of avoiding the conversion fee. On the other hand, the company does not wish to punish customers who in good faith request a removal of an RLS fixture and then subsequently determine they need a new LS fixture at that location. This provision will be applied on a case by case basis by company personnel that work with these customers. An example of when the conversion fee would not be required is if a customer with an overhead fed RLS fixture requests removal because their business is closing indefinitely due to financial hardships. Company's practice will be to remove that fixture. If two years, later that same customer request a new fixture at that business, only LS fixtures will be available and that customer would not be charged a conversion fee.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 87

Responding Witness: John K. Wolfe

Q-87. Refer to the Conroy Testimony, page 35, lines 10–15, which discusses when a Lighting Service Tariff customer must enter into a contract. Explain the reasoning for the additional circumstances under which a contract will be required.

A-87. The goal of this provision is to protect the company in these scenarios where it is making a sizeable investment in new Lighting infrastructure and the customer is making a corresponding financial obligation to the Company. The contract requires the customer to pay the balance of the 5-year contract in the event of early termination and provides an incentive for the customer to maintain its lighting service through the Company long-term. The contract will also help better inform the customer making this commitment of the terms and conditions accompanying that installation. The existing language only requires a contract when additional facilities are required to serve the customer, a requirement that, in part, exists to protect the Company's investment and, in part, to ensure the customer understands what they are agreeing to with the excess facilities charges. It only makes sense to extend this requirement in other scenarios when both parties have a significant financial interest. The Company is not pursuing a contract for every lighting installation due to concerns with operationalizing that requirement and overburdening staff, and to not place unnecessary delays on a straightforward transaction with the customer.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 88

Responding Witness: John K. Wolfe

Q-88. Refer to the Conroy Testimony, page 36, lines 3–6, which discusses the change in the High Volume Application definition in Rate PSA. Explain the extent of additional work required to review wireless attachments when applications are made for more than 30 wireless attachments in a 30-day period.

A-88. The process for reviewing wireless attachments is more time-consuming than wireline applications and goes beyond a review to confirm that safe clearances are maintained between facilities on the pole. The review begins with an assessment of whether an antenna can be safely attached to the targeted pole at all, or if there are electric facilities on the pole that will preclude attachment. It requires checking that the proposed installation method matches the Company's standards, including the meter type and placement, the type and size of conduit and wire to be used, and the type and placement of the required disconnect switch and radiofrequency emissions signage.

If applications are made for more than 30 wireless attachments in a 30-day period, and made by the multiple attaching entities that are currently, the Company will find it difficult to complete all of the reviews—for both wireline and wireless applications—within the time period contained in Rate PSA.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 89

Responding Witness: Robert M. Conroy

Q-89. Refer to the Conroy Testimony, page 37, lines 8–18, which discusses changes to the rates in Rate EVSE and Electric Vehicle Supply Equipment Rider (Rate EVSE-R). Also, refer to the Application, Tab 4, P.S.C. No. 20, Original Sheet No. 41 and P.S.C. No. 20, Original Sheet No. 75. The testimony indicates that Rate EVSE and EVSE-R are being revised to include a rate for the single and dual charger versions of the Level 2 charging stations; however, the only changes being made to the rate section of those two schedules are text changes and the addition of a non-networked charger rate. Explain the discrepancy between the testimony and the proposed tariff.

A-89. The Company inadvertently stated in testimony that Rate EVSE and EVSE-R are being revised to include a rate for the single and dual charger versions of the non-networked Clipper Creek HCS-40 charging station. Only a single version of this unit is to be offered. In this same section, the Company also incorrectly categorized this station as a Level 3 charging station. All existing and proposed EVSE and EVSE-R offerings are Level 2 charging stations. Mr. Seelye's testimony explaining Level 3 charging station rates referenced in this section is related to the rates developed for Rate EVC-Fast.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
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Case No. 2020-00349

Question No. 90

Responding Witness: Eileen L. Saunders

Q-90. Refer to the Conroy Testimony, page 40, lines 10–14, which discusses the situations under which a customer would and would not be charged the initial set-up fee for opting out of AMI. Explain how much notice a customer will receive to elect to opt-out before AMI meter installation at the customer's premises.

A-90. The Companies intend to follow the customer communication schedule found at the top of page 10 of Exhibit ELS-2. Communications in the local area will start roughly six weeks prior to the scheduled meter exchange. There are successive direct customer communications 4 weeks, 2 weeks, and the week of the meter installation. These direct customer communications will include opt-out information to ensure customers have proper notice and adequate time to elect to opt-out. Additionally, customers can proactively elect to opt-out at any time including directly with the meter installation technician on the day of their installation.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 91

Responding Witness: Robert M. Conroy / Eileen L. Saunders

Q-91. Refer to the Conroy Testimony, page 40, line 21, through page 41, line 3, which states that KU may require a customer to opt out if the customer has a history of particularly dangerous or repeated meter tampering and which also states that KU may refuse to allow a customer to opt out if the customer has a history of tampering. Explain how these two statements are not contradictory and how KU will decide whether or not a customer with a history of tampering will be allowed to opt out.

A-91. In the first statement, the Company may require a customer to opt out if the customer has a history of particularly dangerous or repeated meter tampering. An example of this scenario would be a customer splicing additional service drops, e.g. for a previously unserved garage, from their home's service drop. Such cases, though rare, can present dangerous hazards to the public and can be difficult to detect remotely via AMI. Therefore, it may become necessary for the Company to regularly visit those customers' premises to ensure safe, reliable, and accurate services, and it is appropriate for the customers who necessitate such visits to pay their cost through AMI Opt-Out charges.

In the second statement, the Company is establishing that there are also safety, reliability, and accuracy reasons to deny a customer request to be opted out. Conroy Testimony, page 41, lines 4 through lines 6 goes on to identify such scenarios whereby a customer may have opted out and the Company must opt the customer back into the AMI offering.

The Company notes that both statements are similar language to what is included in Duke Energy Kentucky's tariffs and were approved in Case No. 2017-00321 and Case No. 2019-00271.[23] The Company will use the frequency and severity of the events described in Conroy Testimony, page 41, lines 4 through 6, as criteria to determine each course of action. The tariff states that after a year a customer request to opt out would be granted should there not be any evidence of additional events within that year.

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[23] See https://www.duke-energy.com/_/media/pdfs/rates/ky/sheetno91reconchg.pdf?la=en and https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-ky/sheet-no-74-rider-amo-ky-e.pdf?la=en

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 92

Responding Witness: Eileen L. Saunders

Q-92. Refer to the Conroy Testimony, page 40, lines 21–23, and page 41, lines 1–6.

a. Provide the annual number of tampering and repeated tampering issues KU experienced for the past three years.

b. Provide the decision metric that determines whether KU refuses to allow a customer to opt out of the proposed AMI meter due to a history of tampering.

A-92.

a.

Year	Accounts with Tampering	Accounts with Tampering More than Once
2018	1,436	119
2019	1,066	92
2020	299	23

b. See the response to Question No. 91.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 93

Responding Witness: Robert M. Conroy

Q-93. Refer to the Conroy Testimony, page 44, lines 8–9, which discusses KU's proposal to limit their liability for damages resulting from their meter pulse data or the service in general.

a. Generally, explain why it would be appropriate to include language shielding a regulated utility from potential liability in a tariff.

b. Specifically, explain why KU should limit their liability in relation to meter pulse service, include in this explanation a discussion KU's objective for the inclusion of liability limiting language related to meter pulse data or service.

A-93.

a. Liability-limitation clauses are common in many contracts, including KU's standard contract for meter pulse service. A utility's tariff is effectively its standing contract with all who would do business with it, with the notable difference that it is a contract that is governed by the relevant administrative agency and can change only with that agency's approval. Not to have liability-limitation provisions in a utility's tariff could lead to ruinous liability for the utility, which is bound by law to serve all who come; regulated utilities do not get to choose their customers, but rather are obligated to serve all who comply with the terms of the approved tariff. Unlimited liability would pose a grave risk not only to the utility but also its customers, whose service and rates could ultimately be affected by such liability.

Moreover, the Commission has approved liability-limitation provisions in KU's and LG&E's tariffs for decades.[24] The Commission has approved liability-limitation provisions in other utilities' tariffs, as well.[25]

b. Liability limitation is ordinarily a term included in KU's contracts for meter pulse service. Including the liability limitation provision in the tariff helps ensure customers are aware of the provision before seeking the service from KU, and it reduces the length of the meter pulse contract.

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[24] *See, e.g.*, Louisville Gas and Electric Company, P.S.C. of Ky. Electric No. 5, Original Sheet No. 44 (eff. June 29, 1992; refiled Feb. 21, 2000); Louisville Gas and Electric Company, P.S.C. of Ky. Gas No. 5, Original Sheet No. 30 (eff. June 29, 1992; refiled Oct. 16, 2000); Kentucky Utilities Company, P.S.C. No. 12, Original Sheet No. 245-A (eff. Apr. 18, 1994; refiled Feb. 21, 2000).

[18] *See, e.g.*, Duke Energy Kentucky, Inc., Ky. P.S.C. Electric No. 2, Second Revised Sheet No. 21, Ninth Revised Sheet No. 60, Ninth Revised Sheet No. 66, Ninth Revised Sheet No. 68, Ninth Revised Sheet No. 69, Original Sheet No. 87, and Third Revised Sheet No. 92; Kentucky Power Company, P.S.C. Ky. No. 11, First Revised Sheet No. 2-6, Original Sheet No. 2-15, Original Sheet No. 3-1, Original Sheet No. 16-4, Original Sheet No. 32-4.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 94

Responding Witness: William Steven Seelye

Q-94. Refer to the Conroy Testimony, page 45, lines 2–7. Provide support for the decrease in the Meter Pulse Charge from $24 to $21.

A-94. The cost support for the Meter Pulse Charge is shown on page 12 of Exhibit WSS-19 of the Direct Testimony of William Steven Seelye filed on November 25, 2020, in this proceeding.

The primary reason for the proposed decrease in the monthly charge is a reduction in the total cost of the equipment used to provide the service. In KU's previous rate case (Case No. 2018-00294), the equipment cost – including the pulse relay, pulse initiator board, and relay enclosure – was estimated to be $400 per installation. KU now estimates equipment cost to be $305 per installation.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 95

Responding Witness: Robert M. Conroy

Q-95. Refer to the Conroy Testimony, page 45, lines 13–23.

a. Explain why KU is proposing to change the language so that a legal holiday that falls on a weekday will be considered a weekday for purposes of determining an on-peak period.

b. Explain why KU is proposing to change the language from actual variable fuel expenses to actual fuel expenses, excluding those that are fixed and nonvariable.

A-95.

a. The change in classification of a legal holiday that falls on a weekday within the SQF tariff to a weekday aligns the application for billing with the Company's other time-of-day tariff offerings.

b. Currently, due to FERC Uniform System of Accounts requirements, certain fixed and nonvariable costs, such as long-term lease contracts for rail cars used to transport coal, are consumed (that is, expensed) based on unit performance during the month. Therefore, these costs are considered to be variable for purposes of determining avoided energy costs pursuant to the LQF Tariff when in reality, they are fixed. The purpose of the proposed change in language is to allow the Company to exclude fuel related costs that are fixed and nonvariable when originally booked to the fuel inventory account from the determination of avoided energy costs since these costs are not avoidable by the Company.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information Dated January 8, 2021

Case No. 2020-00349

Question No. 96

Responding Witness: Robert M. Conroy

Q-96. Refer to the Conroy Testimony, page 45, lines 16–23, which discusses a change to the definition of hourly avoided energy cost. Explain if this change is strictly for clarification purposes or if this represents a change in how KU determines the hourly avoided energy cost.

A-96. As discussed in the response to Question No. 95, part b, this would represent a change in how the Company determines the hourly avoided energy cost because the non-avoidable fixed and nonvariable fuel costs would no longer be included in the credit provided to LQF customers.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 97

Responding Witness: Robert M. Conroy

Q-97. Refer to the Conroy Testimony, page 46, lines 15–17, which states that Excess Facilities customers who request the facilities be removed are responsible of the actual cost of removing the facilities they ask KU to install. Explain how removal costs are currently recovered from Excess Facilities customers.

A-97. The Company's current tariff and customer contracts are silent regarding removal costs and removal costs were not included in the determination of the excess facility rate. As such on the rare event a customer requests to have these facilities removed, the Company has incurred the cost. This proposed change will allow for the appropriate recovery of the cost incurred from the Excess Facilities customer.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 98

Responding Witness: Robert M. Conroy

Q-98. Refer to the Conroy Testimony, page 50, lines 6–9, which explains that the definition of Single Family Unit is being revised. Explain whether separately metered vacation rental, boat slips, or campers are currently eligible for residential service. If so, explain the reason for the change.

A-98. Separately metered vacation rental, boat slips, or campers are not currently eligible for residential service. Inclusion of this language is to eliminate customer confusion.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 99

Responding Witness: Robert M. Conroy

Q-99. Refer to the Conroy Testimony, RMC-1. For the amount of the unprotected excess ADIT, confirm that this is the balance as of July 1, 2021.

A-99. Confirmed. The amount of non-plant unprotected excess ADIT included in Exhibit RMC-1 represents the balance as of July 1, 2021.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 100

Responding Witness: Robert M. Conroy

Q-100. Provide a table illustrating the customer charges for the last six rate cases as well as the percentage increase between each rate case.

A-100. See attached.

KU							
		RS		RTOD-E		RTOD-D	
Rate Case	Case Number	Customer Charge per month	% Change	Customer Charge per month	% Change	Customer Charge per month	% Change
2020 Rate Case	2020-00349	$ 18.57	15%	$ 18.57	15%	$ 18.57	15%
2018 Rate Case	2018-00294	$ 16.13	32%	$ 16.13	32%	$ 16.13	32%
2016 Rate Case	2016-00370	$ 12.25	14%	$ 12.25	14%	$ 12.25	14%
2014 Rate Case	2014-00371	$ 10.75	0%	$ 10.75		$ 10.75	
2012 Rate Case	2012-00221	$ 10.75	26%	N/A		N/A	
2010 Rate Case	2009-00548	$ 8.50		N/A	-	N/A	

KU							
		VFD		GS-Single Phase		GS-Three Phase	
Rate Case	Case Number	Customer Charge per month	% Change	Customer Charge per month	% Change	Customer Charge per month	% Change
2020 Rate Case	2020-00349	$ 18.57	15%	$ 41.09	30%	$ 65.44	30%
2018 Rate Case	2018-00294	$ 16.13	32%	$ 31.66	0%	$ 50.53	0%
2016 Rate Case	2016-00370	$ 12.25	14%	$ 31.50	26%	$ 50.40	26%
2014 Rate Case	2014-00371	$ 10.75	0%	$ 25.00	25%	$ 40.00	14%
2012 Rate Case	2012-00221	$ 10.75	26%	$ 20.00	14%	$ 35.00	8%
2010 Rate Case	2009-00548	$ 8.50	-	$ 17.50	-	$ 32.50	-

KU							
		AES Single-Phase		**AES Three-Phase**		**PS-Secondary**	
Rate Case	Case Number	Customer Charge per month	% Change	Customer Charge per month	% Change	Customer Charge per month	% Change
2020 Rate Case	2020-00349	$ 85.23	0%	$ 140.01	0%	$ 90.10	0%
2018 Rate Case	2018-00294	$ 85.23	0%	$ 140.01	0%	$ 90.10	0%
2016 Rate Case	2016-00370	$ 85.00	240%	$ 140.00	250%	$ 90.00	0%
2014 Rate Case	2014-00371	$ 25.00	25%	$ 40.00	14%	$ 90.00	0%
2012 Rate Case	2012-00221	$ 20.00	14%	$ 35.00	8%	$ 90.00	0%
2010 Rate Case	2009-00548	$ 17.50	-	$ 32.50		$ 90.00	-

KU							
		PS-Primary		TODS		TODP	
Rate Case	Case Number	Customer Charge per month	% Change	Customer Charge per month	% Change	Customer Charge per month	% Change
2020 Rate Case	2020-00349	$ 240.15	0%	$ 222.80	11%	$ 329.94	0%
2018 Rate Case	2018-00294	$ 240.15	0%	$ 200.28	0%	$ 329.94	0%
2016 Rate Case	2016-00370	$ 240.00	20%	$ 200.00	0%	$ 330.00	10%
2014 Rate Case	2014-00371	$ 200.00	18%	$ 200.00	0%	$ 300.00	0%
2012 Rate Case	2012-00221	$ 170.00	89%	$ 200.00	0%	$ 300.00	0%
2010 Rate Case	2009-00548	$ 90.00	-	$ 200.00	-	$ 300.00	-

KU							
		RTS		FLS - Primary		FLS Transmission	
Rate Case	Case Number	Customer Charge per month	% Change	Customer Charge per month	% Change	Customer Charge per month	% Change
2020 Rate Case	2020-00349	$ 1,499.96	0%	$ 329.94	0%	$ 1,499.96	0%
2018 Rate Case	2018-00294	$ 1,499.96	0%	$ 329.94	0%	$ 1,499.96	0%
2016 Rate Case	2016-00370	$ 1,500.00	50%	$ 330.00	-67%	$ 1,500.00	50%
2014 Rate Case	2014-00371	$ 1,000.00	33%	$ 1,000.00	33%	$ 1,000.00	33%
2012 Rate Case	2012-00221	$ 750.00	50%	$ 750.00	50%	$ 750.00	50%
2010 Rate Case	2009-00548	$ 500.00	-	$ 500.00	-	$ 500.00	

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 101

Responding Witness: Eileen L. Saunders / William Steven Seelye

Q-101. Refer to the Direct Testimony of William Steven Seelye (Seelye Testimony), page 11, lines 16–18. Mr. Seelye indicates the importance of the informational purpose of the separation of the energy charge between the variable energy charge and the infrastructure energy.

a. Provide the number of times since the last base rate case where a customer has called KU to inquire about the energy charge components.

b. Provide any customer service representative dialog scripted for questions regarding the energy and infrastructure charges.

A-101.

a The Company does not maintain the requested data. The Company endeavors to make meaningful information available to customers and stakeholders concerning the types of costs recovered through rates regardless of how many customers have actually inquired about the energy cost components of rates.

b. There is no customer service representative dialog scripted for questions regarding the energy and infrastructure charges. See the response to part a.

KENTUCKY UTILITIES COMPANY

**Response to Commission Staff's Second Request for Information
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Case No. 2020-00349

Question No. 102

Responding Witness: William Steven Seelye

Q-102. Refer to the Seelye Testimony, page 14, Table 4. Provide a similar table representing the last five base rate cases.

A-102. Below is a comparison of the percentage of costs broken down by component (customer cost, demand cost, and energy cost) to the percentage of recovery through the proposed rate components (customer charge and energy charge) as filed in the current case and the preceding five KU base rate cases.

CASE NO. 2020-00349

Component	Percentage of Cost	Rate Design
Customer	19.41%	14.5%
Demand	52.61%	0.0%
Energy	27.98%	85.5%

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CASE NO. 2018-00294

Component	Percentage of Cost	Rate Design
Customer	20.9%	11.7%
Demand	46.9%	0.0%
Energy	32.2%	88.3%

CASE NO. 2016-00370

Component	Percentage of Cost	Rate Design
Customer	20.9%	9.3%
Demand	43.0%	0.0%
Energy	36.1%	90.7%

CASE NO. 2014-00371

Component	Percentage of Cost	Rate Design
Customer	19.39%	9.7%
Demand	43.08%	0.0%
Energy	37.53%	90.3%

CASE NO. 2012-00221

Component	Percentage of Cost	Rate Design
Customer	19.36%	8.74%
Demand	41.61%	0.0%
Energy	39.03%	91.26%

CASE NO. 2010-00548

Component	Percentage of Cost	Rate Design
Customer	19.12%	4.83%
Demand	40.78%	0.0%
Energy	40.10%	95.17%

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 103

Responding Witness: William Steven Seelye

Q-103. Refer to the Seelye Testimony, page 24, lines 1–2. Provide KU's electric winter peak and date for the past ten years.

A-103.

Date	KU+ODP Winter Peak (MW)
2/11/2011	4,292
1/13/2012	4,014
2/1/2013	4,193
1/7/2014	5,068
2/20/2015	5,112
1/19/2016	4,415
1/8/2017	4,004
1/2/2018	4,790
1/31/2019	4,352
1/22/2020	3,642

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
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Case No. 2020-00349

Question No. 104

Responding Witness: William Steven Seelye

Q-104. Refer to the Seelye Testimony, page 25, lines 1–9. Explain why KU is proposing to increase the off-peak Energy Charge and decrease the on-peak energy charge for Rate RTOD-Energy.

A-104. The decrease in the on-peak charge for Rate RTOD-Energy is the result of adding four hours to the peak period during the Winter Months. As explained on page 22 of Direct Testimony of William Steven Seelye filed on November 25, 2020, in this proceeding, the Companies are proposing to add four evening hours (i.e., the hours from 6 PM to 10 PM) to the peak period during the Winter Months. This results in spreading peak period costs under Rate RTOD-Energy over a larger number of peak period kWh, thus resulting in a net decrease in the peak period charge, even after considering the proposed increase to peak period revenue. The increase in the off-peak charge for Rate RTOD-Energy reflects the impact of increasing the overall revenue for the rate class.

As shown on page 3 of Schedule M-2.3 for KU, adding four hours to the winter peak period increases the peak period kWh for the test year from 175,576 kWh to 264,443 kWh. Even though the Company is proposing to increase the peak period infra-structure charge revenue from $42,955 to $50,043, the charge is lower ($0.18924 per kWh as proposed versus $0.24465 per kWh currently) because the peak period revenue is spread over a larger number of kWh. In other words, impact of increasing in the peak period kWh more than offsets the increase in peak period revenue.

See also page 25, lines 7-9, of Mr. Seelye's direct testimony.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
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Case No. 2020-00349

Question No. 105

Responding Witness: Eileen L. Saunders

Q-105. Refer to the Seelye Testimony, page 27, lines 4–5.

a. Provide the amount of KU General Service (GS) customers who currently have an AMI meter.

b. Explain if any GS customers have inquired about time of day rates.

A-105.

a. There are currently 247 KU General Service (GS) customers who have an AMI meter as part of the Advanced Metering Systems Customer Service Offering that would be eligible to take service under Rate GTOD-Energy or GTOD-Demand.

b. The Company does not maintain the requested data. However, the Company is proposing this optional rate to give general service customers the option of a time of day rate if they choose to do so.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
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Case No. 2020-00349

Question No. 106

Responding Witness: Eileen L. Saunders

Q-106. Refer to the Seelye Testimony, page 33, lines 3–10. The outdoor sports lighting service (Rate OSL) can have up to 20 participants, but KU only has four. Explain if KU has proactively discussed this rate option with local schools and parks.

A-106. Yes, the Company has proactively discussed this rate option with local schools and parks.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
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Case No. 2020-00349

Question No. 107

Responding Witness: William Steven Seelye

Q-107. Refer to the Seelye Testimony, page 34, lines 4–13. Explain why KU is proposing to decrease the revenue from Rate OLS by approximately 5 percent.

A-107. KU is proposing a 5 percent decrease for Rate OSL because of the high rate of return for the rate class as determined by the Company's cost of service studies. Based on the LOLP cost of service study, the rate of return for Rate OSL is 30.32%. Based on the 12 CP and 6 CP cost of service studies, the rate of return for Rate OSL is 30.27% and 30.28%, respectively. The rate of return for Rate OSL is the highest of any rate class. See Exhibit WSS-22, page 1 of 2.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
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Case No. 2020-00349

Question No. 108

Responding Witness: William Steven Seelye

Q-108. Refer to the Seelye Testimony, page 47, line 12. Provide the subsidy that KU residential customers are paying to current net metering customers.

A-108. KU's residential customers (non-net metering residential customers) are currently paying two types of subsidies to net metering customers.

(1) With the first type of subsidy, residential and other non-net-metering customers are currently paying subsidies to net metering customers because of the overcompensation provided by the Companies for the energy that net metering customers supply to the grid. If a net metering customer generates more power than the customer uses during the month, the customer is currently compensated at a rate equal to the energy charge in the customer's underlying rate.

If the customer is a residential customer served by KU, the customer is currently compensated at an energy rate of approximately \$0.09950 per kWh, including cost trackers. However, this is several times the cost for which KU could otherwise generate the energy itself or purchase the energy from a third party in the wholesale power market. Based on its avoided cost-based rate set forth in the Small Capacity Cogeneration and Small Power Production Qualifying Facilities (Rate SQF), KU could generate or procure the energy at a cost of only \$0.02173 per kWh. Therefore, KU is currently overcompensating net metering customers \$0.07777 per kWh for the energy that they supply to the grid, which is a cost other customers ultimately bear. For the 12 months ended November 30, 2020, KU residential net metering customers supplied 1,789,151 kWh to the grid at an average credit of \$0.09950, and thereby received billing credits of \$178,021. But KU could have generated the power for only \$38,878 (1,789,151 kWh x \$0.02173 per kWh = \$38,878). Therefore, KU overcompensated its net metering customers by \$139,142 (\$178,021 - \$38,878 = \$139,143).

Although the question does not ask about subsidies received by net metering customers served under Rate GS, the amount is \$59,611. The subsidies received by net metering customers in other rate classes are negligible.

Therefore, the total subsidies provided to KU's net metering customers served under Rates RS and GS by overcompensating these customers for the power they put on the grid are $198,754.

With the introduction of NMS-2, this first subsidy will be eliminated for all new net metering customers. While these subsidies are relatively small in relation to KU's total revenue, they would be expected to increase significantly without the introduction of NMS-2. In the past three years, the amount of net metering generation nameplate capacity for Rates RS and GS has more than tripled on the KU system (from 1,677.0 kW in 2017 to 5,135.9 kW as of November 2020). KU is currently experiencing a 45% growth in the amount of net metering capacity on its system. Under KRS 278.466, net metering capacity is capped at 1% of KU's peak load during a calendar year. If this cap is reached on KU's system, then this first subsidy would increase to over $1.5 million annually. If the current rate of growth in distributed generation nameplate capacity on KU's system were to continue to increase at the current rate, the 1% cap would be reached in approximately 6 years. The large increase in the past few years illustrates how quickly costs can be shifted from one group of customers to another without regard to the underlying cost of service and the associated subsidies.

(2) With the second type of subsidy, residential customers are also currently paying subsidies due to the inability of a two-part rate (consisting of only a customer charge and energy charge) to reflect the actual cost of providing service to net metering customers. As explained in Mr. Seelye's direct testimony, net metering customers can reduce the amount of energy they purchase without reducing the maximum demands they place on the system. With a two-part rate consisting of only a customer charge and an energy charge, a net metering customer will pay lower demand costs recovered through the energy charge even though the demand costs incurred to serve a net metering customer are not typically lower than for a non-net-metering customer. This second type of subsidy is addressed on pages 46-64 of Mr. Seelye's direct testimony.

KU estimates that residential net metering customers are currently receiving $46,399 in annual subsidies from this second type of subsidy, which again is a subsidy other customers ultimately pay. (It should be noted that this estimate is based on a limited amount of load data that KU has for residential net metering customers. The load data used to develop these estimates are not based on a statistically valid sample, particularly considering the large variance in the usage patterns for net metering customers.)

Kentucky Utilities

Annual Fixed Demand Related Costs to Service Residential Net Metering Customer	$	907.09
Average kWh of Net Metering Customer		12,023.95
Proposed Infrastructure Charge	$	0.0675
Revenue Received per Net Metering Customer		811.62
Cost Subsidy Receive by Net Metering Customers	$	95.47
Number of Net Metering Customers		486
Annual Subsidy from Lower Residential Net Metering Customer Load Factor	$	46,399

As explained in Mr. Seelye's direct testimony, KU is not proposing to address this second subsidy at this time but plans to continue to study the issue in the future. However, KU expects these subsidies to increase as more customers install solar panels and possibly other distributed generation facilities. If the 1% cap on net generation capacity is reached on KU's system, then this second subsidy would increase to over $400,000 annually. As noted previously, if the current rate of growth in distributed generation nameplate capacity on KU's system were to continue to increase at the current rate, the 1% cap would be reached in approximately 6 years. This again illustrates how quickly costs can be shifted from one group of customers to another without regard to the underlying cost of service and the associated subsidies.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
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Case No. 2020-00349

Question No. 109

Responding Witness: William Steven Seelye

Q-109. Refer to the Seelye Testimony, page 47.

a. Explain whether a phased approach to implementing KU's preferred net metering rate design would discourage investment in distributed generation in the interim, given that customers taking service under Tariff NMS-2 would risk the change in rate design, at an uncertain point in the future, affecting the economic analysis of the investment.

b. Explain whether meter upgrades would be necessary to provide four- part rates for Tariff NMS-2.

A-109.

a. By "preferred net metering rate design", it is assumed that the question is referring to the implementation of a four-part rate schedule as discussed on pages 46-64 of Mr. Seelye's testimony.

The Companies do not believe that phasing in a four-part rate will discourage investment in distributed generation. It should also be clear to customers, and to intervenors that represent net-metering or solar generation customers, that the Companies' will continue to investigate changes to their rate designs that more accurately reflect the cost of serving customers. While a four-part rate consisting of a Basic Service Charge, Energy Charge, Peak Demand Charge, and Base Demand Charge would more accurately reflect the cost providing service to net metering customers, the Companies' have made no decision if or when they will implement such a rate design.

It should also be noted that utilities in other jurisdictions are taking a gradual approach to implementing three- and four-part rate designs for net-metering and non-net-metering customers. For example, some utilities are introducing three- and four-part rates that include demand charges that are lower than fully cost-based demand charges. Yet, other utilities are choosing to implement fully cost-based three- and four-part rate designs for net-metering and non-net-metering customers. KU and LG&E plan to continue to study the practicability of implementing demand rates for residential net-metering and other customers.

b. Upon implementation of the Company's Advanced Metering Infrastructure ("AMI") program, additional meter upgrades would not be required to implement four-part rates as described in Mr. Seelye's direct testimony.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
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Case No. 2020-00349

Question No. 110

Responding Witness: Robert M. Conroy

Q-110. Refer to the Seelye Testimony, page 65, lines 1–3, which discusses KU's commitment in Case No. 2015-00355 that Level 2 charging service would not result in increased charges to the Companies' customers. Indicate whether KU is willing to make that same commitment in regards to the Level 3 charging service proposed in the instant matter. If not, explain why not.

A-110. KU is not making such a commitment. KU's deployment of Level 2 chargers was a limited pilot program implemented when there was less certainty about the future of electric vehicle ownership. It is now clear that such ownership is increasing but appears to be constrained by a lack of fast charging availability in Kentucky. Therefore, it is reasonable to expect that fast charging, which is an enabling technology for electric vehicle ownership, will help increase electric vehicle ownership in Kentucky and in particular among KU's customers. Therefore, deploying fast chargers will help serve KU's customers and will be a reasonable cost to include in rates in future rate proceedings.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information Dated January 8, 2021

Case No. 2020-00349

Question No. 111

Responding Witness: William Steven Seelye

Q-111. Refer to the Seelye Testimony, page 65, lines 12–15. Provide a cost comparison, including the installation and O&M costs of the Level-2 and Level-3 Electric Vehicle Charge stations.

A-111. Below is an approximation of public dual-port charging station costs deployed through the EVC-L2 and EVC-Fast programs. Level 2 station costs are approximations of actual costs incurred. DCFC station costs are based on non-binding estimates solicited from vendors in a 2020 request for information.

	Dual-Port Level 2 Station	Dual-Port DCFC Station
Equipment & Installation	$15,300	$306,000
Annual O&M	$1,100	$5,000

KENTUCKY UTILITIES COMPANY

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Case No. 2020-00349

Question No. 112

Responding Witness: William Steven Seelye

Q-112. Refer to the Seelye Testimony, page 74, Table 4, which includes DC Fast Charging Rates from several out-of-state utilities. For these same utilities, provide a table showing what they charge for Level 2 charging services.

A-112.

Utility	Level 2 Charging Rate
Baltimore Gas and Electric Company (BG&E)	$0.18/kWh
Duke Energy Carolinas	N/A
Florida Power & Light (FPL)	N/A
Georgia Power Company	$1/hr for first 3 hours; $0.10/minute thereafter
Potomac Electric Power Company (PEPCO)	$0.18/kWh

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
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Case No. 2020-00349

Question No. 113

Responding Witness: William Steven Seelye

Q-113. Refer to the Seelye Testimony, page 94, lines 13–22 and 95, lines 1–17. Explain any differences in the calculation of the excess facilities charge from the 2018 Rate Case.

A-113. The only difference is that the Company's cost of capital has been updated.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
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Case No. 2020-00349

Question No. 114

Responding Witness: Eileen L. Saunders

Q-114. Refer to the Seelye Testimony, page 99, line 4. Explain whether meter readers are contracted by KU or full time employees.

A-114. The Company expects to utilize employee meter readers to support the AMI opt out meter reading needs.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
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Case No. 2020-00349

Question No. 115

Responding Witness: Robert M. Conroy

Q-115. Refer to the Seelye Testimony, page 101, lines 13–20. For the proposed General Time of Day Services, explain whether the number of participants will be limited and if so, what the limit is proposed to be.

A-115. See the testimony of Mr. Conroy at page 29. The General Time of Day Service (GTOD) tariffs will be limited to only those General Service customers participating in the Company's Advanced Metering System Customer Service Offering. If the Company's AMI proposal is approved, then as meter deployment occurs the Company will monitor customers' desire to participate in the GTOD rate to determine if conditions to participate should be revised.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
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Case No. 2020-00349

Question No. 116

Responding Witness: William Steven Seelye

Q-116. Refer to the Seelye Testimony, page 104, lines 8–19. Provide any differences in the jurisdictional separation study between the instant case and the 2018 Rate Case.

A-116. There are no differences between the current case and the 2018 Rate Case.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
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Case No. 2020-00349

Question No. 117

Responding Witness: William Steven Seelye

Q-117. Regarding both the cost of service studies:

a. Provide any significant differences in the allocation factors between the instant case and the 2018 Rate Case.

b. Provide any differences between the current LOLP COSS and the LOLP COSS filed with the 2018 Rate Case.

A-117.

a. There are no significant differences in the allocation factors that were used to prepare the cost of service study in this case and those used in the 2018 Rate Case.

b. There are no differences between the LOLP methodology that was used to prepare the LOLP COSS filed in 2018 as compared to the LOLP COSS methodology filed in this proceeding.

   Any differences in the LOLP allocation factors between the two COSS are a result of differences in the input data for the LOLP calculations such as class loads, system loads, and generating unit characteristics including forced outage rates.

KENTUCKY UTILITIES COMPANY

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Case No. 2020-00349

Question No. 118

Responding Witness: William Steven Seelye

Q-118. Refer to the Seelye Testimony, Exhibit WSS-4. Provide cost support for the following:

a. Total Installed Cost;

b. Fixed Carrying Charge; and

c. Annual Non-Fixture Maintenance Cost.

A-118.

a. See attachment being provided in Excel format.

b. See attachment being provided in Excel format.

c. The annual non-fixture maintenance cost is based on the forecasted test year O&M cost to repair and replace defective fixtures of $467,585 divided by the number of fixtures (172,819).

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

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
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Case No. 2020-00349

Question No. 119

Responding Witness: William Steven Seelye

Q-119. Refer to the Seelye Testimony, Exhibit WSS-5. Provide cost support for the following:

a. Pole allocation factor; and

b. Depreciation Rate.

A-119.

a. The calculation of the pole allocation factor is shown below.

		Average Investment	Calculated
	Units	Per Unit	Net book Value
Fixtures			
OH Fixtures	127,820	$ 516.68	$ 66,042,037.60
UG Fixtures	44,999	$ 310.74	$ 13,983,075.81
Total			$ 80,025,113.41
Poles			
Post Top - Decorative Smooth	7,633	$ 1,485.30	$ 11,337,303.69
Post Top - Historic Fluted	1,589	$ 2,509.79	$ 3,988,059.97
Contemporary	11,598	$ 2,014.28	$ 23,361,596.15
Cobra	24,553	$ 2,180.62	$ 53,540,835.09
Total			$ 92,227,794.91
Grand Total NBV			$ 172,252,908.32
Percent Fixtures			46.46%
Percent Poles			53.54%

b. The depreciation rate matches the number of years the remaining undepreciated balance will be recovered over. The conversion fee will be billed for a 5-year period; therefore, the component (depreciation rate) of the conversion fee designed to recover the undepreciated balance must recover that balance over the 5 years in which the fee will be charged.

KENTUCKY UTILITIES COMPANY

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Case No. 2020-00349

Question No. 120

Responding Witness: William Steven Seelye

Q-120. Refer to the Seelye Testimony, Exhibit WSS-10 at 1 of 2. Indicate how many DC Fast Charging Ports are located in KU's service territory.

A-120. There are four public DC Fast Charging locations (defined as offering charging speeds of 50 kW or greater) in KU service territory with a total of 24 ports. Two of the four stations are accessible only to Tesla drivers.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
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Case No. 2020-00349

Question No. 121

Responding Witness: William Steven Seelye

Q-121. Refer to the Seeley Testimony, Exhibit WSS-11.

a. Provide support for the estimated investment per unit.

b. Explain why fixed charges are estimated to be 20.51 percent of the investment.

c. Provide support for the O&M costs.

d. Provide support for the charge point cost.

A-121.

a. The investment per unit is the Companies' contract pricing for a Clipper Creek HCS-40R single-port charging station with the Share2 option and a branded LG&E or KU sticker applied to the station. The charging station and Share2 option pricing ($796.10 of the $800.85) was obtained via a competitive request for proposal solicited in 2019.

b. The fixed charge consists of the following components:

Cost of Capital	7.206%
Depreciation (10-year life)	10.000%
Income Taxes	1.770%
Property Taxes	1.530%
Total	**20.51%**

c. The annual O&M cost of $126.00 is an estimated amount for unplanned maintenance expenses. There are no planned maintenance costs associated with the Clipper Creek stations. In the absence of real-world unplanned maintenance cost data for Clipper Creek stations, the Company has chosen to include the unplanned maintenance costs proposed and approved in Case No. 2015-00355.

d. The Chargepoint Annual Cost for the Clipper Creek station detailed in Exhibit WSS-11 is $0. The Clipper Creek unit requires no ongoing annual network fees for operation.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
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Case No. 2020-00349

Question No. 122

Responding Witness: William Steven Seelye

Q-122. Refer to the Seelye Testimony, Exhibit WSS-12, pages 1–2 of 4, Cost Support for Redundant Capacity Charge. Explain the derivation of the amounts listed under Billing Demand and Rate Base.

A-122. Billing Demand for the Power Service Secondary ("PSS") class was derived by summing the billed Summer Peak Demand of 2,217,792 kW with the billed Winter Peak Demand 3,055,084 of kW shown on page 7 of Schedule M-2.3 for a total of 5,272,876 kW of billed demand.

Billing Demand for the Time-of-Day Secondary ("TODS") class is the Base Period Demand shown on page 9 of Schedule M-2.3 totaling 6,217,430 kVA of billed demand. The rationale for choosing the Base Period demand is that those billings represent the recovery of distribution-related costs from TODS customers.

Billing Demand for the Power Service Primary ("PSP") class was derived by summing the billed Summer Peak Demand of 132,145 kW with the billed Winter Peak Demand of 169,367 kW shown on page 8 of Schedule M-2.3 for a total of 301,512 kW of billed demand.

Billing Demand for the Time-of-Day Primary ("TODP") class is the Base Period Demand shown on page 10 of Schedule M-2.3 totaling 10,620,000 kVA of billed demand. The rationale for choosing the Base Period demand is that those billings represent the recovery of distribution-related costs from TODP customers.

The Rate Base amounts are derived from the sum of Distribution Substation, Distribution Primary and Secondary Lines, and Distribution Transformers demand-related costs allocated to each respective class in the Cost-of-Service Study shown on Exhibit WSS-28. For PSS this is the sum of cells J143+J147+J154, for TODS it is the sum of cells L143+L147+L154, for PSP it is the sum of cells K143+K147+K154, and for TODP it is the sum of cells M143+M147+M154 on page 5 of Exhibit WSS-28.

KENTUCKY UTILITIES COMPANY

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Case No. 2020-00349

Question No. 123

Responding Witness: William Steven Seelye

Q-123. Refer to the Seelye Testimony, Exhibit WSS-19, Cost Support for Miscellaneous Charges. Identify those services performed by KU employees and those services performed by contract labor. For those performed by contract labor, explain whether KU is charged a flat fee by the contractor or whether KU is charged per service performed.

A-123.

Electric Meter Test Charge
Electric meters are tested by both employees and contractors and are billed on an hourly basis.

Disconnect/Reconnect Service Charge:
Disconnects and Reconnects are performed by field services employees and contractors. Both work on an hourly labor basis.

Unauthorized Reconnect Charge:
Work on UARs is performed by a combination of employees and contractors. They are compensated on an hourly basis.

Gas Inspection Charge:
Gas Operations utilize contractors or employees, depending on resource availability, billed on an hourly basis.

Charge for Temporary and Short Term Service – Gas
Gas Operations utilize contractors or employees, depending on resource availability, billed on an hourly basis.

Additional Trip Charge – Gas:
Gas Operations utilize contractors or employees, depending on resource availability, billed on an hourly basis.

Gas Meter Pulse Service:
Meter Pulse Services are performed by employees and are billed on an hourly basis.

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Response to Commission Staff's Second Request for Information
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Case No. 2020-00349

Question No. 124

Responding Witness: William Steven Seelye

Q-124. Refer to the Seelye Testimony, Exhibit WSS-19, page 2 of 18, Cost Justification for the Disconnect/Reconnect Fee. Provide detailed cost justification, broken down by component, for the amounts listed as "Disconnect Service" and "Reconnect Service".

A-124. The costs were determined based on actual expenses and service orders for March 2019 through February 2020, as adjusted for inflation to reflect test-year costs, as shown below.

Adjusted Costs based on March 2019 through February Actual

Field Service Costs Recorded per Books	$ 7,054,342
Test Year Escalation Factor at 3% inflation	1.06090
Adjusted Test-Year Cost with Inflation Factor for test year	$ 7,483,951
Percentage Related to Disconnect/Reconnect (See below)	39.35%
Total Disconnect/Reconnect Cost	$ 2,945,210
Total Number of Disconect/Reconnect Orders	158,214
Cost per Disconnect or Reconnect Order	$ 18.62

	Orders	**% of Total**
Disconnect/Reconnect Service Orders	158,214	39.35%
Other Service Orders	243,817	60.65%
Total Orders	402,031	100.00%

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 125

Responding Witness: William Steven Seelye

Q-125. Refer to the Seelye Testimony, Exhibit WSS-19, page 4 of 18, Cost Justification for the Meter Test Fee. Explain how the amounts listed as "Labor - One Hour" and "Vehicle - 2/3 Hour" were calculated and provide the detailed calculation.

A-125. The time required to perform the services was based on management estimates. The labor cost was derived from the hourly rate from the IBEW Contract plus the Company's standard burden rate, as escalated for inflation for the test year. See derivation of costs below.

Labor	
IBEW Hourly Rate	$ 43.05
Burden Rate	62.39%
Burdens	$ 26.86
Total Unadjusted Labor	$ 69.91
Test Year Escalation Factor at 3% inflation	1.06090
Total Labor Cost per Hour	$ 74.16
Time Required in Hours	1.00
Total Labor Cost	$ 74.16
Transportation	
Light Duty Pickup	$ 5.96
Medium & Heavy Duty Truck	8.78
Van	7.84
Average Cost	$ 7.53
Test Year Escalation Factor at 3% inflation	1.06090
Average Vehicle Cost per Hour	$ 7.99
Time Required in Hours	0.6667
Total Vehicle Cost	$ 5.32

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 126

Responding Witness: William Steven Seelye

Q-126. Refer to the Seelye Testimony, Exhibit WSS-19, page 12 of 18, Cost Justification for the Meter Pulse Electric Charge. Provide supporting documentation for each amount listed in the cost justification.

A-126. See attachment being provided in Excel format.

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

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 127

Responding Witness: William Steven Seelye

Q-127. Refer to the Seelye Testimony, Exhibit WSS-19, page 15 of 18, Cost Justification for the Electric Unauthorized Meter Reconnect Charge. Provide supporting documentation for each amount listed in the cost justification and explain why the multiple amounts listed as "Charge without meter replacement" do not match the amount listed as "Total Charge without meter replacement at July 31, 2020" and are different for each charge.

A-127. Supporting calculations for the charges are shown below. Documents supporting the cost of the meters and locks are included in separate attachments to this response. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection. The support for the meter cost estimates is shown in the following cells or sections of the referenced documents:

Description	Avg Cost Of Meter	Reference (Excel Spreadsheet or PDF)
1/0 Standard	$20	In "2020 PSC DR2 KU Attach to Q127 – Att 1 Itron Bid Analysis Confidential.xlsx" (cells B7, B9, B19, B21:B22, B26, and B28:B29, with cell B19 being the most common) as part of the 2020 electric RFP
1/0 AMR	$40	In "2020 PSC DR2 KU Attach to Q127 – Att 1 Itron Bid Analysis Confidential.xlsx" (cells B8, B20, and B27, with cell B19 being the most common) as part of the 2020 electric RFP
1/0 AMS	$100	In "2020 PSC DR2 KU Attach to Q127 – Att 2 Landis+Gyr Confidential.xlsx" (cells B11, B26, and B35, with cell B26 being the most common) as part of the 2020 electric RFP
3/0 Standard	$105	In "2020 PSC DR2 KU Attach to Q127 – Att 1 Itron Bid Analysis Confidential.xlsx" (cells B11, B26, and B35, with cell B26 being the most common) as part of the 2020 electric RFP

Description	**Avg Cost Of Meter**	**Reference (Excel Spreadsheet or PDF)**
Lock	$11	See "2020 PSC DR2 KU Attach to Q127 – Att 3 Lock Invoices Confidential.pdf"

The reason that the charges without meter replacement differ from those with meters is that different weighted escalation factors are utilized for the categories depending on the relationship of equipment to labor. Specifically, a 3% escalation rate was used for labor expenses and a 2% escalation rate was used for equipment costs. Therefore, different weighted escalation rates were calculated based on the relative amounts of labor and equipment included in each type of Unauthorized Meter Reconnect Charge. See calculations below.

Charge Without Meter Replacement	
Field Services	
Labor Cost per Hour	$ 26.00
Burden Rate	62.39%
Burdens	$ 16.22
Total Labor Cost per Hour	$ 42.22
Time Required in Hours	0.25
Total Field Services Labor Cost	$ 10.56
Transportation	
Light Duty Pickup	$ 5.96
Time Required in Hours	0.2500
Total Vehicle Cost	$ 1.49
Back Office Admin Labor	
Hourly Rate	$ 22.40
Burden Rate (SERVCO)	72.18%
Burdens	$ 16.17
Total Unadjusted Labor	$ 38.57
Time Required in Hours	0.50
Total Back-Office Labor Cost	$ 19.28
Lock Box	
Cost of Lock Bock (See attachment to response)	$ 11.00
Total - Unadjusted	$ 42.33
Test Year Escalation Factor at 2.74% inflation (74% Labor x 3% + 26% Equipment x 2% = 2.74%)	1.0556
Total - Adjusted for Inflation	$ 44.68

Charge if Standard 1/0 Meter Replacement is Necessary

Charge Without Meter Replacement -- Unadjusted	$ 42.33
Cost of Standard 1/0 Meter (See attachment to response)	$ 20.00
Total - Unadjusted	$ 62.33
Test Year Escalation Factor at 2.68% inflation (68% Labor x 3% + 32% Equipment x 2% = 2.68%)	1.0543
Total - Adjusted for Inflation	$ 65.72

Charge if 1/0 AMR Meter Replacement is Necessary

Charge Without Meter Replacement -- Unadjusted	$ 42.33
Cost of 1/0 AMR Meter (See attachment to response)	$ 40.00
Total - Unadjusted	$ 82.33
Test Year Escalation Factor at 2.51% inflation (51% Labor x 3% + 49% Equipment x 2% = 2.51%)	1.0509
Total - Adjusted for Inflation	$ 86.52

Charge if 1/0 AMS Meter Replacement is Necessary

Charge Without Meter Replacement -- Unadjusted	$ 42.33
Cost of 1/0 AMS Meter (See attachment to response)	$ 100.00
Total - Unadjusted	$ 142.33
Test Year Escalation Factor at 2.30% inflation (30% Labor x 3% + 70% Equipment x 2% = 2.30%)	1.0465
Total - Adjusted for Inflation	$ 148.95

Charge if 3/0 Standard Meter Replacement is Necessary

Charge Without Meter Replacement -- Unadjusted	$ 42.33
Cost of 3/0 Standard Meter (See attachment to response)	$ 105.00
Total - Unadjusted	$ 147.33
Test Year Escalation Factor at 2.30% inflation (29% Labor x 3% + 69% Equipment x 2% = 2.30%)	1.0463
Total - Adjusted for Inflation	$ 154.15

The entire attachment is Confidential and provided separately under seal.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information Dated January 8, 2021

Case No. 2020-00349

Question No. 128

Responding Witness: William Steven Seelye

Q-128. Refer to the Seelye Testimony, Exhibit WSS-23. Also refer to WSS-20 of the 2018 Rate Case. The zero-intercept analysis for Account 365 – Overhead Conductor estimates the customer-related costs to account for 63.99 percent of the total and in the 2018 Rate Case, the customer-related estimates were 61.71 percent. Explain the increase in the customer-related costs.

A-128. Due to the statistical nature of the analysis and the changes in the size and quantity of overhead conductor on the Company's system, the costs classified as customer-related will have inherently changed as conductor types are added to and retired from the Company's distribution system.

Changes in customer-related costs calculated by the zero-intercept analysis are based on the changes in both the quantity of each conductor type installed by the Company and the contribution of the costs of each type of conductor. These conductor quantities and costs are weighted based on their contribution to the overall cost of the conductor included in the analysis and to the extent that the zero intercept value changes it will have an impact on how much of the total cost is classified as customer-related.

In this case, the zero-intercept calculated from the overhead conductor analysis was $1.38 per foot of conductor with a slope of $0.00417/MCM of conductor size. In the Company's 2018 rate case, the zero-intercept was $1.27 per foot of conductor with a slope of $0.00423/MCM. This means that the analysis calculated more cost per foot of conductor associated with the non-size related portion of each conductor type than in 2018 thus increasing the overall percentage of costs classified as customer-related.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 129

Responding Witness: William Steven Seelye

Q-129. Refer to the Seelye Testimony, Exhibit WSS-24. Also refer to WSS-21 of the 2018 Rate Case. The zero intercept analysis for Account 367 – Underground Conductor estimates the customer-related costs to account for 74.88 percent of the total and in the 2018 Rate Case, the customer-related estimates were 77.85 percent. Explain the decrease in the customer-related costs.

A-129. Due to the statistical nature of the analysis and the changes in the size and quantity of underground conductor on the Company's system, the costs classified as customer-related will have inherently changed as conductor types are added to and retired from the Company's distribution system.

Changes in customer-related costs calculated by the zero-intercept analysis are based on the changes in both the quantity of each conductor type installed by the Company and the contribution of the costs of each types of conductor. These conductor quantities and costs are weighted based on their contribution to the overall cost of the conductor included in the analysis and to the extent that the zero intercept value changes it will have an impact on how much of the total cost is classified as customer-related.

In this case, the zero-intercept calculated from the underground conductor analysis was \$4.65 per foot of conductor with a slope of \$0.0135/MCM of conductor size. In the Company's 2018 rate case, the zero-intercept was \$4.78 per foot of conductor with a slope of \$0.012/MCM. This means that the analysis calculated less cost per foot of conductor associated with the non-size related portion of each conductor type than in 2018 thus decreasing the overall percentage of costs classified as customer-related.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 130

Responding Witness: William Steven Seelye

Q-130. Refer to the Seelye Testimony, Exhibit WSS-25. Also refer to WSS-22 of the 2018 Rate Case. The zero intercept analysis for Account 368 – Line Transformers estimates the customer-related costs to account for 45.38 percent to the total and in the 2018 Rate Case, the customer-related estimates were 54.62 percent. Explain the decrease in the customer-related costs.

A-130. For purposes of clarification, in the Company's 2018 rate case the customer-related costs for Account 368 – Line Transformers was 46.45 percent, and this Rate Case is 45.38 percent, resulting in a 1.07% decrease in customer-related costs.

Due to the statistical nature of the analysis and the changes in the size and quantity of transformers on the Company's system, the costs classified as customer-related will have inherently changed as transformer types are added to and retired from the Company's distribution system.

Changes in customer-related costs calculated by the zero-intercept analysis are based on the changes in both the quantity of each transformer type installed by the Company and the contribution of the costs of each types of conductor. These transformer quantities and costs are weighted based on their contribution to the overall cost of the transformers included in the analysis and to the extent that the zero intercept value changes it will have an impact on how much of the total cost is classified as customer-related.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 131

Responding Witness: William Steven Seelye

Q-131. Refer to the Seelye Testimony, Exhibit WSS-30 at 29 of 30. Explain how the external functional vector of Poles, Towers, and Fixtures was determined.

A-131. The Poles, Towers and Fixtures functional vector is equivalent to the Overhead Conductor external functional vector. Given that poles, towers and fixtures are principally installed to support overhead conductor and associated equipment, it is assumed that the split between demand and customer-related costs for Account 364 is equivalent to that of the Overhead Conductor FERC Account 365.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 132

Responding Witness: Robert M. Conroy / William Steven Seelye

Q-132. Refer to KU's response to Commission Staff's First Request for Information, Item 54. Provide cost support for KU's forfeited discount/late payment charge.

A-132. KU reduced the late payment charge from 5% to the current level of 3% for Rates RS and GS in the Settlement Agreement that was filed with the Commission on November 19, 2012 in Case No. 2012-00221. The Settlement Agreement was approved by the Commission in its Order dated December 20, 2012. No cost support was developed at that time nor since to support the settled rate. Ultimately, the late payment charge is intended to be an inducement to encourage customers to pay their bills on time. Without such an inducement to pay on time, behavior of some customers could change in a way that adversely impacts on time payment.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 133

Responding Witness: Christopher M. Garrett

Q-133. Refer to KU's response to Commission Staff's First Request for Information, Item 54.

a. For the base period, explain why the recovered charges exceed the billed charges in the Forfeited Discounts/Late Payment Charges column and the Unauthorized Reconnect Charge column.

b. Explain what is included in the Other Service Charge column, provide a breakdown by each charge included in that column, and explain whether those services are performed by KU employees or by contract labor.

A-133.

a. The recovered charges exceed the billed charges in Forfeited Discounts/Late Payment Charges and Unauthorized Reconnect Charges columns in the base period as a result of a timing difference in recoveries and billings due to the lag in collections. The base period billed charges are for bills rendered from March 1, 2020 through March 16, 2020, while recoveries include collections received from March 1, 2020 through August 31, 2020 for billed charges prior to March 16, 2020. While the billing of late payment charges stopped effective March 16, 2020, the recovery/collections of late payment charges continued for the balance of the base period with the majority of the collections occurring in March, April , May and June.

b. Other Services include electric meter test charges, electric meter pulse charges, temporary to permanent and seasonal service charges. All of these services are performed by both KU employees and contract labor depending on availability.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 134

Responding Witness: Daniel K. Arbough

Q-134. Refer to KU's response to Commission Staff's First Request for Information, Item 56, Schedule C. Provide a breakdown or supporting schedules for Account 404 in the test year.

A-134.

Description	**YE Jun-22** Amortization Expense
KU-130200-Franchises and Consents	$ 5,240.64
KU-130300-Misc Intangible Plant (Software, licenses and other intangible property)	19,932,591.24
KU-130310-CCS Software	1,610,883.14
KU-130330-Cloud Software Non-Current	378,666.12
Total Amortization – Account 404	$ 21,927,381.14

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 135

Responding Witness: Robert M. Conroy

Q-135. Provide any study regarding low-income usage as compared to the average user.

A-135. The Company does not maintain income level by customer. However, see attachment being provided in Excel format for a monthly comparison of residential customer usage as a class for 2019 and 2020 to the usage of residential customers receiving assistance funding for utility bills.

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

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 136

Responding Witness: William Steven Seelye

Q-136. Provide a comparison table of the cost component estimates from each COSS for each rate class.

A-136. See attached.

Kentucky Company Units Costs from Cost of Service Study based on Proposed Rate of Return for each Rate Class

LOLP	Residential Rate RS	General Service Rate GS	All Electric Schools Rate AES	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Rate FLS Transmission
Demand Costs ($/kW or $/kwh)	$0.060167/kWh	$0.089751/kWh	$0.067423/kWh	$17.61/kW	$23.47/kW	$17.11/kW	$18.33/kW	$15.05/kW	$1.57/kW
Energy Costs ($/kWh)	$0.032001	$0.032533	$0.032228	$0.032140	$0.032462	$0.031293	$0.032110	$0.030660	$0.030505
Customer Costs (per customer per day)	$0.82	$1.53	$3.64	$6.83	$2.99	$10.78	$7.31	$35.92	$45.19

12CP	Residential Rate RS	General Service Rate GS	All Electric Schools Rate AES	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Rate FLS Transmission
Demand Costs	$0.060355/kWh	$0.089506/kWh	$0.067831/kWh	$17.57/kW	$23.48/kW	$17.06/kW	$18.34/kW	$15.05/kW	$1.37/kW
Energy Costs	$0.031991	$0.032550	$0.032057	$0.032206	$0.032447	$0.031328	$0.032108	$0.030661	$0.030627
Customer Costs	$0.81	$1.54	$3.44	$6.98	$2.97	$10.90	$7.30	$35.93	$47.97

6CP	Residential Rate RS	General Service Rate GS	All Electric Schools Rate AES	Rate PS Primary	Rate PS Secondary	Rate TOD Primary	Rate TOD Secondary	Rate RTS Transmission	Rate FLS Transmission
Demand Costs	$0.060819/kWh	$0.086900/kWh	$0.067755/kWh	$17.57/kW	$23.47/kW	$17.01/kW	$18.24/kW	$14.99/kW	$1.33/kW
Energy Costs	$0.031968	$0.032543	$0.032089	$0.032205	$0.032468	$0.031359	$0.032156	$0.030728	$0.030650
Customer Costs	$0.79	$1.54	$3.48	$6.98	$3.00	$11.01	$7.37	$37.17	$48.50

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 137

Responding Witness: William Steven Seelye

Q-137. State whether KU is aware of a LOLP COSS being approved in other state jurisdictions. If so, provide the state and docket number.

A-137. Mr. Seelye has not performed a review of the cost-of-service studies approved in most other jurisdictions, but he is unaware of an LOLP COSS being approved in other jurisdictions. However, the LOLP methodology is identified in the NARUC *Electric Utility Cost Allocation Manual*, at page 62, as a reasonable methodology for allocating production fixed costs in an embedded cost of service study. See attached.

ELECTRIC UTILITY COST ALLOCATION MANUAL

January, 1992

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

1101 Vermont Avenue NW
Washington, D.C. 20005
USA
Tel: (202) 898-2200
Fax: (202) 898-2213
www.naruc.org

$25.00

demands are the primary determinants of baseload production plant costs, as indicated by the inter-class allocation of these costs, then they should also be classified as energy-related and recovered via an energy charge. Failure to do so -- i.e., classifying production plant costs as demand-related and recovering them through a $/KW demand charge -- will result in a disproportionate assignment of costs to low load factor customers within classes, inconsistent with the basic premise of the method.

3. LOLP Production Cost Method

LOLP is the acronym for loss of load probability, a measure of the expected value of the frequency with which a loss of load due to insufficient generating capacity will occur. Using the LOLP production cost method, hourly LOLP's are calculated and the hours are grouped into on-peak, off-peak and shoulder periods based on the similarity of the LOLP values. Production plant costs are allocated to rating periods according to the relative proportions of LOLP's occurring in each. Production plant costs are then allocated to classes using appropriate allocation factors for each of the three rating periods; i.e., such factors as might be used in a BIP study as discussed above. This method requires detailed analysis of hourly LOLP values and a significant data manipulation effort.

4. Probability of Dispatch Method

The probability of dispatch (POD) method is primarily a tool for analyzing cost of service by time periods. The method requires analyzing an actual or estimated hourly load curve for the utility and identifying the generating units that would normally be used to serve each hourly load. The annual revenue requirement of each generating unit is divided by the number of hours in the year that it operates, and that "per hour cost" is assigned to each hour that it runs. In allocating production plant costs to classes, the total cost for all units for each hour is allocated to the classes according to the KWH use in each hour. The total production plant cost allocated to each class is then obtained by summing the hourly cost over all hours of the year. These costs may then be recovered via an appropriate combination of demand and energy charges. It must be noted that this method has substantial input data and analysis requirements that may make it prohibitively expensive for utilities that do not develop and maintain the required data.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 138

Responding Witness: Daniel K. Arbough

Q-138. Provide an itemized list of all COVID-19 costs included in the base year and test year.

A-138. For the base period the Company incurred costs primarily for outside services required for additional cleaning and disinfecting of Company facilities, incremental costs associated with inspections and necessary repairs/tree trimming of circuits serving hospitals as well as convenience charges for credit and debit card, and e-check costs that the Company absorbed for the second quarter while business offices were closed to in-person traffic. Other significant costs include purchasing of hand sanitizer, thermometers, and personal protective equipment for employee usage as well as costs incurred to be prepared to sequester employees at power generation plants and control rooms for transmission and distribution operations. There are also small amounts of labor related to employees working specifically on COVID-19 related matters such as taking temperatures of incoming employees and contractors or filling in for someone having to quarantine due to exposure to the virus. The table below presents a breakdown of the KU base period costs:

Expense Type	**Base Period**
Outside Services and Contractors	$ 1,608,494
Materials (including Safety materials)	512,361
Convenience Payments Absorbed	488,624
Office Supplies and Equipment	469,662
Other	101,144
Labor	100,388
Meals	64,311
Freight	15,171
Transportation	15,112
Telecom	5,393
Software	2,151
	$ 3,382,811

For the test year period refer to the testimony of Mrs. Saunders for the impacts to expenses for the additional costs of cleaning for facilities, of which $220,000 is allocated to KU.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 139

Responding Witness: Daniel K. Arbough

Q-139. Provide an itemized list of all COVID-19 benefits included in the base year and test year.

A-139. The Company has defined benefits for the purpose of this question as O&M cost reductions primarily related to training, travel and associated meals. This was derived as the difference between actual versus budget for the months March through August and forecasted lower spend compared to budget for the months September through December. While not all costs can be attributed to COVID-19, the restrictions put in place because of COVID-19 have significantly limited the amount of training courses offered due to distancing rules and in turn impacted travel and meal costs. For the base period reductions related to training, travel and meals totaled $1,567,704 for KU. When compiling the budget for the periods starting 2021, the forecast was not adjusted to reflect the potential of COVID-19 restrictions on training, travel and meals.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information Dated January 8, 2021

Case No. 2020-00349

Question No. 140

Responding Witness: Robert M. Conroy

Q-140. Provide the number of times a month for 2019 and 2020 that visitors to KU's website: https://lge-ku.com/regulatory/rates-and-tariffs have viewed or downloaded the PDFs for KU electric rates.

A-140. The following chart displays the number of viewing or downloads by month related to the Company's rates-and-tariffs website and KU electric rates.

KU Electric Rates		
	2019	**2020**
Jan	174	230
Feb	213	153
Mar	192	75
Apr	175	81
May	247	102
Jun	213	69
Jul	229	65
Aug	300	127
Sep	217	181
Oct	171	250
Nov	198	227
Dec	221	265

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated January 8, 2021

Case No. 2020-00349

Question No. 141

Responding Witness: Daniel K. Arbough

Q-141. Provide any internal investment proposals prepared for projects included in rate base or CWIP in the past two years.

A-141. See attached. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

Investment Proposal for Investment Committee Meeting on: 2/27/2019

Project Name: Advanced Metering Systems (AMS) Early Adopter Program (DSM)

Total Capital Expenditures: $3,830k (Approved on 12/2/2014)

Total O&M: $1,879k ($4,216k revised O&M – all DSM)

Total Revised Capital Expenditures: $6,935k

Project Number(s): 145404 and 145405

Business Unit/Line of Business: Customer Services/Energy Efficiency

Prepared/Presented By: Jonathan Whitehouse/David Huff

Description of Incremental Ask

Original Approved Capital Expenditures		$3,830k
Revised Capital Expenditures Requested		$6,935k
Total Increase Requested		$3,105k

- The Kentucky Public Service Commission order in Demand Side Management (DSM) Case No. 2017-00441 expanded the AMS program to 10,000 LG&E and 10,000 KU residential and small commercial customers. The Commission provided further guidance in its conclusion in Case No. 2018-00005 stating that "The increased investment in AMS will not result in wasteful duplication because the pilot program meters can be used going forward if the Companies refile an application for AMS that satisfies the evidentiary requirements for a CPCN." The Companies are providing the budget estimates for acquiring and serving all 20,000 customers below.

($1,000)	2019	2020	2021	2022	Total
Administration	$ 291	$ 300	$ 309	$ 318	$ 1,218
Implementation CAPX	$ 3,100	$ 122	$ 126	$ 130	$ 3,478
Implementation OPEX	$ 1,183	$ 208	$ 204	$ 206	$ 1,801
Miscellaneous	$ -	$ 46	$ -	$ 48	$ 94
Total	$ 4,574	$ 676	$ 639	$ 702	$ 6,591

- The Companies are planning to reach full subscription by year-end 2019. Costs after 2019 are to maintain the service for customers.

- 2019 capital costs are primarily driven by the purchase of the incremental meters needed to reach 20,000 customers but also include network costs associated with expanding the mesh network in Lexington.
- 2019 O&M costs are primarily driven by marketing and education efforts to drive participation and customer engagement, thus reaching full subscription by the end of 2019. Customer education and awareness is designed to engage and motivate customers to use the additional information to take action to save energy.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	Pre-2019	2019	2020	Post 2020	Total
1. Capital Investment Proposed	3,457	3,100	122	256	6,935
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	3,457	3,100	122	256	6,935
4. Capital Investment 2019 BP	3,830	500	61	195	4,586
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	3,830	500	61	195	4,586
7. Capital Investment variance to BP (4-1)	373	(2,600)	(61)	(61)	(2,349)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	373	(2,600)	(61)	(61)	(2,349)

Financial Detail by Year - O&M ($000s)	Pre-2019	2019	2020	Post 2020	Total
1. Project O&M Proposed	1,103	1,474	554	1,085	4,216
2. Project O&M 2019 BP	1,880	394	428	1,288	3,990
3. Total Project O&M Variance to BP (2-1)	777	(1,080)	(126)	203	(226)

The incremental capital funding for 2019 was approved through the Corporate RAC and the 2020 Business Plan will be adjusted to reflect the updated costs for the 20,000 meters.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the AMS Early Adopter project for $6,935k to reach the increased participant targets ordered by the Commission in Case No. 2017-00441. All expenses are to be recovered through DSM.

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: July 31, 2019

Project Name: BOC Annex Renovation

Total Capital Expenditures: $2,842k (Including $247k of contingency and including $159k of internal labor)

Project Number(s): 00067FACS/L/K

Business Unit/Line of Business: Customer Services / Operating Services

Prepared/Presented By: Zac Conley / Cheryl Bruner / Shannon Montgomery

Brief Description of Project

This project will provide renovations to the existing BOC Annex building located at the Broadway Office Complex (BOC), which has not been renovated in totality since 1982. The project includes the cost to design, renovate and construct new areas within the existing BOC Annex facility space by utilizing internal project management and interior design resources, and external architectural and general contracting services. The area comprises 9,012 sq. ft. on the 1st floor, in addition to 2,516 sq. ft. on the 2nd floor.

The renovations will provide:

- Updated space configuration to better serve the operational needs of the Field Service Operations and the Meter Reading Process by better utilization and maximization of existing space;
- Reconfigured floor plan to allow departments to function and conduct business more effectively and efficiently;
- Expansion of existing restroom facilities to comply with current facility occupancy loads and ADA code requirements;
- Updated HVAC, electrical, plumbing infrastructure in order to comply with modern building code and facility occupancy requirements;
- Abatement of existing asbestos-containing flooring materials by a certified, licensed environmental contractor;
- Modernized and updated space design layout which will provide a collaborative and motivating work environment for 127 Field Services and Meter Reading operations and management personnel.
- Updated Audio/Visual equipment, flooring materials, paint, lighting, ceiling tile and grid, and cabinetry to align with existing Facility Services building construction standards.

This project was not included in the 2019 Business Plan (BP) for 2019. The project was originally opened in January 2018 for engineering and design work, and $97k has been spent through May 2019. Total cost of the project is estimated at $2,842k. The 2019 funding for this project has been reallocated from other Operating Services/Facilities projects through the Corporate RAC process. The economic useful life of the project is 30 years.

Project timeline is as follows:

November 2018	Architectural design commenced
February 2019	Design completed
March – May 2019	Formally bid construction
July 2019	IC review
August 2019	Circulate award recommendation, execute contract, issue PO's
August 2019	Anticipated construction start
December 2019	Anticipated construction completion

Why is the project needed? What if we do nothing?

Prior to Company's purchase of the Broadway Office Complex, the BOC Annex facility functioned as an auto service and repair shop for the former owner, Sears & Roebuck Company. The facility provided service bays, a tire chute, dumbwaiter elevator service for transporting parts to and from storage and various other nuance features that are unique to an auto repair facility, along with a facility infrastructure of the same vintage. Today, the facility functions as a predominantly administrative office environment which has been developed over time around these features. As a result, significant mechanical, electrical, plumbing and structural updates are a necessary part of this renovation to comply with building codes and occupancy requirements, as well as to sufficiently maximize space.

Renovation of the BOC Annex is the next step in continuing to maximize and effectively utilize available office space throughout the Company. It is in the best interest of the Company to create a motivating, collaborative, modern workspace for the Meter Reading and Field Services operations in an effort to obtain operational excellence for our customer-facing personnel. The proposed renovation includes considerations for future growth and operational modifications or variations.

Operational deficiencies of the BOC Annex include:

- The BOC Annex facility is utilized by Meter Reading and Field Services back office and operational personnel. The facility is in need of an overall renovation to improve functionality and aesthetics. The proposed renovation will provide a more operationally functional space which will address issues with inefficient space utilization across the building, provide a dedicated training area, updated assembly room area as well as a tailgate safety meeting area.
- Existing facility does not meet code requirements for egress, ADA compliance, and occupancy requirements. The proposed renovation will include additional restroom facilities to meet ADA and occupancy requirements, and redirection and relocation of egresses.
- Due to current NFPA requirements related to testing for the presence of gas, additional bench-mounted calibration equipment is required for the periodic testing/calibration for specialized equipment. Each Field Service Technician uses this required equipment for gas safety purposes. The proposed renovation will provide an area that will meet building code requirements for gas vessel storage, testing and airflow/exhaust in the dedicated area where the bench-mounted calibration equipment and gas storage area will be located. Field Service currently does not have a calibration station for the GT40 and PS200 air monitoring equipment at the Annex. Today, the Field Services Company technicians and contractor technicians must travel to AOC or EOC to perform the required monthly calibrations. This

travel time negatively affects Field Services' productivity for service order completions. Adding this station for approximately 55 technicians will improve the efficiencies for this necessary task each month.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	37	2,679			2,716
2. Cost of Removal Proposed		126			126
3. Total Capital and Removal Proposed (1+2)	37	2,805	-	-	2,842
4. Capital Investment 2019 BP	500				500
5. Cost of Removal 2019 BP					-
6. Total Capital and Removal 2019 BP (4+5)	500	-	-	-	500
7. Capital Investment variance to BP (4-1)	463	(2,679)	-	-	(2,216)
8. Cost of Removal variance to BP (5-2)	-	(126)	-	-	(126)
9. Total Capital and Removal variance to BP (6-3)	463	(2,805)	-	-	(2,342)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	92	92	92	92	368
2. Project O&M 2019 BP	92	92	92	92	368
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The incremental funding for 2019 was reallocated through the Corporate RAC process in June 2019.

Risks

Asbestos-containing materials (ACM's) have been confirmed in the facility and will require abatement as part of the construction process. This work will be performed by an authorized and certified contractor. The facility will not be occupied during the abatement process and will not pose a health risk to personnel.

Meter Reading and Field Services operations will be relocated to swing space during the project. The project has been planned in such a way that the transition of operations to this space will be seamless and Meter Reading / Field Service personnel will not be impacted by the construction.

Alternatives Considered

1. Recommendation: Annex Facility Renovation NPVRR: $3,174k
   The recommendation is to renovate the BOC Annex located to the south of the BOC main building. The renovation will include modernization of paint and flooring finishes, upgraded ceiling tile, ceiling grid, and lighting, and installation of advanced audio visual technology within the existing space. The area will be reconfigured and new furniture will be purchased for the space to more effectively meet the business needs of the departments. The space reorganization will include relocation and expansion of restroom facilities to meet occupancy building codes and update to meet ADA compliance codes, as well as the removal of hazardous materials throughout the building.

2. Alternative #1: Do Nothing NPVRR: N/A
   This alternative is not recommended as it will not achieve the current and future operational needs of the business. Examples of operational deficiencies include: space constraints for both office space, training and safety meetings, lack of ADA compliance and restroom size for the existing number of building occupants, as well as building code compliance related to egresses within the facility. The existing facility infrastructure does not allow the business to meet current NFPA regulations. These regulations require storage of additional testing equipment and the associated gases which must be adequately stored and properly ventilated. Additionally, building infrastructure components such as plumbing systems are at end of life and require replacement. If this option is chosen, O&M and capital expenses are expected to increase in the near, mid and long-term based on the age and condition of the facility.

3. Alternative #2: Refresh BOC Annex NPVRR: $409k
   The next best alternative is to refresh the BOC Annex space, which will include painting walls and replacing existing flooring on the 1st floor and 2nd floor. The scope of this alternative will not include furniture replacement, reconfiguring existing space plan, relocation or updates to restroom facilities, or Audio Visual equipment updates. This alternative will not include mechanical, electrical, or plumbing updates. The capital cost of this alternative is $339k. This alternative is not recommended as it will not address any issues with office space constraints, ADA compliance and existing ACM's (asbestos containing materials) would still remain throughout the facility. Other operational deficiencies, as noted above, would also not be addressed as part of this alternative scope of work.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the BOC Annex Renovation project for $2,842k to create an updated, modern work environment for key contributors within the Field Services and Meter Reading organizations in an effort to enhance operational excellence.

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: July 31, 2019

Project Name: Kevil Operations Center (Barlow Facilities Consolidation)

Total Capital Expenditures: $5,071k (Including $164k of internal labor and $313k of contingency)

Total O&M: $127k

Project Number(s): 149991

Business Unit/Line of Business: Customer Services/Electric Distribution (EDO)

Prepared/Presented By: Cheryl Bruner/Robby Trimble/Debbie Leist

Brief Description of Project

In 2014, Facilities Services conducted a study to assess the condition of key operations and customer facilities and to facilitate development of a master facility investment and maintenance plan. This study revealed numerous functional inadequacies, space constraints, and safety concerns at the existing Barlow Storeroom and Business Office that cannot be remedied through renovation or expansion of the present facilities.

To address identified deficiencies, Electric Distribution Operations (EDO), Customer Services and Facility Services seek funding authority of $5,071k to construct a new, consolidated operations center to replace and relocate the existing storeroom and business office currently located in Barlow, KY. The proposed site is part of the Western Kentucky Technology Park which is located in Kevil, KY, seven miles east of the existing facilities. The requested funding shall provide for design, construction and project management of a 10,923 square foot facility and a 2,535 square foot materials storage building on a previously purchased 4.4 acre parcel with road frontage and accessibility from U.S. Hwy 60.

The new operations center will contain:

- Customer services area for walk-in customers to make payments and transact other business;
- Drive-thru window for customers to make payments;
- Office space for personnel from EDO, Business Offices, Meter Reading, Field Services, Economic Development, and Material Services and Logistics.
    - The Kevil Operations Center will be the primary work location for the following eight positions:
        - Business Office Customer Representatives (2)
        - Customer Order Technician
        - Contract Meter Reader
        - Line Supervisor
        - Line Technicians (2)
        - Economic Development Project Manager

- The Kevil Operations Center will provide workspace for an additional eight positions on various occasions:
  - Storeroom Supervisor
  - Storeroom Specialist
  - Facility Services Supervisor
  - Area Retail Operations Manager
  - Team Leader, Field Services/Field Operations
  - Team Leader, Line Construction & Maintenance
  - Manager, Business Offices
  - Manager, Operations Center
- Adequate restrooms, shower and locker rooms, break area and conference room space;
- Assembly Room of sufficient size to be used for meetings and training or as a Storm Operations Management Room or War Room during major outage events;
- Storage space for vehicles, materials, equipment, pole storage and transformer storage and containment;
- Dedicated and secure IT/Telecommunications and site Fire/Security systems rooms;
- Communications tower installation for local and radio communications; and
- Wellness Center with fitness equipment.

This joint proposal will address primary Barlow Storeroom and Business Office inadequacies identified in the master facility study. Safety concerns, vehicle congestion and office space constraints will be eliminated through this relocation. Operational constraints associated with land size, materials handling processes, and periodic site flooding at the existing storeroom will be eliminated. Co-locating all personnel from two sites, and the pole-yard from a third site, to a single work location will provide operational benefits and efficiencies as further described herein. The new property will provide for a much needed area for vehicles and materials staging during significant outage events in the Western Kentucky service territory.

In May 2019, approximately 15 miles from the proposed Kevil location, [redacted] restarted the dormant paper mill (formerly Mead/Westvaco/Verso) in Wickliffe, KY. The customer's current energy demand and annual projected revenue is [redacted].
KU's strong, visible presence in the far western Kentucky portion of the service territory supports the company's overall economic development efforts. The 2019 Business Plan (BP) includes funding for facility consolidations, but it was used for Norton and other projects. This project funding will be reallocated from other Facilities projects for 2019 and the 2020 funding will be incorporated into the 2020 BP. The project is currently open for engineering and design work, and $145k has been spent through May 2019. The economic useful life of the project is 30 years. Project timeline is as follows:

- 2015 – 2018 – Preliminary discussions and conceptual design
- January 2019 – Schematic and architectural design commenced
- May 2019 – Design completed
- June 2019 – Formally bid construction
- July 2019 – IC review
- August 2019 – Contract execution, bidder certification

- September 2019 – Permitting
- October 2019 – Anticipated construction start
- November 2020 – Anticipated construction completion

Why is the project needed? What if we do nothing?
The current Business Office and Storeroom facilities in Barlow are 54 and 49 years old, respectively, and have been in use with only minor renovations to date. Over the course of time, operational needs of the Barlow service area have grown beyond the capabilities of the existing facilities.

Operational deficiencies of the Storeroom site include:

- The size of the lot cannot accommodate the pole yard, so poles and other materials are stored offsite at a leased location with no security or fencing.
- Site accessibility limitations present significant challenges for material deliveries and large equipment ingress and egress. Trucks must park on adjacent highway impeding traffic then cross the highway to make deliveries, creating a safety hazard for the public, employees and contractors.
- During inclement weather, accessing the site becomes a safety hazard due to the steepness of the entrance. Site constraints prevent extending the drive entrance.
- A manual gate exists at the facility, so an employee must be present to receive deliveries. This presents an issue coordinating times for an available employee to be present. A motorized gate with card reader/call box cannot be installed without pushing back the entrance, further exacerbating the space constraints.
- The internet/cell signal at the storeroom is very weak, and the ability to use computers and mobile devices in an effective and efficient way is greatly reduced.
- The Storeroom is not equipped with a backup generator or manual transfer switch to allow for a portable backup generator to power the facility.
- There is not enough space at the facility to safely and securely house trucks under cover. A portable cover was recently added to the site, but is only large enough to shelter one of the three trucks.
- The allotted office space is too small for business operations, does not accommodate territory personnel, and is the only space conditioned area onsite. Due to office space constraints, only one exit is present creating a safety hazard in the event of an emergency.
- The lot is shared by the Barlow substation, which creates unique situations surrounding accessibility due to the station and overhead transmission lines.
- The Storeroom location is in a remote area and the fence has been compromised numerous times, and equipment and wire have been stolen repeatedly throughout the years.
- Insufficient space exists for a conference room, training room and Wellness Center.
- The existing site sits below grade and adjacent to a creek and has experienced periodic flooding, increasing environmental challenges.

Operational deficiencies of the Business Office site include:

- The building is located along a busy highway near an intersection that is prone to accidents. With limited customer parking behind building, customers often park unsafely on street.

- Accessibility from the parking lot, which is in the rear of the building, to the customer entrance at the front of the building is hazardous as the walkway is through the drive-through lane.
- The condition of the building is dated and in need of renovation, as well as Customer Representative desk upgrades to enhance employee and customer experience and improve security.
- The drive-through system is antiquated and in need of replacement.
- The drive-through lane is the only access lane from the highway to customer parking located in the rear of the property, which can cause dangerous traffic back-up onto the highway.
- The lobby is inadequate in size with limited space for Customer Education displays.
- Security is compromised due to public access from front entry vestibule into the auditorium/kitchen area allowing access to entire building, including the Customer Representative area.
- Building is located in a rural area far from other retail establishments. Because staff are split between two locations, this reduces the number of staff present in the Business Office, resulting in security concerns for individuals in the office.
- Cell phone service is very limited and internet service is not available at times creating communication and security concerns.
- Facilities are not ADA compliant:
  - Parking lot has only one handicap parking stall and it is not van accessible.
  - Restroom access and restroom water closets are not ADA compliant and cannot be modified to meet ADA requirements due to space limitations.

The construction of a new consolidated operations center is desired to provide a location that promotes safety for employees, contractors and visitors. The new facility would place operations in a location suitable for the current needs of the business, resolve ongoing facility inadequacies and constraint issues, and enhance operational efficiency.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	Pre 2019	2019	2020	Post 2020	Total
1. Capital Investment Proposed	27	950	4,094	-	5,071
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	27	950	4,094	-	5,071
4. Capital Investment 2019 BP	25	-	-	-	25
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	25	-	-	-	25
7. Capital Investment variance to BP (4-1)	(2)	(950)	(4,094)	-	(5,046)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(2)	(950)	(4,094)	-	(5,046)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	44	45	95	184
2. Project O&M 2019 BP	-	20	21	43	84
3. Total Project O&M variance to BP (2-1)	-	(24)	(25)	(52)	(101)

The incremental funding needed in 2019 was reallocated through the Corporate RAC process. The incremental funding needed for 2020 will be included in the 2020 BP.

Risks

- If this consolidated facility is not constructed, a number of safety hazards and work inefficiencies for employees, contractors, and customers cannot be remedied.

Alternatives Considered

1. Recommendation: Construct New Facility NPVRR: $5,426k
   The recommendation is to construct a new facility which will consolidate and replace the existing Storeroom, Pole Yard, and Business Office location, which will alleviate the space constraints at the respective facilities. Because a substation shares the property with the Storeroom, the property will be retained but the Storeroom will be razed and only normal grounds maintenance to keep vegetation from overtaking the premises will be performed. The current Business Office property will be deemed surplus property and listed for sale. The lease of property for the pole yard will be terminated. As a result of these actions, an annual O&M savings of approximately $20k will be recognized. This will be netted against the anticipated annual O&M expense of approximately $44k for the new combined facility. Co-location of the pole yard to the new facility is expected to result in improved outage response times, thereby enhancing customer satisfaction. The new consolidated Kevil Operations Center will alleviate multiple safety hazards and concerns for employees, contractors and customers.

2. Alternative #1: Do Nothing NPVRR: N/A
   This alternative is not recommended as it will not achieve the current and future operational needs of the business. Based upon the functional adequacy evaluation conducted at these facilities in 2014, numerous facility functional needs were identified to provide for the operational needs of the occupants. Examples of these inadequacies are: safety hazards throughout Storeroom and Business Office sites, material delivery vehicles cannot deliver directly to the facility and must park on the adjacent road, lack of space for secure parking for company vehicles, facility is not equipped with a conference room, training room, "War Room" or provisions to support health and employee wellness. Storeroom is in a low-lying area that is prone to flooding, site is not adequate for staging materials and has limited security for storage area and employee vehicles; there is not enough land to expand the existing facilities; and the pole yard is not co-located with the Storeroom resulting in operational inefficiencies. These issues cannot be corrected at the existing facilities due to existing property size, physical facility size and location of both operational facilities. Because of these constraints, significant capital investment into the existing facilities will not result in providing facilities that meet the functional adequacy requirements of the occupants. If this option is chosen, O&M and capital expenses are expected to increase in the near, mid and long-term based on the age and condition of the facility.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Kevil Operations Center project for $5,071k to proceed with addressing issues identified as part of the master facility plan. This project will provide an effective and safe consolidated working environment for employees, contractors and customers and resolve ongoing facility inadequacies and constraint issues.

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: November 1, 2019

Project Name: BOC Heating System Addition

Total Capital Expenditures: $2,493k (Including $217k of contingency)

Total O&M: $2,212k

Project Number(s): 156464

Business Unit/Line of Business: Customer Services

Prepared/Presented By: Cheryl Bruner / Zac Conley / Ken Shreve

Brief Description of Project

This project requests funding for the installation of a centralized heating system for the Broadway Office Complex (BOC) Main Building. The BOC does not have a centralized, managed and controlled heating system today. Rather, the way the BOC is heated today is by heat rejected from equipment and people, along with electric, radiant heat panels placed in the ceiling grid and under employees' desks. As computer and lighting equipment has become much more energy efficient, there is much less rejected heat within the building. The end result is that the comfort level in the building is not adequate for employees and other building occupants, especially in the winter months. This project will install a boiler that will supply hot water to heating coils placed on variable air volume terminals (VAVs) throughout the BOC, thus, providing a heat system that will evenly distribute warm air and adequately temper spaces in the facility during cold weather. Internal project management, external engineering and design, and external mechanical contracting services will be utilized for this project. Project completion is scheduled for Q2 2020.

The installation of a new BOC Heat System will:

- leverage existing VAVs currently being used for cooling only,
- reduce forecasted O&M spend versus the existing maintenance requirements of the current radiant heat panel system,
- provide a building-wide heating system including a boiler, circulation pumps, hot water loop piping, updated building automation system, and localized control units,
- meet code compliance with outside air intake for the facility that it currently lacks,
- enable localized zone control of temperature and updated zoning based on current facility usage,
- increase temperature comfort levels for the BOC employees, and
- improve cold-weather protection for mechanical equipment within the BOC.

Project Milestones:

June 2018	Preliminary project discussions
September 2018	Engaged architectural firm to begin evaluation and design
June 2019	Design complete
July - August 2019	Formally bid project
October 2019	Request approval from Investment Committee
November 2019	Execute contract with successful bidder
December 2019	Heating system install commences
June 2020	Expected Project Completion

Total capital cost of the project is $2,493k. The project is included in the 2019 and 2020 Business Plan. The economical useful life of the project is 40 years.

Why is the project needed? What if we do nothing? - BOC HVAC Background

LG&E purchased the Broadway Office Complex in the early 1980's. At that time, the building temperature was warmed during cold months largely by heat rejected from incandescent lighting, large computer terminals and other electronic equipment. As the space temperature falls, the VAV terminals close off all cool supply air from the air handlers, and the internal load (e.g., people, computer, lights, equipment) would help warm the space. This was an effective way to heat the building decades ago when internal heat loads were higher.

Because of energy efficiency improvements in lighting, computers and other electric/electronic equipment over the last 10-20 years, however, less heat is rejected to the space. To mitigate this, approximately 180 electric radiant heaters have been installed in ceilings, and numerous electric heat panels have been placed under employees' desks as they are requested for comfort. These ceiling-mounted panels provide heat benefit only to the area directly below the heat panel and do not leverage the efficiency of convection air flow throughout the building workspace, thus, resulting in reduced comfort levels for employees. Simply maintaining and installing additional radiant heat panels for building-wide heat is an option, but is not recommended, as it will not address the inadequacies of the existing HVAC system described in the next paragraph.

In addition, building code now requires a certain amount of outside air to be used in ventilation to ensure appropriate indoor air quality. This prohibits completely closing the VAV terminals as was previously done. Because ventilation is required to use outside air (that is introduced at the air handling units, then ducted to the VAV terminals and distributed to the space), this air is very cold during the winter months (air supply is between 55-60 degrees). There is another issue with this current system: The mechanical rooms are used as a mixing chamber for return air and outside air. When the temperatures outside are too cold in the winter to open the outside air intake louvers, an inadequate amount of outside air is introduced into the building.

Proposed BOC Heat System - Add Heat to Variable Air Volume (VAV) Terminals

In evaluating the best heating solution, it is important to consider the building's cooling system. The building's air conditioning system utilizes water-cooled chillers. Air flow is achieved through variable volume air handlers and VAVs that vary the amount of airflow to each zone in the building based on room temperature. The system provides cool air to the space (55 degree air) for cooling.

This project will add heat to the VAVs to allow individual temperature control of each VAV zone. A gas boiler, circulation pumps, and hot water supply/return piping will be installed to provide hot water for heating to the VAVs. New piping will be installed throughout the building and routed to each VAV. New VAVs will be installed that include hot water heating coils. A gas boiler (in lieu of electric boiler) was selected due to the immediate proximity of an existing, active gas service line and gas exhaust line, thus, reducing initial installation costs.

The construction will occur by floor and portions of the ceiling in each area will be removed along the piping route and at each VAV terminal to allow installation of the piping and VAV terminals. Ductwork modifications in the mechanical room will be made to address issues with outside air intake to the building. This is expected to last approximately two (2) months per floor, upon which the existing building automation system (BAS) will be replaced with a new system capable of handling the added control points for the new hot water loop. Installation time is expected to take approximately 6-8 months and work will be performed after business hours and during weekends to minimize interruption to the facility occupants. This option will provide the best control of temperature within each zone throughout the BOC.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2018	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	24	891	1,547			2,462
2. Cost of Removal Proposed	-	31	-			31
3. Total Capital and Removal Proposed (1+2)	24	922	1,547	-	-	2,493
4. Capital Investment 2019 BP	-	2,000	1,500			3,500
5. Cost of Removal 2019 BP	-	-	-			-
6. Total Capital and Removal 2019 BP (4+5)	-	2,000	1,500	-	-	3,500
7. Capital Investment variance to BP (4-1)	(24)	1,109	(47)	-	-	1,038
8. Cost of Removal variance to BP (5-2)	-	(31)	-	-	-	(31)
9. Total Capital and Removal variance to BP (6-3)	(24)	1,078	(47)	-	-	1,007

Financial Detail by Year - O&M ($000s)	2018	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	21	21	2,170	2,212
2. Project O&M 2019 BP	-	-	39	40	2,017	2,096
3. Total Project O&M variance to BP (2-1)	-	-	18	19	(153)	(116)

- The project is included in the 2019 and 2020 BP. The remaining 2019 funding was reallocated to other projects through the Customer Service and Corporate RAC. The 2020BP includes $1,700k in 2020.
- The project has spent $24k in 2018 as well as $134k in 2019 on engineering/design, which is included in the spend above.
- The project includes $217k in contingency which was calculated at 10%.
- O&M expense is anticipated to decrease from the existing systems over the first 10 years with new, more efficient equipment and a 5 year warranty.

Risks

- There are no known risks, environmental or otherwise, associated with this project.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $3,658
The recommendation is to install a hot water loop system to existing VAVs throughout the BOC Main Building and modify ductwork in each mechanical room to provide adequate outside air to the facility. The hot water loop will support the BOC Main Building's existing HVAC configuration and provide improved, localized climate control resulting in the increased comfort of building occupants. The hot water loop will include a new hot water boiler, circulation pumps, all associated piping and a new Building Automation System (BAS). The ductwork modifications in the mechanical rooms will address an issue with code compliance related to improper outside air and return air mixing within the mechanical room plenum. The design of the heat addition also includes modifications to the existing layout of zones within the facility, which will be updated to reflect the current occupancy and use of all areas within the BOC Main Building.

2. Alternative #1: NPVRR: ($000s) $11,159
The next best alternative is to install a "chilled beam system" throughout the BOC. A chilled beam system is a radiation/convection HVAC system designed to heat and cool large buildings by passing water through a heat exchanger (i.e., a system of pipes) integrated into a suspended ceiling system or suspended a short distance from the ceiling. As the beam chills the air around it, the air becomes denser and falls to the floor and is replaced by warmer air moving up from

below, causing constant passive air movement, which cools the room. Converting the BOC to a chilled beam system would be a significant undertaking. While this system would provide the same level of climate control as the recommendation, it would take much longer to install, would be more disruptive to the workplace, and would cost approximately three times as much as the recommendation. A chilled beam system could not utilize existing components of the current BOC HVAC system. The existing air handling units (AHUs) could not be reused for the chilled beam system and chilled water loop piping required for the chilled beam system would be extended throughout the entire BOC main building, creating the need for an evaluation and full redesign of the chilled water system. The existing AHUs have recently been replaced (within 3 years), therefore, replacement of these units is not a prudent option. As such, this alternative is not recommended due to the extensive amount of existing equipment replacement required to support the installation of a chilled beam system. Further, due to space constraints in above-ceiling areas throughout the facility, building modifications would be required to provide the various pathways for necessary new pipework throughout the building. In addition to these space constraints, the current BAS is a legacy-type system with limited expansion capability and would also need to be replaced to support the operation and control of a chilled beam system. This alternative is not recommended.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the BOC Heating System project for $2,493k because the BOC does not currently have an adequate heat system and requires improvements to mechanical rooms to address issues with code compliance related to fresh air intake to the building.

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: November 22, 2019

Project Name: Customer Services Blankets - 2020

Total Expenditures: $5,255k

Project Number(s): Various

Business Unit/Line of Business: Customer Services

Prepared/Presented By: Scott Cooke / Shannon Montgomery

Brief Description of Project

Customer Services uses Blankets to budget and account for the purchase of electric and gas meters, electric transformers (PTs and CTs) and associated labor with the installation of the electric and gas meters. Meter spend is monitored and analyzed on a monthly basis to ensure adequate inventory. This information along with expected changes in the Business Plan years is used to develop the annual budgeted amounts.

Customer Services is requesting approval for $5,255k in Blankets, an increase of $43k from the 2019 Business Plan for 2020.

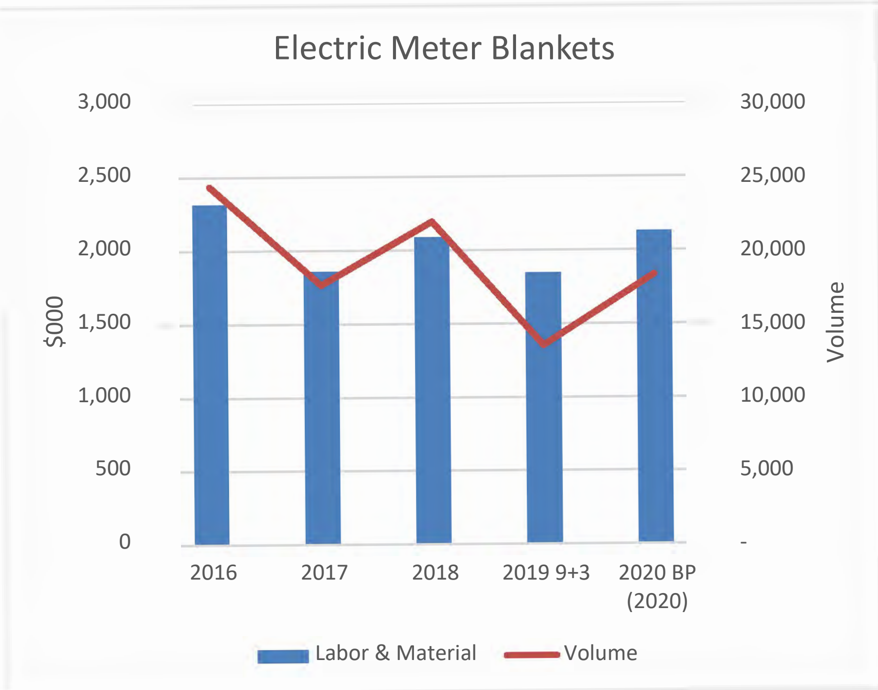
Conclusions and Recommendation

It is recommended that the Investment Committee approve the Customer Services meter blankets for $5,255k to allow for the purchase of meters.

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	



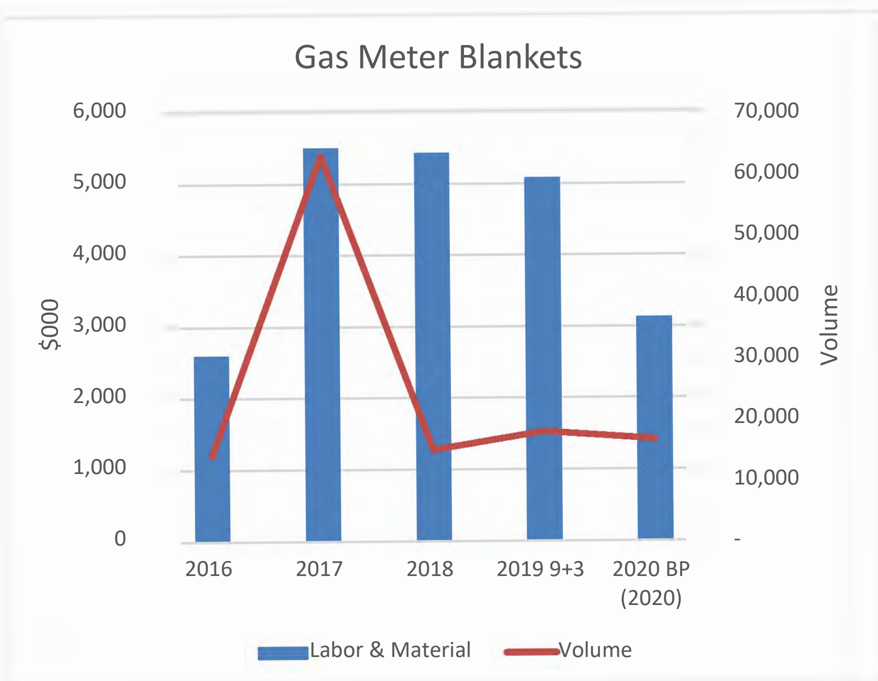
Meter/transformer volumes average 17.9k per year for normal operations.

2016: Failed meter lot purchased 7,000 meters.

2017: Reduced purchase meter plan by 3,400 meters due to planned AMS Project; Failed meter lot purchased 3,000 meters.

2018-2019: Accelerated meter purchases of 6,400 from 2019 to 2018 to prepare for sample meter program in 2019 due to the change in direction of the AMS project.

2020: Projecting typical meter volume.



Gas/ERT volumes average 13.5k per year for normal operations.

2017: Purchased 47,500 gas meters to replace Rockwell 175 gas meters. The meters cost $3.2m.

2018: Labor to install Rockwell 175 meters (~$2m).

2019: Labor to install Rockwell 175 meters (~$2m).

2020: Increase meter purchase volume by 5,500 due to mandatory replacement of residential gas meters at 35 years of age. This will continue to increase volume of gas meters year over year.

Customer Services
2020 Capital Blankets
(In Thousands $)

Blanket Project Number / Description	2020 BP	vs. 2019 BP for 2020			vs. 2019 Forecast (9+3)			Explanations : 2020 BP vs 2019 9+3 Forecast
		2019 BP (2020)	Variance Plan over Plan : (Incr) / Decr	% Chg	2019 9+3 Forecast	Variance to 2019 9+3 : (Incr) / Decr	% Chg	
Electric Meters	2,128	2,271	143	6%	1,848	(279)	-15%	6,390 meters originally planned for 2019 were accelerated into 2018.
Gas Meters	3,128	2,942	(186)	-6%	5,087	1,959	39%	2019 higher due to Rockwell project. Rockwell project will be completed by end of 2019.
Grand Total	5,255	5,213	(43)	-1%	6,935	1,680	24%	

Investment Proposal for Investment Committee Meeting on: 12/19/2019

Project Name: KU General Office Renovation

Total Capital Expenditures: $14,976k (Including $721k of contingency and including $579k of internal labor)

Total O&M: $6,510k

Project Number(s): 00105FACK/L/S

Business Unit/Line of Business: Customer Services / Operating Services

Prepared/Presented By: Cheryl Bruner / Zac Conley

Brief Description of Project

The Kentucky Utilities General Office (KUGO) 9-story building, constructed in 1979 at the corner of Vine and Quality Streets in downtown Lexington, is in need of renovation. Much of the facility infrastructure (mechanical piping, restrooms, windows, and elevators) has reached the end of its useful life creating increased maintenance expense and operational issues. Renovation will also improve space utilization and efficiencies, and replace worn and outdated furniture and finishes.

The facility serves as the primary work location for approximately 250 employees and contractors in Customer Services, Transmission, IT, Electric Distribution, Supply Chain, Communications & Corporate Responsibility, Generation Engineering, and Safety. It houses a customer walk-in Business Office, residential and business customer Contact Centers, a hot backup site for Electric Distribution Control, a Transmission Substation Test Lab, an IT Build Room, and a Fitness Center with shower and locker room facilities. The KU Credit Union is provided space on the 1st floor.

The scope of this project includes a full renovation of floors 2, 5, 6, 7 and 8, a partial renovation of floors 1, 3, 4 and 9, full replacement of the elevators, new windows on most floors, and a "restack" of building occupants. The renovation will address several current building code requirements, primarily related to number of restroom facilities on each floor and Americans with Disabilities Act (ADA) access requirements. Floors being fully renovated will receive new office furniture, flooring, lighting, ceiling grid, ceiling tiles, and paint.

The project was originally opened for preliminary design development in January 2019 for $300k and $276k has been spent to-date. The renovation is planned to occur in phases, with separate bidding for construction to occur as outlined in the timeline below. The project will be completed by the end of 2021. The project is included in the 2020 Business Plan (BP).

Project Timeline

Architectural Services

- March - May 2019 Bid Architectural Services
- June 2019 Award Architectural Service Contract
- October 2019 Finalize Design Drawings for Floors 7 & 8
- April 2020 Finalize Design Drawings for Floor 6

- October 2020 Finalize Design Drawings for Remainder of facility

Construction

- Floors 7 and 8
  - Nov. – Dec. 2019 - Issue RFP, Collect Bids and Issue Contract
  - Jan. – June 2020 - Demo, Construction, Owner Services and Final Move
- Floor 6
  - May – June 2020 - Issue RFP, Collect Bids and Issue Contract
  - July – Dec. 2020 - Demo, Construction, Owner Services and Final Move
- Floor 5 and 9 (Only restrooms and Desktop Area on 9)
  - Nov. – Dec. 2020 - Issue RFP, Collect Bids and Issue Contract
  - Jan. – June 2021 - Demo, Construction, Owner Services and Final Move
- Floors 1, 2, 3 and 4 (Only Business Office staff area on 1; only restrooms on 3 and 4)
  - May – June 2021 - Issue RFP, Collect Bids and Issue Contract
  - July – Dec. 2021 - Demo, Construction, Owner Services and Final Move

Why is the project needed? What if we do nothing?

Since the original construction of the facility in 1979, very few improvements to facility infrastructure (i.e., plumbing, mechanical, electrical) have been completed. Some renovations were made to floors 1, 2, 3, 4, 5 and 9 in the mid-1990's, however, the restrooms were not addressed and are currently in original condition. The 1st floor customer walk-in Business Office was fully renovated within the last seven years and was refreshed again within the last year. In 2015, an area on the southeast corner of the 1st floor was renovated which added a Fitness Center, complete with shower and locker room facilities. Externally, the roof was replaced in 2012 and all sidewalks and concrete around the facility were replaced in 2014-2015.

Currently, there are two capital improvement projects at KUGO in progress. One project is addressing issues with water intrusion across all faces of the building façade. The second is the replacement of major HVAC equipment that has reached the end of its useful life. Completion of these projects in advance of the renovation is paramount to protect any future investments in the facility, as well as assets residing inside the facility.

This project will address the following issues with the facility:

- Restrooms and Galvanized Pipe:
  - Restrooms have original equipment and have reached the end of their useful life.
  - Restrooms do not meet current ADA standards.
  - Restrooms do not meet the Kentucky plumbing and building code (except the 1st floor shower and locker room facilities that were added in the 2015 Fitness Center upgrade).
  - A major flood event in 2018 caused by a 3rd floor plumbing leak affected floors 1, 2, and 3. The flood was due to the failure of galvanized piping. Galvanized piping constitutes the majority of the plumbing piping throughout the building. Galvanized pipe has an expected life span of 30-50 years before failure. The current age of the facility is 40 years and catastrophic failure has already occurred and is expected to continue if replacement is not completed. Unless the plumbing infrastructure of the facility is replaced, a failure is not a matter of if, but when.
  - Restrooms will have all plumbing, fixtures, stalls, floors, ceilings, and lighting replaced. Walls will be painted or tiled.
- Space and Furnishings:
  - There are currently more walled offices in KUGO compared to our other high density office settings (i.e., LG&E Center and Broadway Office Complex). This has resulted in many manager and supervisor positions having walled offices, which is inconsistent with current space usage standards. It also creates space inefficiencies causing a loss of the number of potential employees able to occupy a floor. These numerous walled offices will be demolished.

  - Floors 5 through 8 – These floors will be renovated to similar standards as those used in the recent "tenant improvement" project at the LG&E Center and the "call center renovation" project at the Broadway Office Complex and will include cubicle workstations for managers and below, conference rooms with technology, "hoteling" workspaces, and collaboration spaces. Break-rooms will be added to these floors. Today, employees have converted office cubicles to house microwaves, mini-fridges and coffee makers, and there are no sinks except in the restrooms.
  - Floors 3 and 4 – Only restroom renovations are planned as these floors are not projected to be needed for company employees/contractors in the next several years. These floors can be held for future company use or could be considered for potential leasing opportunities following the completion of this project.
  - Floor 2 – This floor will be renovated and will provide appropriately sized assembly rooms, conference rooms, and space for officers.
  - Floors 1 and 9 – These floors will have renovations to certain areas: the Business Office staff area on 1, the Desktop Operations staff area on 9, and the original restrooms.
  - Certain areas of floors 1, 2 and 9 will remain in existing condition following the renovation:
    - The Transmission Test Lab on the 9th floor and the main Telecom Room on the 2nd floor – both areas house extensive amounts of installed technology and would be very expensive to relocate.
    - The Fitness Center and customer walk-in Business Office on the 1st floor – both have been renovated.
    - The KU Credit Union on the 1st floor.
  - In addition to the space issues as described above, the furniture and finishes in the building are worn and dated, being in excess of 20 years old, and some are original to when the building was constructed in 1979.
- Windows:
  - The existing windows are original (40 years old) to the facility. Over 20% of the 612 windows in the building have visible evidence of failed seals ("foggy" windows). It is probable additional windows have failed seals as well ("micro cracks"). While this is not a concern for water infiltration, it does compromise the energy efficiency of the space, impact the air temperature/comfort for those who sit adjacent to the windows, and presents an aesthetics problem. Due to the age and condition of the windows, this project proposes replacement of the windows on the occupied floors (1-2, 5-9).
  - Waiting to replace the windows outside of renovations to the facility would require interruption to business due to displacement of the building occupants located near windows, removal of furniture and other interferences which would allow access to the windows, and reconstruction of any window sills or any other internal finishes that were disturbed during the window removal and re-installation process.
- Elevators:
  - The elevators are original (40 years old) and are increasingly experiencing issues due to age. In 2018, 20 outages (i.e., entrapments, unexpected shutdowns, etc.) were experienced outside of normal, planned maintenance outages. In 2019, nine such outages have occurred through October.
  - Replacement parts are increasingly difficult and costly to acquire due to the vintage of the equipment. The original manufacturer of the elevators is no longer in business and parts can only be sourced through salvage of other out-of-service elevators of the same manufacturer. Additionally, several outages in 2018 and 2019 lasted more than three business days due to delays resulting from the increased difficulty of parts acquisition.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	260	8,989	5,083		14,332
2. Cost of Removal Proposed	90	187	367		644
3. Total Capital and Removal Proposed (1+2)	350	9,176	5,450	-	14,976
4. Capital Investment 2019/2020 BP	859	4,761	4,255		9,875
5. Cost of Removal 2020 BP	90	187	367		644
6. Total Capital and Removal 2020 BP (4+5)	949	4,948	4,622	-	10,519
7. Capital Investment variance to BP (4-1)	599	(4,228)	(828)	-	(4,457)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	599	(4,228)	(828)	-	(4,457)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed		122	62	6,326	6,510
2. Project O&M 2020 BP		122	62	6,326	6,510
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The 2020BP has the same funding for 2020 and 2021 as the 2019BP for this project. There currently is a funding variance in both 2020 and 2021 of $4,228k and $828k respectively. The 2020 variance will be funded from various projects within Customer Services through the CS and Corporate RAC processes, and the 2021 variance will be addressed in the 2021BP process.

Risks

The timeline of this project coincides with the Town Branch Commons project being performed by the City of Lexington which will construct a walk and bike path along Vine Street. The City has indicated construction around the KUGO facility and parking lot is likely to begin in 2020. While this project should not impact the KUGO renovation work itself, it will impact the employee and customer parking lots. The parking risk has been mitigated by the lease of additional parking spaces in nearby garages.

Asbestos-containing materials (ACMs) have been identified in the facility. The presence of ACMs is limited to the mastic glue located under the original VCT flooring in elevator lobbies and in various locations on all the floors. A certified vendor of the company that specializes in testing and removal of ACMs has already been engaged to identify locations of ACMs throughout the facility and has already performed abatement on floors 7 and 8.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $20,684
   The recommendation is to renovate the floors and restrooms that will be occupied after the renovation: Business Office staff area on 1, floors 2, 5, 6, 7, 8, and the Desktop staff area on 9. The plumbing infrastructure and the existing restrooms on floors 3, 4 and 9 will be replaced so that all old galvanized piping in the facility will be removed. Because floors 3 and 4 will be unoccupied after the project is complete, the remaining space on these floors will stay in its existing condition. The floors being fully renovated will receive new furniture, flooring, paint, ceiling grid and tile, and lighting. The renovation will include construction of additional conference rooms and space plan reconfiguration. New restroom facilities on the fully renovated floors will bring those floors to the current ADA and occupancy standards per the

current Kentucky Building Code. Replacement of the existing elevators and all associated components will be completed. This proposed option also includes replacement of the windows on floors 1, 2, and 5-9. The existing windows are original to the facility and over 20% of the 612 windows across the building have visibly failed seals and, as a result, have a "foggy" appearance and are compromising energy efficiency and building comfort.

2. Alternative #1: NPVRR: ($000s) $27,935
This alternative is to add the renovation of the floors 3 and 4 and full renovation of the 9th floor to the recommended scope, as stated above. Upon completion of the renovations, all floors of the building will be move-in ready; however, because the occupancy load of the facility does not require the additional floor space to be utilized at this time, floors 3 and 4 would be unoccupied after being renovated. Therefore, to reduce costs associated with unnecessary building renovations and furniture purchases, this alternative is not recommended.

3. Alternative #2: NPVRR: ($000s) $24,951
This alternative includes all associated costs to relocate from KUGO to another existing building within downtown Lexington which would be more representative of the current space needs of the business. The purchase of a new building as well as the sale of the existing KUGO facility at market value are included in this alternative. The KUGO facility currently has two unoccupied floors and will also have the same amount of available space if renovations are undertaken. However, relocation to an alternate facility and downsizing square footage would not allow room for future growth and project space in the future. Relocation to an existing, identified, vacant facility would likely require the same level or comparable investment to update aged infrastructure as is being recommended for KUGO, as that building is similar in age and condition. In addition to the needed renovations, the alternative facility would also require expenditures to relocate personnel and equipment to the new site. Two unique functions based at KUGO that would need to be replicated at a new facility include the Transmission Test Lab on the 9th floor and the main Telecom Room on the 2nd Floor. In total, relocating these would cost approximately $2.25-2.5M. The Telecom Room on the 2nd Floor is critical to business operations, and would require a new Telecom Room at a new facility to be operational before decommissioning the existing Telecom Room at KUGO. In addition to housing equipment that communicates with electric substations and circuits, the equipment in the room is also the primary routing point for all toll-free (1-800) calls before they are distributed to call centers. For the aforementioned reasons this alternative is not recommended.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the KUGO Renovation project for $14,976k to ensure building code compliance throughout, replace the aged plumbing, windows, elevators, furniture, and other infrastructure, update the out of date aesthetics, and reconfigure the space plan.

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: January 29, 2020

Project Name: AOC Office Expansion

Total Capital Expenditures: $8,887k (Including $495k of contingency including $285k of internal labor, if applicable)

Total O&M: $458k

Project Number(s): 00029FACL

Business Unit/Line of Business: Customer Services / Gas Distribution Operations

Prepared/Presented By: Cheryl Bruner / Zac Conley / Tom Rieth

Brief Description of Project

In January 2018, Gas Distribution Operations (GDO) announced organizational changes to support Pipeline Hazardous Materials Safety Administration's continual release of extensive new pipeline safety regulations, and its increasing expectations for compliance with existing regulations. As a result of these changes, GDO determined a number of new and existing positions which needed a reporting location at Auburndale Operations Center (AOC) to support operational efficiency. Due to the space constraints in the existing AOC office space, an evaluation at the facility concluded that opportunity exists to expand the office space and provide an area to co-locate existing and new GDO personnel.

The proposed facility expansion will be constructed in an existing area comprising approximately 67,000 square feet which is currently utilized for secure storage of files, warehousing of materials/equipment and storage of emergency response vehicles. The aforementioned materials and vehicles are being relocated to another area which is currently a vacant warehouse space that was previously utilized by the former tenant, Mondi Bags, for storage of their manufactured products. The expansion will accommodate approximately 100 workstations and 7 private offices to support office space needs of GDO engineering, safety, construction and maintenance, analytics, compliance, and administrative positions. The office space expansion also includes space for GDO’s forecasted future headcount growth and space needs.

The expanded facility space will also include areas essential to both gas and electric operations including:

- Assembly Room
- Dedicated Storm Room/War room
- Dedicated Training Room
- Hot backup site for Gas Control
- Updated restroom and locker room facilities
- Wellness Center and Exercise Room
- Conference rooms, collaboration areas and break area

- Space for hotel offices and hotel workstations
- Telecommunications rooms and equipment storage space
- Special Needs Room

Operational efficiencies to be obtained through a facility office expansion include:

- Co-location of approximately 100 GDO managers, engineering, analytics, and design personnel in a single location in order to eliminate workspace in temporary office space and distant on-site warehouse space:
  - Relocation of 30 from AOC main office,
  - Relocation of 34 from AOC temporary office space,
  - Relocation of 35 from AOC warehouse,
  - Of the total personnel listed above, 28 are new employees
- Professional office environment consistent with recruiting and sustaining a professional work force;
- Adequate work space for intern, co-ops, contractors and visitors (hoteling);
- Meeting, training, and collaboration spaces;
- ADA compliance and also addressing issues with existing gender ratio of men's / women's facilities in the current restrooms;
- Dedicated Storm Room (currently the existing Assembly Room is utilized for this purpose)

Milestone timeline for the project is as follows:

• January 2018	GDO Organizational Changes Announced
• February – April 2018	Space needs assessment conducted with GDO
• May 2018	Additional temporary office space brought on-site to AOC
• June – December 2018	Conceptual space plans developed with GDO
• January – March 2019	Project program developed and finalized
• April – June 2019	Architectural services scope developed and awarded
• July – October 2019	Architectural firm developed construction drawings
• October – November 2019	RFP issued; Formal bid process
• December 2019	Investment Proposal submitted
• January 2020	Investment Committee Meeting
• February – March 2020	Award and contract negotiations
• March – December 2020	Construction

The project was originally opened for $250k for engineering and design work. $271k has been spent to date.

<u>Why is the project needed?</u>

The AOC was acquired by LG&E in 1991 from the former H. J. Scheirich Company which previously utilized the complex for the manufacture of cabinets. The complex consists of multiple, large facilities spread across an approximately 40-acre campus in south Louisville. Following the purchase, LG&E subsequently renovated the facility to provide warehousing and office space for operational personnel. Since then, only minor additional renovations have been performed.

AOC is the primary headquarters of GDO's Gas Operations Construction and Engineering, Gas Distribution Integrity and Compliance, Pipeline Safety Management System, Operator Qualification Program, Gas Transmission Integrity and Compliance, Gas Construction, Gas

Engineering and Planning, Gas Control and Storage, and Gas Operations. This facility supports not only GDO staff, vehicles, and parking, but also Electric Distribution Operations' staff, vehicles and parking.

The operational needs of AOC have grown beyond the capabilities of the existing facility, resulting in overcrowding, and an unattractive, diminished professional work environment. Operational deficiencies of the AOC site include:

- The facility lacks the required ADA compliant restrooms.
- Office areas are overcrowded, fragmented across the campus, and not conducive to work group collaboration.
  - Travel throughout the AOC site from the temporary office space and warehouse office space to existing interior main office area is inefficient and hazardous. Employees, contractors, and visitors must navigate in/out of warehouse, temporary office space and outdoor operational areas to reach their necessary work location which creates safety hazards during peak traffic times and inclement weather.
- Workstations and cubicles are an obsolete design and outdated as compared to other company facilities.
- The facility has no available office space/expansion areas for:
  - Additional hires;
  - Interns, Co-ops;
  - Hoteling;
  - Contractors.
- Number of conference and training rooms are inadequate.
  - There are only two conference rooms on-site.
  - There is only one Assembly Room onsite (which can be divided into two with a retractable room divider). It is also utilized as a training room and is converted to a War Room/Storm Room during outage events.
- There is no other location within the facility available for private conversations, closed door meetings, small group meetings, training sessions, employee evaluations, etc.
- There are no dedicated classroom or training spaces.
- The facility has no secure work space for Gas Control to provide for a hot backup. Currently, Gas Control utilizes a SCADA connection which is located in the BOC guard station for their hot backup site.
- Areas currently utilized for office resource areas are spread out through the existing office space resulting in an inefficient use of space for multi-function devices, paper storage, and laydown for document development.
- The engineering teams lack the required open table space for drawing laydown, print approvals and design discussion.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	29	228	8,471	-	8,729
2. Cost of Removal Proposed			158		158
3. Total Capital and Removal Proposed (1+2)	29	228	8,629	-	8,887
4. Capital Investment 2020 BP	650	998	1,500	-	3,148
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	650	998	1,500	-	3,148
7. Capital Investment variance to BP (4-1)	621	770	(6,971)	-	(5,581)
8. Cost of Removal variance to BP (5-2)	-	-	(158)	-	(158)
9. Total Capital and Removal variance to BP (6-3)	621	770	(7,129)	-	(5,739)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed			111	347	458
2. Project O&M 2020 BP			111	347	458
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

As this project has incurred expenses since 2018, three separate Business Plans are reflected in the chart above covering all three years - 2018BP, 2019BP and the latest 2020BP. Included in the $8,887k proposal is $495k in contingency, calculated at 6% of the total project cost prior to project management fees and G&A charges. The balance of the project will be funded in 2020 with the support of the business through the Corporate RAC process.

Risks

- The project will be constructed in an existing indoor environment, therefore, there are no known risks associated with environmental or weather conditions which could potentially interrupt the project schedule.
- If project is not completed there could potentially be risks of impacts to hiring and retention of qualified personnel due to existing conditions of current facility.

Alternatives Considered

1. Recommendation: Facility Expansion NPVRR: $12,322k
   The recommendation from Facility Services and GDO is to convert warehouse space to 67,000 sq. ft. of new office space on the existing AOC site. The expansion will include workstation and office space for approximately 107 people; co-locating key GDO engineering, safety, construction and maintenance, analytical, compliance, and administrative positions. The building will include areas essential to business operations including an Assembly Room and Storm Room, additional restroom and locker room facilities, hot backup site for Gas Control, Wellness Center, collaboration areas, break areas, conference rooms and trainings rooms, and space for hotel offices and workstations.

2. Do Nothing: NPVRR: N/A
   This alternative is not recommended as it will not achieve the current and future operational needs of the business. Based upon evaluation by the Facility Services and the GDO and EDO teams, the functional adequacy of the existing AOC does not meet the operational

needs of the organization. Currently, approximately 37 GDO and EDO personnel are working in the equivalent of six (6) temporary offices on site. Other examples of the inadequacies are: inadequate restroom facilities, ADA compliance issues, over-crowded office areas, lack of space for expansion, lack of space for visitors, co-ops, interns, contractors, lack of conference room and training room space.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the AOC Office Expansion project for $8,887k to better serve the operational needs of the GDO organization and the overall AOC facility.

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: March 31, 2020

Project Name: Corporate Mobile App

Total Capital Expenditures: $2,500k
(Including $400k of contingency & $700k of internal labor)

Total O&M: $294k

Project Number(s): IT0746CG

Business Unit/Line of Business: Customer Services, Corporate Communications, Electric Distribution Operations and Information Technology

Prepared/Presented By: Debbie Leist and Alpha Troutman

Brief Description of Project

Approval is requested for a Corporate Mobile App for $2,500k, which is fully funded in the 2020 Business Plan (BP).

A Request for Information (RFI) was issued in May 2019 to gather additional information on considerations regarding a mobile app solution. The RFI was sent to vendors who were selected based on their experience in creating apps for utilities and recognized through J.D. Power (JDP) and Chartwell. The RFI responses received, confirmed the initial launch functionality should include bill pay and view, outage reporting/status/map and customer service contacts (including social). It was recommended to focus on native app development to take advantage of device specific functionality such as biometrics login, touch to call, GPS, geolocation, and push notifications.

Based on the information gathered from the RFI, a Request for Proposal (RFP) was sent in July 2019 to the same vendors, requesting responses based on the following criteria – price, functionality, customer experience and ongoing support.

Two vendors were invited for onsite presentations in September in which the experience was consistent with the RFP scorecard ratings.

Based on the scorecard, onsite presentations, app store ratings and reference checks, a vendor was selected. The recommended vendor, [redacted] provides a custom developed solution in which LKE would own the code and would require capital investment with minimal ongoing O&M of [redacted] per year.

The team recommends developing a customer mobile app utilizing a minimum viable product (MVP) strategy in which we will develop the app in a short period of time with sufficient features and functionality to satisfy early adopters. It should be feasible to launch the MVP within 12 months of project approval; however, utilizing this strategy depends on building out the application in future phases for which there is money in the BP to cover.

<u>Why is the project needed? What if we do nothing?</u>

Customers prefer to interact with businesses in a variety of ways and through their channel of choice. While customer expectations are constantly changing, we are challenged to determine how we can most effectively meet their needs at a reasonable cost. Therefore, a customer mobile app is recommended for the following reasons:

- Increase in the number of mobile device users on our website/MyAccount from 35% in 2016 to 59% in 2019
  - Customer expectations – mobile device users expect to interact via an app
  - Low effort - an app would make it easier for these customers to self-serve in their preferred channel of choice 24 x 7
- Increase customer engagement and experience as a result of the recent downsizing of Energy Efficiency programs
- According to JDP, 66% of the largest electric, gas and water utility companies have mobile apps
- Launchpad for future company mobile initiatives
- Customers express interest in an app through Outage Map app store rating reviews, social media and our Consumer Advisory Panel members and alumni
- According to Gartner, while mobile apps are currently used by many companies, they are among the few technologies considered to be of great importance in the future

The mobile app will utilize LKE standard interfaces and tools which should align maintenance, resource skillsets and reusability over long term development of self-service channels. Utilizing the MVP strategy will provide the gateway to engage customers in other company offerings and increase customer self-service over time, potentially reducing Customer Service representative interactions in the future. Initially, no financial savings are expected, as is it assumed that transactions will shift from existing self-service channels to the app.

According to JDP, mobile apps rate the highest among consumers for customer engagement - provide better user experience and increased user interaction. Doing nothing in the mobile app space puts our company customer satisfaction ratings at risk. In order to keep pace with self-service demands and customer preferences, a mobile app integrated with the Company's current online offerings is needed.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	1,900	600			2,500
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	1,900	600	-	-	2,500
4. Capital Investment 2020 BP	1,900	600	-		2,500
5. Cost of Removal 2020 BP					-
6. Total Capital and Removal 2020 BP (4+5)	1,900	600	-	-	2,500
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)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	125	61	36	72	294
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	(125)	(61)	(36)	(72)	(294)

The above-referenced financial summary includes a 20% contingency on the capital costs.

The 2020 capital costs will be funded by two projects in the capital plan – $1,200k from the Mobile App Development (MVP – IT0746CG) project and $700k from the My Account Replacement-Enhancement (IT0708B) project. The development of the data interface between the new app and CCS will be reused for the future My Account Upgrade project. The $600k capital cost in 2021 will be funded by the 2021 Mobile App Development (Core App – IT0942B) project. Since the MVP app will be implemented in 2021, less funds will be needed next year for the core app development (additional features).

Estimated training costs, internal and external, and ongoing maintenance account for the O&M variance to the BP in 2020 and 2021. The remaining is ongoing software maintenance for 2022 and beyond.

Risks

- *Project not approved*
    - Unable to meet the expectations of our mobile device customer base
    - Presents challenges to promoting new programs
    - Less personalized communications
    - Promotions delivered through automated calls and mail are less personal and less responsive than direct interaction with customers through a mobile app
- *Project approval*
    - A poor initial mobile app offering will reduce customer adoption and negatively impact app store ratings, creating additional customer experience challenges.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $3,053
   Custom Development - [redacted]
   [redacted] provides a custom developed app, has experience in mobile app development and understands the utility industry. This vendor received the highest RFP scorecard rating. The apps they have developed for utilities have extremely high app store ratings and client references were impressive. They will provide direction for development of our mobile app in conjunction with business and IT resources. Data will be required from our SAP CCS Customer Information System and other ancillary systems. Internal IT resources will assist in project management, defining business requirements, gathering customer focus group data and building services to communicate with the mobile app. [redacted] will lead the customer experience and user interface design and develop the app. [redacted] offered the only custom developed app that provides us with the code for future development. The total capital investment for this alternative is $2,500k and annual ongoing O&M is [redacted].

2. Alternative #1: NPVRR: ($000s) $4,114
   Packaged/Customizable Solution - [redacted]
   [redacted] offers a packaged, cloud-based solution with a minimum level of customization. This vendor received a low RFP scorecard rating, the apps they have developed for utilities have low app store ratings and the client references were lackluster. Due to these reasons, this solution would limit our ability to provide an excellent customer experience, has a higher NPVRR and has costly ongoing O&M support. The total capital investment for this alternative is $1,529k and annual ongoing O&M is [redacted]

3. Alternative #2: NPVRR: ($000s) $NA
   Do nothing
   This is not an option. The risks have been outlined above.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Corporate Mobile App project for $2,500k to meet customer expectations for digital engagement tools. This solution provides customers an additional self-service option in concert with our Company Value of Customer Focus – "We provide the highest quality, safe, reasonably-priced service to all our customers, improving quality of life in the areas we serve. We anticipate and meet the needs of both our external and internal customers. We provide our customers with a wide range of information, programs and tools to help them use energy wisely."

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: April 28, 2020

Project Name: AOC Medical Clinic (161064), BOC Medical Clinic (161157)

Total Capital Expenditures: $1,898k (Including $159k of contingency including $57k of internal labor)

Total O&M: $ $7,383k

Project Number(s): 161064 AOC, 161157 BOC

Business Unit/Line of Business: Human Resources & Facility Services

Prepared/Presented By: DeAnna Hall & Zachary Conley

Brief Description of Project

Following an RFP process, Human Resources (HR) previously received approval to enter into a contract with [redacted] to staff and manage health clinics (including primary care and occupational care) for employees and spouses in the Greater Louisville Area. (See attached Award Recommendation). In this investment proposal, after evaluating the alternatives of constructing the clinics within existing LKE facilities, versus leasing commercial space near LKE's facilities for the clinics, Human Resources and Facility Services are recommending the construction of two on-site health clinics as the lower cost alternative and requesting $1,898k to fund this project. The funds have been reallocated through the Corporate RAC process.

This proposal will locate the health clinics at two major worksites, the Auburndale Operations Center (AOC) and the Broadway Office Complex (BOC), providing the greatest proximity to the largest portion of the LKE workforce. The AOC clinic will serve as the primary location, housing both primary care and occupational care providers, and be the larger of the two sites, utilizing approximately 8,600 square feet of space in the former Mondi Bag office area of the facility. The space allows for an independent entrance for employees, spouses, and new hires, adequate parking to accommodate the large work vehicles, and provides rooms for planned future use, including a physical therapy area, mental health room, an Absence Management room, and a conference room.

The BOC clinic will utilize approximately 2,500 square feet of office space recently vacated through the relocation of the Facility Services office to the former Electric Distribution Control Center space. This clinic will staff one Nurse Practitioner whose main focus will be primary care, but who will also offer some occupational health services.

The design of both clinic locations was finalized at the end of Q1-2020. Construction is anticipated to begin in Q2-2020 following Investment Committee approval and formal bidding/permitting. Both clinic locations are anticipated to be completed by December 31, 2020.

The projects were opened for $48k each in November 2019 for design work. $61k has been spent on AOC Medical Clinic and $48k has been spent on BOC Medical Clinic.

Why is the project needed? What if we do nothing?

The benefits of and business case supporting the employer-provided health clinics were previously set forth and the contract with new business partner [redacted] was approved. This proposal offers additional information supporting the lower cost alternative of hosting the Louisville area clinics at existing company facilities where there is suitable, available space, as opposed to leasing commercial space at an off-site location.

According to Mercer, a benefits consulting company, on-site health services are the most direct way for employers to influence healthcare delivery and provide quality services to employees and families. Mercer's most recent survey of employers with on-site health clinics includes the following key points:

- The top three reasons why employers have implemented clinics are: better management of overall health spend, reducing member health risk, and reducing absenteeism.
- Of employers who have measured return on investment (ROI), over half reported an ROI of 1.5 or higher – meaning that for every $1 invested in the clinics, they saved at least $1.50. Of those, there are several that reported an ROI of 3 or greater.
- Clinics are a core component of their Company's workforce attraction and retention strategy.

Budget Comparison & Financial Summary.

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	1,863				1,863
2. Cost of Removal Proposed	35				35
3. Total Capital and Removal Proposed (1+2)	1,898	-	-	-	1,898
4. Capital Investment 2020 BP	-	-	-	-	-
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(1,863)	-	-	-	(1,863)
8. Cost of Removal variance to BP (5-2)	(35)	-	-	-	(35)
9. Total Capital and Removal variance to BP (6-3)	(1,898)	-	-	-	(1,898)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	1,391	1,432	1,476	3,084	7,383
2. Project O&M 2020 BP					-
3. Total Project O&M variance to BP (2-1)	(1,391)	(1,432)	(1,476)	(3,084)	(7,383)

This capital project has been funded through the Corporate RAC process. In the Capital Evaluation Model ("CEM") for both scenarios (i.e., own the clinics or lease the clinic space), O&M includes all the expenses relating to the [redacted] contract to provide medical staff and supplies/medication to clinics. That O&M spend is offset by projected savings to the company's medical plan and occupational spend calculated by Mercer. (See attached Summary of Medical Savings). For purposes of this analysis, medical savings were assumed to be the same under an own or lease scenario, however, actual savings are likely to be lower in a leased clinic setting because of the loss of convenience as compared to an on-site clinic. [redacted] has projected that the savings reduction with the lease option could be up to a 50% reduction from the on-site facility option. Therefore, the only difference between the two CEMs is the “own” scenario includes $1,898k of capital and removal spend, with facility maintenance O&M of $26k (starting in 2021 and escalated at 2% annually), and the “lease” scenario includes no capital with $344k O&M annually for lease payments (starting in June 2020 and escalated at 2% annually). While both models result in savings to the Company, as reflected in the NPVRR totals below, the savings are much greater under the recommendation to construct the clinics at existing LKE facilities.

Risks

If the construction costs are not approved, the clinic model will be forced to move to an alternative solution, such as an off-site clinic space for LKE.

Alternatives Considered

1. Recommendation: NPVRR: ($7,407k)

   The recommendation is to construct two on-site health clinic locations, one at the AOC and the other at the BOC. Both locations will provide occupational and primary care for employees and spouses around the Greater Louisville Metro area. The AOC clinic site will be constructed in such a way to allow for expansion of medical services without disrupting clinic operations. The AOC location was selected because it includes a large portion of the workforce onsite that require occupational care and is geographically close to two LG&E power generation sites. Additionally, logistically it is important the primary site providing occupational care has the ability to accommodate the large vehicles within the LKE fleet, and at times, multiple large vehicles. The BOC location was selected because it provides care to one of our larger employee groups in Louisville, including contact center and business office employees who, because of the operational needs, have limited flexibility in being away from their desk for longer periods of time. Total capital cost of this option is $1,898k.

2. Alternative #1: NPVRR: ($3,630k)

   The alternative would provide a single off-site health clinic by leasing commercial space outside of the current LG&E facilities. This approach is not recommended as it does not provide the benefits offered through on-site clinics.

Conclusions and Recommendation

It is recommended that Management approve the AOC and BOC Medical Clinic projects for $1,898k to improve consistency in care and overall health, as well as to realize cost savings in medical spending.

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 Chief Financial Officer	Paul W. Thompson Date Chairman, CEO and President

7. Provide justification for amended award recommendation.

An RFP for Comprehensive Health Services was issued in 2018, which included a scope of work for worksite clinic providers, however, a contract was not awarded at the same time that contracts were awarded for the other above listed services, due to the complexity of scope of work.

Three bidders submitted proposals for the worksite clinic services – [redacted]. Each supplier offered a different cost model and approach to provide occupation and primary care, however [redacted] is the most cost effective and recommended supplier. They propose a cost model that offers flexibility and control, and their use of technology to enhance the patient experience and care exceed that of its competitors.

[redacted] provides a comprehensive model, and has experience providing worksite clinic services in the utility industry. They utilize technology that offers personalized educational videos for each patient and artificial intelligence (AI) to provide better patient experience and outcomes. In addition, they offer a patient app that is built in-house and is customizable to fit the LKE culture.

Each of the competitors have experience in providing occupation and primary care, and while [redacted] overall cost in the Pricing Summary table appears to be approximately 2% lower than [redacted] they do not include the cost for prepackaged medications, costing approximately $250k over the 3 year term of the contract. In addition, [redacted] does not propose the use of any technology that would promote proactive care and enhance patient experience. [redacted] offered a cost prohibitive model, offering only one shared (multiemployer) clinic. Their primary care cost is based on a participant per month flat fee, and variable costs are not included. [redacted] model also restricts care to participants identified within a certain proximity to the clinic, unlike [redacted] who allow access to all participants.

[redacted] is the most cost effective and preferred supplier for worksite clinic services. They are experienced in the utility industry and currently include in their portfolio of customers, Florida Power and Light, the largest energy company in the Untied States, who has extensive experience in offering the worksite clinic to its employees.

This Amended Award Recommendation is to award contract spend authority of [redacted] to [redacted] for 3 years, however, this amount is offset by current approved spend [redacted] of [redacted] that will be redirected to clinic operating cost and projected primary care costs of [redacted] that run through the medical plans. See Aggregate Clinical Pricing Summary and [redacted] tables below.

[redacted]

AGGREGATE CLINICAL PRICING SUMMARY

VENDOR	[redacted]
COST CATEGORY	
START-UP COSTS:	
OPERATING COSTS ([redacted] ***ssumes 2 clinics.*** [redacted] ***nly assumes 1 clinic.)***	
VARIABLE COSTS	
GRAND TOTAL THREE (3) YEAR COST	

Footnotes:

[redacted]
Assumes 2 exclusive onsite clinics in Louisville - Broadway Office Complex and Auburndale Operations Center
Louisville BOC clinic assumes 1 Nurse Practitioner, 1 FT LPN/Medical Assistants operating at 25-27 hours. Clinic to provide primary care and occupational medicine. Escalations included each year.
Louisville AOC clinic assumes 1 FT Physician, 1 FT Occupational Nurse Practitioner, 2 FT LPN/Medical Assistants operating at 40 hours. Clinic to provide primary care and occupational medicine. Escalations included each year.
Variable costs includes pre-packaged medications for both locations.

[redacted]
Assumes 2 exclusive onsite clinic in Louisville
Louisville BOC clinic assumes 1 Nurse Practitioner, 1 LPN, 1 Medical Assistant operating at 25-27 hours. Clinic to provide primary care. Escalations included each year.
Louisville AOC clinic assumes 1 FT MD, 1 FT Nurse Practitioner (beginning in Year 3), 1 FT LPN, 1 Health Center Manager, 1 Receptionist operating at 40 hours. Clinic to provide primary care and occupational medicine. Escalations included each year.
Variable costs **does not** include pre-packaged medications for both locations.

[redacted]
[redacted] tilizes shared clinics (multiemployers) and assumes 1 clinic in Louisville.
A one-time activation fee of $50; assumed 2,078 eligible employees in Louisville.
Louisville clinic assumes 1 FT Physician, 1 FT Nurse Practitioner, 3.5 FT Medical Assistants, 1 PT Health Coach, 1 Clinic Host. Clinic to provide primary care and occupational medicine. Escalations included each year. Primary care costs are based on a per employee per month flat fee. Occupation care is determined by projected Baseline Volume; if volume increases, the monthly flat fee increases as well.
Does not include variable costs.

[redacted]	Year 1	Year 2	Year 3	Total
Operating Costs	[redacted]			
Start up Costs for two (2) Louisville Clinics				
Sub-Total				
~10% Contingency				
Total 3 Year Contract Authority				
Offsets				
Current approved spend [redacted]				[redacted]
Projected Primary Care Cost that will run through Medical Plans				
Estimated Net Cost Impact (including contingency)				

8. Recommendation/Approval - It is recommended that Management approve the Amendment to the Comprehensive Health Services contract(s) for [redacted] for 3 years to [redacted].

Sherrie Whitaker Sourcing Lead Date 4/6/2020 | 4:30 PM EDT	DocuSigned by: Sherrie H. Whitaker BE12FA6D7C824EC	Amanda Faulkner Health & Well-Being Program Lead Date 4/6/2020 | 5:04 PM EDT	DocuSigned by: Amanda Faulkner 78821C7D581E486...
Eboni Edwards Supplier Diversity Manager Date 4/6/2020 | 4:36 PM EDT	DocuSigned by: Eboni Edwards 7E5902E5B221496...	DeAnna Hall Manager – Health & Well-Being Date 4/6/2020 | 5:28 PM EDT	DocuSigned by: DeAnna Hall 4AFB06AD12BF42F...
Stephanie R. Pryor Supply Chain Manager Date 4/6/2020 | 4:31 PM EDT	DocuSigned by: Stephanie R. Pryor 71A4781FBF1B48A...	Gregory Meiman VP Human Resources Date 4/7/2020 | 11:17 AM PDT	DocuSigned by: Gregory Meiman 5096C881CE8B402...
David L. Cosby, Jr. Director – Supply Chain Date 4/6/2020 | 4:58 PM EDT	DocuSigned by: David L. Cosby Jr. E234B4DA6E57447...		
Kent Blake CFO Date 4/7/2020 | 11:39 AM PDT	DocuSigned by: Kent Blake C055E669F1EB443...		

CONFIDENTIAL INFORMATION REDACTED

AWARD RECOMMENDATION

PRIVATE AND CONFIDENTIAL

SUBJECT:
RFP NO. 1310118371: COMPREHENSIVE HEALTH SERVICES

This award recommendation represents the authority for Supply Chain, Commercial Operations, or Project Engineering Department to execute a supply agreement. Attach evaluation spreadsheet or Executive Summary.

Scope of Work:	The goal of this RFP is to select an experienced contractor(s) to provide comprehensive health services for Company employees across the service territory. Contract Term will be three (3) years beginning April 1, 2019.

EVALUATION AND SELECTION PROCESS:

Recommended Contractors:	[redacted] Recommendation is based on competitive cost estimates, sufficient work experience, quality of care, enhanced flexibility, robust vendor networks and minimal exceptions to the scope of work/terms and conditions.
Benefits from Selection:	1. **GENERAL SUMMARY:** Company issued RFP for contracted comprehensive health services, which include, but are not limited to: occupational services, staffing services (pre-employment and physical abilities testing), drug and alcohol collection and Medical Review Officer services. Company also requested information for on-site/near site clinics for primary care; however, Company is still reviewing final proposals at this time. Said services impact numerous Company departments such as Health and Well-being, Health Compliance, Absence Management, Staffing, and Safety. By exploring market options, Company identified well-qualified, cost-effective vendors to perform services across its service territory. Company requested relevant work experience, references, implementation strategies, overall work plan, and staffing information with final proposals to perform a robust bid evaluation. Occupational services, including drug and alcohol collection, will be provided by [redacted] providing enhanced flexibility and optimal operational support due to rapidly changing market prices. Drug and alcohol MRO services will be provided by [redacted]), which maintains a robust collection network throughout the service territory providing operational efficiencies for Company. Staffing services will be provided by [redacted], which currently provides said services as a subcontractor under [redacted]. Contracting directly with [redacted] will reduce subcontractor markups and allows for a more direct testing approach. **Attached documents: (1) Aggregate Pricing Summary and (2) Award Recommendation Forecast** 2. **PRICING SUMMARY:** **Unit Rate Cost Extensions:** Bidders provided unit rates for various health services requested by Company (absence management, drug and alcohol testing, MRO services, and staffing). Said rates were extended by estimated annual quantities per respective service; separate annual estimates were derived for absence management, drug and alcohol testing and staffing services. [redacted] bid on all three (3) aforementioned service categories, while [redacted] bid exclusively on staffing services.

CONFIDENTIAL INFORMATION REDACTED

Aggregate Pricing Summary:
Annual estimates for absence management, drug and alcohol testing, MRO services, and staffing services were extended over a three (3) year Contract Term and compared across three (3) vendors and Company's last price paid. Company has maintained extremely competitive rates as a result of its original contract, circa 1990, with [redacted]. Prior contract was 28 years old and has rarely increased unit rates or billed for medical director services. In the open market, obtaining a stand-alone MD would cost approximately [redacted] Moreover, Company's exact historical spend regarding occupational health services is difficult to annualize as different departments utilize various vendors depending on their respective testing needs. Company will include reporting SLAs and invoicing requirements in new contracts to alleviate this issue moving forward. Due to the aforementioned reasons, all bids received were high relative to Company's current contract structure. Company forecasted its annual aggregate cost assuming a joint award structure, and three (3) year cost was estimated at [redacted] relative to a previous three (3) year cost estimate of [redacted]. Please see accompanying pricing summaries for additional details.

3. **PROPOSED WORK PLAN:**

Implementation Strategies:
All awarded vendors submitted implementation plans indicating resources and timing necessary to provide services. Additional topics such as communication plans, scheduling needs and available networks were outlined as well. Company is comfortable with strategies proposed.

Account Management:
Company requested information on how its account would be managed by vendors. All awarded vendors provided qualified account teams along with senior management support. Contacts were clearly outlined for Company reference.

Vendor Presentations:
All awarded vendors have presented to internal Company evaluation team. Vendors provided clarity on any follow-up items from Company, and Company evaluated said vendors highly.

4. **EXPERIENCE:**

Resumes:
All vendors provided resumes for key personnel who will be involved with facilitating work. Said personnel were highly qualified and experienced; Company is confident in vendors' ability to complete Work in accordance with its expectations.

References:
Vendors have been in business for over 30 years at a minimum and have vast experience providing services requested by Company.

5. **CONTRACT VALUATION:**
Contract valuation is based on joint three (3) year aggregate cost estimate of [redacted]. [redacted] has been included to account for unforeseen changes in scope of work or unanticipated increases in Work volumes. Total contract valuation is [redacted] as detailed below.

Contract Term:	April 1, 2019- March 31, 2022
Contract Value:	Proposed Contract Value: [redacted] [redacted] ~20% Contingency: [redacted] [redacted] **Total Approval Amount:** [redacted] [redacted]

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BIDDERS:

Company	MBE/WBE/VOB/Small/Large/Union	Remarks/Notes/Summary
[redacted]	Large Business	**Selected**: Bidder submitted acceptable bid based on all evaluation criteria considered.
[redacted]	Large Business	**Selected**: Bidder submitted acceptable bid based on all evaluation criteria considered.
[redacted]	Large Business	**Selected**: Bidder submitted acceptable bid based on all evaluation criteria considered.
[redacted]	Small Business	Not Selected: Bidder elected not to bid on select services as its outside core offerings.
[redacted]	Small Business	Not Selected: Bidder elected not to bid as is too small for Company support.
[redacted]	Large Business	Not Selected: Bidder only bid on clinical SOW, offers occupational health via onsite/near site ER clinic.
[redacted]	Small Business	Not Selected: Bidder elected not to bid as it focuses on clinical services, not occupational health.
[redacted]	Small Business	Not Selected: Bidder elected not to bid as it focuses on clinical services, not occupational health.
[redacted]	Small Business	Not Selected: Bidder elected not to bid for an unknown reason.
[redacted]	Large Business	Not Selected: Bidder only bid on clinical SOW, not occupational health.
[redacted]	Large Business	Not Selected: Bidder only bid on clinical SOW, offers occupational health via onsite/near site ER clinic.
[redacted]	Small Business	Not Selected: Bidder elected not to bid for an unknown reason.

Type of agreement:	New contract resulting from an RFP.
Team members and goals:	DeAnna Hall: Manager, Health and Well-Being Amanda Elder: Health and Well-Being Program Lead David Wigginton: Sourcing Leader
Supplier Diversity (SD) Effort:	No diverse vendors were identified to participate in this RFP process.

CONFIDENTIAL INFORMATION REDACTED

AWARD RECOMMENDATION

PRIVATE AND CONFIDENTIAL

SUBJECT:
RFP NO. 1310118371: COMPREHENSIVE HEALTH SERVICES

This award recommendation represents the authority for Supply Chain, Commercial Operations, or Project Engineering Department to execute a supply agreement. Attach evaluation spreadsheet or Executive Summary.

Scope of Work:	The goal of this RFP is to select an experienced contractor(s) to provide comprehensive health services for Company employees across the service territory. Contract Term will be three (3) years beginning April 1, 2019.

EVALUATION AND SELECTION PROCESS:

Recommended Contractor:	[redacted] Recommendation is based on competitive cost estimates, sufficient work experience, quality of care, enhanced flexibility, robust vendor networks and minimal exceptions to the scope of work/terms and conditions.
Benefits from Selection:	Please see above description.
Contract Term:	April 1, 2019- March 31, 2022
Contract Value:	Proposed Contract Value: [redacted] ~20% Contingency: [redacted] **Total Approval Amount:** [redacted]

RECOMMENDATION/APPROVAL:

It is recommended that Management approve the [redacted] from April 1, 2019 – March 31, 2022 to [redacted]

Sourcing Leader: **David Wigginton** 2/20/2019 | 6:28 PM EST	DocuSigned by: David Wigginton 6760E9DDA6E24D1...	Proponent- Health and Well-Being Program Lead: **Amanda Elder** 2/21/2019 | 3:57 PM EST	DocuSigned by: Amanda Elder 5924E72584B147E...
Manager, Supplier Diversity: **Eboni Edwards** 2/20/2019 | 6:33 PM EST	DocuSigned by: Eboni Edwards 4FF3615FAA1840F...	Manager, Health and Well-Being: **DeAnna Hall** 2/21/2019 | 4:30 PM EST	DocuSigned by: DeAnna Hall 4AFB06AD12BF42F...
Manager, Supply Chain: **Stephanie Pryor** 2/21/2019 | 2:47 PM EST	DocuSigned by: 71A4781FBF1B48A...	VP, Human Resources: **Gregory J. Meiman** 2/22/2019 | 9:47 AM PST	DocuSigned by: Gregory J. Meiman 5096C881CE88402...
Director, Supply Chain: **David L. Cosby Jr.** 2/21/2019 | 12:18 PM PST	DocuSigned by: David L. Cosby Jr. E2B4B4DA6E57447...		

* This form is not to be used for purchases, after a bid process, of over $10,000,000. A Contract Proposal Form is required as well as presentation at an Investment Committee monthly meeting. The Contract Proposal Form can be found on the Financial Planning and Analysis SharePoint site.

COMPREHENSIVE HEALTH SERVICES AWARD RECOMMENDATION FORECASTS

VENDOR NAME	LAST PRICE PAID [redacted]	[redacted]	[redacted]	[redacted]	JOINT AWARD RECOMMENDATION
ABSENCE MANAGEMENT SERVICES ANNUAL ESTIMATE	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DRUG AND ALCOHOL TESTING ANNUAL ESTIMATE	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]0
STAFFING SERVICES ANNUAL ESTIMATE	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]0
TOTAL ANNUAL ESTIMATE	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]0
MONTHLY BURN RATE	$ [redacted]	[redacted]	[redacted]		[redacted]
Annual $ Differential from LPP		[redacted]	[redacted]		[redacted]
Annual % Differential from LPP		[redacted]	[redacted]		[redacted]
TOTAL 3 YEAR ESTIMATE	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3 Year $ Differential from LPP		$ [redacted]	[redacted]		[redacted]
3 Year % Differential from LPP		$ [redacted]	[redacted]		[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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COMPREHENSIVE HEALTH SERVICES AWR FORECAST (4/1/19 - 4/1/22)

YEAR				2019-2020			2020-2021		2021-2022		
COST CATEGORY	[redacted]	[redacted]	UNIT OF MEASURE	[redacted]	[redacted]	TOTAL ANNUAL PRICE PER CATEGORY	ANNUAL 3% INCREASE	TOTAL ADJUSTED PRICE PER CATEGORY	ANNUAL 3% INCREASE	TOTAL ADJUSTED PRICE PER CATEGORY	
ABSENCE MANAGEMENT SERVICES [1] :			*Each or Hourly:*								
CDL/Crane Physicals	$ [redacted]	[redacted]	600	$ [redacted]	[redacted]						
Executive Profile Lab (includes SMA 24, CBC, Ur)	[redacted]	$ -	100	$ [redacted]	[redacted]						
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1,750.00 [redacted]						
				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DRUG AND ALCOHOL TESTING SERVICES [2] :			*Each or Hourly:*								
BAT Testing	$ [redacted]	[redacted]	1050	[redacted]	[redacted]						
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]						
				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
STAFFING SERVICES [3] : [redacted] UNIT RATES	[redacted]		*Each or Hourly:*								
On-site Physical Abilities Job Analysis (Per Job Code)	$ [redacted]	$ -	[redacted]	[redacted]	[redacted]						
[redacted]	[redacted]	-	[redacted]	$ [redacted]	[redacted]						
						[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	TOTAL STAFFING COST [redacted]
			TOTAL ANNUAL ESTIMATE			[redacted]		[redacted]		[redacted]	
			TOTAL 3 YEAR ESTIMATE							[redacted]	PROJECTED MONTHLY BURN RATE [redacted] 3

[redacted] [redacted]

Notes:

1. Absence Management services will be performed by [redacted]. LKE will attempt to funnel services to lowest cost provider. Annual quantities assume total volume for one year.

[redacted] will be performed by [redacted] Vendor has robust network in place across the state, which is invaluable for Company. Annual quantities assume total volume for one year.

3. Staffing Services will be performed by [redacted] assumes 2 hours of work; cost is likely inflated but conservative. Annual quantities assume total volume for one year.

Summary of Medical Savings Calculated by Mercer

		2021	2022	2023	2024	2025
HR Budget O/S	Physical and Medical Exams (0335)	$ 250,000	$ 250,000	$ 250,000	$ 250,000	$ 250,000
Burdens	Worker's Compensation	$ 187,777	$ 187,777	$ 187,777	$ 187,777	$ 187,777
Burdens	LG&E and KU Active Medical Plan*	$ 829,223	$ 1,088,389	$ 1,301,335	$ 1,340,780	$ 1,381,579
	Occupational Care* **	$ 250,000	$ 250,000	$ 250,000	$ 250,000	$ 250,000
		$ 1,517,000	**$ 1,776,166**	**$ 1,989,112**	**$ 2,028,557**	**$ 2,069,356**

**Savings will occur throughout the year; total expected savings noted above to occur by 12/31.*

***This is estimated savings to the various lines of business, but given the nature of the program it cannot be determined which budget(s) will be favorably impacted.*

Investment Proposal for Investment Committee Meeting on: November 20, 2020

Project Name: Customer Services Blankets - 2021

Total Expenditures: $5,112k

Project Number(s): Various

Business Unit/Line of Business: Customer Services

Prepared/Presented By: Scott Cooke / Shannon Montgomery

Brief Description of Project

Customer Services uses Blankets to budget and account for the purchase of electric and gas meters, electric transformers (PTs and CTs) and associated labor with the installation of the electric and gas meters. Meter spend is monitored and analyzed on a monthly basis to ensure adequate inventory. This information along with expected changes in the Business Plan years is used to develop the annual budgeted amounts.

The 2021 Business Plan assumes full AMI deployment. Legacy electric meter inventory will be managed carefully to maximize reuse of good quality meters and minimize purchases of new legacy electric meters.

Customer Services is requesting approval for $5,112k in Blankets, a decrease of $489k from the 2020 Business Plan for 2021.

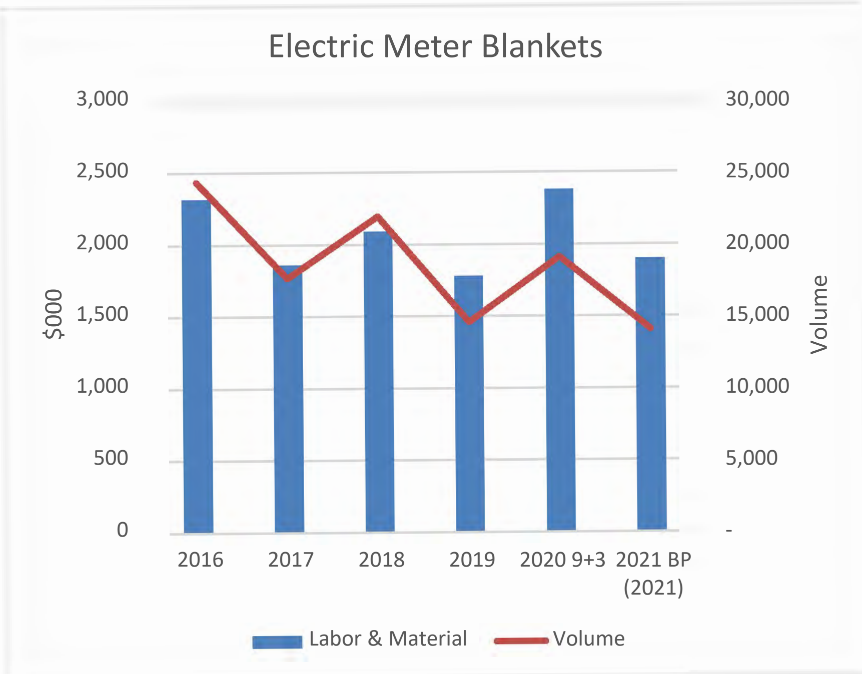
Conclusions and Recommendation

It is recommended that the Investment Committee approve the Customer Services meter blankets for $5,112k to allow for the purchase of meters.

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



Meter/transformer volumes average 17.9k per year for normal operations.

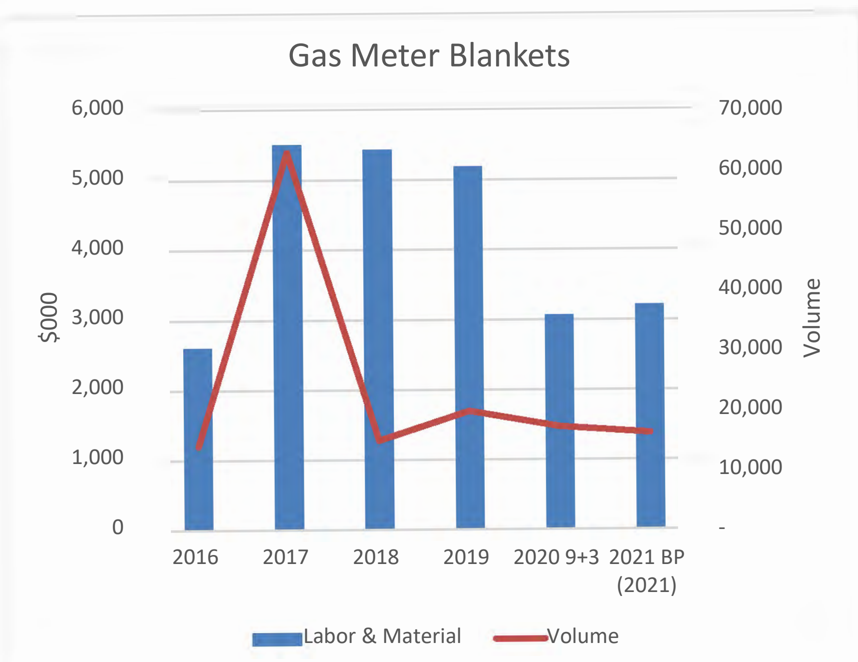
2016: Failed meter lot purchased 7,000 meters.

2017: Reduced purchase meter plan by 3,400 meters due to planned AMI Project; Failed meter lot purchased 3,000 meters.

2018-2019: Accelerated meter purchases of 6,400 from 2019 to 2018 to prepare for sample meter program in 2019 due to the change in direction of the AMI project.

2020: Projecting typical meter volume.

2021: Volume and $ decreasing due to AMI meter purchases in 2021 BP.



Gas/ERT volumes average 13.5k per year for normal operations.

2017: Purchased 47,500 gas meters to replace Rockwell 175 gas meters. The meters cost $3.2m.

2018: Labor to install Rockwell 175 meters (~$2m).

2019: Labor to install Rockwell 175 meters (~$2m).

2020: Increase meter purchase volume due to PSC required replacement of residential gas meters at 35 years of age. The PSC required replacement will continue to increase year over year.

Customer Services
2021 Capital Blankets
(In Thousands $)

Blanket Project Number / Description	2021 BP	vs. 2020 BP for 2021			vs. 2020 Forecast (9+3)			Explanations : 2021 BP vs 2020 9+3 Forecast
		2020 BP (2021)	Variance Plan over Plan : (Incr) / Decr	% Chg	2020 9+3 Forecast	Variance to 2020 9+3 : (Incr) / Decr	% Chg	
Electric Meters	1,900	2,428	528	22%	2,380	480	20%	2021 BP included expectation of AMI project starting in 4th quarter of 2021. Eliminated ~5,000 meters.
Gas Meters	3,212	3,173	(39)	-1%	3,061	(151)	-5%	Compared to 2020 Forecast, 2021 BP includes increased volume of meter purchase and exchanges due to PSC required 35 year end of life replacement of residential type meters.
Grand Total	5,112	5,601	489	9%	5,441	329	6%	

Investment and Contract Proposal for Investment Committee Meeting on: December 18, 2020

Project Name: AMI Full Deployment

Contract Name (Good/Service): System Integration, meters, network, Meter Data Management Expansion

Selected Vendor(s): System Integration – [redacted]

Contract Estimates Update: [redacted] (Contract authorizations will be requested at a later date. Request confirmation of the approach to the major contracts presented in this IP.)

Contract Term: *System Integrator – 3 years;* [redacted] *– 6 years;* [redacted] *– 5 years*

Total Capital Expenditures Requested: $ 352,067k (Including $22,327k of contingency and $50,469k of internal labor)

Total O&M: $39,802k

Project Number(s): Attachment 1

Business Unit/Line of Business: Customer Service & Information Technology

Prepared/Presented By: David Huff / Stuart Wilson / Mike Lowery

Brief Contract/Project Description

This project consists of the purchase and installation of Advanced Metering Infrastructure ("AMI") gas modules and electric meters, purchase and installation of AMI RF mesh networking equipment, the enhancement of the Meter Data Management System ("MDMS"), system integration, and any other necessary items to fully deploy AMI meters across the electric service territory.[1] Gas Automatic Meter Reading ("AMR") will be deployed in the gas service area not served by LG&E or KU electric. LG&E and KU will deploy systems beginning in 2021 (go live for systems in 2023 and 2024) and approximately 1.3M meters from 2022 through 2026. A list of the contracts and anticipated amounts are described below.

All contracts may be canceled without penalty should approval for the project not be granted by the Kentucky Public Service Commission ("KPSC"). A Certificate of Public Convenience and Necessity ("CPCN") has been filed as part of the rate case 2020-349 (KU) and 2020-350 (LG&E). KPSC decision is expected to be known in the second quarter of 2021.

[1] Approximately 3,000 MV90 customer meters and 2,400 commercial gas meters are not included or planned for replacement as part of this project.

Why is the project needed? What if we do nothing?

The Companies' existing population of electro-mechanical and electronic meters is aging and meter failures are expected to increase in future years. Furthermore, the Companies have recently experienced significant increases in meter reading and field services contractor labor costs. Given this increase and the forecasted increase in the number of annual meter replacements, the Companies completed an analysis of metering alternatives to determine the best alternative for reliably serving customers at the lowest reasonable cost. The analysis considered alternatives with AMI and AMR metering technologies in addition to a "Status Quo" alternative where the Companies continue to replace existing meters as they fail with non-communicating electronic meters. Analysis demonstrates that the status quo is no longer the best economic solution and moving to AMI is the least-cost method for reading meters and billing customers and is the most prudent long-term business decision.

The major drivers of Present Value of Revenue Requirements ("PVRR") differences are meter reading, field services costs, meter costs, and two forms of fuel savings from AMI: (1) those resulting from the ability to reduce customers' energy requirements by incrementally lowering distribution voltages through Conservation Voltage Reduction ("CVR"); and (2) those resulting from customers choosing to reduce their energy usage due to access to enhanced usage data made available through the Companies' online ePortal system. The financial analysis is focused entirely on revenue requirements and sets aside difficult-to-quantify benefits for the AMI alternatives that either have no impact on revenue requirements or are hard to quantify ("non-quantified benefits"). Non-quantified benefits include improved safety, improved reliability, improved customer experience, additional customer programs or services, and reduced non-technical losses.

AMI w/ Gas-Only AMR consists of: replacing current meters to avoid on-going labor contract increases, deploying CVR, streamlining meter-related processes, and producing operational savings, all of which are supported by the economic analysis as the lowest reasonable cost option. The request is to approve the project contingent upon KPSC approval of the AMI w/ Gas-Only AMR project submitted to the KPSC as part of the base rate case.

Contract Bid Summary (Major contracts – Does not cover every contract expense)

[redacted] This contract will be submitted to the Investment Committee upon completion of negotiations and KPSC approval.

- Sole source agreement required to implement the metering solution across the territory. Final bulk prices from [redacted] will be compared to a competitively bid metering Request for Proposal ("RFP") in July 2020 to demonstrate competitive prices. The July 2020 RFP confirmed that [redacted] is the least cost supplier of advanced metering compatible with our existing network and systems.
- Contract will include a sub-contract for meter and network installation across the territory that will be awarded following a competitively issued RFP on the Companies' behalf. The Companies will review and confirm the scope of work prior to bid and have access to the bid evaluation.
- Contract will include licensing and technical support expansion to align with the additional meters that will be deployed.

- Contract will include review and support of network devices to ensure communications coverage for AMI meters.
- Jointly responsible for establishing the Meter Operations Center ("MOC") with the system integrator.
- Contract negotiations with [redacted] are on-going. Contract will be contingent upon project approval by the KPSC.
- Estimated Contract Value: [redacted]

System Integrator (SI) – This contract will be submitted to the Investment Committee upon completion of the evaluation, negotiations, and KPSC approval.

- RFP issued in the 3rd quarter 2020. Analysis planned to be completed by year-end 2020.
- SI responsible for meter-to-cash integration of systems between LG&E/KU, [redacted]
- SI responsible for development and implementation of remote service switch processes
- SI responsible for integration of AMI data to Electric Distribution Operations ("EDO") systems for use with voltage sensing, CVR, and EDO benefits included in the business case.
- Jointly responsible for establishing the MOC with [redacted].
- Responsible for enhancement to the Meter Asset Management system ("MAM").
- Contract will be contingent upon project approval by the KPSC.
- Estimated Contract Value: [redacted]

[redacted] – Enhanced MDMS– This contract amendment will be submitted for approval upon completion of negotiations and KPSC approval.

- Result of a competitive bid.
- Contract amendment and amended award recommendation required for the work to enhance the MDMS system to include all rates for customers receiving AMI meters.
- Responsible for technical implementation of meter-to-cash processes in the MDMS.
- Validation, Estimation, and Editing of interval meter data from the [redacted] head-end (raw meter data).
- Responsible for information transfer and synchronization between SAP, applicable metering systems, and the MDMS.
- Contract will be contingent upon project approval by the KPSC.
- Estimated Contract Value: [redacted]

Contract Financial Summary

Contract Expenses ($000s)	2021	2022	2023	2024	2025	2026	Total
Amount projected based on contract award estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Contingency Amount Projected	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total contract authority estimates to requested at a later date	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Project Financial Summary

Financial Detail by Year – Capital ($000s)	2021	2022	2023	2024	2025	2026	Total
1. Project Capital Investment Proposed	17,443	58,851	91,796	90,946	78,102	14,929	352,067
2. Project Capital in 2021 BP	16,843	57,010	88,637	87,628	75,052	11,398	336,568
3. Total Capital variance to BP (2-1)[2]	(600)	(1,841)	(3,159)	(3,318)	(3,050)	(3,531)	(15,499)

Financial Detail by Year – O&M ($000s)	2021	2022	2023	2024	2025	2026	Total
1. Project O&M Proposed	966	7,344	11,365	9,827	8,698	1,602	39,802
2. Project O&M in 2021 BP	966	7,344	11,365	9,827	8,698	1,602	39,802
3. Total O&M variance to BP (2-1)	0	0	0	0	0	0	0

Risks
We will conduct credit reviews to determine risk at the time the contracts are submitted to the Investment Committee for final approval.

Contracts can be postponed or cancelled due to delays or a denial by the KPSC without penalty.

[2] Variances to the 2021 BP are due to AMI assumption changes after the BP was finalized and will be addressed by the Resource Allocation Committee (RAC) in 2021 and in the 2022 BP. Additionally, the capital spend was not included in the calculation of the stores rate for the 2021 BP as it is subject to approval by the PSC. However, from a total corporate standpoint stores admin costs and A&G are covered in the current BP as the AMI project does not project an increase in the total corporate expense in these areas. Upon approval, the rates for the 2022 BP would be recalculated including the burdens attributable to the AMI project; thus, appropriately allocating the stores and A&G burdens across all projects in the Company.

Project Alternatives Considered

The analysis considered the following alternatives:

- Status Quo: Continue to replace existing meters with electronic meters as they fail; continue to manually read meters and manually provide field services.
- Full AMI: Install AMI in electric and gas-only service territories; remotely read AMI meters and remotely provide some field services for electric customers.
- AMI w/ Gas-Only AMR: Install AMI in electric service territory and AMR in gas-only service territory; remotely read AMI meters and remotely provide some field services for electric customers.
- Full AMR: Install AMR in electric and gas service territories; manually read meters with a reduced contractor workforce and continue manually providing field services.

The long-term viability of AMR is a key uncertainty in this analysis. The Companies issued a request for information ("RFI") in March 2020 to gather information from meter vendors regarding the future availability and pricing for various meter types. The responses indicated that only one vendor is committing to future AMR research and investment. Moving forward, AMR metering costs are more likely to escalate faster than other metering technologies, and the risk of obsolescence for AMR meters is high. For this reason, the Companies evaluated the metering alternatives under two AMR obsolescence scenarios: one where AMR becomes obsolete midway through the analysis period and one where AMR remains viable for the full 30-year analysis period.

PVRR Summary Table ($M, 2021 – 2050)

				AMR Becomes Obsolete		AMR Remains Viable		
Alternative	Meter Reading	Field Services	EDO Integration	PVRR (A)	PVRR Delta to Status Quo	PVRR (B)	PVRR Delta to Status Quo	AMR Obsolescence Risk (A less B)
Status Quo	Manual reads	Manual disconnect/ reconnect	No benefit	734.2	0.0	729.9	0.0	4.3
Full AMI	Remote reads	Remote disconnect/ reconnect	Improved outage response, proactive failure detection, CVR	683.0	-51.3	683.0	-47.0	0.0
AMI w/ Gas-Only AMR	Remote reads	Remote disconnect/ reconnect	Improved outage response, proactive failure detection, CVR	680.9	-53.3	679.6	-50.4	1.3
Full AMR	Drive-by reads	Manual disconnect/ reconnect	No benefit	749.3	15.0	687.8	-42.1	61.4

The unfavorable impact of AMR obsolescence is greatest for the Full AMR alternative. The Companies currently read approximately 105,000 electric and gas meters by vehicle using AMR metering technology. This number is reduced to 19,000 in the AMI w/ Gas-Only AMR alternative and zero in the Full AMI alternative. Based on this analysis and the forecasted increases in meter reading and field services costs, if the Companies installed AMR throughout the LG&E and KU service territories and then AMR became obsolete, the most economical solution would be to replace the AMR meters with AMI. While customers would ultimately see the cost savings and other benefits associated with AMI, the early replacement of meters makes this scenario very costly. AMR obsolescence increases the PVRR of the Full AMR alternative by $61.4M and the PVRR of the AMI w/ Gas-Only AMR alternative by only $1.3M. Based on the risk of obsolescence, deploying AMR throughout the Companies' service territories is not a prudent investment for customers.

The AMI w/ Gas-Only AMR alternative reduces the Companies' exposure to AMR obsolescence risk compared to the Status Quo by reducing the total number of meters read by AMR. In addition, unlike the Full AMI alternative, the AMI w/ Gas-Only AMR alternative enables the Companies to utilize existing gas meter assets in the gas-only service territory. Compared to the Full AMI alternative, the favorability of the AMI w/ Gas-Only AMR alternative is relatively small, but it is clearly the preferred alternative for these reasons.

The Companies evaluated the PVRR difference between the AMI w/ Gas-Only AMR and Status Quo alternatives over 243 cases created by varying input assumptions to which the analysis is most sensitive. The PVRR of the AMI+AMR_GO alternative is favorable to the Status Quo in 99.6% of the cases evaluated and ranges from only $4.2M unfavorable to $115.4M favorable. In addition, the favorability of the AMI w/ Gas-Only AMR alternative does not depend on any single input assumption. These results demonstrate that the AMI w/ Gas-Only AMR alternative has virtually no downside risk.

Finally, the timeline for implementing the AMI w/ Gas-Only AMR alternative is 5 years and was developed to deliver savings as soon as possible and provide a good customer experience. In the final phase of the analysis, the Companies evaluated the AMI w/ Gas-Only AMR alternative over different implementation timelines. Delaying the beginning of the 5-year implementation project or deferring AMI systems implementation so that more in-scope meters can be replaced as they fail increases the PVRR by postponing the project's benefits. This analysis shows that the AMI w/ Gas-Only AMR alternative is least-cost and that the proposed 5-year implementation timeline beginning in October 2021 is optimal.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the AMI w/ Gas-Only AMR project for $352,067k as well as grant authorization to complete contract negotiations with the providers discussed above.

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced:

The Capital project spending and contract authority requests included in this Investment Proposal have 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 the capital project and contract authority requests.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

ATTACHMENT 1 – Project Numbers

Project Description	Servco Project #	LGE Project # (Common)	LGE Project # (Electric)	LGE Project # (Gas)	KU Project #
IT Systems	163438	163438LC	n/a	n/a	163438KU
Meters	n/a	n/a	163441LE	163441LG	163441KU
Meter Deployment	163444	163444LC	n/a	n/a	163444KU
Network Communications	163447	163447LC	n/a	n/a	163447KU
Customer Engagement	163454	163454LC	n/a	n/a	163454KU
Meter-to-Cash	163459	163459LC	n/a	n/a	163459KU
Remote Service Switch	163462	163462LC	n/a	n/a	163462KU
Integration with Distribution	163465	163465LC	n/a	n/a	163465KU

Investment Proposal for Investment Committee Meeting on: February 27, 2020

Project Name: South Service Center Renovation and New Facility Construction

Total Capital Expenditures: $9,490k (Including $624k of contingency and $339k of internal labor)

Total O&M: $229k

Project Number(s): 161861/161852LKS/161852LGE/161852KU

Business Unit/Line of Business: Electric Distribution Operations / Facility Services

Prepared/Presented By: Ray Connolly / Denise Simon / Cheryl Bruner

Brief Description of Project

Electric Distribution Operations (EDO) proposes to invest $9,490k at South Service Center (SSC) on construction of a new office building and renovation of the existing operations facility. SSC is the primary operations center for EDO's substation engineering, design, construction, maintenance and asset management functions. The location also supports key materials storage and processing, distribution transformer repairs, and vehicles and equipment staging.

EDO's proposed new 16k ft^2 building will be constructed on a 2.3-acre section of the SSC property which has road frontage to Jennings Lane. The added building space will provide for up to fifty-five workstations and space needs not currently available at SSC, including an adequately sized assembly room, needed professional conference rooms, and "hotel" spaces for employees, interns, vendors and contractors who frequently visit the site. Site work associated with the new building will also provide for roughly forty-eight new parking spaces.

The existing 16k ft^2 SSC operations building is more than fifty-years old and is comprised of multiple building segments which have been added over time. Little renovations have been made to the facility over several decades despite a substantial increase in the number of professional workers assigned to the site. Renovations planned for the existing facility include repurposing some existing employee workstations to add floor space for worker collaboration areas, conference rooms, file storage areas, a larger fitness center, and a much-needed relay lab. Upgrades are also planned for remaining employee workstations and existing restroom and shower facilities, flooring, and lighting.

The combined enhancements of the site will enable EDO to further co-locate key management, engineering, analytical, and technical positions from Broadway Office Complex (BOC) and Auburndale Operations Center (AOC) to SSC. This organizational change will expand operational synergies, facilitating increased and accelerated knowledge transfer between multiple technical, engineering, and analytical personnel, and enable enhanced recruitment, development, and retention of diverse engineering and data analyst talent for the Company. Office space vacated as part of this plan will be repurposed by Operating Services to address existing worker and organizational needs of multiple organizations.

All proposed funding for the project is included in Operating Services' 2020 Business Plan (BP) between 2020 and 2022.

Why is the project needed?

Additional building space and site renovations are needed at SSC to address two primary issues:

I. The existing building space of the operations center is inadequate for current and future staffing and business needs and has prevented strategic co-location of other key EDO engineering and analytical personnel at the site.

II. The current operations center layout and condition encumbers operational efficiencies and hurts the recruitment, development, and retention of individuals with diverse technical and analytical skills.

Over the last three decades, SSC has transitioned from primarily a gas and electric "craft" (field) employee facility to its current mix of field technicians and office workers. Eighty-one employees, interns, and resident-contractors currently work out of site; approximately 42% of the site's workers work primarily in the office, and are primarily engineers, designers, or management personnel. Unfortunately, facility upgrades have not maintained pace with basic business and human resource needs as more diverse site workers have been added. Fundamental deficiencies at the facility currently include:

- Inadequate restroom facilities for female employees
- Outdated workstations, restroom facilities, lighting, and flooring
- Inadequate assembly room area for existing staff
- Inadequate private meeting rooms
- Non-secure storage of critical substation drawings and records
- Overcrowded offices and worker collaboration areas
- No space available for much a needed protection and control lab

Ongoing and projected transformation of the distribution grid will continue to increase operational, transactional, and technical complexity for EDO and continue to necessitate more advanced and diverse technical and analytical skills. As the grid continues to experience advancement of grid and customer end device intelligence/digitalization, greater proliferation of distributed energy resources – including vehicle electrification, the distribution grid will further transform from one-way to multi-directional flow. These factors will require more sophisticated and robust system planning, enhanced protection and control schemes, and increased asset management and operations analytics to assure the Company continues to provide safe, reliable, secure, and resilient electric service to customers.

As part of its strategy to best situate the Company to meet these ongoing and future challenges, EDO plans to co-locate some of its existing system planning and reliability engineers and data analysts (26 employees) with existing substation engineers, designers, and field technicians at SSC. This organizational strategy builds on a similar strategy shaped roughly two decades ago, which provided for the co-location of key substation and asset management engineering and analytical employees with substation field technicians at SSC to help gain operational synergies, facilitate knowledge transfer between subject matter experts, and accelerate technical and operational development.

The proposed new building and renovations at SSC will provide the necessary building space to enable EDO's organizational and transformational strategy, and help to attract, develop, and retain diverse engineering and data analysts candidates to the Company, at a time when the industry is struggling with its image and competition for these skillsets are increasing across all industries.

Milestone timeline for the project is as follows:

- November 2018 — Preliminary project meeting
- January 2019 — Project kick-off meeting with key stakeholders and architectural design firm
- February 2019 — Preliminary design / space plan meeting with stakeholders
- February 2019 — Site survey completed by architectural design firm;
- March 2019 — Progress meeting with stakeholders to review civil and architectural updates, 3D images, narratives for structural and MEP
- April 2019 — Final schematic design complete
- May 2019 — Obtained pricing for full design
- July 2019 — PO requested for full design; Finalizing space plan design
- August 2019 — Officer provided direction to reduce cost and headcount
- September - December 2019 — Development of option 2 for a single-story building
- January 2020 — IP due to Budgeting
- February 2020 — Investment Committee Meeting
- March 2020 - May 2020 — Development of Engineered Drawings
- June 2020 - July 2020 — Bid New Building
- August - September 2020 — Award and Contract Negotiations
- October 2020 — Permitting for New Building
- November - December 2021 — Construction of New Building
- December 2021 — Construction of New Building Complete
- January 2022 - April 2022 — Renovation of Existing Building
- April 2022 — Renovation of Existing Building Complete

The project was opened for $650k in May 2019 for architectural, engineering and project design work. $203k has been spent to date.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	203	1,057	7,016	1,189	9,465
2. Cost of Removal Proposed		25			25
3. Total Capital and Removal Proposed (1+2)	203	1,082	7,016	1,189	9,490
4. Capital Investment 2020 BP	1,483	5,533	7,353		14,369
5. Cost of Removal 2020 BP					-
6. Total Capital and Removal 2020 BP (4+5)	1,483	5,533	7,353	-	14,369
7. Capital Investment variance to BP (4-1)	1,280	4,476	337	(1,189)	4,904
8. Cost of Removal variance to BP (5-2)	-	(25)	-	-	(25)
9. Total Capital and Removal variance to BP (6-3)	1,280	4,451	337	(1,189)	4,879

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	229	229
2. Project O&M 2020 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	(229)	(229)

The 2020 surplus will be reallocated to other projects through the Corporate RAC process. Excess capital needs for remaining years will be addressed in the 2021 BP process. Identified O&M expenses will be included in the 2021 Business Plan.

Risks

- The proposed construction site may potentially have environmental contaminants due to the historical use of PCB-containing materials on the property. Facility Services has consulted with Environmental Affairs and elected to pursue a construction method that will result in the disruption and creation of the least amount of excess soils (spoils) that will be displaced as part of the foundational work for the building. Those “spoils” will be disposed of in a manner that is compliant with all state, federal and regulatory environmental requirements.
- If project is not completed there will be risks of impacts to hiring and retention of employees due to conditions of current facility.

Alternatives Considered

1. **Recommendation: Construct New Office Building at SSC and Renovate Existing SSC Operations Center** NPVRR - $12,629k
   The recommendation from Facility Services and EDO is to construct a new 16k ft^2 office building on available space at SSC and renovate the existing operations center. The new facility will include workstation and office space for up to 55 people and enable co-location of key EDO engineering functions (Reliability Engineering, Electrical Engineering and Planning, Data Analytics, Distribution Asset Management, Distribution Substation Engineering and Design) from BOC and AOC. Construction will include a flexible office area with capacity to reconfigure to add 7-21 workstations in the future. A parking lot with forty-eight parking spaces will be constructed to accommodate expansion. The building will include areas

essential to business operations including an assembly room, collaboration area, break areas, private conference rooms, and space for hotel offices and workstations. This recommendation will also include partial renovation of the existing 16k ft^2 SSC Office Building. The renovation will enhance the facility by repurposing building space to correct some current business needs, including constructing a protection and control/relay lab, increasing the size of the existing training center, and adding secure records areas and private conference rooms. Updates to existing restrooms, lighting, and flooring will also be made.

2. **Alternative #1: Purchase Property Adjacent to East Operations Center, Construct New Office Building, and Renovate Existing SSC Operations Center** NPVRR - $26,536k

This alternative would provide for the purchase of a 9-acre parcel adjacent to East Operations Center in east Louisville, construction of a new office building on the new site, and renovation of the SSC operations center as indicated in the recommended alternative for substation construction and maintenance personnel that would remain at the site. The cost to purchase the needed property adjacent to EOC was evaluated at approximately $10M. While not all nine acres in the parcel would be needed, the current property owner indicated to LKE unwillingness to subdivide the parcel. Accordingly, the property purchase alone would exceed the cost of EDO's recommended alternative. Additionally, this option eliminates existing and projected operational, organizational, and professional synergies which will remain in effect and be enhanced with EDO's recommended alternative. Co-location of engineering with Substation Construction and Maintenance is considered a "best practice", and any separation of the two functions would impact productivity and diminish/dissolve the before mentioned synergies. This is not a recommended approach.

Note: Electric Distribution Operations and Operating Services also considered co-locating referenced engineering and data analytics personnel at AOC. However, it was determined that use of space at AOC for relocation of just over fifty employees from SSC and BOC would prohibit ongoing and planned staffing and building improvements already planned for existing gas and electric work groups stationed at AOC.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the South Service Center Engineering Facility project for $9,490k to better serve the operational needs of Electric Distribution Operations.

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	

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Investment Proposal for Investment Committee Meeting on: February 27, 2019

Project Name: Underground Faulted Circuit Indicators

Total Expenditures: $13,867k (Including $1,261k of contingency)

Project Number(s): 163013 (KU), 163014 (LGE), 163100 (ODP)

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Chase Mills / Denise Simon

Executive Summary

LG&E and KU Electric Distribution Operations seek authorization from the Investment Committee to invest $13,867k over the next three years to install underground faulted circuit indicators (UG FCIs) on approximately 40,000 padmount transformers across LG&E, KU, and ODP service territories.

UG FCIs provide restoration crews with a visual indication (blinking LED) on the exterior of padmount transformers allowing crews to quickly identify the location of underground faults and immediately begin switching to restore customers. UG FCIs do not prevent outages, rather, they reduce the time required to restore underground outages. It is estimated that the average underground outage will be reduced by 53 minutes where UG FCIs are installed. Distribution system SAIDI will be reduced by approximately 0.76 minutes and $31.5k of operating cost will be avoided annually.

The FCI equipment and installation labor contracts were bid separately.[redacted] has been awarded the FCI contract and currently provides the LG&E and KU standard underground and overhead faulted circuit indicators. An increase in the Power Delivery Products contract value is requested via a separate award recommendation to support the equipment needs of this program. Installation labor bids are still open. [redacted] responded with the lowest unit cost, and will be awarded the contract for installation following project approval.

Total cost of the project is estimated to be $13,867k which includes 10% contingency. The UG FCI project is funded in the 2019 Business Plan.

Background
Underground electric facilities are typically more reliable than overhead facilities in that they are naturally shielded from vegetation, wildlife, and other types of interference. While this is a benefit, when underground electric facilities fail, fault identification and isolation is generally more involved and more time consuming than similar activities for overhead facilities. During the past 5 years, there have been 4,236 individual underground distribution outage events in the LG&E and KU service territory. To restore service in underground outage events, line technicians test each cable section of an underground circuit to locate the faulted section. This activity requires opening padmount transformers, unplugging and parking cable terminating elbows inside the transformers and testing the cable for faults. This testing is completed for each cable section in the underground circuit until the fault is located. Once a fault is located, it is isolated and service is restored by unplugging and parking cable terminating elbows inside the padmount transformers at each end of the faulted section. Cable replacement is then scheduled and completed during normal business hours.

The attached Standards Watch “Faulted Circuit Indicator for Underground Conductors” from 2017 shows examples of the PDP underground FCIs, recommended installation locations and an example of service restoration on a typical underground loop circuit following a cable fault.

Deploying FCIs to padmount transformers will provide restoration crews the ability to quickly identify faulted sections of underground cable thus the failure can be immediately isolated and customers restored. The FCI LEDs will be visible from a distance and in many instances will eliminate the need for line technicians to enter customer property to observe the FCI status in addition to elimination of the requirement to test underground cables. FCIs further reduce potential threats to employee safety on customer property such as dogs, fences, and various tripping hazards.

A reduction in average underground outage duration from 128 minutes to 75 minutes, which should equate to a 0.76 minute annual reduction in SAIDI, is the expected reliability improvement associated with this program. The estimate is based on 5 years of historical outage restoration data as well as results of an FCI pilot program completed in 2018. Further, installation of FCIs will improve underground restoration technician efficiencies and result in avoided annual labor expense of about $31.5k.

Alternatives Considered

1. Recommended: Target 40,000 Padmounts: NPVRR: ($000s) $19,187

Targeting all loop fed, underground installations in LG&E and KU requires the installation of approximately 40,000 FCIs. Estimated project cost is $13,867k which includes a 10% contingency. Anticipated benefits include LG&E and KU SAIDI reduction of 0.76 minutes and avoided operating expense of $31.5k annually. Reduced outage durations and entry to customer property are expected to improve the customer experience. Reduced entry to customer property should additionally mitigate the associated risks to employee safety.

2. Install UG FCIs on all Padmounts: NPVRR: ($000s) $24,117

Installation of UG FCIs on all LGE and KU padmount transformers would take place over 5 years at a cost of about $22 million. In addition to the recommended alternative's scope of work, UG FCIs would be installed on non-loop fed transformers where fault location is relatively straightforward without the use of FCIs and in locations where access to customer property is unlikely to be avoided to complete repairs. Reliability and operational advantages associated with this alternative are not sufficient to support its recommendation.

3. Do Nothing: NPVRR: ($000s) $20,269

Neither operational nor financial analysis support the do nothing alternative. The do nothing NPVRR exceeds that of the recommendation due to the cost of unserved energy and the value of operational efficiencies gained. Further, the customer experience and potential safety risk mitigation associated with the recommendation would be forgone.

Project Description

- **Project Scope and Timeline**

Beginning in 2019, approximately 13,000 underground FCIs will be installed annually by business partners. These FCI units will be mapped in the GIS. Business partners will be compensated on a per unit basis. UG FCIs will provide immediate benefits to the customer once they have been installed through reduced restoration durations.

In addition to installing FCIs, our business partners will be responsible for completing a visual inspection of padmount transformers as part of the installation process. Issues discovered during the installation process will be documented and provided to the local operations center as circuits are completed so that corrective actions can be taken.

FCIs have been used in the electric distribution industry for 50+ years. A small number of antiquated, mechanically actuated FCIs still exist on some distribution transformers from past installations. These units no longer function, and have exceeded their useful life. They will be removed and scrapped as they are encountered on this program.

- **Project Cost**

The estimated cost of $13,867k includes 10% contingency.

Firm pricing for FCIs from [redacted] and unit-based installation pricing have been successfully negotiated and 10% contingency should be sufficient to cover project risks.

Economic Analysis and Risks

- **Bid Summary**

The UG FCI contract was bid to [redacted] was awarded the LG&E and KU contract for UG FCIs and currently provides the company standard FCI for both overhead and underground faulted circuit indicators. [redacted] provided the low cost, but did not meet specifications. [redacted] requires a minimum of 2 primary amps continuously, which would limit the application to specific locations.

	[redacted]	[redacted]	[redacted]	[redacted]
UG FCI (Including Fiber Cable)	[redacted]	[redacted]	[redacted]	[redacted]
Total Cost ($000s)	[redacted]	[redacted]	[redacted]	[redacted]

The FCI installation labor contract was bid to [redacted] did not respond. [redacted] was the low cost responder and the full contract will be awarded upon project approval.

	[redacted]	[redacted]	[redacted]	[redacted]
1Ø Install Per Unit	[redacted]	[redacted]	[redacted]	[redacted]
3Ø Install Per Unit	[redacted]	[redacted]	[redacted]	[redacted]
Total Cost ($000s)	[redacted]	[redacted]	[redacted]	[redacted]

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed	4,570	4,595	4,702	-	13,867
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	4,570	4,595	4,702	-	13,867
4. Capital Investment 2019 BP	4,000	4,000	4,000	4,000	16,000
5. Cost of Removal 2019 BP	-	-	-		-
6. Total Capital and Removal 2019 BP (4+5)	4,000	4,000	4,000	4,000	16,000
7. Capital Investment variance to BP (4-1)	(570)	(595)	(702)	4,000	2,133
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(570)	(595)	(702)	4,000	2,133

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)	-	-	-	-	-

The 2019 incremental funding will be requested through the Corporate RAC process and the 2020-2023 changes will be incorporated into the 2020 BP.

Financial Summary ($000s):

Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$0
Contract Labor:	$2,439
Materials:	$7,945
Local Engineering:	$1,127
Burdens:	$1,095
Contingency:	$1,261
Reimbursements:	($0)
Net Capital Expenditure:	$13,867

- **Assumptions**

The cost of unserved energy ($17.2/kWh) was applied in the NPVRR calculation as a financial offset to the project cost. The cost of unserved energy calculation was based on the annual SAIDI improvement resulting from the projected 53 minute reduction in underground outage durations. Outages occurring during major events were included in the cost of unserved energy calculations.

[redacted] has confirmed that their UG FCIs should last 20+ years and has completed testing to support this claim.

Escalation was included for both labor and material costs and was based on negotiated contracts.

- **Environmental**

The sealed lithium ion battery inside the underground FCIs will require proper disposal at the end of their useful life.

- **Risks**

Following approval of the project, the FCI installation labor contract will be awarded to [redacted] The project timeline may be impacted if [redacted] is unable to execute on the UG FCI plan and meet the installation schedules.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Underground Faulted Circuit Indicator project for $13,867k to improve underground distribution system reliability of LGE, KU and ODP.

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	

Date: 7/7/2017

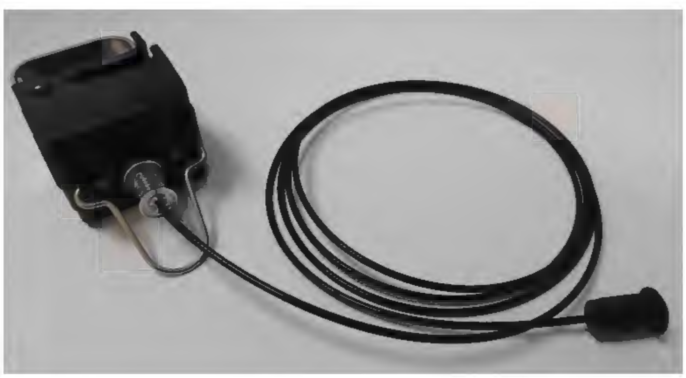
Item: Faulted Circuit Indicator for Underground Conductors

From: Jonathan Wilson

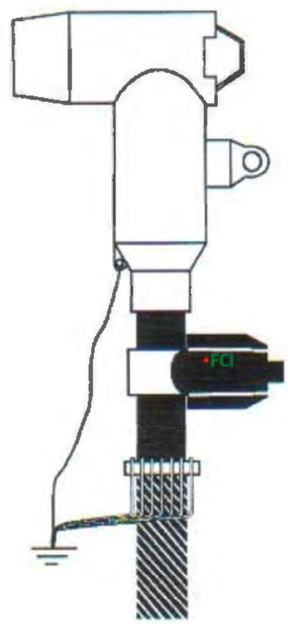
Faulted Circuit Indicators have been used for over fifty years on transmission and distribution circuits to quickly identify the location of faulted equipment.

Faulted Circuit Indicators (FCI) will be added to select underground circuits. The new FCI is a Load Tracker (LM) made by Power Delivery Products. There is not an IIN# at this time. The FCI Load Tracker LM is a snap-on device that will be installed directly below a loadbreak elbow in a padmount transformer. A fiber optic cable will be attached to the FCI for LED remote indication. The remote indicator will be mounted to side of transformer to eliminate the need to open the transformer doors. A flashing red LED will indicate a fault has been detected. The FCI can be configured to be reset manually or automatically after a set period of time. Below each remote indicator will be a label indicating the presence of the FCI.

After installation, the FCI will be added to both Smallworld and Field Smart. The underground indicators will have the same appearance as overhead fault indicators.



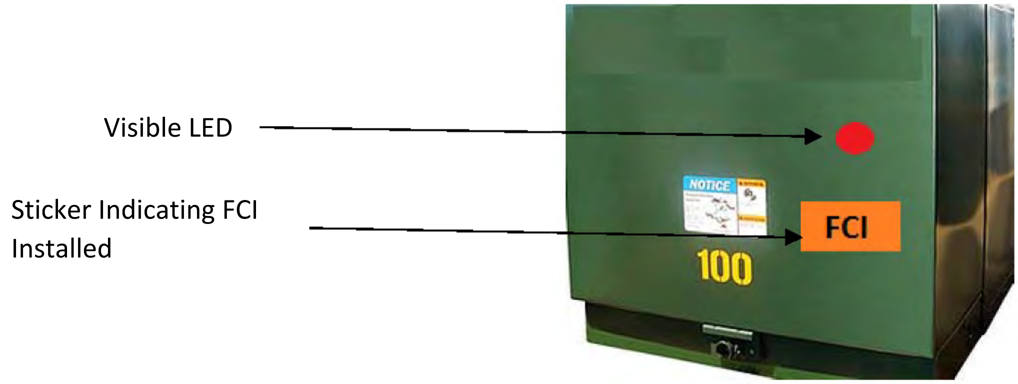
FCI Load Tracker LM with Fiber Optic Remote Indication



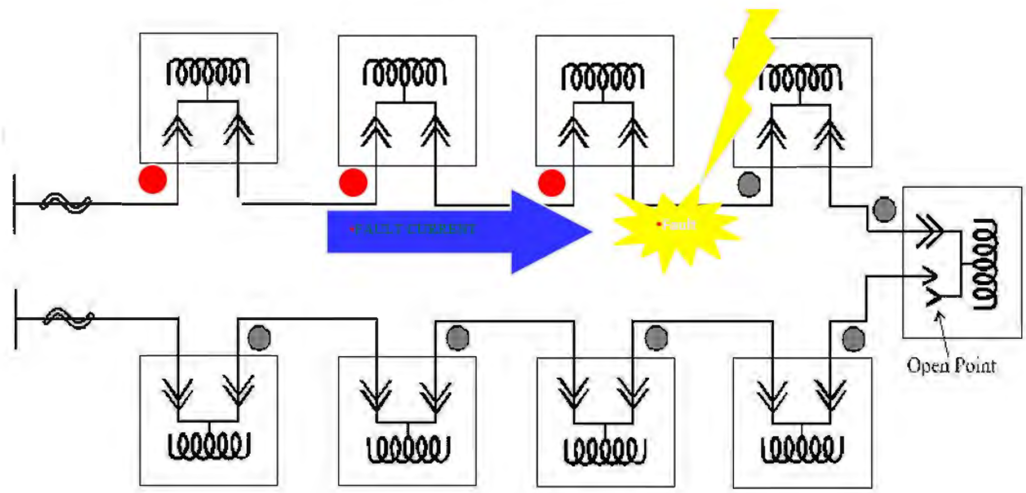
FCI mounted below Loadbreak Elbow

Using the FCI to locate a fault:

When a fault occurs downstream of an FCI, the FCI will recognize the fault and begin flashing. The flash will be a red LED, which will be visible without opening the transformer. Transformers that have an FCI installed will have an orange sticker with “FCI” in black lettering.



By locating the last flashing FCI and the first FCI not flashing, the trouble men have isolated the fault to a specific segment of the circuit.



Typical URD Loop Circuit

By switching out the faulted segment, power can be restored to the balance of the circuit while the faulted segment is repaired. FCI's can be used for troubleshooting or can be permanently left in place on the circuit. Reducing the duration of the outage can lead to improvements in reliability indices such as SAIDI and CAIDI.

Investment Proposal for Investment Committee Meeting on: June 26, 2019

Project Name: West High Street Substation Expansion Project

Total Capital Expenditures: $9,262k (Including $304k of contingency including $442k of internal labor)

Project Number(s): Substation 159809, Distribution 159811

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Tim Smith/Kevin Patterson/Dan Hawk

Brief Description of Project

KU Electric Distribution requests approval for funding to expand and upgrade the two substation transformers and underground distribution facilities at West High Street Substation in downtown Lexington, Kentucky. This capital investment proposal provides for the replacement of both substation transformers with 37MVA 69kV/12kV transformers, five 69kV circuit breakers, two new switchgears, a control house and two additional underground circuits to serve commercial developments in west Lexington. This capital project is needed due to new developments and customer expansion projects associated with Rupp Arena/Heritage Hall, Lexington Town Branch Commons, and the University of Kentucky. These electrical facility upgrades are essential to meet the increased load, as well as maintain the existing underground electrical distribution system design serving customers in downtown Lexington.

Approval is requested in the amount of $9,262k for the West High Street Substation Expansion Project.

Why is the project needed? What if we do nothing?

KU Electric Distribution recommends system upgrades at the West High Substation due to identifiable customer load growth on the downtown Lexington system. The West High Street Substation has two 14.0 MVA 69kV/12kV transformers (West High Street 516-1 and West High Street 516-2) that serve approximately 750 customers in downtown Lexington via seven distribution circuits. These circuits are a major component of the distribution system design that ties to the other two downtown Lexington Substations (Race Street Substation and Vine Street Substation) via automatic switchgear to form an underground "dual lateral" 12kV distribution system that has proven to be very reliable.

Electric Distribution seeks funding to upgrade the West High Street Substation due to new customer growth and existing customer expansions driving forecasted substation transformer overloads. The Electric Distribution loading limits for substation transformers are 100% of top nameplate for the summer (summer loading guideline) and 120% of nameplate for the winter (winter loading guideline). The summer and winter loading limits on the West High Street transformers are 14MVA summer and 16.8MVA winter. Distribution Planning estimates that when all publicized customer development projects planned for the area are completed in years

2021/2022, West High Street 516-1 will reach 110% of its summer rating and 92% of its winter rating. West High Street 516-2 is predicted to be 85% and 71%, of its summer and winter rating respectively. Upgrades are imperative for both substation transformers due to the "dual lateral" design of the Lexington underground 12kVdistribution system that could result in a catastrophic overload on either of the West High Street transformers during a circuit or substation transformer outage.

Electric Distribution Planning recommends site grading improvements on West High Street Substation property (much of the property is not accessible by foot or vehicle), replacement of two 14 MVA 69kV/12kV transformers with two 37MVA 69kV/12kV transformers, installation of five 69kV high side breakers for system protection, installation of associated equipment (switchgear and a control house), rework all seven existing underground distribution circuit exits, and installation of two new underground circuit exits.

A transmission service request has been submitted to TranServ due to this proposed substation capacity increase.

Known projects under construction driving load growth in the area served by West High Street Substation (10.38MW total) are listed below:

- Rupp Arena/Heritage Hall Expansion/Town Branch Commons 8.3 MW
- The Hub at Lexington/associated with UK housing 1.12 MW
- Krikorian Rupp Theatre 0.96 MW

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed	600	5,670	2,992		9,262
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	600	5,670	2,992	-	9,262
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)	(600)	(5,670)	(2,992)	-	(9,262)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(600)	(5,670)	(2,992)	-	(9,262)

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)	-	-	-	-	-

The project was not included in the 2019 BP since all the new development was not known when 2019 BP funding was allocated. The 2019 funding has been approved by the Corporate RAC and the 2020-2021 funding is included in EDO's proposed 2020 BP.

Risks

- There have not been any significant system upgrades or transformer capacity increases in the downtown Lexington system in over 10 years. A deferral to add system capacity will result in substation transformer overloads.
- The downtown Lexington distribution system serves high profile customers and the city of Lexington hosts significant public events where reliable service is expected and the Company's image will be negatively impacted during an unplanned outage event.
- No environmental risks are known.

Alternatives Considered

1. Recommendation: NPVRR:($000s) $10,150
   Replace two 14MVA Substation transformers with two 37MVA 69kV/12kV Substation transformers. Install five- 69kV high side breakers, two switchgears, one control house, rework all seven underground exit circuits, and install two new underground circuits, SCADA facilities and associated equipment. The estimated cost of this solution is $9,262k.

2. Do Nothing Option NPVRR: ($000s) N/A
   LG&E/KU has an obligation to serve all customers and the associated load. The "do nothing" option is not considered an acceptable option because, based on expected loads, it exceeds Distribution Planning's operating limits for distribution substation power transformers and distribution line conductors, and this practice reduces the life of these assets and elevates the risk of failure of a high value, critical asset. This option is not recommend because new business developments and loads are expected to be completed in the 2021/2022 time frame.

3. Build a new 37MVA 69kv/12kV substation on a green field site in the Lexington area that could support the downtown system. NPVRR:($000s) $14,505
   This option was reviewed, but due to project timing, transmission service considerations and the proximity of West High Street Substation to the current developments this option is not recommended. Additionally, KU does not currently own property in the area and purchasing property in this developing area is expected to make this option more expensive than the recommendation. Based on recent land prices and an actual appraisal of land in downtown Lexington ($57 per square foot) one acre could cost $2,483k or more.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the West High Street Substation Expansion Project for $9,262k to rebuild West High Substation and provide reliable electric service for downtown Lexington, Kentucky.

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	

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Investment Proposal for Investment Committee Meeting on: July 31, 2019

Project Name: Corporate Drive Substation Upgrade

Total Capital Expenditures: $4,607k (Including $419k of contingency and $696k of internal labor)

Project Number(s): Distribution Substations 160211, Distribution Lines 160212, Transmission Lines LI-159436

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: James Burns/Kevin Patterson/Dan Hawk

Brief Description of Project

KU Electric Distribution seeks funding authority for distribution substation and circuit improvements in and near the KU Corporate Drive Substation in Winchester, KY. The purpose of this proposed project is to upgrade the Corporate Drive #1 7 MVA transformer to 37.33 MVA transformer, upgrade associated substation equipment and construct an additional distribution circuit to avoid forecasted overloads in the Winchester Industrial Park. The Corporate Drive Substation is located in the Winchester Industrial Park near the intersection of Interstate 64 and KY 627 (Paris Road) and directly serves approximately 48 industrial customers. [redacted] a major customer in the industrial park, has purchased additional property and has begun construction of buildings for new injection molding processes. A contract for service has been signed with the customer for [redacted] MVA of additional load by December, 2020. This additional load would result in 2021 Summer forecasted loading of 154% on the Corporate Drive #1 transformer (7 MVA) or 111% on the Corporate Drive #2 transformer (22.4 MVA) if no upgrades are done.

Approval is requested in the amount of $4,607k ($600k-2019, $2,844k-2020, $1,163-2021) to complete the Corporate Drive Substation Upgrade project.

Why is the project needed? What if we do nothing?

The Winchester Industrial Park is located near the town of Winchester in Clark County, and lies adjacent on the north right of way of Interstate 64. A portion of the park is served by the Corporate Drive substation, which consists of two 69-12kV transformers with top nameplate ratings of 7 MVA and 22.4 MVA. Previous forecasts for this station indicate summer loading as follows:

				2019		2020	
Transformer	Bus	Top Nameplate kVA Capacity	pF	non-coinc kW	% Loading kVA	non-coinc kW	% Loading kVA
CORPORATE DRIVE 12 1	6631	7000	0.91	3957	62%	4074	64%
CORPORATE DRIVE 12 2	6632	22400	0.89	15277	77%	15938	80%

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[redacted] currently operates at two locations in the industrial park, with a combined demand of nearly 10 MW. [redacted] has recently revealed a ten year growth plan in order to keep up with demand for their products. The first two phases of this plan have been approved. A large tract of land has been purchased and construction is underway on two new buildings. The contracted projected load addition is as follows:

Adjustment Date	Adjusted Capacity Level
3/1/2020	1,300 kVA
11/1/2020	5,000 kVA
12/1/2020	6,200 kVA

The resulting additional load creates an overload condition for the Corporate Drive substation. Projected summer transformer loading with the addition of this load on either transformer is shown below:

				2020		2021	
Transformer	Bus	Top Nameplate kVA Capacity	pF	non-coinc kW	% Loading kVA	non-coinc kW	% Loading kVA
CORPORATE DRIVE 12 1	6631	7000	0.91	5257	83%	9834	154%
CORPORATE DRIVE 12 2	6632	22400	0.89	17095	86%	22118	111%

EDO recommends the replacement of the Corporate Drive #1 7 MVA transformer with a 37.3 MVA transformer, the addition of two 69kV breakers for transformer protection, the addition of two 12kV breakers, a control house and construction of approximately 4400 feet of a new 795 AA 12kV circuit. Approximately 600 feet of the 69kV transmission route will also need to be upgraded to accommodate the new circuit.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	600	2,763	1,163		4,526
2. Cost of Removal Proposed		81			81
3. Total Capital and Removal Proposed (1+2)	600	2,844	1,163	-	4,607
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)	(600)	(2,763)	(1,163)	-	(4,526)
8. Cost of Removal variance to BP (5-2)	-	(81)	-	-	(81)
9. Total Capital and Removal variance to BP (6-3)	(600)	(2,844)	(1,163)	-	(4,607)

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)	-	-	-	-	-

The project is included in the proposed 2020 BP and the funding in 2019 has been approved through the Corporate RAC process.

Risks

- The cost of the distribution portion of the project could escalate because costs are based on similar completed work for other projects of similar scope and size.
- Failure to approve this project could negatively impact the company's ability to provide service to Infiltrator Systems new load and future new industrial customers.

Alternatives Considered

1. Recommended Option**:** NPVRR: $5,101k
   The recommended option is to remove the existing Corporate Drive #1 7 MVA 69-12kV transformer and install a 37.3 MVA transformer, two 69kV breakers, one 2000A breaker, one 1200A breaker, a control house, and construct 4400 feet for a new 795AA three phase circuit. In addition to providing adequate capacity for the new load, the new transformer would also provide contingency capacity for the Corporate Drive #2 transformer and the Winchester Industrial substation. The estimated total capital cost of this option is $4,607k.

2. Do Nothing Option: NPVRR: N/A
   KU has an obligation to serve all customers and associated load. The "do nothing" option is not considered an acceptable option because it exceeds Distribution Planning's operating limits for distribution substation power transformers, and this practice reduces the life of the substation transformer and elevates the risk of failure of a high value, critical asset.

3. Alternative 1: NPVRR: $9,301k
   This option considers the extension of a 69kV line to the customer's property and the construction of a new 22.4 MVA 69-12kV substation. This option is not recommended, as it is more costly and does not provide the additional reliability benefit to surrounding customers compared to the recommended option. The estimated capital cost of this alternative is $8,400k.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Corporate Drive Substation Upgrade project for $4,607k to prevent transformer overload and to provide capacity for future customers in the Winchester Industrial Park.

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	

Revised Capital Investment Proposal

Investment Proposal for Investment Committee Meeting on: August 29, 2019

Project Name: Distribution Wood Pole Inspection and Maintenance Program - 2019

Total Capital Expenditures: $12,278k (Including $246k of contingency) (Approved on 12/19/2018)

Total O&M: $506k original; $281k revised

Total Revised Capital Expenditures: $14,268k

Project Number(s): LGE: 19PITP340, KU: 19PITP216, 19PITP156, 19PITP246, 19PITP315, 19PITP766, 19PITP416, 19PITP366, 19PITP236 and 19PITP426

Business Unit/Line of Business: Electric Distribution Operations / Distribution

Prepared/Presented By: Denise Simon

Description of Incremental Ask

Original Approved Capital Expenditures		$ 12,278k
Revised Capital Expenditures Requested		$ 14,268k
Total Increase Requested		$ 1,990k

Electric Distribution Operations (EDO) is authorized to invest $12,278k during 2019 toward continuation of its Distribution Wood Pole Inspection and Maintenance Program. The revised costs do not change the fact that this recommendation is still the best alternative. As 2019 has progressed, several factors have combined to result in the necessity to obtain additional project funds. The most significant of these is the impact of the new overhead construction contract which has resulted in pole replacement costs increasing by roughly 16%. Further, as of June, the number of Priority (replace ASAP) and P1 (replace within 6 months) poles in the pole replacement backlog exceeds the number of poles that can be replaced with remaining 2019 project funds.

In order to replace all Priority and P1 poles in the current backlog and provide funds for replacement of newly identified Priority poles in 2019, EDO recommends approval of an additional $1,990k for its 2019 Distribution Wood Pole Inspection and Maintenance Program.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	Pre-2019	2019	2020	Post 2020	Total
1. Capital Investment Proposed	-	13,446	-	-	13,446
2. Cost of Removal Proposed	-	822	-	-	822
3. Total Capital and Removal Proposed (1+2)	-	14,268	-	-	14,268
4. Capital Investment 2019 BP	-	10,949	-	-	10,949
5. Cost of Removal 2019 BP	-	1,329	-	-	1,329
6. Total Capital and Removal 2019 BP (4+5)	-	12,278	-	-	12,278
7. Capital Investment variance to BP (4-1)	-	(2,497)	-	-	(2,497)
8. Cost of Removal variance to BP (5-2)	-	507	-	-	507
9. Total Capital and Removal variance to BP (6-3)	-	(1,990)	-	-	(1,990)

Financial Detail by Year - O&M ($000s)	Pre-2019	2019	2020	Post 2020	Total
1. Project O&M Proposed	-	281	-	-	281
2. Project O&M 2019 BP	-	506	-	-	506
3. Total Project O&M Variance to BP (2-1)	-	225	-	-	225

The incremental capital funds have been approved through the Corporate RAC process.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the revised authority requested for the 2019 Distribution Wood Pole Inspection Maintenance Program for $14,268K to address the Priority and P1 poles in the current backlog as well as Priority poles identified by year-end.

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	

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Investment Proposal for Investment Committee Meeting on: September 25, 2019

Project Name: Magazine Substation Upgrade

Total Capital Expenditures: $22,884k (Including $2,656k of contingency including $1,671k of internal labor, if applicable)

Total O&M: N/A

Project Number(s): Distribution Substation 160107; Transmission Substation SU-000444; Distribution Lines 160598; Transmission Lines LI-160154

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

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

Brief Description of Project

LG&E Electric Distribution Operations requests approval for funding to improve and upgrade the electric facilities at the Magazine Substation in downtown Louisville. This capital investment proposal provides for the rebuilding and redesign of the existing substation, including installation of two new 44.8 MVA 138/13.8kV transformers, a new switchgear, 5 new 138kV breakers, a new control house, and other associated equipment. This capital project is needed to address overall substation design deficiencies and engineering and operational concerns with aged assets that make up the substation. With approval, this proposed solution will enhance the overall level of service provided to critical customers served from this substation in the downtown Louisville area. The estimated in-service date for this project is December 2022.

Approval is requested in the amount of $22,884k ($400k-2019, $6,039k-2020, $9,623-2021, $6,822-2022) to complete the Magazine Substation Upgrade project. Funding was included in the 2020 Business Plan (BP) for $17,857k ($5,298k – 2020; $8,048k – 2021; $4,511 – 2022). Variance in 2020 ($741k) will be handled via the RAC process in January 2020. 2021-2022 variance will be accounted for in the 2021 BP process.

Why is the project needed? What if we do nothing?

The Magazine Substation is located in downtown Louisville and serves a significant portion of the downtown "business district." There are currently two transformers in the station sourced from the 69kV system that serve 5 "network circuits." The majority of the load served from this substation is connected to these secondary network circuits and is designed to provide top tier reliability performance, serving customers primarily from 11th and Broadway to 5th and Muhammad Ali. Significant customers served on this system include [redacted] (Appendix 2 contains full customer list). Due to the design of a network configuration, however, circuit ties to other substations are not feasible. This leaves this substation at a risk for long duration outages following a catastrophic event.

Since 2012, EDO has significantly invested in the downtown network circuits that serve this area. As part of the PILC replacement project, the majority of the underground distribution facilities have been upgraded. While this is a huge improvement to the service of the customers, very little investment has been made at the substation level serving these network circuits.

The state of the equipment inside the Magazine substation is in dire need of upgrade. Since 2017, there has been two events at the station that have led to complete substation outages. These outages were attributed to legacy equipment failing. Inside the station, there currently is equipment in service, such as the power transformers and control house, that dates back to the 1950's and prior. While station performance over the years has shown to be above average, upgrades inside it are required to proactively prevent future catastrophic failures and maintain the high level of reliability provided to connected customers. Replacing/upgrading existing assets in their current physical locations is an unacceptable practice due to concerns in the existing overall design. The design of the substation (shown in Appendix 1) introduces great risk through equipment being in close proximity that presents catastrophic risk for events such as fire. The entire network served from this substation could be de-energized for up to 72 hours or more for an event such as this. An event of this magnitude would result in significant political and public backlash towards the company – likely making national news and destroying the customer experience for these customers that expect to receive top tier reliability.

This proposed project will correct legacy design deficiencies by rebuilding and redesigning the substation. The existing substation property has adequate room to provide for the substation to be rebuilt with more appropriate equipment spacing. Additionally, associated load will be transferred to the more reliable 138kV transmission system and will include 5 new 138kV breakers inside the substation to provide for transmission level contingency options. Distribution will install two new power transformers, replacing the existing 1950's vintage units. A new switchgear house and control house are also included in the scope of this project – providing for future offset of on-going maintenance associated with the existing switchgear house that was constructed prior to 1950. Overall, the rebuild of this station will reduce on-site risks and offset additional planned capital replacements inside the substation. Four transmission oil filled breakers will be replaced – eliminating a large potential risk for environmental contamination. Other upgrades included in this project that offset planned capital work include transmission protection relays, distribution bus duct replacement, and grounding transformers replacements – approximately $5,000k worth of planned investments.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	400	6,039	8,970	6,673	22,082
2. Cost of Removal Proposed			653	149	802
3. Total Capital and Removal Proposed (1+2)	400	6,039	9,623	6,822	22,884
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)	(400)	(6,039)	(8,970)	(6,673)	(22,082)
8. Cost of Removal variance to BP (5-2)	-	-	(653)	(149)	(802)
9. Total Capital and Removal variance to BP (6-3)	(400)	(6,039)	(9,623)	(6,822)	(22,884)

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)	-	-	-	-	-

The 2019 spend has been approved through the Corporate RAC process. The 2020 BP includes $17,858k ($741k more in 2020 which will be covered via other EDO projects through the RAC process. Increases in 2021 and 2022 will be incorporated into the 2021 BP process.

Risks

- Not completing this project continues the risk of catastrophic failure and prolonged outages inside the Magazine substation which serves portions of downtown Louisville.
- The cost of the of the project could escalate due to the complex nature of the engineering, design, and construction aspects of this project. Costs are based on similar completed work for other projects of similar scope and size.

Alternatives Considered

1. Recommendation: Rebuild Magazine Substation NPVRR: ($000s) $24,026
   Magazine Substation Rebuild project is recommended in order to replace legacy facilities and correct existing design deficiency inside this in order to serve a key portion of downtown Louisville. This project is estimated at $22,884k.

2. Alternative #1: Build a new Substation NPVRR: ($000s) $28,339
   This alternative evaluates the option of rebuilding an equivalent substation to serve the downtown network load at a separate location. This project is estimated to be more expensive than the rebuild of the substation on-site due mainly to no available sites that are readily obtainable within close proximity to Transmission service and the existing network circuits. Building on a separate location greatly increases the costs to extend a service from the transmission system and then construct network circuits back to the existing network infrastructure. This alternative was estimated with a capital spend of $26,780k.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Magazine Substation Upgrade project for $22,884k to replace assets near end of life, correct substation design deficiencies, and maintain safe, reliable power to a portion of the downtown Louisville area.

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	

CONFIDENTIAL INFORMATION REDACTED

[redacted]

CONFIDENTIAL INFORMATION REDACTED

[redacted]

Appendix 2 – Customers served from the Magazine Network

Name	Address
[redacted]	[redacted] [redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
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[redacted]	[redacted]
[redacted]	[redacted] [redacted]
[redacted]	[redacted] [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Investment Proposal for Investment Committee Meeting on: November 22, 2019

Project Name: Electric Distribution Operations Blankets - 2020

Total Expenditures: $131,387k

Project Number(s): Various

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Denise Simon/Steve Woodworth

Brief Description of Project

Electric Distribution Operations (EDO) uses Blankets to budget and account for annual routine short cycle, high volume work types. Capital Blankets are comprised of a multitude of individual small jobs necessitating capital investment. EDO subdivides its Blankets into distinct categories for new customer connections, network enhancements, network maintenance and network repairs. These categories align with primary work drivers for EDO.

Blanket spend is monitored, analyzed and trended on a monthly basis, using a combination of financial and volumetric measures, applicable area economic indicators, and detailed input from area operational managers. This information, with consideration for known influences to historical trends, is used to develop annual budget allocations.

EDO is requesting approval for $131,387k in Blankets, a decrease of $879k from the 2019 Business Plan for 2020.

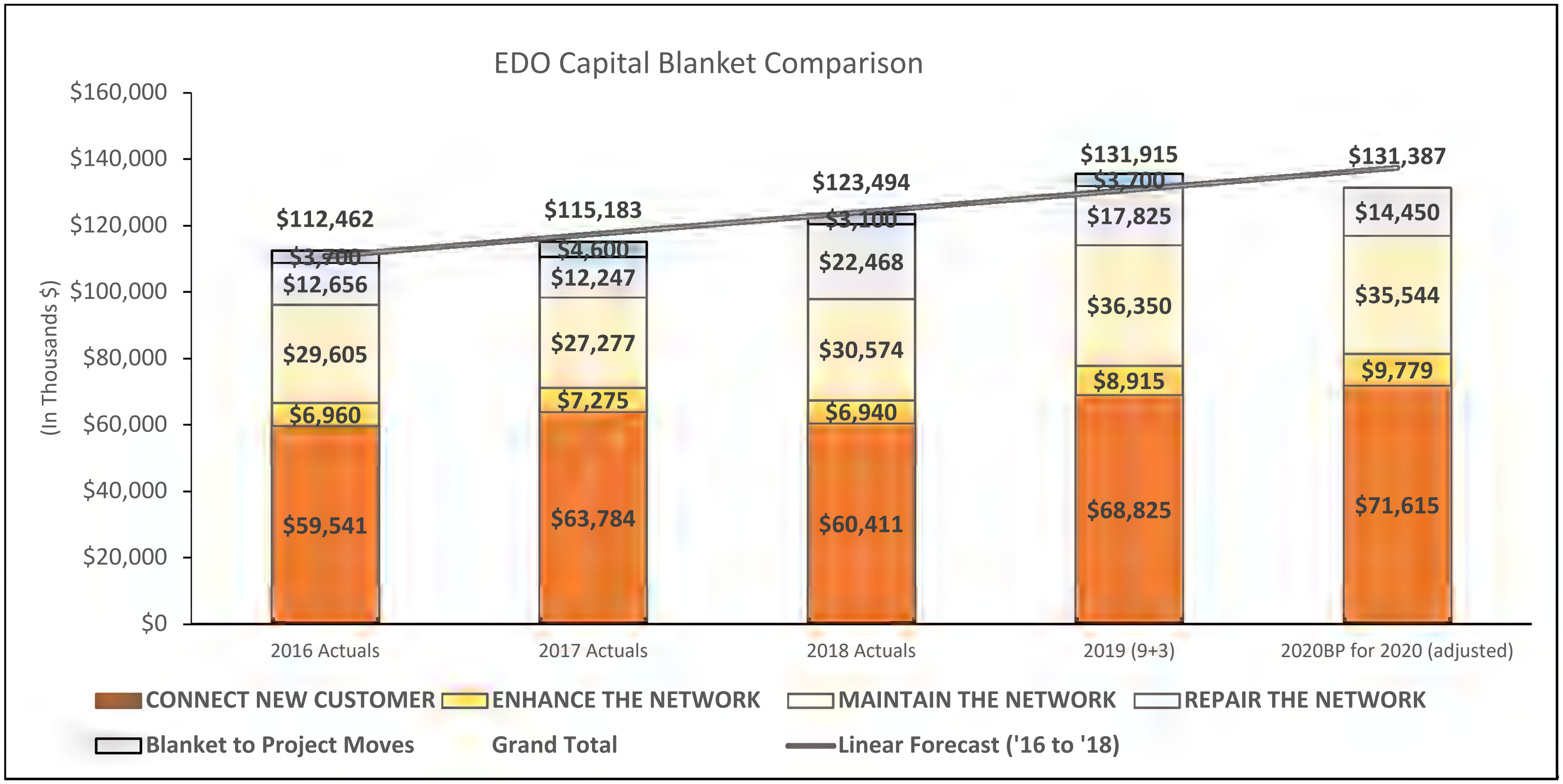
Conclusions and Recommendation

It is recommended that the Investment Committee approve the EDO blankets for $131,387k to allow for the needed work to be completed.

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	



• The chart above compares 3 years of actual spend, the forecast for 2019, and the proposed 2020BP. The gray line is a linear regression trend line using 2016 to 2018 actual spend plus the 2019 forecast to project 2020 spend

• Approximately $3.7 million has been moved from capital blankets to projects in 2019 (primarily new vaults and public works)

• The proposed adjusted 2020 BP is 2.5% higher than the 9+3 forecast, or relatively flat when you consider dollars moved from blankets to projects

• EDO has seen increased spend in new business residential and commercial. EDO expects those spend levels to continue throughout 2020 and is thus requesting an increases in those categories totaling $3.1 million for the 2020 BP, making the BP for those categories flat with 2019 forecast

• EDO has also recognized lower than expected spends in Transformers and New Business Street Lighting and thus is recommending reducing those budgets in the 2020BP by a combined $1.7 million

• EDO is also requesting an additional $800k in Cap/Recloser Maintenance, shifting funds from the 2019 BP for replacment of oil reclosers to 2020 BP

• The net increase of the proposed changes to the 2020 BP is $2.1 million and those changes are reflected throughout the charts and tables in this document

• The proposed 2020 BP was projected using historic spend trends (using annual average growth rate by spend category).

• The 2019 9+3 is approximately $6.8 million higher than 2019 3+9, which was used in April when the 2020 BP was originally proposed.

Electric Distribution Operations
2020 Capital Blankets (In Thousands $)

Blanket Project Description	2020 BP	vs. 2019 BP: 2019 BP for 2020	vs. 2019 BP: Variance Plan over Plan	vs. 2019 BP: % Chg	vs. 2019 Forecast (9+3): 2019 9+3 Forecast	vs. 2019 Forecast (9+3): Variance to 2019 9+3	vs. 2019 Forecast (9+3): % Chg	Variance - 2020 BP vs 2019 Forecast
CONNECT NEW CUSTOMER	$71,615	$74,528	$2,912	4%	$68,825	($2,791)	-4.1%	• $2.1 million variance in new vaults due to $2.1 million moved from blankets to vault projects (2019 vault projects include Brown Hotel, Cambria, Zirmed, Holiday Inn, Westin Moxy, Kunz, Grants, 640 S. 4th Street) • EDO has seen increased spend in new business commercial and residential, spending $1.5 million and $2.8 million, respectively, over budget in those categories. EDO projects New Business Commercial spend in 2019 to be $4.6 million over 2018 actual spend, and 2018 was the lowest spend year since 2014 for this category at $13.1 million. • EDO expects 2020 to trend very closely to 2019 in terms of New Business Commercial and Residential spend and therefore recommends keeping 2020 BP for those categories flat with the 2019 forecast, an increase of $.9 million in Commercial and $2.2 million in Residential. • EDO has not seen yet seen significant increase in demand for new LED lighting and thus recommends reducing New Street Ligthing by $.7 million to $6.4 million (2.2% over 2019 forecast). •Transformer spend has stabilized from '16 to '18 with average spend of $13.9 million. EDO recommends reducing Transformer budget to 3% over 2019 forecast consistent with increases built into transformer supplier contracts. • The total 2020 BP adjustment for New Business is $1.3 million
ENHANCE THE NETWORK	$9,779	$9,763	($16)	0%	$8,915	($864)	-9.7%	• $1.4 million variance in Public Works due to $1.7 million moved from blankets to projects. Public works in 2020 BP is $400k less than 2019 BP • Public works projects slated for 2020 include KY 146 & English Station, KY 22 & Springcrest, I-71 Oldham Co Interchange, and Billtown Rd.
MAINTAIN THE NETWORK	$35,544	$34,624	($919)	-3%	$36,350	$806	2.2%	• The planned oil recloser replacement project included in the Cap/Recloser Maintenance blanket was $1.8 million higher in 2019 than that project in the 2020 BP. With the shift of $800k from 2019 to 2020 in this category, the variance between 2019 forecast and 2020BP is nominal. • Estimated incremental material cost of $1 million added to Repair/Replace Street lights for replacing failed lighting fixtures with more expensive LEDs as opposed to HIDs •Repair/Replace pole has seen consistent spend around $10.1 million from 2015 through 2018. 2019 spend projection is $12.9 million. EDO expects spend in this category to start to return to more normal levels in 2020 with a budget of $11.7 million •Recommend increasing Maintain the Network in the 2020BP by $800k (Cap/Recloser Blanket)
REPAIR THE NETWORK	$14,450	$13,351	($1,099)	-8%	$14,125	($324)	-2.3%	•Using 3-year average for storms resulting in $500k of total variance
BLANKET TO PROJECT MOVES					$3,700	$3,700	100.0%	Approximately $3.7 million has been moved from capital blankets to projects in 2019 (primarily new vaults and public works)
Grand Total	**$131,387**	**$132,266**	**$879**	**1%**	**$131,915**	**$528**	**0.4%**	• Adding the money moved from blankets to projects ($3.7 million) into the 9+3 forecast gives you a new forecast a $131.9 million. • Including blanket to project moves, 2020 BP compared to spend projections for 2019 is essentially flat

*** The 9+3 forecast includes blanket to project moves in the amount of $3,700 (in thousands)*

Electric Distribution Operations
2020 Capital Request (in Thousands $)

		2020 BP	vs. 2019 BP for 2020			vs. 2019 Forecast (9+3)			WR Volumes and Projections					Other Volumetrics		
	Blanket Project Number/Description	**2020 BP**	**2019 BP for 2020**	**Variance Plan over Plan**	**% Chg**	**2019 Forecast (9+3)**	**Variance to Forecast**	**% Chg**	**2017 WRs Closed**	**2018 WRs Closed**	**2019 (9+3) WRs Closed**	**2019 WRs Projected**	**2020 Est WRs Closed**	**2019 % WRs Closed <30 days**	**2019 % WRs Closed <180 days**	**2020 BP Adjustments**
CN	CXGTM-Transformers	$14,466	$18,690	$4,224	22.6%	$14,045	($421)	-3.0%	N/A	N/A	N/A	N/A	N/A	87.6%	100.0%	-$994
CN	CNBCD - New Business Commercial	$17,715	$17,799	$84	0.5%	$17,715	$0	0.0%	1,143	981	795	1,058	1,061	47.0%	94.3%	$877
CN	CNBRD - New Business Residential	$18,560	$16,820	($1,740)	-10.3%	$18,560	$0	0.0%	1,189	1,216	919	1,228	1,211	65.8%	98.9%	$2,177
CN	CNBSV - New Business Electric Services	$12,304	$12,358	$54	0.4%	$12,252	($52)	-0.4%	25,007	22,597	17,070	23,016	23,540	78.4%	96.5%	$0
CN	CNBVLT - New Network Vaults	$2,186	$1,817	($370)	-20.3%	$9	($2,177)	-23973.6%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$0
CN	CSTLT - Street Lighting	$6,384	$7,043	$659	9.4%	$6,244	($140)	-2.2%	5,112	4,493	3,342	4,573	4,726	94.0%	99.8%	-$735
Total Connect New Customer (CN)		**$71,615**	**$74,528**	**$2,912**	**3.9%**	**$68,825**	**($2,791)**	**-4.1%**	**32,451**	**29,286**	**22,126**	**29,875**	**30,537**			**$1,324**
EN	CPBWK - Public Works Relocations ELEC	$2,959	$3,473	$514	14.8%	$1,604	($1,354)	-84.4%	91	37	37	44	57	44.0%	92.0%	$0
EN	CRCST - Relocations Cust Request	$1,890	$1,686	($204)	-12.1%	$2,034	$143	7.1%	736	898	527	667	767	57.5%	97.2%	$0
EN	CRELD - Circuit Hardening / Reliability	$1,762	$1,899	$137	7.2%	$1,953	$191	9.8%	1,399	1,321	774	1,024	1,248	84.4%	98.8%	$0
EN	CSYSEN - System Enhancements ELEC	$3,168	$2,705	($463)	-17.1%	$3,324	$156	4.7%	273	263	247	380	305	43.8%	98.5%	$0
Total Enhance Network (EN)		**$9,779**	**$9,763**	**($16)**	**-0.2%**	**$8,915**	**($864)**	**-9.7%**	**2,499**	**2,518**	**1,585**	**2,114**	**2,377**			**$0**
MN	CNETVLT - Maintain Network Vaults	$1,377	$1,371	($6)	-0.4%	$1,324	($52)	-4.0%	N/A	N/A	N/A	N/A	N/A	84.0%	100.0%	$0
MN	CCAPR-Cap/Recloser Maintenance	$3,563	$2,743	($820)	-29.9%	$3,658	$95	2.6%	489	638	364	488	538	71.0%	98.1%	$800
MN	CRDD - Repair Defective Equipment OH	$7,045	$8,142	$1,097	13.5%	$7,713	$668	8.7%	14,785	15,710	11,918	15,189	15,228	85.3%	99.6%	$0
MN	CRDD - Repair Defective Equipment UG	$3,110	$2,928	($182)	-6.2%	$3,071	($39)	-1.3%	1,043	1,007	612	784	945	75.9%	98.8%	$0
MN	CRSTLT - Repair Defective Street Lights	$8,687	$7,352	($1,335)	-18.2%	$7,712	($975)	-12.6%	32,851	33,917	23,635	33,165	33,311	98.8%	100.0%	$0
MN	CRPOLE - Repair/Replace Pole	$11,762	$12,089	$327	2.7%	$12,872	$1,109	8.6%	3,033	3,120	1,943	2,452	2,868	60.7%	97.5%	$0
Total Maintain Network (MN)		**$35,544**	**$34,624**	**($919)**	**-2.7%**	**$36,350**	**$806**	**2.2%**	**52,201**	**54,391**	**38,472**	**52,078**	**52,890**			**$800**
RN	CTPD - Repair 3rd Party Damage	$1,869	$1,636	($232)	-14.2%	$1,913	$45	2.3%	602	510	369	509	540	88.0%	99.2%	$0
RN	CSTRM - Storms	$4,650	$4,345	($305)	-7.0%	$4,158	($492)	-11.8%	7,039	6,529	10,042	6,512	6,693	N/A	N/A	$0
RN	CTBRD - Trouble Orders ELEC	$7,931	$7,370	($561)	-7.6%	$8,054	$122	1.5%	25,358	26,959	33,005	26,866	26,394	N/A	N/A	$0
Total Repair Network (RN)		**$14,450**	**$13,351**	**($1,099)**	**-8.2%**	**$14,125**	**($324)**	**-2.3%**	**32,999**	**33,998**	**43,416**	**33,887**	**33,628**			**$0**
Blanket to Project Moves						**$3,700**	**$3,700**	**100.0%**								
	Grand Total	**$131,387**	**$132,266**	**$879**	**0.7%**	**$131,915**	**$528**	**0.4%**	**120,150**	**120,193**	**105,599**	**117,954**	**119,432**			**$2,124**

*** The 9+3 forecast includes blanket to project moves in the amount of $3,700 (in thousands)*

Investment Proposal for Investment Committee Meeting on: November 22, 2019

Project Name: N1DT Centerfield Distribution Substation Transformer Contingency Project

Total Capital Expenditures: $8,904k (Including $884k of contingency including $408k of internal labor)

Project Number(s): Distribution Substations 157627, Distribution Lines 157626, Transmission Lines LI-160050, Transmission Substations TBD

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Alan Black / Dan Hawk

Brief Description of Project

Electric Distribution Operations (EDO) seeks funding authority for distribution substation, distribution circuit, and transmission line improvements in and near the LG&E Centerfield Substation. The Centerfield substation is located near the intersection of Highway 393 and Centerfield Drive. Centerfield substation directly serves approximately 5,000 commercial and residential customers. The purpose of this proposed project is to provide year-round full contingency to serve load at the Centerfield TR1, and Crestwood TR1 and TR2 transformers in support of the Company’s Distribution Substation Transformer Contingency Program (N1DT). This will be accomplished by increasing substation capacity at the Centerfield Substation through the installation of a second 44.8 MVA transformer, switchgear, and two 138kV high side breakers. Two additional 138kV breakers are proposed as part of this project in order to provide for better resiliency and reliability on the transmission system serving this station. Two new distribution circuits are proposed as well to better provide operational flexibility, resiliency, and load balancing.

Approval is requested in the amount of $8,904k ($4,639k-2020, $4,265k-2021) to complete the Centerfield Distribution Substation Transformer Contingency project. This project is included in the 2020BP for $8,525k ($3,495k - 2020, $5,030k – 2021). Variance for 2020 funding will be handled in the RAC process. This project was also included in the 2019BP for $8,485k ($4,615k - 2021, $3,870k – 2022). A review of potential N1DT projects during 2019 indicated that the Centerfield Distribution Substation Transformer Contingency Project should receive higher priority.

Why is the project needed? What if we do nothing?

The Distribution Substation Transformer Contingency Program (N1DT) list identifies substation transformers, which in the event of a transformer failure during high load periods, cannot be completely restored by switching to surrounding substations and circuits. Complete restoration to all customers would require either replacement of the failed transformer or installation of a portable transformer, which could take multiple days depending on the specific location.

Centerfield TR1, Crestwood TR1 and Crestwood TR2 have been identified as part of the N1DT Contingency Program. Loading on these existing stations is presented below:

Substation Transformer	Customers	Capacity (MVA)	2018 Summer Load (Actual MVA)	2021 Summer Load (Forecasted MVA)
Centerfield TR1	5064	44.8	28.3	27.9
Crestwood TR1	4332	28	20.2	21.1
Crestwood TR2	3698	28	20.1	20.1

The Centerfield Substation is adjacent to Crestwood Substation, has tie circuits, has available space for expansion, and provides benefit to multiple substations identified as part of the N1DT Contingency Program. The installation of a new 44.8 MVA substation transformer and associated improvements in the Centerfield Substation are proposed in order to provide the existing 44.8 MVA transformer at Centerfield and the two 28 MVA transformers at Crestwood with contingency. Over 13,000 customers are served from these three existing transformers. At the completion of this project, Distribution Operations will be able to restore all customers affected by a transformer outage at either substation within minutes (via bus tie and automated switches) or hours (via manual switching). Without this project, some customers could be out of service for a combined 24 hours while a portable transformer is installed.

This project includes the addition of two 138kV breakers on the Transmission system. The addition of these breakers is required to bring the overall substation design up to today's standards for equipment protection. With the addition of these improvements, communication assisted protection will no longer be needed for the 138kV/69kV autotransformer at the station. Additionally, each facility will be independently protected which will prevent a single facility outage from removing any other facilities from service.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed		4,619	4,218		8,837
2. Cost of Removal Proposed		20	47		67
3. Total Capital and Removal Proposed (1+2)	-	4,639	4,265	-	8,904
4. Capital Investment 2019 BP			4,615	3,870	8,485
5. Cost of Removal 2019 BP					-
6. Total Capital and Removal 2019 BP (4+5)	-	-	4,615	3,870	8,485
7. Capital Investment variance to BP (4-1)	-	(4,619)	397	3,870	(352)
8. Cost of Removal variance to BP (5-2)	-	(20)	(47)	-	(67)
9. Total Capital and Removal variance to BP (6-3)	-	(4,639)	350	3,870	(419)

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)	-	-	-	-	-

Risks

- The cost of the distribution portion of the project could escalate because costs are based on similar completed work for other projects of similar scope and size.
- Additional private easements (including highway and railroad crossings) will need to be obtained to complete work as planned. Failure to obtain easements could result in transfer of work from distribution to transmission at similar funding level.
- The potential for rock removal could increase costs but should be covered by the contingency included for the Distribution Circuit work estimates.
- Failure to approve this project could negatively impact the company's ability to provide service to existing customers during planned or unplanned outage events.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $11,080k
   The recommended option is to install a new 138/12kV, 44.8 MVA transformer and all associated substation equipment in the Centerfield Substation. Also included are transmission and distribution line improvements to provide year-round contingency for three area transformers while enhancing the reliability of the transmission service to this station. This project includes the cost of adding two 138kV breakers as required per Transmission, including a breaker on the high side of the 138/69kV transformer at Centerfield. The estimated capital cost of this option is $8,904k. The recommended option also includes "Cost of Unserved Energy" of approximately $563k in 2020 and $287k in 2021 using a 5% annual probability of a failure of any of the three transformers, a "Cost of Unserved Energy" of $17.895/kwh, a reduction in outage duration of 24 hour outage with the loads going unserved at Centerfield (24.2 MW) and Crestwood TR1 and TR2 (2 MW).

2. Do Nothing Option: NPVRR: ($000s) $11,456k
   This project is consistent with the objectives of the Company's Distribution Substation Transformer Contingency Program. The "do nothing" option was evaluated using standard corporate metrics to quantify the "Cost of Unserved Energy" benefit for providing contingency throughout the year for three area substation transformers. Without adequate contingency capacity, the failure of any of the three transformers addressed by this project could result in an extended outage for some customers of up to a total of 24 hours until the transformer can be replaced, or a mobile transformer is installed. Using a 5% annual probability of a failure of any of the three transformers, a "Cost of Unserved Energy" of $17.895/kwh, a reduction in outage duration of 24 hour outage with the loads going unserved at Centerfield (24.2 MW) and Crestwood TR1 and TR2 (2 MW), the "Cost of Unserved Energy" is approximately $563k in 2020 (escalated annually).

3. Alternative #1: NPVRR: ($000s) $16,920k
   This option considers the addition of a 44.8 MVA transformer at Crestwood Substation. Extensive circuit additions would be required for Crestwood and Skylight substations. Russell Corner substation would also need to be built between Skylight and Centerfield substations in order to remove Centerfield TR1 from the N1DT Contingency List. This option is more expensive, is a less effective system design, and results in less distribution reliability improvements than the recommended option and is not recommended. The estimated capital cost of this alternative is $14,000k.

Alternative #1 also includes "Cost of Unserved Energy" of approximately $563k in 2020 and $287k in 2021 using a 5% annual probability of a failure of any of the three transformers, a "Cost of Unserved Energy" of $17.895/kwh, a reduction in outage duration of 24 hour outage with the loads going unserved at Centerfield (24.2 MW) and Crestwood TR1 and TR2 (2 MW).

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Centerfield Distribution Substation Transformer Contingency Project for $8,904k to provide Distribution Substation Transformer Contingency Program (N1DT) benefits in Louisville, KY.

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	

CONFIDENTIAL INFORMATION REDACTED

Attachment 1: Single Line Drawings

[redacted]

Existing Station Configuration

[redacted]

Proposed Station Configuration

Investment Proposal for Investment Committee Meeting on: November 22, 2019

Project Name: N1DT Middlesboro Area Conversion

Total Capital Expenditures: $5,469k (Including $497k of contingency including $465k of internal labor)
Project Number(s): Distribution Substations 130756 and 155325, Distribution Lines 155305

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: James Burns/Kevin Patterson/Dan Hawk

Brief Description of Project

Electric Distribution Operations (EDO) seeks funding authority for distribution substation and circuit improvements in and near the Middlesboro 1 4kV (124) and Middlesboro 2 4kV (780) substations in Middlesboro, KY. Both of these substations consist of one 7MVA, 4kV transformer and two 14MVA, 12kV transformers. Middlesboro 1 substation is located on the east side of Middlesboro and serves approximately 3,241 customers. Middlesboro 2 substation is located on the west side of Middlesboro and serves approximately 3,465 customers. In the event of a transformer failure, four of these six transformers could not be backed up without the risk of damage or failure of another transformer due to overload. The purpose of this proposed project is to provide year-round full contingency to serve load on the Middlesboro area transformers in support of the Company's Distribution Substation Transformer Contingency Program (N1DT). This will be accomplished by retiring both 4kV transformers, converting the 4kV distribution circuits to 12kV, and replacing both 12kV transformers at Middlesboro 1 (124) substation with 37 MVA 69-12kV units. Additionally, distribution circuit enhancements will be made through circuit upgrades.

Approval is requested in the amount of $5,469k ($2,580k-2020, $2,889k-2021) to complete the N1DT Middlesboro Area Conversion project. This project is included in the 2020 Business Plan (BP) for $5,168k (2020 - $1,250k, 2021 - $2,529k, 2022 - $1,389k). 2020 funding variance will be handled as part of the 2020 RAC process. 2021 and 2022 variances will be addressed in the 2021BP. This project was also included in the 2019 Business Plan (BP) for $5,148k (2021 - $2,648k, 2022 - $2,500k). The project was originally proposed as separate capacity projects for the Middlesboro 1 and Middlesboro 2 Substations. A review of potential N1DT projects during 2019 indicated that the combined N1DT Middlesboro Area Conversion Project should receive higher priority than in the 2019BP.

Why is the project needed? What if we do nothing?

The Distribution Substation Transformer Contingency Program (N1DT) list identifies substation transformers, which in the event of a transformer failure during high load periods, cannot be completely restored by switching to surrounding substations and circuits. Complete restoration to all customers would require either replacement of the failed transformer or installation of a portable transformer, which could take multiple days depending on the specific location. Four of the six transformers in Middlesboro have been identified as part of the N1DT Contingency Program.

The town of Middlesboro, located in Bell County, Kentucky is served by two substations, each having one 4kV-7MVA transformer and two 12kV-14MVA transformers with projected loading as presented below:

Sub Name	**Sub#**	Top namplate MVA	Projected Winter 2022/23 MVA		Projected Summer 2023 MVA		Customers
[redacted]	(124-5)	7	6.9	99%	4.7	67%	1270
[redacted]	(124-6)	14	8.3	59%	7.5	54%	988
[redacted]	(124-7)	14	10.2	73%	9.5	68%	983
total			25.4		21.7		3241
[redacted]	(780-1)	7	6.2	89%	4.8	68%	1049
Middlesboro 2 12kV	(780-2)	14	4.3	30%	6.7	48%	502
Middlesboro 2 12kV 2	(780-3)	14	12.4	89%	6.4	46%	1914
total			22.9		17.8		3465
[redacted]					Total both subs		6706

The proposed solution to provide full contingency during the event of a transformer outage is to convert all 4kV distribution to 12kV and add 12kV substation capacity. There are presently two 4kV direct tie circuits between the substations, which cannot provide full 4kV transformer outage contingency. The conversion and upgrade of these circuits will result in the addition of two 12kV direct ties between the two substations and provide better means for operational flexibility. This is a significant improvement over the two long, heavily loaded indirect existing 12kV ties, and it will allow year around coverage during the event of any transformer outage. Several solutions for adding transformer capacity were proposed and analyzed, and the most cost-efficient plan is to replace the two existing 12kV transformers at the Middlesboro 1 (124) substation with 37MVA units and retire the 4kV transformers in both substations. This will allow either of those new transformers to cover an outage on the other one, as well as covering any transformer outage at the Middlesboro 2 substation.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed		2,553	2,632		5,185
2. Cost of Removal Proposed		27	257		284
3. Total Capital and Removal Proposed (1+2)	-	2,580	2,889	-	5,469
4. Capital Investment 2019 BP			2,648	2,500	5,148
5. Cost of Removal 2019 BP					-
6. Total Capital and Removal 2019 BP (4+5)	-	-	2,648	2,500	5,148
7. Capital Investment variance to BP (4-1)	-	(2,553)	16	2,500	(37)
8. Cost of Removal variance to BP (5-2)	-	(27)	(257)	-	(284)
9. Total Capital and Removal variance to BP (6-3)	-	(2,580)	(241)	2,500	(321)

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)	-	-	-	-	-

Risks

- Failure to approve this project could negatively impact the company's ability to provide service to existing customers during planned or unplanned outage events.
- The cost of the project could escalate due to the complex nature of the engineering, design, and construction aspects of this project. Costs are based on similar completed work for other projects of similar scope and size.

Alternatives Considered

1. Recommended Option: NPVRR: $7,078k

   The recommended option is to replace the two existing 14 MVA 69/12kV transformers in the Middlesboro 1 (124) Substation with 37.3 MVA transformers and all associated substation equipment. Also recommended is the removal and retirement of the 4kV transformers at Middlesboro 1 (124-5) and Middlesboro 2 (780-1) substations and to convert all 4kV distribution lines to 12kV. Improvements to two tie circuits are also recommended. The estimated capital cost of this option is $5,469k. The recommended option also includes cost of $550k in 2020 and $281k in 2021 calculated using a 5% annual probability of a failure for the transformers, a "Cost of Unserved Energy" of $17.895/kwh and a reduction in outage duration of 30 hour outage with the loads going unserved at Middlesboro 1 4KV(7.7 MW), Middlesboro 2 4kV(8.0 MW), Middlesboro 1 12kV (2.9 MW) and Middlesboro 1 12kV 2 (2.6 MW).

2. Do Nothing Option: NPVRR: $10,951k

   This project is consistent with the objectives of the Company's Distribution Substation Transformer Contingency Program. The "do nothing" option was evaluated using standard corporate metrics to quantify the "Cost of Unserved Energy" benefit for providing contingency throughout the year for the four Middlesboro substation transformers. Without adequate contingency capacity, the failure of one of the transformers addressed by this project could result in extended total outage time for some customers of up to 30 hours until the transformer can be replaced, or a mobile transformer installed. An annual cost of $550k was calculated using a 5% annual probability of a failure for the transformers, a “Cost of Unserved Energy” of $17.895/kwh and a reduction in outage duration of 30 hour outage with the loads going unserved at Middlesboro 1 4KV(7.7 MW), Middlesboro 2 4kV(8.0 MW), Middlesboro 1 12kV (2.9 MW) and Middlesboro 1 12kV 2 (2.6 MW).

3. Alternative #1: NPVRR: $8,619k
This option is to replace the two existing 14 MVA 69/12kV transformers in the Middlesboro 1 (124) substation with 22.4 MVA transformers and move one of the 14 MVA transformers to Middlesboro 2 (780) substation in replacement of the 4kV transformer. This alternative also includes the removal and retirement of the 4kV transformer at Middlesboro 1 (124-5) substation and to convert all 4kV distribution lines in Middlesboro to 12kV. Improvements to two tie circuits are also recommended. This option is not recommended, as it is more expensive with an estimated capital cost of $6,812k. Alternative #1 also includes cost of $550k in 2020 and $281k in 2021 calculated using a 5% annual probability of a failure for the transformers, a “Cost of Unserved Energy” of $17.895/kwh and a reduction in outage duration of 30 hour outage with the loads going unserved at Middlesboro 1 4KV(7.7 MW), Middlesboro 2 4kV(8.0 MW), Middlesboro 1 12kV (2.9 MW) and Middlesboro 1 12kV 2 (2.6 MW).

Conclusions and Recommendation

It is recommended that the Investment Committee approve the N1DT Middlesboro Area Conversion project for $5,469k to provide Distribution Substation Transformer Contingency Program (N1DT) benefits in Middlesboro, KY.

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: November 22, 2019

Project Name: Uniontown Substation Upgrade and 4kV to 12kV Conversion Project

Total Capital Expenditures: $2,813k (Including $256k of contingency including $297k of internal labor)

Project Number(s): Substation 160219, Distribution 159857

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Tim Smith/ Kevin Patterson

Brief Description of Project

Electric Distribution Operations seeks approval to invest $2,813k towards upgrade of Kentucky Utility's (KU) Uniontown Substation. The proposed upgrade will necessitate replacement of an existing 5.25 MVA 69kV/4kV transformer with a 14.0 MVA 69kV/12kV transformer, conversion of the associated distribution system to 12kV, and extension of 3-phase distribution feeder from Overland North 4kV Substation to [redacted] Upgrade of the substation and extension of the feeder will enable elimination of Transmission's proposed project to rebuild the two-mile Overland North 69kV tap, and provides a contingency tie-circuit to the Morganfield distribution system.

The proposed project is included in EDO's 2020 Business Plan (BP) for $3,636 (2020 – $1,687k, 2021 - $1,949k).

Why is the project needed? What if we do nothing?

Earlier in 2019, Transmission proposed a project to re-conductor and rebuild the Overland North 69kV Radial Tap which consists of two miles of 3/0 ACSR 69kV conductor between Uniontown Substation and the Overland North Substation. The referenced transmission line is in substandard condition and is very difficult to access. Many of the structures in the route have been identified for replacement and are located in a low-lying area subject to flooding. Overland North serves one customer, [redacted] (less than 200kW).

As part of coordination efforts with Transmission, EDO proposed to upgrade the KU Uniontown substation as an alternative to Transmission's proposed replacement project. EDO's proposed alternative provides mutual benefits at a comparable cost and is deemed a better long-term overall solution for both organizations. Upgrade of Uniontown Substation and the associated circuitry to 12kV:

- Provides for a more efficient, standard, and resilient distribution operating system.
- Enables decommissioning of the existing two-mile 69kV transmission radial feed, and avoidance of capital investment and maintenance expenses needed to rebuild and maintain it.
- Enables decommissioning of the existing Overland North Substation, and avoidance of capital anticipated to be needed in the next five-years to rebuild it.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed		1,411	1,298		2,709
2. Cost of Removal Proposed		100	4		104
3. Total Capital and Removal Proposed (1+2)	-	1,511	1,302	-	2,813
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)	-	(1,411)	(1,298)	-	(2,709)
8. Cost of Removal variance to BP (5-2)	-	(100)	(4)	-	(104)
9. Total Capital and Removal variance to BP (6-3)	-	(1,511)	(1,302)	-	(2,813)

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)	-	-	-	-	-

The project is included in the 2020 BP. In 2019, it was originally proposed as a Transmission project as described above.

Risks

- Overland North 69KV Tap is subject to flooding.
- Overland North Substation's wood structures will need substantial repairs if not decommissioned or replaced in the near future.

Alternatives Considered

1. **Recommended Option** NPVRR $3,238k
   Upgrade the Uniontown Substation, convert the Uniontown 4kV distribution system to 12kV, and extend a three-phase distribution feeder to the former Overland North customer at 12kV. This option upgrades the existing Uniontown 4kV substation to a 14.0 MVA 69kV/12kV transformer. This capital investment includes the following: An A-frame structure, one 69kV breaker, 2-12kV 1200-amp SCADA vacuum breakers, a SCADA RTU and a control house. Also, a conversion of the distribution system to 12kV and a 3,500' three phase line extension to one customer. The estimated capital cost of this option is $2,813k.

2. **Alternative 1:** NPVRR $3,228k
   Replace/Repair the Existing Transmission and Distribution Facilities:
   This option was not chosen due to the ongoing difficulty Transmission crews have operationally accessing the facilities and the small amount of load served. Many of the transmission structures in the Overland North 69kV tap (about two circuit miles) are in disrepair and located in an area prone to flooding. The substation served by this transmission line has a peak demand of only about 200kW and there are no significant load increases expected. Replacement of the remaining seven structures is expected within 5 years. Additionally, in the near future, capital investment will be required at the Overland

North Substation due to the wood structures deteriorating. The estimated capital cost for these investments is $2,838k.

3. **Do nothing Option:** NPVRR N/A
This option is not recommended. The Overland North 69KV Tap serving the small load at the Overland North 4KV Substation has deteriorated through time and needs replacement. Transmission structure failures and lengthy repairs times are a risk. These structures have been identified as part of inspections to be replaced and waiting until failure to replace them will result in higher costs compared to a proactive plan.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Uniontown Substation Upgrade and 4kV to 12kV Conversion Project for $2,813k in lieu of Transmission's proposed project to rebuild two miles of 69kV transmission line and the associated transmission structures from Uniontown Substation to Overland North Substation.

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: December 19, 2019

Project Name: LGE PILC UG Network Cable Replacement Program-2020

Total Capital Expenditures: $11,705k (includes no contingency including $817k of internal labor)

Total O&M: N/A

Project Number(s): 155363

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Jason Tipton / Shawn Stickler

Brief Description of Project

Electric Distribution Operations (EDO) proposes to invest $11,705k in 2020 towards the continuation of the PILC Cable Replacement Program. The program was initiated in 2013, and involves replacement of bare (unjacketed), paper insulated, lead covered (PILC) low voltage (LV) secondary and medium voltage (MV) primary cables operating in the downtown Louisville network distribution system. The program places replacement priority on secondary cable sections, and provides for necessary reconstruction or replacement of any discovered defective duct lines and manhole structures. The Program is included in the proposed 2020 Business Plan (BP) funded at $11,705k. The $11,705k includes $1,100k to meet enhanced street resurfacing requirements imposed by Louisville Metro Public Works.

This program originally was anticipated to span 11 years and conclude in 2023. The total 11-year program cost, originally projected at $62,000k (2013 dollars), is expected to reach an estimated $74,492k by program completion. Additionally, EDO has accelerated the PILC program from 11 years to 9 years (2013-2021). The remaining program requires a 2-year (2020-2021) capital investment of approximately $22,025k. This will yield replacement of approximately 19 miles of cable in the remaining two years of the program. Actual amounts in any year will vary based on the mix of cable replacement, duct replacement, and manhole work. The higher than expected rate of defective duct line replacement has been partially offset by improved cable replacement efficiencies during the cable installation and removal processes.

PILC Network Cable Replacement Program	2020	2021
PILC Cable Replacement ($000s)	10,605	9,220
PILC Cable Replacement - Curb to Curb Paving ($000s)	1,100	1,100
Cable Replacement Targets (Miles)	10	9

Projected program costs are reevaluated annually as additional data becomes available to better quantify the amount of PILC cable in the network and the condition of ducts and manholes.

The PILC Replacement program is summarized in the following table:

Period (Project #)	Costs Applied (Budget)	Cable Circuit Miles Replaced	Duct line Ft Installed
2013 (#139271)	$1,990,597	1.65	820
2014 (#141195)	$5,833,931	6.57	4,110
2015 (#146442)	$6,050,569	7.07	7,353
2016 (#148497)	$6,274,861	7.24	5,236
2017 (#148739)	$9,290,788	8.27	11,530
2018 (#148899)	$11,153,959	10.14	20,285
2019 (#151486) *Estimated*	$11,871,897	12	12,000
2020 (#155363) *Proposed*	$11,705,000	10	15,000
Total Program 2013 thru 2020	$64,171,602	62.94	76,333

Why is the project needed? What if we do nothing?

LG&E operates five separate network systems with 27 circuits within the core downtown Louisville business and medical districts, roughly bounded by the Ohio River (north), Floyd Street (east), York Street (south), and 8th Street (west). Three of the five network systems, served by the Waterside, Magazine, and Madison Substations, contain bare PILC cables. All primary and secondary conductors in main thoroughfares are completely underground and installed in manhole and duct systems.

Network distribution systems were developed in the early 1910’s in order to provide the highest degree of service reliability to downtown business districts and to facilitate service to densely populated areas desiring a totally underground distribution system. The original LG&E network was built using PILC cables, constructed of oil impregnated paper tape insulations and jacketed with a bare lead sheath, the most reliable cable construction available at the time. At the beginning of this program, an estimated 70 miles of bare primary and secondary PILC cables, ranging in age from 48 to 100 years old, were in service in the downtown Louisville network distribution system.

Early PILC primary cables and all PILC secondary cables utilized bare lead sheaths that have experienced varying degrees of surface corrosion over their service lives. Corrosion and/or mechanical damage allow the insulating oil to leak from the insulation and allow water to enter the cable, ultimately leading to a cable failure. Insulating oils in the older bare PILC cables are also reportedly much drier than when newly manufactured, indicating the degree of insulation aging and degradation. While service from the downtown network is designed for high reliability, and the number of cable failures is relatively small, primary PILC cable failure rates had shown an increasing trend over the past fifteen years and were failing at twice the average rate per mile as the rest of the LG&E and KU underground systems. Primary cable failures over the three consecutive five-year periods preceding program initiation increased from an average of 3.2 (1999-2003), to 5.6 (2004-2008), to 8.2 (2009-2013). Known secondary failures averaged approximately two each year and had significantly greater consequences than primary failures due to high fault currents, and because secondary cables are not protected against faults and must burn in the clear before a fault is extinguished. The increase in secondary cable burnouts, the documented primary cable failure incidence rate, and the risk posed to adjacent cables in the duct and manhole system highlights the need to continue replacement program funding to address secondary and primary PILC cables.

Under this program, PILC cables are replaced with the latest generation of solid dielectric cables using either rubber or crosslinked polyethylene insulation. The new cables are not subject to corrosion under wet conditions and will be more resistant to water ingress with aging. Current generation cables have a life expectancy of more than 50 years.

Since program initiation, asset field inventories of cable and duct line capacity assessments in the network continue to reveal that significant quantities of aged duct lines are collapsed and deteriorated, requiring the need for additional duct lines and manhole capacities. Thus far, during the program, additional PILC secondary cable failures have been found located out of sight within the duct line that had not yet propagated to the point of a violent burnout or loss of customer service. Nearly all manholes encountered required replacement of cable support hardware and repositioning of fallen cables.

<u>Budget Comparison & Financial Summary</u>

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed		11,108			11,108
2. Cost of Removal Proposed		597			597
3. Total Capital and Removal Proposed (1+2)	-	11,705	-	-	11,705
4. Capital Investment 2020 BP		11,108			11,108
5. Cost of Removal 2020 BP		597			597
6. Total Capital and Removal 2020 BP (4+5)	-	11,705	-	-	11,705
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 2020 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks

Failure to proceed with the bare PILC cable replacement program will incrementally increase risks to network system reliability. Delays could compress a planned multi-year replacement program into a shorter term, requiring greater annual manpower and funding levels to address system reliability.

No additional environmental issues are anticipated beyond the normal lead and cable oil handling and disposal requirements.

Alternatives Considered

1. Recommendation: NPVRR: $15,406k

   EDO recommends investing $11,705k during 2020 towards continuance of the PILC Cable Replacement Program to ensure the ongoing operating reliability of the Downtown Louisville Network distribution system.

2. Do Nothing: NPVRR: N/A

   While the total loss of one of the three grid networks in downtown Louisville is a very low probability event, it could occur if more than two circuits on the same network system containing PILC cable sustained failures to primary system components at the same time. Failure to proceed with the bare PILC cable replacement program introduces growing risk for cable failures caused by increasingly aged PILC cables, which could result in a significant partial or total outage to one of Louisville's three downtown grid networks which contain PILC cable. The network could be partially or completely restored only after one or two of the failures were located and repaired, depending on loading. In addition, 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.

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

   There are no alternatives to a traditional replacement program for extending the useful life of aged and deteriorating PILC cable systems and no reliable and/or practical method for testing the physical or electrical condition of bare PILC cable systems.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the continuance of the PILC Replacement Project for $11,705k for 2020 in order to ensure the ongoing operating reliability of the Downtown Louisville Network distribution system by the replacement of aged, defective, and deteriorating PILC cable and structural assets.

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: December 19, 2019

Project Name: Distribution Wood Pole Inspection and Maintenance Program - 2020

Total Capital Expenditures: $12,653k (Including $253k of contingency including $300k of internal labor)

Total O&M: $260k

Project Number(s): LGE: 20PITP340, KU: 20PITP256, 20PITP216, 20PITP156, 20PITP246, 20PITP315, 20PITP766, 20PITP416, 20PITP366, 20PITP236, 20PITP426

Business Unit/Line of Business: Electric Distribution Operations / Distribution

Prepared/Presented By: Alan Lewis / Denise Simon

Brief Description of Project

The Investment Committee approved the Electric Distribution Operations' Distribution Wood Pole Inspection and Maintenance (Treatment) Program (PITP) 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 2020 program funding authority from the Investment Committee. The 2020 program scope is focused on providing a detailed pole inspection; preservative re-treatment and load analysis of approximately 36,000 poles and reinforcement or replacement of structures found to be defective. The program projections for 2020 include replacement of approximately 1,900 defective poles and reinforcement of 300+ poles.

The other option considered is to only inspect 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 dependent only on the regulatory cycle inspections will result in decreased life of the assets, increase pole failures and associated outages.

The 2020 Business Plan (BP) includes $12,653k for this program in 2020.

Background

EDO's PITP was implemented in 2010. By year end 2019, approximately 543,000 poles will have been inspected, 171,650 poles will have been treated, 21,240 poles will have been replaced and 1,630 poles will have been reinforced by splinting. Cumulative spend from 2010-2018 is $88.8 million with the 2019 forecasted spend at $14.3 million.

EDO has more than 517,000 distribution wood poles in the asset base with an estimated average age of 30 years. An additional 155,000 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, 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.

EDO's PITP 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 2020-2024 capital costs included in the 2020BP are shown below. This proposal only requests funding for 2020.

	2020	2021	2022	2023	2024
Amount in 000s	$12,653	$13,034	$13,427	$13,820	$14,173

<u>Why is the project needed? What if we do nothing?</u>
Kentucky mandated bi-annual inspections of the electric distribution system help to identify obvious physical defects and unsafe conditions of distribution equipment. However, this inspection process doesn't focus singularly on poles, doesn't provide for life extending preservative retreatment of poles, and doesn't include pole loading calculations or below grade inspection for ground line rot.

EDO's PITP is consistent with prudent industry practice for maintaining pole assets. The program provides a systematic and focused approach to prolonging the service life of poles through a pole-by-pole inspection and assessment, and execution of condition based corrective actions where deficiencies are identified. Potential corrective actions include preservative retreatment, pole reinforcement, or pole replacement. Preservative retreatment arrests any decay present and can significantly increase the useful life of the pole at a very small cost relative to replacement costs. (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.) Pole replacement and reinforcement has been required on approximately 3.9% and 0.3% respectively of poles inspected through the program.

Annual SAIDI and SAIFI benefit of 0.40 minutes and 0.002 interruptions per customer have been realized on circuits where PITP has been completed

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	11,112				11,112
2. Cost of Removal Proposed	1,541				1,541
3. Total Capital and Removal Proposed (1+2)	12,653	-	-	-	12,653
4. Capital Investment 2020 BP	11,112				11,112
5. Cost of Removal 2020 BP	1,541				1,541
6. Total Capital and Removal 2020 BP (4+5)	12,653	-	-	-	12,653
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	260				260
2. Project O&M 2020 BP	260				260
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The 2020 Business Plan includes this funding in projects 0100PITP and 0110PITP 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.

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.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $16,926
2. Alternative #1: NPVRR: ($000s) $40,949
   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 $11,573k), and the resulting cost of unserved energy from these failures (costs of $27,737k). Projections indicate approximately 1,900 poles will be replaced as part of the PITP program during 2020. Without remedial actions, these 1,900 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.

Conclusions and Recommendation

EDO recommends the Investment Committee approve continuation of the Distribution Wood Pole Inspection and Maintenance Program, and authorize 2020 investments of $12,653k 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 $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: 12/19/2019

Project Name: DSP Versailles Bypass 69kV Tap Upgrade Project

Total Capital Expenditures: $2,386k (Including $215k of contingency including $181k of internal labor)

Total O&M: N/A

Project Number(s): Substation- 161089, Distribution- 159860, Transmission- 151608

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Tim Smith/ Dan Hawk

Brief Description of Project

Electric Distribution Operations (EDO) requests authority to invest $2,386k towards upgrade of the 69kV transmission tap at Versailles Bypass Substation. The proposed investment will enable installation of two transmission taps to allow independent operation of the two Versailles Bypass Substation transformers, enhancing operational flexibility and system resiliency for 3,800 customers.

The transmission component of the proposed investment will provide for installation of five custom self-supporting steel poles and three-69kV switches at the Versailles Bypass Substation tap point. Required substation site work includes fence expansion, modifications to the existing steel structure, and installation of a mobile substation, which will be placed in service throughout completion of the planned transmission work. The distribution component of the proposed investment will provide for relocation of two distribution exit circuits to make room for the new 69kV tap structures.

The proposed project is included in EDO's and Transmission's 2020 Business Plan (BP) for $1,333k ($456k Distribution Operations and $877k Transmission Lines) with estimated spend of $75k in 2019, and $1,258k in 2020. Subsequent to the 2020 BP planning process, a decision was made by Transmission Lines to use self-supporting structures due to design constraints, increasing the project cost to $2,386k ($456k Distribution Operations and $1,930k Transmission Lines). Incremental spend of $1,053k will be funded by a reduction in other Transmission Lines capital projects.

Why is the project needed? What if we do nothing?

Distribution Planning and the Distribution System Control Center have an operational need to operate the two 22.4 MVA transformers at Versailles Bypass Substation independently. At the present time, all switching operations involving the transformers for contingency or maintenance situations require the entire substation to be de-energized, removing a total of 44.8 MVA of transformer capacity from service. The distribution system in the Versailles area does not have the additional reserve transformer capacity at other substations to handle this amount of load. The proposed system enhancements will directly improve reliability, resiliency and operational flexibility for approximately 3,800 customers (including a high school and most of the large industrial customers in Versailles, KY) served from the Versailles Bypass Substation.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	20	2,201			2,221
2. Cost of Removal Proposed		165			165
3. Total Capital and Removal Proposed (1+2)	20	2,366	-	-	2,386
4. Capital Investment 2020 BP	75	1,204			1,279
5. Cost of Removal 2020 BP		54			54
6. Total Capital and Removal 2020 BP (4+5)	75	1,258	-	-	1,333
7. Capital Investment variance to BP (4-1)	55	(997)	-	-	(942)
8. Cost of Removal variance to BP (5-2)	-	(111)	-	-	(111)
9. Total Capital and Removal variance to BP (6-3)	55	(1,108)	-	-	(1,053)

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

Risks

- Continued extreme system switching operations difficulty and added expenses to install the portal substation transformer for planned operations.
- Potential extended outages for substation contingency events.
- Several of the Company's large industrial customers are impacted during all switching operations at this substation.

Alternatives Considered

1. **Recommendation:** NPVRR: $2,900k
   Modify the existing 69kV transmission tap at Versailles Bypass Substation to provide separate transmission sources for the two Versailles Bypass Substation transformers. The recommended option includes Cost of Unserved Energy of $179k in 2019 and $91k in 2020 at $17.89/KwH given planned outage needs and risks of failures.

2. **Alternative #1:** NPVRR: $3,560k
   Do Nothing Option, continue to operate Versailles Bypass 1 and Versailles Bypass 2 from one 69kV tap. The existing configuration is non-standard and creates unnecessary operational challenges to maintain and repair equipment serving over 3,800 customers in the Versailles area. The calculated Cost of Unserved Energy at $17.89/KwH is $179k per year (escalated annually) given planned outage needs and risks of failures. This option is not recommended.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the DSP Versailles Bypass Substation 69KV Tap Upgrade Project for $2,386k so that Versailles Bypass Substation transformers can be served by separate Transmission taps and operated independently.

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	

Attachment 1 – Substation Diagram

[redacted]

Existing Substation Configuration

[redacted]

Proposed Substation Configuration

Investment Proposal for Investment Committee Meeting on: 4/28/2020

Project Name: Paynes Mill Substation Project

Total Original Capital Expenditures: $7,234k (Approved on 06/28/2017)

Amendment Value: $840k

Total Revised Capital Expenditures including Amendment: $8,074k

Project Number(s): Distribution- 152860, Substation- 138168, Transmission- 134256

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Tim Smith/Kevin Patterson

Description of Incremental Ask

Original Approved Capital Expenditures		$ 7,234 k
Revised Capital Expenditures Requested including Amendment		$ 8,074 k
Total Amendment Requested		$ 840 k

Distribution Substation Construction and Maintenance (SC&M) seeks authority to invest an additional $840k on the Paynes Mill Substation Project which was originally approved in June 2017. Justification for the increased funding:

I. Property Change.

[redacted] owns property around the original planned location for the Paynes Mill substation. After the original project was approved, [redacted] approached KU about changing the location of the proposed substation to allow them to utilize the original planned project property to maintain access to front road footage along Highway 60. [redacted] proposal offered KU access to a larger parcel of their land which is located approximately 800' further off US 60 than the original project footprint.

SC&M evaluated the proposed property against the original site and determined it to be the best value for the Company. The terrain of the original site was uneven and had two sink holes that would have required additional engineering and major mitigation costs. The amount of usable real estate was restricted and would have presented perpetual operations challenges for company personnel and limited access for large vehicles and equipment. The offered site is flat and facilitates easy access to the entire 2.615 acres footprint.

A portion of the proposed incremental funding is needed to extend distribution and transmission circuitry an additional 800 feet to tie to the new substation.

II. Timing

Original project estimates were completed during 2017. Due to property negotiations, property zoning litigations and other politically oriented delays, substation construction was delayed three years. Incremental funds have also been added to account for estimated materials, equipment, and labor costs increases incurred since the original project estimate was completed.

The Paynes Mill Substation and three distribution circuits is the recommended solution for distribution system capacity relief for three substations in the Versailles service area and remains the best and most cost-effective alternative. The new substation will be positioned to serve new residential and commercial developments planned in the future.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	Pre-2020	2020	2021	Post 2021	Total
1. Capital Investment Proposed	2,787	4,899	276	-	7,962
2. Cost of Removal Proposed	-	95	17	-	112
3. Total Capital and Removal Proposed (1+2)	2,787	4,994	293	-	8,074
4. Capital Investment 2020 BP	3,233	2,483	229	-	5,945
5. Cost of Removal 2020 BP	-	79	21	-	100
6. Total Capital and Removal 2020 BP (4+5)	3,233	2,562	250	-	6,045
7. Capital Investment variance to BP (4-1)	446	(2,416)	(47)	-	(2,017)
8. Cost of Removal variance to BP (5-2)	-	(16)	4	-	(12)
9. Total Capital and Removal variance to BP (6-3)	446	(2,432)	(43)	-	(2,029)

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

The 2020 incremental funding will be covered by the Corp RAC if funds are available, otherwise covered by another EDO project. The project was fully funded (from the original approved amount) in the 2019 BP, at $7,694k. Due to shifts in 2019 from the property delays and the timing of the 2020 BP, the 2020 BP amount did not reflect the shift from 2019 to 2020.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the Paynes Mill Substation Project for $8,074k.

Approval Confirmation for Capital Projects Greater Than $2 million:

The incremental 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 27, 2020

Project Name: Camargo Substation Upgrade

Total Capital Expenditures: $7,145k (Including $650k of contingency including $882k of internal labor, if applicable)

Total O&M: N/A

Project Number(s): Substations: 163575 Transmission Substations: 163586 Distribution Lines: 163576 Transmission Lines: LI-162327

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: James Burns/Kevin Patterson/Karmen Powell

Brief Description of Project

Electric Distribution Operations (EDO) seeks funding authority for substation and circuit improvements at the Camargo substation in Mount Sterling service area. The Camargo 12kV transformer 1 loading reached 121% of top nameplate during January 2018, a colder than average winter peak and is projected to peak at 121% during winter 2022/2023 during an average winter. The proposed project will replace the two 69-12KV 14 MVA transformers at Camargo with two 37.3 MVA units and construct two new distribution exit circuits. This will relieve overloading on the Camargo transformer 1 , provide load assistance to the nearby heavily loaded Mount Sterling 737 substation and will provide full backup coverage for all three transformers at the Camargo and Mount Sterling substations, removing them from the company's Distribution Substation Transformer Contingency Program (N1DT) list.

Approval is requested in the amount of $7,145k ($2,990k-2021, $4,155k-2022) to complete the Camargo Substation Upgrade project. This project is included in the proposed 2021 EDO Business Plan (BP) (as DSP Mount Sterling Substation projects 159874 and 160206) with a total funding level of $5,895k ($2,993k-2021, $2,902k-2022) and Transmission BP with a total funding level of $798k (2022), and is scheduled to begin in January 2021 with completion in December 2022. The 2022 EDO budget shortfall of $455k will be reallocated from other EDO projects in the 2022 BP. The increased cost results from a change in scope to add 69kV line breakers for reliability improvement, the addition of a small distribution lines enhancement for significant load shifting flexibility and increased expected labor cost for distribution lines work. The property for expansion was secured with a previously approved project 162829 for $86k.

	Distribution Substation	Transmission Substation	Distribution Lines	Transmission Lines	Total
Total 2021	$2,192k	$600k	$198k	$0k	$2,990k
Total 2022	$2,244k	$809k	$304k	$798k	$4,155k
Project Total	$4,436k	$1,409k	$502k	$798k	$7,145k
Contingency	10%	10%	10%	10%	

Why is the project needed? What if we do nothing?

The KU service area surrounding the town of Mount Sterling is served by four substations with six transformers. The Ewington substation, with two transformers, is on the far northeast side of town and mostly serves a large industrial park. The other three substations serve the residential and commercial customers in and around Mount Sterling. Camargo substation transformer 1, 14 MVA, is projected to reach 121% of top nameplate rating, exceeding the Distribution Planning acceptable winter rating. The Mount Sterling substation 14MVA transformer is also heavily loaded, currently projected at 90% summer 2022 and 99% winter 2022/2023.

Transformer	Top Nameplate Capacity (MVA)	Customers	Winter Peak (Actual MVA)	22/23 Winter Load (Forecasted MVA)
Camargo 12kV 1	14	2717	17.0 (121%)	17 (121%)
Camargo 12kV 2	14	1485	9.4 (67%)	8.8 (63%)
Mount Sterling 12kV 737-1	14	2393	14.3 (102%)	13.8 (99%)

Solutions were considered to address this projected overload, including the addition of capacity at the Mount Sterling substation or a new substation on land to be purchased. The originally submitted 2021 BP project was to add transformer capacity at the Mount Sterling 737 substation. The unexpected inability to obtain adequate additional property from an adjacent property owner resulted in a shift of scope to the Camargo substation. The recommended solution is the addition of capacity at the Camargo substation by replacing both 14 MVA transformers with 37.3 MVA units. This will provide capacity for future load growth and will also provide full backup at all times to both Camargo transformers and the Mount Sterling transformer, thus removing these three transformers from the company's N1DT list. Also recommended is the construction of two new exit circuits to divide more heavily loaded circuits and provide better system resiliency and flexibility.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2021	2022	2023	Post 2023	Total
1. Capital Investment Proposed	2,927	4,072			6,999
2. Cost of Removal Proposed	63	83			146
3. Total Capital and Removal Proposed (1+2)	2,990	4,155	-	-	7,145
4. Capital Investment 2021 BP	2,993	3,671			6,664
5. Cost of Removal 2021 BP		29			29
6. Total Capital and Removal 2021 BP (4+5)	2,993	3,700	-	-	6,693
7. Capital Investment variance to BP (4-1)	66	(401)	-	-	(335)
8. Cost of Removal variance to BP (5-2)	(63)	(54)	-	-	(117)
9. Total Capital and Removal variance to BP (6-3)	3	(455)	-	-	(452)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed					-
2. Project O&M 2021 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks

- The cost of the distribution portion of the project could escalate because costs are based on similar completed work for other projects of similar scope and size.
- Failure to approve this project could negatively impact the company's ability to provide service to existing and future customers in the Mount Sterling area.

Alternatives Considered

1. Recommended Option: NPVRR: $8,151k
   The recommended option is to remove the two existing Camargo Substation 14 MVA 69-12kV transformers and install two 37.3 MVA transformers, four 69kV breakers, two 2000A 15kV breakers, two additional 1200A 15kV line breakers, a control house, construct 3,000 feet of new 795AA three phase circuit and reconductor 1,100' of 1CWP three phase with 397ACSR. In addition to providing adequate capacity for the new load, the new transformers would also provide contingency capacity for the Camargo transformers and the Mount Sterling substation transformer. The estimated total capital cost of this option is $7,145k

2. Do Nothing Option: NPVRR: N/A
   KU has an obligation to serve all customers and associated load. The "do nothing" option is not considered an acceptable option because it exceeds Distribution Planning's operating limits for distribution substation power transformers, and this practice reduces the life of the substation transformer and elevates the risk of failure of a high value, critical asset.

3. Alternative 1: NPVRR: $12,126k
   This option considers the extension of a 69kV line to the property and the construction of a new 37.3 MVA 69-12kV substation. This would also include distribution circuit construction. This option is not recommended, as it is more costly and does not provide the additional reliability benefit to surrounding customers compared to the recommended option. The estimated capital cost of this alternative is $10,634k.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Camargo Substation Upgrade project for $7,145k to prevent transformer overload and to provide capacity for future customers in the Mount Sterling area.

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 Chief Financial Officer	Paul W. Thompson Date Chairman, CEO and President

Investment Proposal for Investment Committee Meeting on: October 27, 2020

Project Name: Hoover Distribution Substation Transformer Contingency Project

Total Capital Expenditures: $11,467k (Including $1,042k of contingency and $1,229k of internal labor)

Total O&M: N/A

Project Number(s): Distribution Substations – 162939
Transmission Substations - 163423
Distribution Lines - 162943
Transmission Lines – 137807

Business Unit/Line of Business: Distribution and Transmission

Prepared/Presented By: Karmen Powell

Brief Description of Project

This Investment Proposal (IP) requests funding authority for distribution substation, transmission substation, distribution circuit, and transmission line improvements in and around Kentucky Utilities Company's Hoover Substation in Georgetown, KY. The goals of this project are to address the forecasted overload of the Lemons Mill TR1 distribution substation transformer and to provide greatly improved contingency support for three existing transformers (Lemons Mill TR1, Lemons Mill TR2, Hoover TR1) to further advance the Company's Distribution Substation Transformer Contingency Program (N1DT).

This project proposes to install a new 37.3 MVA distribution substation transformer (TR2), replace the existing 22.4 MVA transformer with a 37.3 MVA transformer (TR1), install four 69 kV breakers, and install two 12 kV switchgears and other associated equipment in the Hoover substation. In addition, distribution circuit improvements along with transmission pole upgrades are proposed in order to provide adequate distribution circuit capacity to support the substation enhancements.

A total of $11,467k is being requested in order to complete the proposed project. The $11,467k is included in the 2021 BP. The property for expansion was secured with a previously approved project 157070 for $62k.

The distribution circuit costs are preliminary and are based on field experience from similar projects; more detailed engineering designs will be conducted after project approval. There is an estimated 10% of contingency ($1,042k) incorporated into the project cost estimates.

	Distribution Substation	Transmission Substation	Distribution Operations	Transmission Lines	Total
Total 2021	$2,701k	$855k	$1,300k	$0k	$4,856k
Total 2022	$4,299k	$1,112k	$1,000k	$200k	$6,611k
Project Total	$7,000k	$1,967k	$2,300k	$200k	$11,467k
Contingency	10%	10%	10%	10%	

Why is the project needed? What if we do nothing?

According to Distribution Planning Guidelines, improvements are justified when substation loads are forecasted to exceed 100% of the transformer top nameplate rating during 50/50 summer peak conditions or 120% during 50/50 winter peak conditions. Furthermore, the Company's N1DT list identifies substation transformers, which in the event of a transformer failure during high load periods, cannot be completely restored by switching to surrounding substations and circuits. Complete restoration to all customers would require either replacement of the failed transformer or installation of a portable transformer, which could take 24 hours or more depending on the specific location.

Normal Service Loads:

Substation Transformer	Customers	Top Nameplate Capacity (MVA)	Actual Peak (%) (S) Summer (W) Winter	2023-2024 (W) or 2023 (S) 50/50 Forecast (%)
Lemons Mill TR1	2,887	22.4	111% (W)	120% (W)
Lemons Mill TR2	2 (see Note 1)	22.4	90% (S)	93% (S)
Hoover TR1	3,467	22.4	107% (W)	108% (W)

Note 1: The Lemons Mill TR2 transformer provides dedicated service to [redacted]

As noted in the prior chart, the Lemons Mill TR1 transformer is forecasted to reach 120% of its top nameplate rating by the winter of 2023-2024, so substation improvements (taking two years to complete) would normally be scheduled to start in 2022 in order to comply with Distribution Planning Guidelines. Also, as a result of the high normal service peak load levels, customers served from the Lemons Mill TR1, Lemons Mill TR2, and Hoover TR1 transformers are at risk of extended outages during a transformer contingency event. These three transformers have been evaluated using accepted N1DT criteria and rank near the top of the priority list. So, in consideration of the above, the proposed Hoover substation project is being presented for approval in 2020 in order to secure funding in 2021-2022 from EDO's budgeted and approved N1DT initiative. Upon completion, the project is expected to reduce the normal service loading on the Lemons Mill TR1 and Hoover TR1 substation transformers, plus reduce the normal service loading on the Georgetown TR2 transformer (3,079 customers; 14.0 MVA capacity; 99% actual summer peak load) and Adams TR1 transformer (3,021 customers; 22.4 MVA capacity; 100% actual winter peak load). Furthermore, the project is expected to provide N1DT support for the Hoover (TR1 and new TR2) substation transformers plus greatly improve N1DT support for the Lemons Mill (TR1 and TR2) substation transformers. Any remaining N1DTdeficiencies/concerns in the Georgetown area are expected to be addressed upon completion of the next planned substation improvement project currently scheduled in 2023-2024, although the improvement is expected to be accelerated to 2022-2023 because of new business growth in the area.

The "do nothing" option is not considered to be an acceptable option because it does not address the forecasted overload on the Lemons Mill TR1 substation transformer.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2021	2022	2023	Post 2023	Total
1. Capital Investment Proposed	4,809	6,527			11,336
2. Cost of Removal Proposed	58	73			131
3. Total Capital and Removal Proposed (1+2)	4,867	6,600	-	-	11,467
4. Capital Investment 2021 BP	4,809	6,527			11,336
5. Cost of Removal 2021 BP	58	73			131
6. Total Capital and Removal 2021 BP (4+5)	4,867	6,600	-	-	11,467
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)	2021	2022	2023	Post 2023	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

A Hoover substation improvement is included in the proposed 2021 BP at the following levels: Substation project #162939 $8,968k ($3,567k-2021; $5,401k-2022); Distribution Lines project #162943 $2,300k ($1,300k-2021; $1,000k-2022); Transmission project #137807 $200k ($0k-2021; $199k-2022).

Risks

- The estimated costs of the distribution circuits are considered high level estimates at this time because the projects have not been formally designed. The costs are based on completed work for other projects of similar scope and size.
- Failure to advance and complete this project in a timely fashion could expose the Company to substation transformer overloads and could negatively impact the Company's ability to provide service to existing customers during planned and unplanned events.
- There are no known environmental issues at this time.

Alternatives Considered

1. Recommendation: NPVRR: $13,087k
   The recommended option proposes to install a new 37.3 MVA transformer (TR2), replace the existing 22.4 MVA transformer with a 37.3 MVA transformer (TR1), and install other related substation equipment (12 kV switchgear, breakers, etc.) in the Hoover substation. In addition, the project proposes other related distribution line and transmission line

improvements in order to satisfy the project goals. The estimated capital cost of this option is $11,467k.

2. Alternative #1: Do Nothing NPVRR: $21,699k
As previously discussed, the "do nothing" option is not considered an acceptable option because it does not address the forecasted Lemons Mill TR1 transformer normal service overload and thus violates the Company's Distribution Planning Guidelines. Although the N1DT related components of the project (replace Hoover TR1; one extra distribution circuit; not specifically needed to satisfy the normal service requirements) can be considered as optional, the improvements are consistent with the objectives of the Company's N1DT initiative and are recommended. The "do nothing" option was evaluated using standard corporate metrics to quantify the "Cost of Unserved Energy" benefit for providing contingency throughout the year for the three identified substation transformers. Without adequate contingency capacity, the failure of any of the transformers addressed by this project could result in extended total outage time for the majority of the impacted customers of up to 24 hours until the transformer can be replaced or a mobile transformer installed. Using a 5% annual probability of a failure of any of the three transformers, a "Cost of Unserved Energy" of $18.30/kwh, and a reduction in outage duration of a 24 hour outage with the loads going unserved at Lemons Mill TR1 (17.7 MW), Lemons Mill TR2 (19.1 MW), and Hoover TR1 (20.6 MW), the "Cost of Unserved Energy" is approximately $1,259k annually.

3. Alternative #2: NPVRR: $15,722k
This option considers improvements to the Lemons Mill (replace 2-22.4 MVA with 2-37.3 MVA transformers) and Hoover (install new 22.4 MVA transformer) substations as well as other related distribution line and transmission line improvements in order to satisfy the normal service and N1DT related project goals. The estimated capital cost of this option is $13,780k.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Hoover Distribution Substation Transformer Contingency Project for $11,467k to alleviate the forecasted substation transformer overload and provide N1DT benefits in Georgetown, KY.

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: November 20, 2020

Project Name: Electric Distribution Operations Blankets - 2021

Total Expenditures: $127,606k

Project Number(s): Various

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Steve Woodworth/Jamie Archer

Brief Description of Project

Electric Distribution Operations (EDO) uses Blankets to budget and account for annual routine short cycle, high volume work types. Capital Blankets are comprised of a multitude of individual small jobs necessitating capital investment. EDO subdivides its Blankets into distinct categories for new customer connections, network enhancements, network maintenance and network repairs. These categories align with primary work drivers for EDO.

Blanket spend is monitored, analyzed and trended on a monthly basis, using a combination of financial and volumetric measures, applicable area economic indicators, and detailed input from area operational managers. This information, with consideration for known influences to historical trends, is used to develop annual budget allocations.

EDO is requesting approval for $127,606k in Blankets, a decrease of $5,740k from the 2020 Business Plan for 2021.

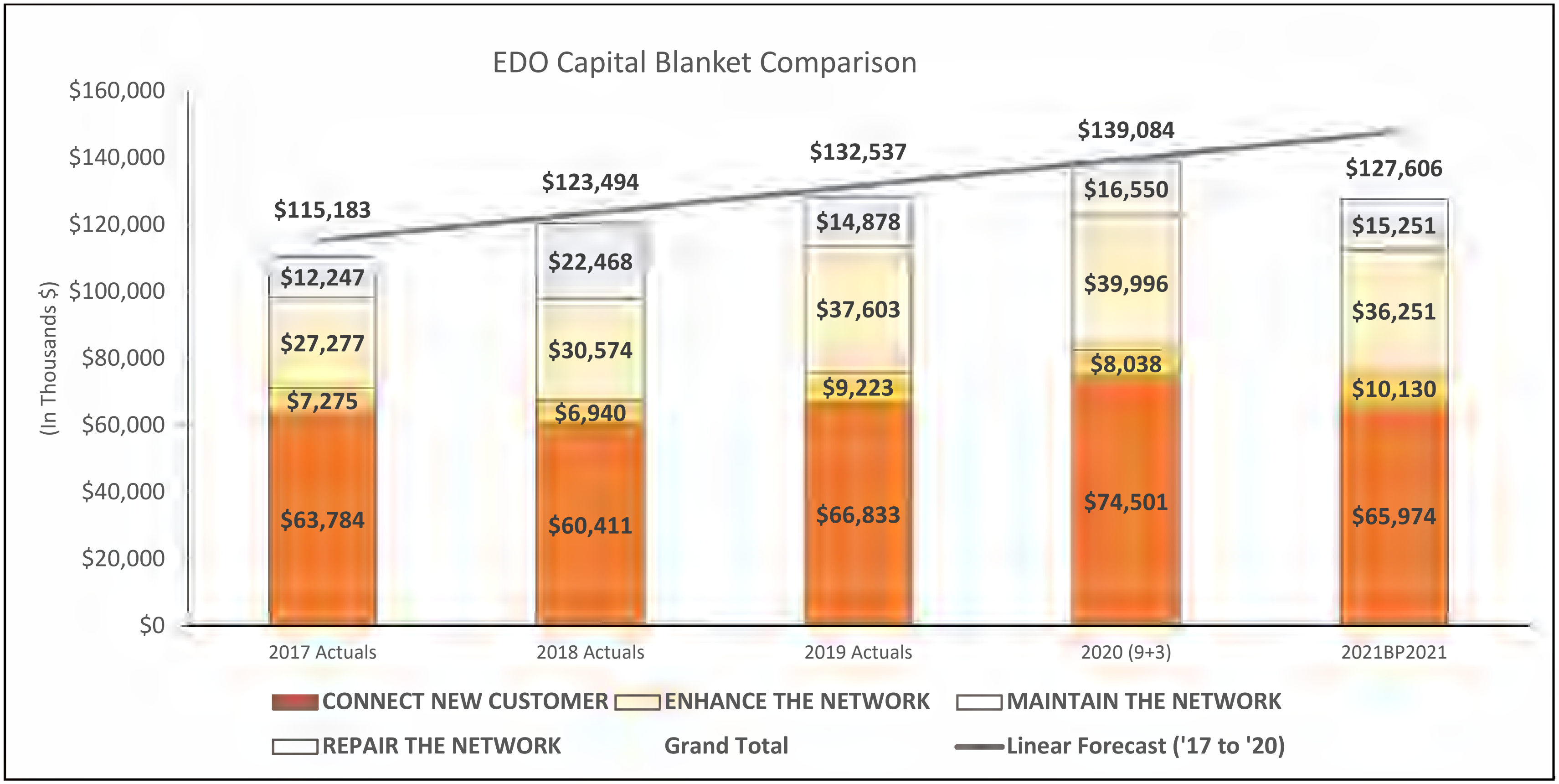
Conclusions and Recommendation

It is recommended that the Investment Committee approve the EDO blankets for $127,606k to allow for the needed work to be completed.

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



- The chart above compares 3 years of actual spend, the forecast for 2020, and the proposed 2021BP. The gray line is a linear regression trend line using 2017 to 2019 actual spend plus the 2020 forecast to project 2021 spend
- In March 2020 New Business categories were decreased by 10% in the 2021 BP due to anticipated pandemic driven market decline (Transformers was decreased by 6%)
- The proposed 2021 BP represents a 8.3% decrease from the 9+3 forecast and a 4.3% decrease plan over plan
- The 10% decrease applied to New Business blankets in the 2021 BP is the primary cause of these variances
- New Business spend (excluding Vaults) is up $5 million compared to the 1+11 forecast
- The $3.7 million variance between the 2021BP and 9+3 in Maintain the Network is primarily due to an incremental add of $3 million to target a backlog of defective poles in LG&E.

Electric Distribution Operations
2021 Capital Blankets (In Thousands $)

Blanket Project Description	2021 BP	vs. 2020 BP			vs. 2020 Forecast (9+3)			Variance - 2021 BP vs 2020 Forecast
		2020 BP for 2021	Variance Plan over Plan	% Chg	2020 9+3 Forecast	Variance to 2020 9+3	% Chg	
CONNECT NEW CUSTOMER	$65,974	$72,656	$6,681	9.2%	$74,501	$8,527	11.4%	• In March 2020 New Business categories other than Transfromers were decreased 10% from 2020 BP for 2021 figures due to anticipated economic downturn from the COVID-19 pandemic • $1,295k has been moved from New Vault blanket to Vault projects (variance to forecast include Vault projects = $9,822k)
ENHANCE THE NETWORK	$10,130	$10,129	($0)	0.0%	$8,038	($2,092)	-26.0%	• Public works projects slated for 2021 include Greenwood Rd, E Kentucky St Bridge, N English Station, Brandenburg Sidewalk, New Circle, Newtown Pike, KY 480 (Maysville), and KY 25 (London) • $1,127k moved from Public Works blankets to Public Works projects • $585k moved from Sys Enhance blanket to project for (WHAS-11116) • Variance to forecast including Public Works projects and Sys Enahnce project = $38k, Enhance the Network category is essentially flat compared to forecast and 2020 Business Plan
MAINTAIN THE NETWORK	$36,251	$35,648	($603)	-1.7%	$39,996	$3,745	9.4%	**2021BP vs forecast** • 9+3 Forecast for Repair/Replace Pole is $3 million over 2021 BP as LG&E Ops secured additional $3 million in funding in 2020 to address backlog of defective poles • The planned oil recloser replacement project included in the Cap/Recloser Maintenance blanket is $1.5 million (2020 plan is $2.1 million for this project) • Repair Defective Equipment (CRDD) is utlized based on need and varies year/year. CRRD OH has seen fluctuations between $600k and and $900k over the past 3 years, has CRDD UG in 9+3 is up $900k compared to 2019 and dollars were shifted between these two to help cover these fluctations in 2020 **•2021 BP vs 2020 BP** • In 2019 Lexington performed an analysis of certain Trouble related OM/CAP expenditures resulting in a more appropriate costing to certain projects, this results in an estimated increase in repair defective street lighting spend of approximately $600k in 2021 BP (and a correspdoning Trouble OM reduction). LEXOC 9+3 forecast for repair defective street lightings is ~$700k above the 1+11 forecast (other Ops Centers have spent less than expected causing the $600k variance to forecast in this category)
REPAIR THE NETWORK	$15,251	$14,913	($338)	-2.3%	$16,550	$1,299	7.8%	**2021BP vs forecast** • Repair 3rd Party Damage spend is up 28% over historic 3 year average **2021 BP vs 2020BP** • Lexington Trouble expenditure analysis described above also resulted in a $300k addition to Capital Trouble Orders Blanket • Using 3-year average for storms
Grand Total	$127,606	$133,346	$5,740	4.3%	$139,084	$11,479	8.3%	

BLANKET TO PROJECT MOVES					$3,007			Approximately $3 million was moved from capital blankets to projects in 2020 (new vaults (1,295k), public works (1,127k), and Sys Enhance (585k)

2021 Capital Request (in Thousands $)

		2021 BP	vs. 2020 BP for 2021			vs. 2020 Forecast (9+3)			WR Volumes and Projections					Other Volumetrics	
	Blanket Project Number/Description	**2021 BP**	**2020 BP for 2021**	**Variance Plan over Plan**	**% Chg**	**2020 Forecast (9+3)**	**Variance to Forecast**	**% Chg**	**2018 WRs Closed**	**2019 WRs Closed**	**2020 (9+3) WRs Closed**	**2020 WRs Projected**	**2021 Est WRs Closed**	**2020 % WRs Closed <30 days**	**2020 % WRs Closed <180 days**
CN	CXGTM-Transformers	$14,929	$15,935	$1,006	6.3%	$15,402	$473	3.1%	N/A	N/A	N/A	N/A	N/A		
CN	CNBCD - New Business Commercial	$15,675	$17,417	$1,742	10.0%	$18,084	$2,409	13.3%	981	981	1,080	791	918	51.07%	92.12%
CN	CNBRD - New Business Residential	$15,246	$16,940	$1,694	10.0%	$19,258	$4,012	20.8%	1,216	1,216	1,284	1,014	1,148	70.29%	99.22%
CN	CNBSV - New Business Electric Services	$11,468	$12,747	$1,278	10.0%	$13,126	$1,658	12.6%	22,597	23,626	18,833	25,111	23,778	65.45%	80.21%
CN	CNBVLT - New Network Vaults	$2,030	$2,256	$226	10.0%	$578	($1,451)	-251.0%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CN	CSTLT - Street Lighting	$6,626	$7,362	$736	10.0%	$8,053	$1,427	17.7%	4,493	4,782	3,697	4,929	4,735	94.15%	99.86%
Total Connect New Customer (CN)		**$65,974**	**$72,656**	**$6,681**	**9.2%**	**$74,501**	**$8,527**	**11.4%**	**29,286**	**30,605**	**24,894**	**31,845**	**30,579**		
EN	CPBWK - Public Works Relocations ELEC	$3,058	$3,058	$0	0.0%	$1,790	($1,268)	-70.9%	37	57	68	85	60	77.78%	100.00%
EN	CRCST - Relocations Cust Request	$1,969	$1,968	($1)	-0.1%	$1,627	($343)	-21.1%	898	683	388	485	689	59.87%	93.20%
EN	CRELD - Circuit Hardening / Reliability	$1,825	$1,825	$0	0.0%	$1,992	$167	8.4%	1,321	1,639	1,172	1,465	1,475	82.98%	99.64%
EN	CSYSEN - System Enhancements ELEC	$3,277	$3,278	$1	0.0%	$2,629	($648)	-24.6%	263	357	241	301	307	81.54%	97.69%
Total Enhance Network (EN)		**$10,130**	**$10,129**	**($0)**	**0.0%**	**$8,038**	**($2,092)**	**-26.0%**	**2,518**	**2,736**	**1,869**	**2,336**	**2,530**		
MN	CNETVLT - Maintain Network Vaults	$1,420	$1,420	$0	0.0%	$1,623	$203	12.5%	N/A	N/A	N/A	N/A	N/A		
MN	CCAPR-Cap/Recloser Maintenance	$2,672	$2,673	$1	0.0%	$3,255	$583	17.9%	638	177	244	305	373	67.39%	98.91%
MN	CRDD - Repair Defective Equipment OH	$7,285	$7,287	$1	0.0%	$6,409	($877)	-13.7%	15,710	15,601	11,753	14,691	15,334	88.07%	99.46%
MN	CRDD - Repair Defective Equipment UG	$3,209	$3,207	($1)	0.0%	$3,824	$616	16.1%	1,007	913	878	1,098	1,006	55.73%	69.97%
MN	CRSTLT - Repair Defective Street Lights	$9,512	$8,911	($601)	-6.7%	$8,954	($559)	-6.2%	33,917	32,766	20,831	26,039	30,907	99.30%	99.99%
MN	CRPOLE - Repair/Replace Pole	$12,152	$12,150	($2)	0.0%	$15,931	$3,779	23.7%	3,120	2,915	2,939	3,674	3,236	66.34%	97.75%
Total Maintain Network (MN)		**$36,251**	**$35,648**	**($603)**	**-1.7%**	**$39,996**	**$3,745**	**9.4%**	**54,391**	**52,372**	**36,645**	**45,806**	**50,857**		
RN	CTPD - Repair 3rd Party Damage	$1,934	$1,935	$1	0.0%	$2,375	$442	18.6%	510	545	537	671	575	79.46%	84.99%
RN	CSTRM - Storms	$4,801	$4,761	($40)	-0.8%	$5,337	$536	10.1%	7,039	6,529	10,042	8,007	7,192	N/A	N/A
RN	CTBRD - Trouble Orders ELEC	$8,517	$8,217	($299)	-3.6%	$8,837	$321	3.6%	25,358	26,959	33,005	35,140	29,152	N/A	N/A
Total Repair Network (RN)		**$15,251**	**$14,913**	**($338)**	**-2.3%**	**$16,550**	**$1,299**	**7.8%**	**32,907**	**34,033**	**43,584**	**43,818**	**36,919**		
	Grand Total	**$127,606**	**$133,346**	**$5,740**	**4.3%**	**$139,084**	**$11,475**	**8.3%**	**119,102**	**119,746**	**106,992**	**123,806**	**120,884**		

Investment Proposal for Investment Committee Meeting on: December 18, 2020

Project Name: Limestone Loudon Relocation Property Acquisition

Total Capital Expenditures: $3,400k

Total O&M: $0k

Project Number(s): 164056

Business Unit/Line of Business: Electric Distribution Operations/Customer Services

Prepared/Presented By: Paul Weis

Brief Description of Project

Electric Distribution Operations (EDO) and Customer Services (CS) seek funding authority up to $3,400k to purchase property to construct a new operations facility and a warehouse within Lexington/Fayette County for the Limestone Loudon Relocation Project ("Project"). Proposed funding for the full project of $19,266k (including property purchase) is included in the CS 2021 Business Plan (BP) between 2021 and 2022.

The Project will construct a new operations facility, warehouse, and outside storage yard for the relocation of staff and operations from the current Limestone and Loudon facilities. The current facilities no longer meet the operational needs of the EDO, Transmission, and CS workgroups. Modifications or enhancements to the current sites are not feasible or recommended due to their age and location constrictions. This project proposes to purchase a minimum of ten (10) acres of industrial-zoned property within Lexington/Fayette County with nearby access to major thoroughfares. The new location will have 25,000 - 35,000 sq. ft. of office and workbench space for the approximately 125 personnel, adequate parking spaces, safe vehicle ingress and egress to handle semi-truck deliveries, a 30,000 - 35,000 sq. ft. warehouse, and associated workspace for Material Services and Logistics (MS&L) personnel.

A tentative timeline and key milestones for the overall project is noted with the property purchase to be completed in early 2021.

Key Tasks / Milestones	**Duration:**
Property Identification and Purchase	August 2020 – January 2021
Design & Budget Development	November 2020 – March 2021
Investment Proposal Reviews	April 2021 - May 2021
Formal Bid / Contract Execution	June 2021 – July 2021
Construction	August 2021 – September 2022
Operational	October 2022

Why is the project needed? What if we do nothing?

The Limestone facility serves as the primary operations center for EDO's Substation Engineering, Construction, Maintenance and Asset Management functions for KU. Additionally, Distribution and Transmission Substation Protection and Control personnel are located at Limestone. Limestone provides space for materials storage for distribution and transmission substation equipment (transformers, breakers, switchgear, etc.), vehicles, and equipment staging. The Loudon facility serves as the Lexington area operations center for CS's Meter Assets, Meter Reading, and Field Services departments, and supports meter testing, material storage, meter reading, and field service functions.

The purchase of a minimum of ten (10) acres is needed to execute the relocation and consolidation of the Limestone and Loudon facilities to support and enhance the following operational and safety objectives:

- Improvement of safety and health issues associated with the aging and inadequate facilities.
- Enhancement of employee quality of work life through the replacement of said facilities.
- Accessibility to main thoroughfares (i.e. New Circle Road and Interstates 64 and 75) to facilitate efficient crew deployment.
- Functional and safer ingress/egress route for tractor trailer deliveries.
- Improvement of warehousing efficiencies by the centralized management of materials.
- Elimination of storing material in hazardous areas.
- Freeing up warehouse space at the Midway Service Center occupied by portable substations.
- Improved workshop space for the Meter groups to operate in a centralized work area.
- Co-location of personnel for collaboration relocated from the KU General Office.
- Provision of adequate parking spaces for employees, business partners, and team meetings.
- Elimination of ADA compliance issues.
- Provision for needed space for conference and break rooms to facilitate staff meetings, training, hotel office space, and general administrative needs.

Property Search Summary

Property of this size zoned industrial or with the potential to be zoned industrial is very limited within Lexington/Fayette County. Real Estate and Right of Way (REROW) engaged a commercial/industrial real estate broker to assist with the site search and analysis. Additionally, outreach was made to local real estate contacts for properties and buildings not listed for sale or publicly available.

A total of twelve (12) properties were evaluated for their location, size, zoning, and suitability for development. The properties, which were evaluated by a team of operations, facility construction, and real estate personnel, eliminated sites due to undesirable locations, lack of needed acreage, inadequate zoning, road access, and drainage/flood plain issues. This review resulted in the identification of one (1) viable site within Lexington/Fayette County located on Lisle Industrial Ave. (Appendix A).

The Lisle Industrial Ave. site is listed at $4,500k for two parcels totaling 10.86 acres. LKE ordered an appraisal of the property which determined a valuation of $4,020k. The appraisal amount was used to formulate an offer and guide the purchase negotiations. [redacted]

CONFIDENTIAL INFORMATION REDACTED

Centralized Location Enhances Reliability and Customer Experience

EDO and CS recommend the location of the new operations center be within Lexington/Fayette County due to multiple operational needs. Primary amongst these is locating nearest the population center of the central Kentucky area to minimize travel time for substation, meter reading, and field service personnel (Lexington/Fayette County comprises over 70% of the 176,000 meters currently read out of Loudon Avenue and contains 49 substations). Employees in the Substation Department are expected to live within a 30 mile radius of the operation center expressly to minimize the time it takes to report to the center during emergency restoration efforts. Locating the new center outside Lexington/Fayette County would result in many employees living further from the operation center with the consequence being longer restoration times and negative impact on SAIDI reliability numbers. By contrast, locating along a thoroughfare such as New Circle Road should result in quicker overall response and restoration times. A location within Lexington/Fayette County positions the center closer to critical substation loads such as the hospitals, universities, downtown businesses, and industrial customers thus improving response times. Finally, there is community goodwill to maintaining and strengthening KU's presence within the Lexington/Fayette Urban County Government limits.

The targeted location for a new facility is considered to be near New Circle Road, for quick access to all the major Lexington thoroughfares. A facility located in the northern portion of the county positions it closer to the interstates that will reduce travel times to the outlying metering and substation service areas.

<u>Budget Comparison & Financial Summary</u>

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	40	3,360			3,400
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	40	3,360	-	-	3,400
4. Capital Investment 2021 BP		3,360			3,360
5. Cost of Removal 2021 BP					-
6. Total Capital and Removal 2021 BP (4+5)	-	3,360	-	-	3,360
7. Capital Investment variance to BP (4-1)	(40)	-	-	-	(40)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(40)	-	-	-	(40)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed					-
2. Project O&M 2021 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The BP amount listed in the table above is only a portion of the budget for this project, since only the property purchase is being requested at this time. The full project is budgeted at $19,266k in 2021 and 2022. The [redacted] in 2020 is for an option purchase agreement to secure the [redacted]

[redacted] property under contract to close in Q1 2021. Funding will be reallocated from other CS projects through the CS RAC process.

Risks

- Continued operations at Limestone expose employees and business partners to known safety risks.
- Not completing the property purchase for the project prevents the execution of the project in 2021 and 2022, as planned.
- Delays in the property purchase substantially impact the timing of the due diligence required and the ability to complete the design and construction start of the project.
- Purchase of property not currently zoned industrial could create delays and additional expense associated with obtaining the necessary regulatory approvals.

Alternatives Considered

The alternatives below consider the costs for the full project and are based upon the preliminary work estimates of the full project. The financial analysis will be updated and finalized when the full project is requested for approval, the completion of the property purchase, and final design are complete.

1. Recommendation: Relocate to a Consolidated Facility NPVRR: $27,408k
   Relocate EDO operations and Transmission from Limestone and CS operations from Loudon to a single property that will house the operations of both current facilities. This alternative addresses all operational needs. The Loudon property will be listed as surplus property and sold. The Limestone property will be retained due to the presence of an operational substation. (It is recommended a separate project be planned subsequently to relocate the Transmission control house out of the Powerhouse to another location on site, so the Powerhouse can be demolished.)

2. Alternative #1: Reconfigure Existing Properties NPVRR: $31,169k
   Demolish all existing structures (except for the active electric substation) at both Limestone and Loudon, build new facilities, and reconfigure the sites to provide as much functionality as possible on the existing parcels. This alternative includes the requirement to relocate an existing Transmission control house, demolish a retired Powerhouse, and remediate underground voids at Limestone, and to demolish the Ice House storage structure at Loudon. This alternative would require the personnel and operations at Limestone to relocate temporarily to a leased facility during demolition and construction of the new structures. This alternative has the potential need for major environmental cleanup measures, although an environmental site assessment would be necessary to determine actual site conditions. This alternative is not recommended for several reasons: space and logistical constraints can be improved but not overcome at Limestone; the additional time and operational disruption required to relocate the personnel and operations at Limestone twice; the additional time needed to relocate the substation control house and demolish the Powerhouse (approximately two years) prior to beginning construction on the site.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Limestone Loudon Relocation Property Acquisition project for $3,400k to complete the purchase of and due diligence on the property needed for the construction and development of the consolidated Limestone and Loudon Service Center.

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	

CONFIDENTAIL INFORMATION HIGHLIGHTED

Appendix A

[redacted]

- Located inside New Circle Road within the northwestern portion of Lexington/Fayette County between Old Frankfort Pike and Leestown Road
- Approximately less than 1 mile from New Circle Road and 4.75 miles to I-64

[redacted]

Investment Proposal for Investment Committee Meeting on: December 18, 2020

Project Name: Pavilion Drive Substation Property Purchase

Total Capital Expenditures: $670k (Including $7k of contingency and $0k of internal labor)

Total O&M: N/A

Project Number(s): Distribution Substations – 162979

Business Unit/Line of Business: Electric Distribution Operations and Transmission

Prepared/Presented By: James Cline/ Karmen Powell

Brief Description of Project

Electric Distribution Operations (EDO) requests funding authority for purchase of a 6.1-acre site on Pavilion Drive in Georgetown, KY in order to accommodate future distribution substation, transmission substation, distribution line, and transmission line improvements. When completed, these future substation related improvements will address the forecasted overload of the Oxford TR1 distribution substation transformer plus will provide contingency support for three existing transformers (Oxford TR1, Oxford TR2, and Georgetown TR2) to further advance the Company's Distribution Substation Transformer Contingency Program (N1DT).

The identified 6.1-acre site is located directly adjacent to the Adams-Toyota South 138 kV transmission line, Adams-Cynthiana 69 kV transmission line, and Oxford TR1 12 kV Circuit 0471, plus it is also in very close proximity to Oxford TR2 12 kV Circuit 0472. The site has sufficient physical space to accommodate at least two distribution substation transformers plus a 138 kV or 69 kV transmission ring bus configuration if desired.

See attached map of the property location.

A total of $670k is being requested in order to purchase the identified property (purchase price of $600k) The additional $70k requested will cover the option ($45k in 2020),appraisal, survey, environmental studies, closing costs, contingency and burdens. There is $600k budgeted in 2021 for this project as a part of the 2021 Business Plan (BP), and additional funding needed will be allocated from another project through the EDO RAC process.

For the economic evaluation, cost of the property and associated future Pavilion Drive substation, transmission, and distribution improvements was compared to the cost of improvements for the alternative option (i.e. upgrades to the existing Oxford substation) to determine if it was economically feasible to pursue a new green field substation site.

The property purchase costs presented in this Investment Proposal are based on a verbal agreement with the property owner and includes normal rates for company burdens and overheads. There is a 1% contingency ($7k) incorporated into the project cost estimates.

Why is the project needed? What if we do nothing?

Distribution Planning Guidelines provide that system improvements are prudent when substation loads are forecasted to exceed 100% of transformer top nameplate rating during 50/50 summer peak conditions or 120% during 50/50 winter peak conditions. Furthermore, the Company's N1DT program systematically addresses substation transformers, which in the event of a transformer failure during high load periods, cannot be completely restored by switching to surrounding substations and circuits. Complete restoration to all customers would require either replacement of the failed transformer or installation of a portable transformer, which could take 24 hours or more depending on the specific location.

The Lexington Op Center has identified an estimated 3.5 MVA of new growth (from three new customers) that will be served from the Oxford TR1 transformer.

Normal Service Loads:

Substation Transformer	Customers	Top Nameplate Capacity (MVA)	Actual Peak (%) (W) Winter	2021-2022 (W) 50/50 Forecast (%)	2021-2022 (W) 50/50 Forecast (%) + 3.5 MVA
Oxford TR1	1,340	14.0	104% (W)	102% (W)	126% (W)

As noted in the chart, the Oxford TR1 transformer is forecasted to exceed 120% of its top nameplate rating with the anticipated new customer growth, so it is recommended that substation improvements (taking two years to complete) be started following the acquisition of the substation property. Also, as a result of the high normal service peak load levels, customers served from the Oxford (TR1 and TR2) and Georgetown TR2 transformers are at risk of extended outages during a transformer contingency event. These transformers have been evaluated using accepted N1DT criteria and rank near the top of the priority list. So, in consideration of the above, the proposed Pavilion Drive substation property project is being presented for approval to secure the property in 2021 so substation improvements can be pursued in 2023-2024. Upon completion, the substation improvements are expected to reduce the normal service loading on the Oxford TR1 substation transformer and provide N1DT support for the Oxford (TR1 and TR2) and Georgetown TR2 substation transformers.

The "do nothing" option is not considered to be an acceptable option because it does not advance the company's plan to address the forecasted overload on the Oxford TR1 substation transformer.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	45	625	-		670
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	45	625	-	-	670
4. Capital Investment 2021 BP		600			600
5. Cost of Removal 2021 BP					-
6. Total Capital and Removal 2021 BP (4+5)	-	600	-	-	600
7. Capital Investment variance to BP (4-1)	(45)	(25)	-	-	(70)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(45)	(25)	-	-	(70)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The additional funding needed in 2020 has been allocated from other projects through the EDO RAC process. The additional funding in 2021 will also be allocated through the EDO RAC process.

Risks

- Failure to advance and complete this project in a timely fashion could expose the company's need to purchase property that could require additional transmission and distribution costs.
- Delaying in purchasing property could result in a higher price at a later time.
- There are no known environmental issues at this time. A geotechnical survey is planned prior to the land being developed.

Alternatives Considered

The estimates used in the alternatives for the financial analysis are for the full project and are based upon the preliminary work estimates on the full project.

1. Recommendation: NPVRR: $8,732k

   The recommended option in this Investment Proposal proposes to purchase property on Pavilion Drive in Georgetown, KY. For the purposes of the economic comparison of options, the property purchase has been included with the total cost of the associated future substation, distribution, and transmission improvements to determine if developing a new green field site was justified. The scope of the evaluated option includes the purchase of property (this Investment Proposal) and the installation of a 138 kV ring bus, 37.3 MVA 138-12 kV substation transformer, 12 kV switchgear, breakers, and other related substation equipment on the proposed Pavilion Drive green field site. The Pavilion drive property allows for additional capacity in the future with the space available to build a second transformer. In addition, the project proposes other related distribution line and transmission line improvements in order to satisfy the project goals. The estimated capital cost of this option is $9,050k.

2. Alternative #1: Do Nothing NPVRR: N/A
As previously discussed, the “do nothing” option is not considered an acceptable option because it does not address the forecasted Oxford TR1 transformer normal service overload and thus violates the Company’s Distribution Planning Guidelines.

3. Alternative #2: NPVRR: $9,857k
This option considers improvements to the Oxford substation (replace 2-14.0 MVA with 2-22.4 MVA transformers) as well as other related distribution line and transmission line improvements in order to satisfy the normal service and N1DT related project goals. The Oxford substation will have additional complications constructing on the existing site. This alternative includes the costs associated with the addition of a 69kV ring bus, property purchase to the north of the substation, line breakers and the relocation of the 69kV line to accommodate the ring bus. In addition, the Transmission voltage is limited to 69kV. The estimated capital cost of this option is $10,403k.

Conclusions and Recommendation

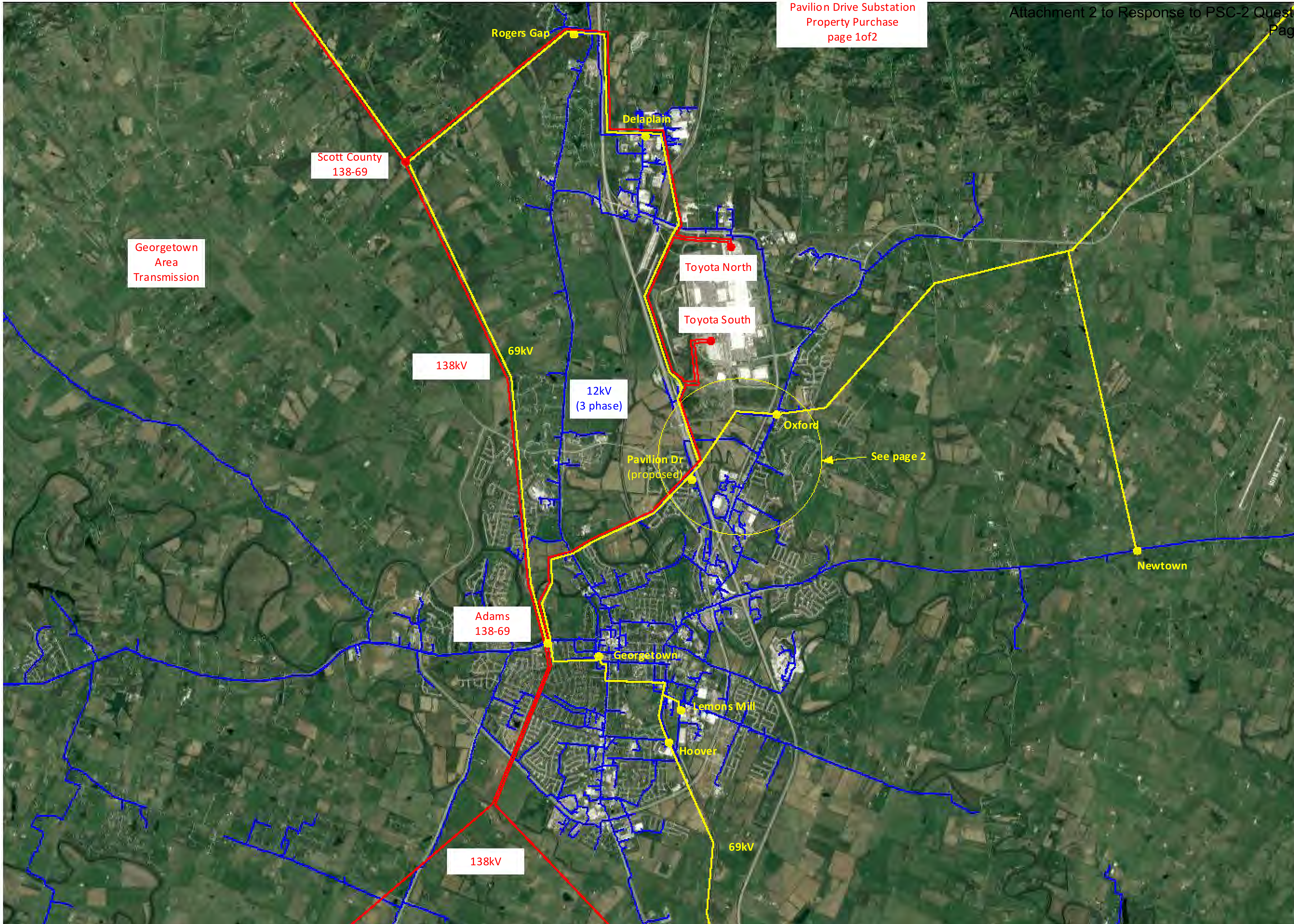
EDO recommends that the Investment Committee approve investing $670k towards purchase of 6.1 acres of property on Pavilion Drive in Georgetown, KY. The property will enable future construction of a new substation being planned to alleviate a forecasted overload of Oxford TR1 plus provide distribution substation transformer contingency benefits to three substation transformers in Georgetown, KY.

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
Chief Financial Officer

Paul W. Thompson Date
Chairman, CEO and President


Pavilion Drive Substation
Property Purchase
page 1of2
Rogers Gap
Delaplain
Scott County
138-69
Georgetown
Area
Transmission
Toyota North
Toyota South
138kV
69kV
12kV
(3 phase)
Oxford
See page 2
Pavilion Dr
(proposed)
Newtown
Adams
138-69
Georgetown
Lemons Mill
Hoover
69kV
138kV


Pavilion Drive Substation
Property Purchase
page 2of2
69kV
138kV
12kV
(3 phase)
Oxford
Substation
Pavilion
Drive
(proposed)

Investment Proposal for Investment Committee Meeting on: December 18, 2020

Project Name: LGE PILC UG Network Cable Replacement Program-2021

Total Capital Expenditures: $11,163k (includes contingency $800k)

Total O&M: NA

Project Number(s): 142487

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Jason Tipton / Shawn Stickler

Brief Description of Project

Electric Distribution Operations (EDO) proposes to invest $11,163k in 2021 towards the continuation of the PILC Cable Replacement Program. The program was initiated in 2013, and involves replacement of bare (unjacketed), paper insulated, lead covered (PILC) low voltage (LV) secondary and medium voltage (MV) primary cables operating in the downtown Louisville network distribution system. The program places replacement priority on secondary cable sections, and provides for necessary reconstruction or replacement of any discovered defective duct lines and manhole structures. The Program is included in the proposed 2021 Business Plan (BP) for $11,163k. The $11,163k includes $1,100k to meet enhanced street resurfacing requirements imposed by Louisville Metro Public Works.

This program originally was anticipated to span 11 years and conclude in 2023. The total 11-year program cost, originally projected at $62,000k (2013 dollars), is expected to reach an estimated $74,751k by program completion. Additionally, EDO has accelerated the PILC program from 11 years to 9 years (2013-2021). The requested capital investment of $11,163k is expected to bring the project to completion in 2021. This will yield replacement of approximately 10 miles of cable in the final year of the program. Actual amount could vary based on differences in estimates extracted from SmallWorld versus what is found in the field. The higher than expected rate of defective duct line replacement has been partially offset by improved cable replacement efficiencies during the cable installation and removal processes.

The PILC Replacement program is summarized in the following table:

Period (Project #)	Costs Applied (Budget)	Cable Circuit Miles Replaced	Duct line Ft Installed
2013 (#139271)	$1,990,597	1.65	820
2014 (#141195)	$5,833,931	6.57	4,110
2015 (#146442)	$6,050,569	7.07	7,353
2016 (#148497)	$6,274,861	7.24	5,236
2017 (#148739)	$9,290,788	8.27	11,530
2018 (#148899)	$11,153,959	10.14	20,285
2019 (#151486)	$12,076,031	12.48	11,956
2020 (#155363) *Estimated (2020FC 9+3)*	$10,917,634	9.5	12,000
2021 (#142487) *Proposed*	$11,163,000	10	5,000
Total Program 2013 thru 2021	$74,751,370	72.92	78,290

Why is the project needed? What if we do nothing?

LG&E operates five separate network systems with 27 circuits within the core downtown Louisville business and medical districts; roughly bounded by the Ohio River (north), Floyd Street (east), York Street (south), and 8th Street (west). Three of the five network systems served by the Waterside, Magazine, and Madison Substations contain bare PILC cables. All primary and secondary conductors in main thoroughfares are completely underground and installed in manhole and duct systems.

Network distribution systems were developed in the early 1910's in order to provide the highest degree of service reliability to downtown business districts and to facilitate service to densely populated areas desiring a totally underground distribution system. The original LG&E network was built using PILC cables constructed of oil impregnated paper tape insulations and jacketed with a bare lead sheath; the most reliable cable construction available at the time. At the beginning of this program, an estimated 70 miles of bare primary and secondary PILC cables ranging in age from 48 to 100 years old were in service in the downtown Louisville network distribution system.

Early PILC primary cables and all PILC secondary cables utilized bare lead sheaths that have experienced varying degrees of surface corrosion over their service lives. Corrosion and/or mechanical damage allow the insulating oil to leak from the insulation and allow water to enter the cable, ultimately leading to a cable failure. Insulating oils in the older bare PILC cables are also reportedly much drier than when newly manufactured, indicating the degree of insulation aging and degradation. While service from the downtown network is designed for high reliability the number of cable failures is relatively small. Primary PILC cable failure rates had shown an increasing trend over the past fifteen years and were failing at twice the average rate per mile as the rest of the LG&E and KU underground systems. Primary cable failures over the three consecutive five-year periods preceding program initiation increased from an average of 3.2 (1999-2003), to 5.6 (2004-2008), to 8.2 (2009-2013). Known secondary failures averaged approximately two times a year with significantly greater consequences than primary failures due to high fault currents, secondary cables not protected against faults, and secondary cables had to burn in the clear before a fault was extinguished. The increase in secondary cable burnouts, the documented primary cable failure incidence rate, and the risk posed to adjacent cables in the duct and manhole system, highlights the need to continue the replacement program funding specifically to address secondary and primary PILC cables.

Under this program, PILC cables are replaced with the latest generation of solid dielectric cables using either rubber or crosslinked polyethylene insulation. The new cables are not subject to corrosion under wet conditions and are more resistant to water ingress with aging. Current generation cables have a life expectancy of more than 50 years.

Since program initiation, asset field inventories of cable and duct line capacity assessments in the network continue to reveal that significant quantities of aged duct lines are collapsed and deteriorated, requiring the need for additional duct lines and manhole capacities. Through this program, discovery of additional PILC secondary cable failures have been found located out of sight within the duct line that had not yet propagated to the point of a violent burnout or loss of customer service. Nearly all manholes encountered required replacement of cable support hardware and repositioning of fallen cables.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2021	2022	2023	Post 2023	Total
1. Capital Investment Proposed	10,605				10,605
2. Cost of Removal Proposed	558				558
3. Total Capital and Removal Proposed (1+2)	11,163	-	-	-	11,163
4. Capital Investment 2021 BP	10,947				10,947
5. Cost of Removal 2021 BP	216				216
6. Total Capital and Removal 2021 BP (4+5)	11,163	-	-	-	11,163
7. Capital Investment variance to BP (4-1)	342	-	-	-	342
8. Cost of Removal variance to BP (5-2)	(342)	-	-	-	(342)
9. Total Capital and Removal variance to BP (6-3)	(0)	-	-	-	(0)

Financial Detail by Year - O&M ($000s)	2021	2022	2023	Post 2023	Total
1. Project O&M Proposed					-
2. Project O&M 2021 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks

Failure to proceed with the bare PILC cable replacement program will incrementally increase risks to network system reliability. Delays could compress a planned multi-year replacement program into a shorter term, requiring greater annual manpower and funding levels to address system reliability.

No additional environmental issues are anticipated beyond the normal lead and cable oil handling and disposal requirements.

Alternatives Considered

1. Recommendation: NPVRR: $14,693k

   EDO recommends investing $11,163k during 2021 towards continuance of the PILC Cable Replacement Program to ensure the ongoing operating reliability of the Downtown Louisville Network distribution system.

2. Do Nothing: NPVRR: N/A

   While the total loss of one of the three grid networks in downtown Louisville is a very low probability event, it could occur if more than two circuits on the same network system containing PILC cable sustained failures to primary system components at the same time. Failure to proceed with the bare PILC cable replacement program introduces growing risk for cable failures caused by increasingly aged PILC cables, which could result in a significant partial or total outage to one of Louisville's three downtown grid networks which contain PILC cable. The network could be partially or completely restored only after one or two of the failures were located and repaired, depending on loading. In addition, 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.

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

   There are no alternatives to a traditional replacement program for extending the useful life of aged and deteriorating PILC cable systems and no reliable and/or practical method for testing the physical or electrical condition of bare PILC cable systems.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the continuance of the PILC Replacement Project for $11,163k for 2021 in order to ensure the ongoing operating reliability of the Downtown Louisville Network distribution system by the replacement of aged, defective, and deteriorating PILC cable and structural assets.

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: December 18, 2020

Project Name: Distribution Wood Pole Inspection and Maintenance Program - 2021

Total Capital Expenditures: $13,026k (Including $261k of contingency, including $400k of internal labor)

Total O&M: $536k

Project Number(s): LGE: 21PITP340, KU: 21PITP256, 21PITP216, 21PITP156, 21PITP246, 21PITP315, 21PITP766, 21PITP416, 21PITP366, 21PITP236, 21PITP426

Business Unit/Line of Business: Electric Distribution Operations / Distribution

Prepared/Presented By: Seth Hendrix / Karmen Powell

Brief Description of Project

Electric Distribution Operations seeks authority to allocate $13,026k for the Pole Inspection and Maintenance (Treatment) Program (PITP) during 2021. The PITP was originally approved by Investment Committee in February 2010, under provision that EDO would present subsequent year capital allocation proposals for review and approval during the budget cycle each year. EDO's proposed 2021 funding will provide for a detailed inspection of 61,300 wooden distribution poles, and dependent on their discovered conditions, preservative retreatment of 19,000 poles, reinforcement of 250 poles, and replacement of 1,900 poles.

Prior to 2010, EDO only inspected its wooden distribution poles biennially, in conformance with Kentucky Public Service Commission (PSC) regulations. The biennial inspection requirements are not thorough enough to adequately identify at-risk poles, and do not require pole ground line rot inspection, loading calculations, or treatments to extend their in-service life. Foregoing a pole inspection and treatment program dependent only on the biennial regulatory inspection requirements will result in the decreased life of pole assets, an increase in pole failures, and reduced system reliability and resiliency.

Since its inspection, more than 578k wooden distribution poles have been inspected under the PITP. EDO estimates that all remaining distribution wooden poles that have not been inspected under the first cycle of the PITP will be inspected under the program before the end of September 2022. As the first cycle of the PITP nears completion, EDO will assess pole failure trends and system reliability performance to target future year inspection schedules and investment levels under a second inspection cycle.

EDO's 2021 Business Plan (BP) includes $13,026k for this program in 2021.

Background
EDO's PITP was implemented in 2010. By year end 2020, approximately 578,600 company and foreign-owned poles will have been inspected, 182,619 poles will have been treated, 23,360 poles will have been replaced and 1,872 poles will have been reinforced by splinting. Cumulative spend from 2010-2019 is $103.6 million with the 2020 forecasted spend at $12.6 million.

EDO has more than 518,500 distribution wood poles in the asset base with an estimated average age of 30 years. An additional 155,400 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, 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.

EDO's PITP 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 2021-2025 capital costs included in the 2021 BP are shown below. This proposal only requests funding for 2021.

	2021	2022	2023	2024	2025
Amount in 000s	$13,026	$13,417	$13,820	$14,173	$14,528

Why is the project needed? What if we do nothing?
Kentucky mandated bi-annual inspections of the electric distribution system to identify obvious physical defects and unsafe conditions of distribution equipment. However, this inspection process doesn't focus singularly on poles, doesn't provide for life extending preservative retreatment of poles, and doesn't include pole loading calculations or below grade inspection for ground line rot.

EDO's PITP is consistent with prudent industry practice for maintaining pole assets. The program provides a systematic and focused approach to prolonging the service life of poles through a pole-by-pole inspection and assessment, and execution of condition based corrective actions where deficiencies are identified. Potential corrective actions include preservative retreatment, pole reinforcement, or pole replacement. Preservative retreatment arrests any decay present and can significantly increase the useful life of the pole at a very small cost relative to replacement costs. (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.) Pole replacement and reinforcement has been required on approximately 4% and 0.3% respectively of poles inspected through the program.

Annual SAIDI and SAIFI benefit of 0.45 minutes and 0.002 interruptions per customer have been realized on circuits where PITP has been completed.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	**2021**	**2022**	**2023**	**Post 2023**	**Total**
1. Capital Investment Proposed	11,085				11,085
2. Cost of Removal Proposed	1,941				1,941
3. Total Capital and Removal Proposed (1+2)	13,026	-	-	-	13,026
4. Capital Investment 2021 BP	11,085				11,085
5. Cost of Removal 2021 BP	1,941				1,941
6. Total Capital and Removal 2021 BP (4+5)	13,026	-	-	-	13,026
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)	**2021**	**2022**	**2023**	**Post 2023**	**Total**
1. Project O&M Proposed	536				536
2. Project O&M 2021 BP	536				536
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The 2021 Business Plan includes this funding in projects 0100PITP and 0110PITP 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 EDO and Corporate RAC processes.

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.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $17,693

2. Alternative #1: NPVRR: ($000s) $42,356
   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 $12,320k), and the resulting cost of unserved energy from these failures (costs of $28,144k). Projections indicate approximately 1,900 poles will be replaced as part of the PITP program during 2021. Without remedial actions, these 1,900 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.

Conclusions and Recommendation

EDO recommends the Investment Committee approve continuation of the Distribution Wood Pole Inspection and Maintenance Program, and authorize 2021 investments of $13,026k 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 $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: December 18, 2020

Project Name: Polo Club Blvd Sale

Total Capital Expenditures: N/A

Total O&M: N/A

Project Number(s): 163998

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Tiffany Koller/Paul Weis

Brief Description of Project

In 2008, KU purchased 7.5 acres located at 2975 Polo Club Blvd. in southeastern Fayette County (near Man O War Blvd. & I-75) for $730k to construct a future substation. The property is incumbered with an access easement, a greenway easement, and underground telecommunication wires. Due to expanding development in this area and development plans along Man O War Blvd., it was determined that the ability to connect to the nearest transmission circuit (approx. 1 mile) would be prohibitive and no longer feasible for a substation location. A new substation in this area is not included within the 2021 Business Plan (BP) or Substation's long term planning cycle.

Substations and Asset Management, KU Electric Distribution Operations, and Transmission all agree the property is no longer viable for company operations.

Why is the project needed? What if we do nothing?

In 2019, KU was approached by [redacted] requesting access through the property to build an access road connected to Barrington Ln. that is required for their planned mixed use residential development on a neighboring parcel. KU rejected this request at the time due to the location of the planned access road limiting the company's ability to construct a substation on the site.

In June 2020, [redacted] re-approached KU requesting access to the property to build an access road with an alternate design required for their proposed development. The revised access road request was determined not to impact the potential construction and operation of a future substation.

In September 2020, [redacted] approached KU to purchase the Polo Club Blvd. site for [redacted] is seeking a commitment from KU to sell the property or grant a permanent access agreement so they can file a development plan for their neighboring development.

As part of the Limestone Loudon Relocation project, this site was evaluated as a potential location for the new consolidated facility. This location was eliminated due to size, zoning issues, surrounding residential development, and substantial egress and ingress limitations.

Substations & Asset Information are the proponents for the sale of the property and have agreed with the sale of the lot to [redacted] versus providing a permanent access easement. A counter offer of [redacted] was made to [redacted] on and accepted in October 2020.

The difference between the sale price of [redacted] and the current book value $792,599 will be recorded as a gain.

Financial Summary

• Cost of Original Lot	$ 730,000
• Current Book Value	$ 792,599
• Property Appraisal[1]	[redacted]
• Current Offer	[redacted]

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Polo Club Blvd Sale project for [redacted] because the property is no longer viable for company operations.

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	

[1] Tamplin Company completed a review of the [redacted] appraisal at our request and concurred with the appraised price. The [redacted] offer of [redacted] /acre is at the upper end of the property sale comparisons [redacted] /acre). [redacted] utilized the same appraiser the Company uses for property appraisals in Lexington and the eastern portion of the KU service territory.

Investment Proposal for Investment Committee Meeting on: June 26, 2019

Project Name: West U.S. Hwy 42 Public Works Relocation

Total Capital Expenditures: $ 7,058k gross, $6,328k net (Including $1,118k of contingency)

Total O&M: $0k

Project Number(s): Distribution Gas 406000026, Distribution Electric Lines 159679, Transmission Lines LI-159724

Business Unit/Line of Business: Gas Distribution, Electric Distribution and Electric Transmission

Prepared/Presented By: Bill Harper

Brief Description of Project

LG&E Gas and Electric Distribution Operations and Electric Transmission seek capital authority of $7,058k to replace and relocate gas and electric distribution and electric transmission facilities that are located in private easements and in the West U.S. Hwy 42 right-of-way, between east of Rose Island Road in Jefferson County and Ridgemoor Drive in Oldham County. The Kentucky Transportation Cabinet (KYTC) recently confirmed plans to widen this section of West U.S. Hwy. 42 from two to three lanes, starting in 2020. Kentucky Revised Statutes (KRS) and traditional common-law rule, as reaffirmed by the U.S. Supreme Court in 1983, provide that private utilities are required to bear the entire cost of relocating utilities from a public right-of-way when necessary for road widening construction.

This project will relocate gas and electric distribution and electric transmission facilities to clear for proposed roadway construction.

Gas - $4,367k

- Install approximately 4,610’ of 12” steel high pressure (HP) distribution pipeline and install approximately 7,500’ of 4” & 2” medium pressure (MP) plastic pipeline along U.S. Hwy. 42 in the River Bluff area. This project will eliminate 3 existing regulator facilities and 20 farm taps with all being fed from an existing distribution system, due to being within the right-of-way and in conflict with the proposed road widening plans. The cost of this portion of the project is $4,367k, none of which is reimbursable by KYTC.

Electric Distribution - $475k (cost net of KYTC reimbursement)

- Installation of 16 distribution poles, under-build on 19 transmission poles, install 4,100’ of 795AA 3ph primary wire, install 4,100’ 195AA neutral wire, install 220’ of 123AAAC 3ph primary wire, install 220’ of 123AAAC 1ph primary wire, install 440’ of 123AAAC neutral wire, install 2,300’ of triplex secondary and service wire, install 18 transformers and other miscellaneous equipment. The existing electric facilities are within road right-of-way and in private easements, both in conflict with the proposed road widening plans.

The gross cost for this portion of the project is $809k, of which $334k (41.3%) will be reimbursed by KYTC.

Electric 69kV Transmission - $1,486k (cost net of KYTC reimbursement)

- Installation of 19 steel poles with polymer horizontal post insulators, install 13,500' of 397 ACSR conductor and 4,500' of static wire. This will include tree trimming and tree removal for the new proposed route. The existing transmission electric facilities are within road right-of-way and in private easements, both in conflict with the proposed widening plans. The gross cost for this portion of the project is $1,882k, of which $396k (21.0%) will be reimbursed by KYTC.

The project estimate includes a 10% contingency for electric and 25% contingency for gas. The gas contingency is higher to cover any additional labor or rock removal that may be needed due to the fact that there are two trenches that need to be dug for the gas work with greater risk of hitting rock.

Project Timeline

- June 2019: Open projects.
- August – December 2019: Transmission starts construction and plans to finish.
- August 2019 – December 2020, Gas to start relocation work.
- November 2019 – February 2020 Complete electric distribution work.

Why is the project needed? What if we do nothing?

KYTC recently confirmed plans to widen this section of West U.S. Hwy. 42 from two to three lanes, starting in 2020. KRS and traditional common-law rule, as reaffirmed by the U.S. Supreme Court in 1983, provide that private utilities are required to bear the entire cost of relocating utilities from a public right-of-way when necessary for road widening construction.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	3,007	2,896	-	-	5,903
2. Cost of Removal Proposed	385	40	-	-	425
3. Total Capital and Removal Proposed (1+2)	3,392	2,936	-	-	6,328
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)	(3,007)	(2,896)	-	-	(5,903)
8. Cost of Removal variance to BP (5-2)	(385)	(40)	-	-	(425)
9. Total Capital and Removal variance to BP (6-3)	(3,392)	(2,936)	-	-	(6,328)

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)	-	-	-	-	-

This proposed project was not included in the 2019 Business Plan (BP). Funding for 2019 was approved through the Corporate RAC process in May and 2020 funding is included in the 2020 proposed BP.

Risks

- There are timing and cost risks associated with completing the project as planned and include delays and higher cost due to the amount of rock encountered and any associated weather delays.

Environmental:

- LG&E will fall under the KYTC site disturbance permits.
- LG&E will cut and or remove trees in the proposed route for the new facilities in accordance with KYTC guidelines.
- The existing gas coal tar wrapped mains that conflict with the road construction will be removed and disposed of in accordance with environmental regulations. Any main that is not conflicting will be abandoned in place in accordance with environmental regulations.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $7,934k
   Relocate the gas and electric distribution facilities and electric transmission as noted above, in conjunction with the widening of U.S. Hwy 42 in Jefferson and Oldham Counties.

2. Do Nothing: NPVRR: N/A
   Doing Nothing is not an option because LG&E is required to relocate conflicting utilities within the road right of way under traditional common law.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the West U.S. Hwy 42 Public Works Relocation project for $ 7,058k gross ($6,328k net) to replace and relocate gas and electric distribution and electric transmission facilities that are located in private easements and in the West U.S. Hwy 42 right-of-way.

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	

Revised Capital Investment Proposal

Investment Proposal for Investment Committee Meeting on: February 27, 2019

Project Name: Bullitt County System Reinforcement

Total Capital Expenditures: $7,295k (Approved by email vote on 9/4/2018)

Total O&M: $0k

Total Revised Capital Expenditures: $10,043k

Project Number(s): 153662

Business Unit/Line of Business: GDO/Gas Operations

Prepared/Presented By: Tom Rieth

Description of Incremental Ask

Original Approved Capital Expenditures		$ 7,295 k
Revised Capital Expenditures Requested		$10,043 k
Total Increase Requested		$ 2,748 k

- The Bullitt County Reinforcement project was approved for $3,654k in November 2016 for the engineering, surveying, real estate and right-of-way (ReROW) and other preliminary activities necessary to develop a final pipeline route and detailed design specification and drawings required for submitting applicable permits and creating construction bid documents.
- During the November 2016 Investment Committee approval it was communicated that the remainder of the project would be brought to the Investment Committee after the pipeline construction costs were bid. Due to volatile steel prices from tariff changes, the project team went to the Investment Committee in August 2018 to request additional authorization of $3,641k to purchase pipe in 2018 in order to mitigate potential higher material costs and needed additional authorization for this expenditure. The Investment Committee approved the request and the project authorization was revised to $7,295k.
- At the time of the August 2018 request it was anticipated that the pipeline construction bids would be received and the project team would come back to the Investment Committee for full project authorization in the November/December 2018 timeframe. The pipeline construction bidding process was delayed due primarily to real estate issues. The real estate issues delayed necessary work on properties needed for the pipeline construction bid and additional engineering/design work to modify easement documents. The additional work and time required by the project team for this work in turn also

delayed construction bid material preparation as well. The pipeline construction bidding will occur in February/March 2019 and the project team plans to bring the project and pipeline construction contract to the Investment Committee in May 2019.

- Additional authorization of $2,748k is being requested to continue work on the project prior to May. The additional authorization is required to continue acquiring remaining easements, engineering and design work, execute the pipeline construction bid and material purchases for long lead items. The authorization includes $88k for overage through December 2018, $2,419k of projected expenses from January 2019 through May 2019 and 10% contingency ($241k) on the projected January through May spend.
- The additional funding request does not change the original Investment Proposal's determination that this is the recommended option.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	Pre-2019	2019	2020	Post 2020	Total
1. Capital Investment Proposed	7,383	2,660	-	-	10,043
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	7,383	2,660	-	-	10,043
4. Capital Investment 2019 BP	7,295	19,997	11,451	-	38,743
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	7,295	19,997	11,451	-	38,743
7. Capital Investment variance to BP (4-1)	(88)	17,337	11,451	-	28,700
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(88)	17,337	11,451	-	28,700

Financial Detail by Year - O&M ($000s)	Pre-2019	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)	-	-	-	-	-

The proposed capital spend in the table above reflects expected spending through May, when it is anticipated full project approval will be requested. The 2019 BP amounts reflect the entire project spend.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Bullitt County System Reinforcement project for $10,043k to continue acquiring remaining easements, engineering and design work needed to finalize permitting applications, pipeline construction bid documents, and material purchases.

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: April 24, 2019

Project Name: Magnolia Amine Plant Replacement

Total Capital Expenditures: $5,459k (Including $500k of contingency, including $200k of internal labor, if applicable)

Total O&M: $10,493k

Project Number(s): 448000030

Business Unit/Line of Business: Gas Distribution Operations

Prepared/Presented By: Barry Walker / John Skaggs / Zach Thomas

Brief Description of Project

The project consists of replacing amine gas processing plants #1 and #2 at Magnolia Compressor Station with hydrogen sulfide (H_2S) scavenging systems. Project scope includes installation of contactor vessels, piping, valves, fittings, and H_2S scavenger media to remove H_2S from gas withdrawn from Magnolia Upper and Magnolia Deep Storage Fields. Two large contactor vessels are proposed to be installed at Magnolia Compressor Station and seventy small contactor vessels installed at gas storage wells in Magnolia Upper Storage Field.

Why is the project needed? What if we do nothing?

Gas withdrawn from underground gas storage contains hydrogen sulfide (H_2S), a toxic and corrosive gas that must be removed before storage gas is supplied to the gas distribution system. H_2S is currently removed from natural gas withdrawn from Magnolia Upper and Magnolia Deep Storage Fields by two amine gas processing plants. The amine gas processing plants use a wet regenerative chemical gas treatment process that includes the following types of equipment: wet contactor towers, liquid pumps, heat exchangers, aerial coolers, boilers, amine filtration systems, controls, and H_2S flare. Amine plants #1 and #2 are 59 and 54 years old respectively and continued operation will require significant upgrades/investments to maintain reliable operations. Replacement of the amine plants with H_2S scavenging technology using a dry expendable media is proposed. The H_2S scavenger technology is less complex requiring only vertical contactor towers filled with a non-regenerative dry iron oxide granulated media. Natural gas containing H_2S flows thru the contactor towers, H_2S in the gas reacts with the iron oxide scavenger media to form iron sulfide. Spent scavenging media is removed from the towers and replaced with new media. The spent scavenging media is disposed of in a landfill as non-hazardous waste.

Engineering analysis determined replacement of existing amine gas processing plants with dry H_2S scavenging technology provides a lower lifecycle cost and additional benefits including: reduced operational complexity resulting in increased reliability, reduced H_2S exposure risk, sulfur dioxide emission elimination, reduced environmental risks, and reduction in required workforce resources by 6 positions.

The "Do Nothing" is not a viable alternative as it will lead to unreliable operation of the existing amine gas processing plants resulting in inability to provide reliable and adequate supply of pipeline quality natural gas from storage to meet system supply requirements.

Budget Comparison & Financial Summary

The total project cost estimate is based on engineering design, PVF material quotes, vessels bids, scavenger media bids and construction estimates. The project was opened in 2018 for $432k for engineering and design work and vessel fabrication. $399k has been spent through March 2019. The 2019 Business Plan (BP) includes $7,068k in 2019 for construction and installation of the new vessels. Estimated expenses for this project are lower than budget because the recommended option is to install the scavenger vessels for the Magnolia Upper Storage field at the storage field well sites instead of the station as originally proposed. The funding surplus will be given back to the Corporate RAC in April of 2019. Replacement of amine units with H_2S scavenging technology will enable reducing headcount by six positions at Magnolia Compressor Station. The O&M savings is based on reduction of four positions because the Gas Control Center will require two additional positions due to workload increases when Magnolia Compressor Station transitions to remote monitoring and control in 2021.

Financial Detail by Year - Capital ($000s)	2018	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	364	5,095	-	-	-	5,459
2. Cost of Removal Proposed	-	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	364	5,095	-	-	-	5,459
4. Capital Investment 2019 BP	-	7,068	-	-	-	7,068
5. Cost of Removal 2019 BP	-	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	-	7,068	-	-	-	7,068
7. Capital Investment variance to BP (4-1)	(364)	1,973	-	-	-	1,609
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(364)	1,973	-	-	-	1,609

Financial Detail by Year - O&M ($000s)	2018	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed		2,138	2,040	2,134	4,181	10,493
2. Project O&M 2019 BP		2,138	2,170	2,127	4,049	10,484
3. Total Project O&M variance to BP (2-1)	-	-	130	(7)	(132)	(9)

Risks

Risks associated with not completing this project include unreliable operating of the existing amine gas processing plants and inability to provide adequate gas supply from gas storage to meet system demand.

Technology change risk from an amine based treatment process to H_2S scavenger technology is very low. H_2S scavenger systems were installed in 2016 at Magnolia Compressor Station for peaking and polishing of gas withdrawn from Magnolia Upper and Deep storage fields. H_2S scavenger technology was also installed at Center Compressor Station in 2016 for treatment of gas withdrawn from Center Storage Field. The H_2S scavenger technology has met operational expectations, proven reliable, and met operating cost projections.

Alternatives Considered

1. Recommendation: NPVRR: ($1,396k)
   Install two 8 foot diameter by 30 foot tall H_2S scavenger vessels at Magnolia Compressor Station for treatment of Magnolia Deep storage gas and seventy 42 inch diameter by 11 foot tall scavenging vessels at storage wells for treatment of Magnolia Upper storage gas. This alternative provides the following benefits: decreased operational complexity, increased reliability, decreased H_2S exposure risks, reduced environmental risk, eliminates H_2S in Magnolia Upper storage field pipelines, and decreases required workforce size.

2. Alternative #1: NPVRR: $39k
   Install seventy and forty five H_2S scavenger vessels at storage wellsites in Magnolia Upper and Magnolia Deep storage fields respectively. This alternative provides the same benefits as the recommended alternative plus an additional benefit of eliminating H_2S in Magnolia Deep storage field pipelines.

3. Alternative #2: NPVRR: $195k
   Install two 8 foot diameter by 30 foot tall and six 12 foot diameter by 30 foot tall scavenger vessels at Magnolia Compressor Station to treat Magnolia Upper and Magnolia Deep storage gas. This alternative provides the following benefits: decreased operational complexity, increased reliability, decreased H_2S exposure risks, reduced environmental risk, decreases required workforce size, but does not eliminate H_2S in Magnolia Upper and Magnolia Deep storage field pipelines.

4. Alternative #3: NPVRR: $8,781k
   Continue operation of existing amine plants #1 and #2. This alternative includes upgrades/investments in amine plants #1 and #2 to maintain operational reliability. This alternative will not enable workforce size reduction and has increased operational complexity with lower reliability compared to the recommended alternative. In addition, the existing amine plants have more single points of failure than the H_2S scavenger vessels, higher environmental risks, higher H_2S exposure risk, and do not eliminate H_2S from the Upper storage field pipelines.

5. Alternative #4: Do Nothing
   The do nothing option is not recommended since the existing amine plant equipment has exceeded its design life and the failure risk is inherently more uncertain as time progresses eventually resulting in equipment failure and inability to provide adequate supplies of pipeline quality gas from gas storage to meet system supply requirements. Inability to utilize one of either purification plants #1 or #2 would decrease Magnolia Compressor Station deliverability up to 55 MMcf/day. Additional Texas Gas pipeline service would be required to replace lost storage supply in the event of an unplanned outage. The Texas Gas no-notice service (NNS) rate most closely replicates LG&E's gas storage capacity, but may not be available at the time of an outage. If adequate no-notice capacity were available, such capacity must be purchased for the entire winter season. 55 MMcf/day of NNS capacity for a winter season would cost approximately $3.5 million.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Magnolia Amine Plant Replacement project for $5,459k to lower gas processing lifecycle cost, increase reliability, lower operational complexity, decrease H_2S exposure risks, and lower environmental risks.

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: April 24, 2019

Project Name: Muldraugh Amine Plant Replacement Project

Total Capital Expenditures: $14,208k (Including $1,217k of contingency and $276k of internal labor)

Total O&M: $10,166k

Project Number(s): 447000022

Business Unit/Line of Business: Gas Distribution Operations

Prepared/Presented By: Barry Walker / Mike Cummins

Brief Description of Project

The project consists of replacing amine gas processing plants #2 and #3 at Muldraugh Compressor Station with hydrogen sulfide (H_2S) scavenging systems. Project scope includes the replacement of Muldraugh Compressor Station amine purification plants #2 and #3 with six vertical H_2S scavenger vessels 12 foot diameter by 30 feet tall and associated valves, fittings, and piping.

Why is the project needed? What if we do nothing?

Gas withdrawn from underground gas storage contains hydrogen sulfide (H_2S), a toxic and corrosive gas that must be removed before storage gas is supplied to the gas distribution system. H_2S is currently removed from natural gas withdrawn from Muldraugh and Doe Run storage fields by three amine gas processing plants. The amine gas processing plants use a wet regenerative chemical gas treatment process that includes the following types of equipment: wet contactor towers, liquid pumps, heat exchangers, aerial coolers, boilers, amine filtration systems, controls, and H_2S flare. Amine plants #2 and #3 are 1960's vintage and have been in service for over 50 years. Continued operation will require significant upgrades and investments to maintain reliable operations. Replacement of the amine plants with H_2S scavenging technology using a dry expendable granular media is proposed. The H_2S scavenger technology is less complex requiring only vertical contactor towers filled with a non-regenerative dry iron oxide granulated media. Natural gas containing H_2S flows thru the contactor towers, H_2S in the gas reacts with the iron oxide scavenger media to form iron sulfide. Spent scavenging media is removed from the towers and replaced with new scavenging media. The spent scavenging media is disposed of in a landfill as non-hazardous waste.

Engineering analysis determined replacement of existing amine gas processing plants with dry H_2S scavenging technology provides a lower lifecycle cost and additional benefits including: reduced operational complexity resulting in increased reliability, reduced H_2S

exposure risk, sulfur dioxide emissions elimination, reduced environmental risks, and reduction in required workforce resources by 5 positions.

Engineering analysis identified the optimal design included continuing to use amine purification plant #1 for late season storage withdrawals with high H_2S levels and installing six H_2S scavenger vessels for early season and to meet peak day capacities. The optimal design results in lower lifecycle costs with decreased operational complexity, increased reliability, and decreased H_2S exposure risk than continuing to maintain/operate all three existing amine plants. Major components on amine plant #1 have been replaced over the past 10 years.

The "Do Nothing" is not a viable alternative as it will lead to unreliable operation of the existing #2 and #3 amine gas processing plants resulting in inability to provide reliable and adequate supply of pipeline quality natural gas from storage to meet system supply requirements. Alternative pipeline gas supplies might not be available during critical operating periods.

Budget Comparison & Financial Summary

The total project cost estimate is based on engineering design, PVF material quotes, vessels bids, scavenger media bids and construction estimates. The project was opened in 2018 for $377k for engineering and design work. $329k has been spent through March 2019. The 2019 Business Plan (BP) includes $11,790k ($3,502k in 2019, $7,755k in 2020 and $533k in 2021) for demolition, construction, and installation of the new vessels. Additional funding will need to be requested in the 2020 BP process.

Financial Detail by Year - Capital ($000s)	2018	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	228	3,079	9,909	-	-	13,216
2. Cost of Removal Proposed	-	-	496	496	-	992
3. Total Capital and Removal Proposed (1+2)	228	3,079	10,405	496	-	14,208
4. Capital Investment 2019 BP	-	3,502	6,397	-	-	9,899
5. Cost of Removal 2019 BP	-	-	1,358	533	-	1,891
6. Total Capital and Removal 2019 BP (4+5)	-	3,502	7,755	533	-	11,790
7. Capital Investment variance to BP (4-1)	(228)	423	(3,512)	-	-	(3,317)
8. Cost of Removal variance to BP (5-2)	-	-	862	37	-	899
9. Total Capital and Removal variance to BP (6-3)	(228)	423	(2,650)	37	-	(2,418)

Financial Detail by Year - O&M ($000s)	2018	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	2,380	2,127	1,886	3,772	10,166
2. Project O&M 2019 BP	-	2,380	2,127	2,037	4,081	10,627
3. Total Project O&M variance to BP (2-1)	-	-	-	151	309	461

Risks

Risks associated with not completing this project include unreliable operating of the existing amine gas processing plants and inability to provide adequate gas supply from gas storage to meet system demand.

Technology risk associated with using H_2S scavenger technology is very low. H_2S scavenger systems were installed in 2016 at Magnolia Compressor Station for peaking and polishing of gas withdrawn from Magnolia Upper and Deep storage fields. H_2S scavenger technology was also installed at Center Compressor Station in 2016 for treatment of gas withdrawn from Center Storage Field. The H_2S scavenger technology has met operational expectations, proven reliable, and met operating cost projections.

Risk associated with a construction delay in 2020 after starting the project includes the loss of 105 MMcf/day of gas processing capacity for the 2020-2021 winter operating period due to required removal of amine purification plant #2 to provide area for the installation of the new H_2S scavenger vessels.

Proposed project will require revision of Title V permit due to elimination of multiple emissions units currently listed.

Alternatives Considered

1. Recommendation: NPVRR: $4,792k
   Replace existing amine plant #2 and #3 with H_2S scavenger vessels, keep amine plant #1 operating as base load unit. The following benefits are provided: decreased operational complexity, increased reliability, decreased H_2S exposure risks, reduced sulfur dioxide (SO_2) emissions, reduced environmental risk, and decreased workforce size.

2. Alternative #1: NPVRR: $7,003k
   Continued operation of amine plants #2 and #3 will require significant upgrades/investments to maintain operational reliability. This alternative will not enable reduction of workforce size and has increased operational complexity with lower reliability compared to the recommended alternative. In addition, the existing amine plants have more single points of failure than the H_2S scavenger vessels, higher environmental risks, and higher H_2S exposure risk.

3. Alternative #2: Do Nothing
   The do nothing option is not recommended since the equipment has exceeded its design life and the failure risk is inherently more uncertain as time progresses eventually resulting in equipment failure and inability to provide adequate supplies of pipeline quality gas from gas storage to meet system supply requirements during critical operating periods. Inability to utilize one of either purification plants #2 or #3 would decrease Muldraugh Compressor Station deliverability by up to 105 MMcf/day. Additional Texas Gas pipeline service would be required to replace lost storage supply in the event of an unplanned outage. The Texas Gas no-notice service (NNS) rate most closely replicates LG&E’s gas storage capacity, but may not be available at the time of an outage. If adequate no-notice capacity were available, such capacity must be purchased for the entire winter season. 105 MMcf/day of NNS capacity for a winter season would cost approximately $6.6 million.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Muldraugh Amine Plant Replacement project for $14,208k to lower gas processing lifecycle cost, increase reliability, lower operational complexity, decrease H_2S exposure risks, and lower environmental risks.

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: July, 31 2019

Project Name: Gas Control SCADA

Total Capital Expenditures: $2,876k (Approved on May 1, 2017)

Total Revised Capital Expenditures: $3,459k

Project Number(s): 149422

Business Unit/Line of Business: Gas Distribution

Prepared/Presented By: Brian Lenhart / Barry Walker

Description of Incremental Ask

Original Approved Capital Expenditures		$2,876k
Revised Capital Expenditures Requested		$3,459k
Total Increase Requested		$583k

The Gas Control SCADA project was originally approved for a total capital expenditure of $2,876k, which included $66k of contingency. The project was scheduled for completion by the end of 2018, and is now expected to be completed in the third quarter of 2019. Several factors have contributed to the necessity for additional funding, including:

- Twelve [redacted] change orders [redacted] for items that were identified throughout the course of the project that were outside of the original project scope.

- LG&E internal labor costs totaling $319k through 6-10-2019 that are above the original project estimate due to project schedule creep. Factors that have contributed to the schedule creep include multiple attempts at baseline testing, extended acceptance testing, and defect resolution.

- Additional hardware requirements were identified that were necessary to enable High Availability on all Gas SCADA virtual machines in order to increase the reliability of the system. The additional hardware costs totaled $171k.

- Other underruns of $149k.

The following table illustrates project actuals to date, the project outstanding project commitments, and the requested capital expenditure increase to complete the project.

[redacted]

The revised project costs still result in this alternative being the recommended action.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	Pre-2019	2019	2020	Post 2020	Total
1. Capital Investment Proposed	2,133	1,326	-	-	3,459
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	2,133	1,326	-	-	3,459
4. Capital Investment 2019 BP	2,864	-	-	-	2,864
5. Cost of Removal 2019 BP	8	-	-	-	8
6. Total Capital and Removal 2019 BP (4+5)	2,872	-	-	-	2,872
7. Capital Investment variance to BP (4-1)	731	(1,326)	-	-	(595)
8. Cost of Removal variance to BP (5-2)	8	-	-	-	8
9. Total Capital and Removal variance to BP (6-3)	739	(1,326)	-	-	(587)

Financial Detail by Year - O&M ($000s)	Pre-2019	2019	2020	Post 2020	Total
1. Project O&M Proposed	-	109	225	1,230	1,564
2. Project O&M 2019 BP	-	80	180	905	1,165
3. Total Project O&M Variance to BP (2-1)	-	(29)	(45)	(325)	(399)

The incremental $1,326k of capital funding for 2019 has been reallocated through the GDO RAC process in June 2019. The incremental O&M is included in the 2020 BP.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Gas Control SCADA project for $3,459k to ensure the continued safe and reliable operation of the gas 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: September 25th, 2019

Project Name: Gas Service Line Replacement Program - 2019

Total Capital Expenditures: $9,704k (Approved on 11/28/2018)

Total O&M: $0k

Total Revised Capital Expenditures: $12,184k

Project Number(s): 414000001

Business Unit/Line of Business: Gas Distribution Operations / Gas Construction

Prepared/Presented By: Lesley Hill/Tom Rieth

Description of Incremental Ask

Original Approved Capital Expenditures		$ 9,704k
Revised Capital Expenditures Requested		$12,184k
Total Increase Requested		$2,480k

Gas Distribution Operations instituted a systematic large-scale replacement program of steel gas distribution customer service lines and targeted removal of county loops and steel curbed services. This program began in 2018 and will enhance the safe and reliable delivery of natural gas service to LG&E's customers. Over time, steel gas service lines are susceptible to corrosion, which could lead to gas leaks developing in close proximity to a home or business. County loops and curbed services would be removed because of an elevated risk of third-party damage due to their physical location.

At the beginning of 2019, the Gas Service Line Replacement program utilized nine contractor construction crews. The project production targets and actual costs were reviewed in the 2020 BP process and it was determined the project could be accelerated in 2019 to meet the objectives of replacing steel customer service lines, curbed services and county loops. Based on the review for the 2020 BP contractor resources were increased to fourteen total crews with plans to maintain that number. The original program was planned for 15 years with completion in 2032. With the additional crews added in 2019, the current 2020 BP estimates, and the number of services originally identified, the end date for this program is expected to be in 2029. Work is being accelerated based upon review during the 2020 BP process, in which it was determined that additional crews could be effectively managed to achieve the benefits of this program described in the paragraph above.

The updated target for the steel curbed services included dedicating a crew in April for removing high pressure curbed services. The high-pressure steel curbed services are generally more expensive and time consuming to complete than a normal curbed service, due to difficult locations and the time, materials, and welder labor required to remove them. The costs and production for the high-pressure steel curbed services will be tracked separate from the other steel curbed services for developing cost and production targets. The high-pressure steel curbed services make up approximately 240 of the estimated 4,400 steel curbed services when the project started.

Budget Comparison & Financial Summary

The total projected difference in spending is $2,480k, and the project will exceed the original $9,704k spending from the 2019 BP at some point in October of 2019. The original budget plan accounted for replacing 3,394 steel services and 1,467 curbed services. Through July of 2019, a total of 2,418 steels services and 577 curbed services have been completed, and at the revised spending amount, the project will actually complete 4,289 steel services and 1,019 curbed services by the end of 2019.

Financial Detail by Year - Capital ($000s)	Pre-2019	2019	2020	Post 2020	Total
1. Capital Investment Proposed	-	11,068	-	-	11,068
2. Cost of Removal Proposed	-	1,116	-	-	1,116
3. Total Capital and Removal Proposed (1+2)	-	12,184	-	-	12,184
4. Capital Investment 2019 BP	-	8,818	-	-	8,818
5. Cost of Removal 2019 BP	-	886	-	-	886
6. Total Capital and Removal 2019 BP (4+5)	-	9,704	-	-	9,704
7. Capital Investment variance to BP (4-1)	-	(2,250)	-	-	(2,250)
8. Cost of Removal variance to BP (5-2)	-	(230)	-	-	(230)
9. Total Capital and Removal variance to BP (6-3)	-	(2,480)	-	-	(2,480)

Financial Detail by Year - O&M ($000s)	Pre-2019	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)	-	-	-	-	-

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Gas Service Line Replacement Program for $12,184k to replace at risk steel customer service lines, remove county loops as encountered, and targeted curbed services. This replacement program is consistent with the risks and recommendations identified in the LG&E DIMP and will provide a safer, more reliable gas service to customers.

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: November 22, 2019

Project Name: Elevated Pressure Replacement Program - 2020

Total Capital Expenditures: $3,374k (Including $307k of contingency including $393k of internal labor)

Total O&M: $5k

Project Number(s): 406000022

Business Unit/Line of Business: Gas Distribution Operations

Prepared/Presented By: David McGuire/Tom Rieth

Brief Description of Project

This proposal is requesting funding for the third year (2020) of a systematic program to reinforce areas of the Elevated Pressure (3.0 PSIG Max Allowable Operating Pressure (MAOP)) LG&E Gas Distribution System. The proposed funding for 2020 will support the installation of approximately 3.3 miles of new main, the uprate of approximately 0.5 miles of existing polyethylene main, the installation of approximately 200 new service lines, the uprate of approximately 75 existing polyethylene service lines, and the installation of one new regulator station. Due to the lack of specific information on materials, installation, and design available on much of the existing elevated pressure system, uprating the system without the enhancements listed above is not recommended. In addition, many of the components for which adequate records do exist are unsuitable for operation at the proposed higher operating pressures and would likely result in excessive leaks during the uprating process.

Where reinforcement occurs, existing elevated pressure steel main pipelines will be replaced with plastic (polyethylene) pipelines, which are used in all distribution systems with a MAOP less than 60 psig. Likewise, existing steel service lines will be replaced with new polyethylene service lines. Existing elevated pressure polyethylene main lines and service lines will be uprated to operate at medium pressure. In some instances, existing polyethylene facilities may be replaced when the cost for replacement is less or when construction or customer considerations dictate the need for replacement.

The primary driver for the reinforcement work is to mitigate reliability risks in the elevated pressure system. These risks present in three major forms: hydraulic constraint in locations with substantial impact, uncertainty in total connected load due to unreported back-up generator installations, and the age of the system components and historical construction practices. The reinforcement work will have additional benefits including improving operational and emergency response flexibility. The majority of the current elevated pressure system is constructed of steel pipeline components with a limited number of valves in the existing system. The steel pipelines and limited valves can result in more costly and time-consuming shutdown techniques in the case of emergency or operational need. Furthermore, the relatively low operating pressure of the elevated pressure system (MAOP of 3 psig) greatly limits the ability to isolate small sections of the system. This could result in either higher customer and system impact or the necessity for a costly and time-consuming by-pass installation when isolations are necessary.

The estimated cost for 2020 is $3,374k, $2,512k is included in the proposed 2020 Business Plan (BP), the remaining funding will be handled through the 2020 RAC process. Requested funding is higher than the proposed business plan to to complete all planned work and install a second source of supply into the medium pressure system replacing the existing elevated pressure system eliminating risks of a one-way feed serving significant number of customers. There is also a need for an estimated $5k in O&M funding which was not included in the 2020 BP and will be handled in through normal processes.

This project will consist of all activities and responsibilities necessary to achieve the following scope:

Scope Item Description	**Quantity**
Install new 2" Polyethylene Pipeline	9,750 Feet
Install new 4" Polyethylene Pipeline	2,150 Feet
Install new 6" Polyethylene Pipeline	810 Feet
Install new 8" Polyethylene Pipeline	4,530 Feet
Uprate Existing Polyethylene Pipeline	2,400 Feet
Install New Service (Customer and Company)	207 Services
Uprate Existing Polyethylene Service	73 Services
Upgrade existing Regulator Station	1 Regulator Station

In many ways this project will be very similar to both the Priority Main Replacement Program and the Large Scale Main Replacement Program. We have established company procedures and have built a repository of experience and knowledge in this type of work over the past 21 years. The project has been planned in a modular nature to minimize extended restoration times (including street) to reduce the impacts of our work on the surrounding community.

All hydraulic analysis and material specification have been completed for this project. General pipe routes have been selected, and exact locations will be selected in the field based off in-situ conditions and existing utility locations. Preliminary right-of-way and easement research has started. Estimates of necessary man-hours and other logistics have been completed for completion of an estimate.

This project will start construction in January of 2020 and the first module is intended for completion by the end of June 2020. At the completion of the first module the second module (included in this IP scope) would immediately begin and be completed in December 2020. Both modules will follow as closely as possible the following timeline:

-Month 1-2: Install or uprate main lines
-Month 2-4: Finish installation of main lines and start and complete service lines
-Month 5-6: Complete restoration of all public and private assets

Why is the project needed? What if we do nothing?

LG&E's Elevated Pressure Distribution System consists largely of three separate distribution systems within Louisville. These systems combined contain approximately 160 miles of main pipeline and 14,000 service lines. The customers consist mostly of residential, commercial, and light industrial groups. These three systems all have an operating pressure of 2.0 PSIG and an established MAOP of 3.0 PSIG. The Elevated Pressure is regulated and supplied to the distribution system by fifteen regulator facilities spread throughout the three systems. Customer services have individual service regulators at the meter reducing the pressure to the customer's side of the meter to standard houseline pressure.

Many parts of the elevated pressure system were designed and installed as far back as the 1950s. Over time customer load has increased and through system planning and monitoring several areas of the elevated pressure system have been identified as needing reinforcement to mitigate declining operating pressures, especially during the heating season when demand is generally higher. On very cold days it is possible for pressures in some isolated sections of the system to drop sufficiently to risk customer service outages.

In some portions of the elevated pressure system, the installation of emergency generators without information being provided to LG&E has created potentially significant undocumented transient demand on the elevated system. It is difficult to determine the effect this demand could have on the elevated pressure system if a large-scale electrical disruption were to occur. If such a large-scale electrical disruption were to occur it would activate all of the transient loading associated with the backup generators, which could cause the inability of the elevated pressure system to supply gas to all elevated pressure customers.

Finally, there are reliability concerns related to the age of the existing elevated pressure system. The oldest components of this system date from the early 1950s. Construction practices at the time do not conform to current standards and best practices. The elevated pressure system has a large number of mechanical couplings. Additionally, the older parts of the elevated pressure system have very few mainline or service valves. This limits our ability to quickly isolate a leak in an emergency situation and requires more expensive and time consuming isolation methods to be employed.

This proposal only includes the scope for 2020. As previously mentioned the project has been planned in a modular format so customers will experience reliability benefits from the 2020 work, but the workcan be built upon by future projects on the elevated pressure system.
The proposed work will follow the same general layout as the current elevated pressure system with only minor changes in layout as necessary. Pipeline sizes will be selected utilizing system level hydraulic modeling to account for current customer demand as well as system robustness and reliability.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	3,284	-	-	-	3,284
2. Cost of Removal Proposed	90	-	-	-	90
3. Total Capital and Removal Proposed (1+2)	3,374	-	-	-	3,374
4. Capital Investment 2020 BP	2,255	-	-	-	2,255
5. Cost of Removal 2020 BP	257	-	-	-	257
6. Total Capital and Removal 2020 BP (4+5)	2,512	-	-	-	2,512
7. Capital Investment variance to BP (4-1)	(1,029)	-	-	-	(1,029)
8. Cost of Removal variance to BP (5-2)	167	-	-	-	167
9. Total Capital and Removal variance to BP (6-3)	(862)	-	-	-	(862)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	5	-	-	-	5
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	(5)	-	-	-	(5)

Risks

- Poor weather could delay the completion of this project. As a result, financial obligation for restoration would continue into 2021 and the social impact of the project would be extended.
- Lack of contractor resources available to start this project on our proposed schedule could slow or delay the construction and push additional work and cost into 2021.
- Cold winter weather may discourage customers from scheduling their service change over. This will reduce the project efficiency, drive up costs, and possibly delay work and costs into 2021.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $4,401

2. Alternative #1: NPVRR: ($000s) $5,054
   Replace all pipeline, services and components in the section of the elevated pressure system to be reinforced so it can operate at medium pressure (MAOP up to 60 psig). This option would replace all existing steel and plastic pipeline and components with plastic pipe and components that are suitable for uprating and compatible with the project design with no additional safety or efficiency benefits.

3. Alternative #2: NPVRR: ($000s) N/A
   Do nothing. This is an option but has considerable risk of service interruption and poor positioning for future load growth

Conclusions and Recommendation

It is recommended that the Investment Committee approve the 2020 Elevated Pressure Replacement project for $3,374k to increase system reliability and eliminate existing system risks.

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: November 22, 2019

Project Name: Gas Distribution Blankets - 2020

Total Expenditures: $26,273k

Project Number(s): Various

Business Unit/Line of Business: GDO

Prepared/Presented By: Tom Rieth

Brief Description of Project

Blankets are used to budget and account for annual routine short cycle, high volume work types and infrastructure work in GDO. Capital Blankets are comprised of a multitude of individual small projects necessitating capital investment. GDO subdivides its Blankets into distinct categories for new customer connections, network enhancements, network maintenance, and network repairs. These categories align with primary work drivers for GDO.

Blanket spend is monitored, analyzed, and trended on a monthly basis, using a combination of financial, applicable area economic indicators, and detailed input from area operational managers and other departments. This information, with consideration for known influences on historical trends, is used to develop annual budget allocations.

GDO is requesting approval for $26,273k in Blankets, an increase of $1,311k from the 2019 Business Plan for 2020.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the 2020 GDO Blanket projects for $26,273k to help manage the GDO capital work budgeted for 2020.

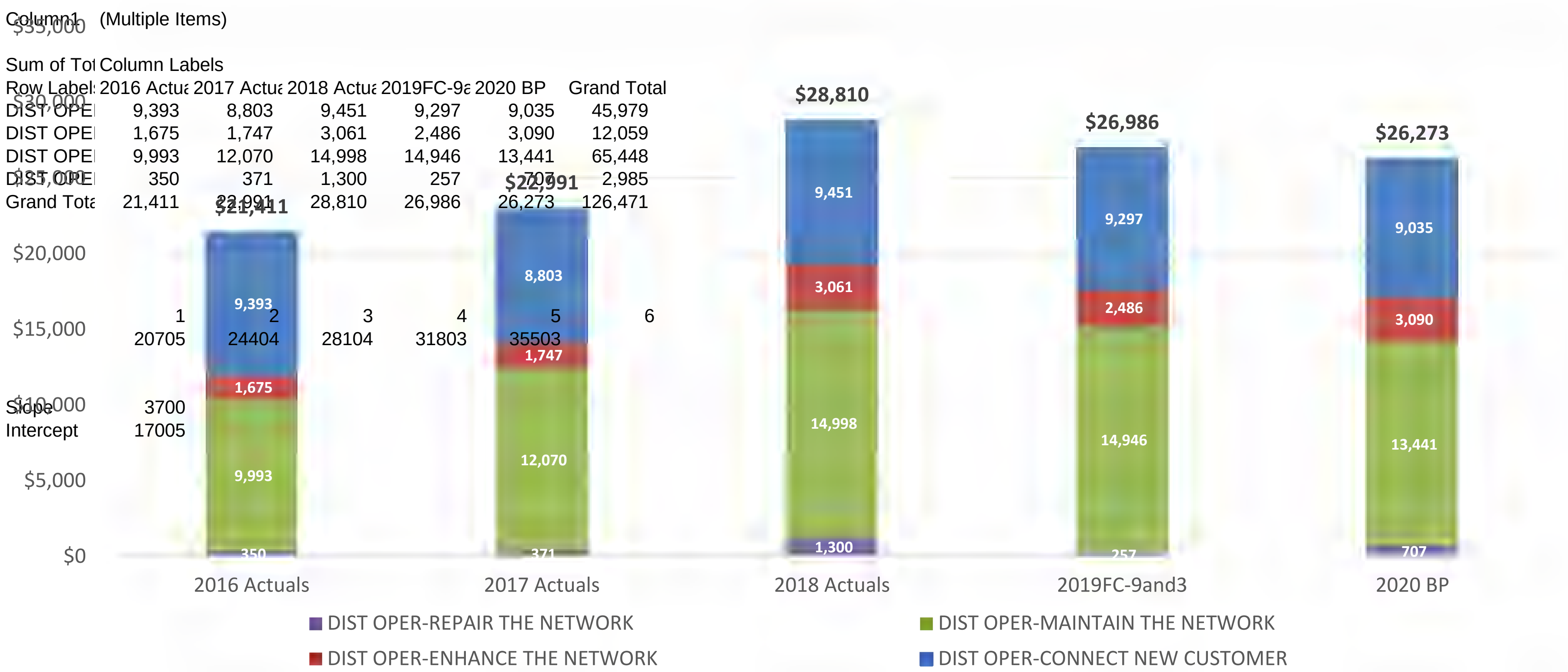
Approval Confirmation for Capital Projects Greater Than $2 million:

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

GDO Capital Blanket Comparison

Column1	(Multiple Items)					
Sum of Tot	Column Labels					
Row Label	2016 Actua	2017 Actua	2018 Actua	2019FC-9a	2020 BP	Grand Total
DIST OPE	9,393	8,803	9,451	9,297	9,035	45,979
DIST OPE	1,675	1,747	3,061	2,486	3,090	12,059
DIST OPE	9,993	12,070	14,998	14,946	13,441	65,448
DIST OPE	350	371	1,300	257	707	2,985
Grand Tota	21,411	22,991	28,810	26,986	26,273	126,471
	1	2	3	4	5	6
	20705	24404	28104	31803	35503	
Slope	3700					
Intercept	17005					



High Level Variance Explanations:

Enhance the Network - the 2020 requested amount is higher than the forecast due to:
- Public Works 2019 forecast funding was reallocated to individual projects that exceeded that blanket threshold (I-65 and US 60 @ Johnson).

Maintain the Network - the 2020 requested amount is lower than the forecast due to:

- Higher Company Service Leak Repairs in 2019, orders up 48% (compared to 2018 figures through 9/30). Budget was developed using a 5 year historical average.
- Higher Gas Regulator Facility Upgrade costs in 2019 due to additional facilities identified for replacements and system upgrades.

- Higher Station and Storage Field costs in 2019 at Muldraugh for various small engine room piping and controls upgrade in the station and additional drips replaced in Doe Run storage field and retire Ft. Knox Regulator station G-532. Amine Replacement project is also expected to reduce costs incurred on this project going forward.

Repair the Network - the 2020 requested amount is higher than the forecast due to:
- Large credit in third party damages in the 2019 forecast related to Hurstbourne Lane damage (occurred in 2018, completed in 2019). Incident was moved to another (non-blanket) project.

Gas Distribution Operations
2020 Capital Blankets (In Thousands $)

Blanket Project Number/Description	2020 BP	vs. 2019 BP			vs. 2019 Forecast (9+3)			Variance - 2020 BP vs 2019 Forecast
		2019 BP (2020)	Variance Plan over Plan	% Chg	2019 9+3 Forecast	Variance to 2019 9+3	% Chg	
DIST OPER-CONNECT NEW CUSTOMER								
CGME406 - Gas Main Extensions	2,735	2,240	-495	-22%	2,639	-95	-4%	
CNBCS - New Business Customer Service (GLT)	4,590	4,749	160	3%	4,724	134	3%	22% increase in new customer service orders in 2019 (compared to 2018 through September 30). Budget was developed using a 5-year historical average.
CNBGS - New Business Gas	1,596	1,813	217	12%	1,815	219	12%	50% increase in new company service orders in 2019 (compared to 2018 through September 30). Budget was developed using a 5-year historical average.
CNBREG - Purchase Regulators New Business	115	90	-25	-28%	119	4	3%	
DIST OPER-CONNECT NEW CUSTOMER TOTAL	**9,035**	**8,893**	**-118**	**-1%**	**9,297**	**258**	**3%**	
DIST OPER-ENHANCE THE NETWORK								
CFTCUS-Gas Control FT Customer Conversions	90	90	-1	-1%	44	-47	-107%	
CKYTCR - Public Works - Customer Requests				N/A	-24	-24	100%	The 2019 BP assumes customer payments will offset spending.
CPBWK - Public Works Relocations Gas	2,287	1,368	-919	-67%	1,387	-900	-65%	In the 2019 forecast funding was reallocated to individual projects that exceeded that blanket threshold (I-65 and US 60 @ Johnson).
CRCST - Relocations Cust Request		-1	-1	100%	115	115	100%	The 2020 BP assumes customer payments will offset spending. The 2019 9+3 forecast reflects some projects that were not 100% reimbursable and timing differences.
CSYSEN - System Enhancements Gas	712	768	56	7%	965	253	26%	The 2020 BP reflects lower spending on the blanket project but more spending on individual system enhancement project numbers.
DIST OPER-ENHANCE THE NETWORK TOTAL	**3,090**	**2,224**	**-865**	**-39%**	**2,486**	**-603**	**-24%**	
DIST OPER-MAINTAIN THE NETWORK								
CACMIT-Regulatory AC Mitigation	1,180	1,175	-5	0%	246	-934	-380%	Challenges in establishing contracts in 2019 limited work completion.
CCAPAC-Gas Regulation Capacity Project	604	600	-3	-1%	382	-222	-58%	Project scope reduction. Funding and resources shifted to the CREGFC, Gas Regulator Facility Upgrade project.
CCGUPG-Upgrade Facilities at City Gate	51	50	-1	-2%	57	6	11%	
CCOCNT-Replace Controllers at City Gate	60	60	-	0%	61	1	1%	
CCPIMP-CP Impressed Current System Improvement	35	33	-2	-7%	34	-1	-2%	
CCSO - Replace Existing Customer Service (GLT)	2,625	2,722	97	4%	2,870	245	9%	Customer service leak repair orders up 36% (compared to 2018 through September 30). Budget was developed using a 5-year historical average.
CDEFEQ-Storage Equipment Replacement	331	333	2	1%	454	122	27%	Muldraugh requested additional $32k in 2019 to purchase laser leak detection equipment for storage area. No other additional increases anticipated for 2019 or 2020 (Cummins). Amine Replacement project is also expected to reduce costs incurred on this project going forward.
CEBREG & CCAPR -Purchase Regulators Existing Cust	160	25	-135	-542%	163	3	2%	
CHPSRV-High Pressure Gas Service Upgrade	1,006	999	-6	-1%	949	-56	-6%	
CPLUG-Plug Wells	871	873	2	0%	598	-273	-46%	Project scope decreased due to resources shifted to completion of Storage Well Integrity Inspection work accelerated into 2019.
CREGFC-Gas Regulator Facility Upgrade	645	640	-4	-1%	1,303	659	51%	Project scope increase due to additional facilities identified for replacements and system upgrades. Funding and resources shifted from the CCAPAC, Gas Regulation Capacity project and other funding sources.
CREGST-Upgrade Facilities at Regulator Station	50	50		1%	52	2	5%	
CRELI-Reline Wells	645	603	-42	-7%	640	-6	-1%	
CROTAR - Upgrade Obsolete Rotary Meters				N/A			N/A	
CSTATN-Station Blanket	609	609	-1	0%	1,112	503	45%	Muldraugh requested an additional $226k in 2019 for various small engine room piping and controls upgrade in the station. Small projects were not originally included in 2019 BP estimate. Amine Replacement project is also expected to reduce costs incurred on this project going forward.
CSTOR-Storage Field/Transmission Blanket	1,681	1,689	8	0%	2,044	363	18%	Muldraugh requested an additional $387k to replace 7 additional drips in Doe Run storage field and retire Ft. Knox Regulator station G-532. No additional increase anticipated for 2019 or 2020.

Gas Distribution Operations
2020 Capital Blankets (In Thousands $)

Blanket Project Number/Description		2020 BP	vs. 2019 BP			vs. 2019 Forecast (9+3)			Variance - 2020 BP vs 2019 Forecast
			2019 BP (2020)	Variance Plan over Plan	% Chg	2019 9+3 Forecast	Variance to 2019 9+3	% Chg	
	RRCS - Replace Company Gas Services (GLT)	2,888	2,968	81	3%	3,979	1,092	27%	Company service leak repair orders up 48% (compared to 2018 through September 30). Budget was developed using a 5-year historical average. Project was previously incorporated into the Leak Mitigation IP approvals. Since the Leak Mitigation program is now complete, but this blanket work is ongoing, it is now being added to the blanket approvals.
	DIST OPER-MAINTAIN THE NETWORK TOTAL	**13,441**	**13,431**	**-10**	**0%**	**14,946**	**1,504**	**10%**	
DIST OPER-REPAIR THE NETWORK									
	CTBRD - Trouble Orders Gas	563	226	-337	-149%	536	-28	-5%	Coupling replacement policy change has driven this number higher in 2019. This trend will continue into 2020 and beyond.
	CTPD - Repair 3rd Party Damage	144	163	19	12%	-279	-422	152%	Variance driven by Hurstbourne Lane damage (occurred in 2018, completed in 2019). Incident was moved to another (non-blanket) project.
	DIST OPER-REPAIR THE NETWORK TOTAL	**707**	**389**	**-318**	**-82%**	**257**	**-450**	**-175%**	
	REPORT TOTAL	**26,273**	**24,937**	**-1,311**	**-5%**	**26,986**	**709**	**3%**	

Investment Proposal for Investment Committee Meeting on: 11/22/2019

Project Name: Gas Service Line Replacement Program - 2020

Total Capital Expenditures: $10,028k

Total O&M: $0k

Project Number(s): 414000002

Business Unit/Line of Business: Gas Distribution Operations / Gas Construction

Prepared/Presented By: Lesley Hill/Tom Rieth

Brief Description of Project

Gas Distribution Operations proposes to continue a systematic large scale replacement program of steel gas distribution customer service lines and targeted removal of county loops and steel curbed services. This program began in 2018 and will enhance the safe and reliable delivery of natural gas service to LG&E's customers. Over time, steel gas service lines are susceptible to corrosion, which could lead to gas leaks developing in close proximity to a home or business. County loops and curbed services would be removed because of an elevated risk of third party damage due to their physical location.

The majority of steel customer services were installed before the mid 1980's until the industry began installing polyethylene (PE) pipe as the primary service line material. Many of the steel services in the LG&E service territory have already been replaced through projects such as the large scale main replacement program or through a reactive replacement. Since 2013, LG&E has had responsibility to make the reactive replacements through renewal projects. If left in service, the remaining steel service lines are likely to continue to intermittently fail from corrosion and require replacement. From a customer experience perspective the program will replace the steel services on a planned basis, reducing the chance of unexpected service interruptions.

In addition, if a steel customer service is attached to a steel company service, the company service will be replaced as well. This will provide an opportunity to install Excess Flow Valves (EFV) at the main as further protection to the customer (except where conditions exist that would prevent proper function, for example, where system pressure is less than 10 psig). This is already a regulatory requirement for all new service installations except for the previously mentioned conditions and supports regulations finalized in 2016 for expanded EFV usage.

This proposal seeks approval for $10,028k for the third year of the program. Approval for the remaining years will be brought to the Investment Committee annually. This project is included in the 2020 Business Plan (BP). The Kentucky Public Service Commission approved recovery of this program through the Gas Line Tracker (GLT) Mechanism ending in mid 2022.

The project labor was bid to qualified contractors (Infrasource Construction, Meade Inc., Miller Pipeline, Premier Energy Services, Southern Pipeline) in September 2017 to cover the first three years of the program plan (2018-2020). The contract was bid as a combination of unitized pricing and blended labor rates for work outside of the defined unit price scopes. [redacted]

Materials will be purchased through existing contracts through the normal Supply Chain purchasing process.

Project History

Through September 2019, the service program has replaced 5,195 steel services. There are approximately 36,000-40,000 steel customer services remaining out of the approximate 300,000 active gas services. The steel services are primarily operating on the medium pressure gas distribution system, but are also found on the high pressure, elevated pressure and low pressure systems. Within the scope of this program, all steel customer services will be targeted for a systematic large scale replacement program that will be worked geographically across the service territory. The program count is currently estimated from existing GIS records. However, LG&E recently took over customer service ownership in 2013, therefore records prior to this date are not reliable or are unknown. Upon conclusion of the gas riser replacement program in 2017, the customer service information in the GIS system has been updated with more complete data to better determine the program count of services to replace.

In 2017, during project planning there was an estimated 400-900 active county loops in the system. This specific type of service is not tracked separately in the GIS, therefore could not be estimated using this system. The first 2 years of the program, have addressed the areas of the system known to have county loops and the actual number replaced was 175. If additional county loops are identified they will be replaced. There are also approximately 11,500 curbed services remaining in the system, 3,100 steel (approximately 4,400 at beginning of program) and 8,900 plastic. To date in 2019, 1,291 steel curbed services have been removed. Curbed services are difficult to locate and are prone to third party damage from excavation activities. This program will target steel curbed services that do not have the potential to be re-connected. The remaining curbed services would be disconnected at the main and retired in place according to company service abandonment procedures.

The original large scale replacement project proposed in 2017 to accelerate the time frame to remove steel customer services over a 15 year period to improve system integrity and public safety. The first 3 years of the program assumed completion of the planned number of steel service replacements for this period and all county loop removals and targeted curbed service abandonments. The remainder of the steel service lines would have then been replaced over the last 12 years of the program. In 2019, the goals and project schedule were reevaluated, and those changes are discussed in the Project Timeline section below.

Project Scope and Timeline

The original schedule and budget were reevaluated in 2019, and changed based on actual production rates and project spending. Through the 2020 BP process the budget for 2021 – 2024 was increased to approximately $10M per year, and resultant increase in services removed. This increase would move up the project completion by approximately three years, and based on unit costs for the steel customer services, county loops and steel curbed services at the time of the 2020 BP process could lower or have minimal impact to the overall project cost in nominal dollars. Spending in years after 2024 were calculated using the original production goals from 2017 and actual costs from 2019.

Curbed service goals were also updated based on actual production, and the completion was extended to year five of the program versus year three. Curbed service production has been lower than originally estimateThe revised goals were changed to reflect both the timing and projected costs to replace the steel curbed services.

The program will be worked geographically across the service territory and if the customer service line is connected to a steel company service line, the company service will also be replaced and excess flow valve (EFV) installed at the main. The chart below assumes the continuation of reactive replacement of service lines, and has the updated cumulative service totals.

Year	2017 BP Spending	Cumulative Service Total 2017	Cumulative Curbed Service Total	2020 BP Spending	Cumulative Service Total 2020	Cumulative Curbed Service Total	Cumulative Difference in spending	2020 BP Spending +5% service cost increase	Cumulative Difference in spending	2020 BP Spending +10% service cost increase	Cumulative Difference in spending
2018	$9,415	3,375	1,467	$5,860	2,100	356*	$3,555	$5,860	$3,555	$5,860	$3,555
2019	$9,706	6,769	2,934	$12,184	6,673**	1,101**	$1,077	$12,184	$1,077	$12,184	$1,077
2020	$10,001	10,181	4,400	$10,028	9,412	2,149	$1,050	$10,397	$681	$10,917	$161
2021	$4,832	12,205		$10,033	12,727	3,193	($4,151)	$10,915	($5,402)	$11,461	($6,468)
2022	$5,019	14,246		$10,043	15,808	4,400	($9,175)	$10,662	($11,045)	$11,195	($12,644)
2023	$5,213	16,304		$10,000	20,395		($13,962)	$11,230	($17,062)	$11,792	($19,223)
2024	$5,412	18,378		$10,000	24,816		($18,550)	$11,329	($22,979)	$11,895	($25,706)
2025	$5,618	20,469		$5,015	26,907		($17,947)	$5,266	($22,627)	$5,517	($25,605)
2026	$5,830	22,575		$5,202	29,013		($17,319)	$5,462	($22,259)	$5,722	($25,497)
2027	$6,049	24,697		$5,399	31,135		($16,669)	$5,669	($21,879)	$5,939	($25,387)
2028	$6,274	26,834		$5,600	33,272		($15,995)	$5,880	($21,485)	$6,160	($25,273)
2029	$6,506	28,985		$4,589	35,521		($14,078)	$4,818	($19,797)	$5,048	($23,815)
2030	$6,746	31,150			0		($7,332)		($13,051)		($17,069)
2031	$6,992	33,329			0		($340)		($6,059)		($10,077)
2032	$7,247	35,521			0		$6,907		$1,188		($2,830)
Total	**$100,860**			**$93,953**				**$99,672**		**$103,690**	

*actual 2018 spending and production numbers
**Actual numbers completed not yet known

Risk of Failure

The main threat posed by steel service lines is deterioration over time from corrosion, eventually causing leaks that have the potential to be in close proximity to homes or businesses. The main threat posed by county loops and curbed services are the physical location and risk of third party damage. County loops are located on the property line and typically exposed in a front yard with minimal protection or barricades, raising the potential of damage from a vehicle or other equipment. Curbed services are gas lines that have been cut and capped at the property line but are still attached to an active main. In particular, steel curbed services present the most risk because of their age. They are more susceptible to corrosion and are more difficult to shut off the flow of gas if damaged. They will not be re-connected.

The risks and recommendations associated with these types of services are detailed in LG&E's Distribution Integrity Management Plan (DIMP). All steel mains and services are vulnerable to corrosion, particularly if the line lacks a protective external coating or is not under cathodic protection. Without the presence of original installation records on customer service lines, it is difficult to determine how many service lines in operation are not properly protected. Damage of a facility by excavation or vehicular damage can lead to a catastrophic event caused by the ignition of a release of gas. The curbed service and county loops have elevated risks for these types of damages. LG&E is controlling these risks via surveillance, leak survey, corrosion prevention, odorization and damage prevention procedures as well as reactive replacement of failed services. A large scale service line replacement program and removal of county loops and curbed services would mitigate these risks within the proposed program plan time frame.

The majority of steel customer services have an in service time of over 30 years, further enhancing the risk of corrosion leaks. In a study of LG&E leak data from December 2010 to March 2016, when a leak occurred resulting in renewal of a steel service, approximately 95% of the time the cause was attributed to material defect/deterioration or corrosion. This leak pattern on active steel service lines will likely increase over time, resulting in the eventual replacement of most steel services once a leak is identified. Repairs at the point of discovery are not only a safety threat, but a possible inconvenience to the customer if the leak occurs during the heating season. The ability to schedule the replacement and have the service line constructed of modern materials and construction practices is all a positive for the customer experience.

DOT Code Parts 192.381 and 193.383 (effective February 12, 2010) requires the installation of excess flow valves on new or replaced service lines that feed a single-family residence and operate continuously at 10 psig or above. LG&E Construction Standard GCS 20 10 007 details the procedure for sizing and installing EFV's on new service lines. Records indicate that most of the remaining steel customer service lines will be connected to a steel company service at the property line. If the company service is steel, it will also be replaced at the time the customer service line is replaced and as an added benefit, allow the opportunity to install an EFV at the gas main. The EFV will protect the customer against catastrophic damage to the service line, for example from a dig-in, by shutting off the flow of gas at the main in the event of a rupture. This is consistent with LG&E's current process that when a customer service leak results in renewal and is also connected to a steel company service, the company service is also replaced and an EFV installed at the main. Today, approximately 30% of existing services have an EFV installed and after the program it is anticipated this would increase to approximately 44% or higher through this program and in conjunction with additional EFVs installed through new business installations over the same time period.

Industry Action

Multiple state commissions, including the Kentucky Public Service Commission, have approved mechanisms designed to recover the cost of natural gas pipe replacement programs. All five investor owned natural gas utilities in Kentucky currently have or have had in the past a pipe replacement mechanism. Other states, such as Arizona, have similarly taken ownership of customer service lines and started replacing aging facilities via recovery mechanisms. Southwest Gas has been proactively taking ownership and replacing steel service lines throughout its territory since 2012. The GLT Large Scale Main Replacement (LSMR) and Gas Riser Replacement Programs have positioned LG&E as an industry leader in proactively addressing identified problems with long-term targeted replacement programs. The LSMR program has replaced many of the company's steel services over its 20 year history. However, since service work from the LSMR program ended in 2017, this project is a continuation on LG&E's proactive effort to remove at-risk metallic lines from service and ultimately upgrade the service of customers that were not impacted by the main replacement or riser replacement GLT programs.

Budget Comparison & Financial Summary

The estimated capital cost to complete the program over a 12 year period is $93,953k ($82,000k for steel service replacement, $11,953k for county loop and curbed service removal) based on unit costs at the time of the 2020 BP process. The overall program cost was evaluated using a 5% and 10% higher sensitivity for the steel customer service lines and the overall program cost is approximately $104 million, which is about 3% higher than the original program estimate. Program cost was calculated by estimating the per unit cost of each type of service replacement/removal and projecting out over the planned years. Historical costs were compared to the estimate and no contingency is included. This Investment Proposal is seeking approval of the third year of the program only. In 2020, this program is requesting $7,130k capital, and $2,898k removal costs (curbed service removal).

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	7,130	-	-	-	7,130
2. Cost of Removal Proposed	2,898	-	-	-	2,898
3. Total Capital and Removal Proposed (1+2)	10,028	-	-	-	10,028
4. Capital Investment 2020 BP	8,183	-	-	-	8,183
5. Cost of Removal 2020 BP	1,845	-	-	-	1,845
6. Total Capital and Removal 2020 BP (4+5)	10,028	-	-	-	10,028
7. Capital Investment variance to BP (4-1)	1,053	-	-	-	1,053
8. Cost of Removal variance to BP (5-2)	(1,053)	-	-	-	(1,053)
9. Total Capital and Removal variance to BP (6-3)	-	-	-	-	-

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks of completing the project:

- Meeting customer expectations. The project will impact a significant number of customers over the life of the program. It will require restoration of property from the construction activity and require a planned interruption of gas service.
- Managing costs. The labor contract for the first three years of the program has been bid for the specified scope. There is the risk of unforeseen cost increases from regulatory changes, non-typical services, higher restoration costs, or higher than anticipated services to complete.

Risks of not completing the project:

- Customer Experience Impact. The aging steel service lines are a risk to leak causing a safety concern to person and property. The gas service could be interrupted to the customer at inconvenient time upon discovery of a service line failure.
- Higher Cost. LG&E assumed customer service ownership in 2013 and became obligated to make repairs upon discovery of abnormal operating conditions. Unplanned repairs to service lines are more expensive and take more time to complete.

Risks of completing the project outside of the optimal window:

- Higher Cost. As cost of labor and material increase, the services will become more expensive to replace past the 12 year proposed program plan.

Environmental

- There are no known environmental issues associated with this project. The project was bid to labor contractors with specific requirements for abandonment of gas services to comply with all EPA and Pipeline and Hazardous Materials Safety Administration (PHMSA) Regulations.

Alternatives Considered

1. Recommendation: NPVRR: $13,066k
   It is recommended to replace the planned number of steel customer services and remove the planned number of county loops and targeted curbed service during year three (2020) of the proposed program plan. The NPVRR reflects the estimated capital cost to complete this work in 2020. The cost per service was estimated from existing labor rates and.

2. Alternative #1: Reactive Replacement NPVRR: $17,486
   The primary alternative would be to continue replacement of steel services, county loops, and curbed services on a reactive only basis. This alternative is based on the estimated cost and time to replace the same number of services from year three of the program (3,185 services). Using recent historical data (2018 leak data and costs of repair), if customer services continue to be replaced at a similar rate (approximately 900 per year) it would take 4 years to replace the same number of services in a reactive manner. For an equivalent NPVRR comparison, the costs associated with county loop & curbed service work in the program were also included in year one of the alternative case. This case is not recommended due to the increased cost and time period of service replacement. More importantly, service replacements are

unpredictable and only occur at the point of failure, which presents a safety threat to the customer as well as potentially leaving the customer without gas service at inconvenient times.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the third year of the Gas Service Line Replacement Program plan for $10,028k to replace at risk steel customer service lines and remove targeted curbed services as detailed in the first year of the work scope. This replacement program is consistent with the risks and recommendations identified in the LG&E DIMP and will provide a safer, more reliable gas service to customers.

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: February 27, 2020

Project Name: Gas Service Line Replacement Program - 2019

Total Capital Expenditures: $12,184k (Approved on 9/25/2019)

Total O&M: $0k

Total Revised Capital Expenditures: $12,722k

Project Number(s): 414000001

Business Unit/Line of Business: Gas Distribution Operations / Gas Construction

Prepared/Presented By: Lesley Hill/Tom Rieth

Description of Incremental Ask

Revised Approved Capital Expenditures		$12,184k
Revised Capital Expenditures Requested		$12,722k
Total Increase Requested		$538k

Project was originally approved for $9,704k in November 2018 and revised for a total of $12,184k in September 2019. The recommended option of proactively replacing services is still the lower cost option over the alternative of replacing services reactively.

Gas Distribution Operations instituted a systematic large-scale replacement program of steel gas distribution customer service lines and targeted removal of county loops and steel curbed services. This program began in 2018 and will enhance the safe and reliable delivery of natural gas service to LG&E's customers. Over time, steel gas service lines are susceptible to corrosion, which could lead to gas leaks developing in close proximity to a home or business. County loops and curbed services would be removed because of an elevated risk of third-party damage due to their physical location.

The higher than expected spend from the last revision is due to a combination of factors that due to timing were not fully accounted for in the revision. These factors included:

- Costs for steel services during the time of revision were higher than the basis for the September revision primarily due to some non-unit charges associated with the services.
- As mentioned in the September revision a crew was dedicated to removing high pressure steel curbed services (these make up approximately 240 of the 4,400 targeted steel curbed services). At the time of the September revision it was anticipated costs would higher, but limited data was available, and this incremental cost resulted in about a 35% higher cost

(on average about $22k/month) for the dedicated crew than the other steel curb service crews. The higher cost was primarily due to using a welder and the work was completed on hourly charges versus units because of the variability for the work scope of each service. The high-pressure steel curbed services have potential of higher consequence than medium pressure both from a safety and reliability perspective and it was decided to dedicate a crew to these in 2019.

- Dedicating a crew in the November time frame to work on service with Grade 3 leaks to help reduce the backlog. This work was done on an hourly basis versus units due to the geographic diversity.
- Costs from replacing steel services as part of the Elevated Pressure System reinforcement project were included in this project. This cost (approximately $25k per month) was not addressed in the September revision as this work had just recently started.

Budget Comparison & Financial Summary

Projected spend for this project is expected to be $3,018k higher than what was originally approved in the 2019 BP. The original budget plan accounted for replacing 3,394 steel services and 1,467 curbed services. The project completed 3,726 services, 1,444 curbed services, 95 High Pressure curbed services, and 53 county loops.

Financial Detail by Year - Capital ($000s)	Pre-2019	2019	2020	Post 2020	Total
1. Capital Investment Proposed	-	9,246	39	-	9,285
2. Cost of Removal Proposed	-	3,437	-	-	3,437
3. Total Capital and Removal Proposed (1+2)	-	12,683	39	-	12,722
4. Capital Investment 2019 BP	-	8,818	-	-	8,818
5. Cost of Removal 2019 BP	-	886	-	-	886
6. Total Capital and Removal 2019 BP (4+5)	-	9,704	-	-	9,704
7. Capital Investment variance to BP (4-1)	-	(428)	(39)	-	(467)
8. Cost of Removal variance to BP (5-2)	-	(2,551)	-	-	(2,551)
9. Total Capital and Removal variance to BP (6-3)	-	(2,979)	(39)	-	(3,018)

Financial Detail by Year - O&M ($000s)	Pre-2019	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)	-	-	-	-	-

The 2020 spending is related to accrual differences and with be funded through other GDO project reductions, coordinated with the RAC.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Gas Service Line Replacement Program for $12,722k to replace at risk steel customer service lines, remove county loops as encountered, and targeted curbed services. This replacement program is consistent with the risks and recommendations identified in the LG&E DIMP and will provide a safer, more reliable gas service to customers.

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: April 28, 2020

Project Name: Magnolia Crossings Replacement Project

Total Capital Expenditures: $6,344k (Including $576k of contingency including $77k of internal labor, if applicable)

Total O&M: $0k

Project Number(s): TMPMAGRC

Business Unit/Line of Business: Gas Distribution Operations

Prepared/Presented By: Damien Simmons/Tom Rieth

Brief Description of Project

LG&E Gas Distribution Operations (GDO) requests funding approval for the Magnolia Crossings Replacement Project. This project will replace approximately 3,800 feet of oversized piping on our Magnolia natural gas transmission lines to facilitate the use of enhanced in line inspections (ILI) for these lines. This project will make our Magnolia Transmission Lines uniform diameter from end to end. Use of the enhanced in-line inspection tools will be necessary to meet requirements from the Gas Transmission and Gathering line rule (aka the "Mega-Rule"). These transmission pipeline segments were installed between 1959 and 1988, using the prevailing materials and construction methods of that time. These pipeline segments are critical for LG&E to safely and reliably serve its customers, as they are used to transport gas from Magnolia Gas Storage to Louisville.

The 2021 funding will need to be moved into 2020 through the GDO and Corporate RAC processes. The project was opened for $145k in April 2019 for engineering design and survey work. The project was revised in March 2020 for $950k for material procurement, to finalize engineering and design work, and begin construction on the project in April 2020. We are now requesting total investment of $6,344k from the Investment Committee to complete construction. Construction should be completed on the project by November 2020.

Why is the project needed? What if we do nothing?

This project is necessary to complete successful ILI runs of the Magnolia Transmission Lines and to ensure regulatory compliance. The oversized sections of the Magnolia Transmission Lines cause speed excursions during ILI runs, which results in a lack of data being gathered in these segments. Custom multi-diameter tools could be developed for completion of the ILI runs, but are found to have a useful life of 2-3 runs before needing to be refurbished. Electro Magnetic Acoustic Transducer (EMAT) tools used for crack detection and Magnetic Flux Leakage (MFL) tools used for seam defect detection are currently available for single diameter pipelines only. If we are unable to gather adequate data from the ILI runs in a High Consequence Area (HCA), we could be forced to complete a direct examination of the pipeline to ensure regulatory compliance.

One of the eight oversized segments of the Magnolia Transmission Lines is located within an HCA.

Quality EMAT and MFL data are also required in the Engineering Critical Assessment method of Maximum Allowable Operating Pressure (MAOP). Reconfirmation which will be required on the Magnolia Transmission Lines when the revisions to federal regulation 49 CFR 192.619 take effect on July 1, 2020. If this project is not completed, we may be out of compliance in the future.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Total
1. Capital Investment Proposed	156	6,128		6,284
2. Cost of Removal Proposed		60		60
3. Total Capital and Removal Proposed (1+2)	156	6,188	-	6,344
4. Capital Investment 2020 BP	146	4,716	669	5,531
5. Cost of Removal 2020 BP		160	54	214
6. Total Capital and Removal 2020 BP (4+5)	146	4,876	723	5,745
7. Capital Investment variance to BP (4-1)		(1,412)	669	(743)
8. Cost of Removal variance to BP (5-2)		100	54	154
9. Total Capital and Removal variance to BP (6-3)	(10)	(1,312)	723	(599)

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

Costs for this project were budgeted in project TMPMAG-2.

Risks

- The planned replacement method for 5 of the 8 oversized sections of the Magnolia Transmission Lines is to convert them into casings for the new carrier pipe. If these pipes are found to be unfit for use as casings, actual project cost may be higher than estimated and construction could take longer than expected.
- If the project is not completed between April 1 – November 1, 2020 we may interfere with storage injections and withdrawals. This could result in construction delays and increased project cost.
- There should not be any impacts to customer services as part of this project. Some outside parties will be impacted by construction activities as part of the project. Any potential impacts to customers or outside parties will be communicated using notification letters or through our Real Estate and Right of Way Contractor, Emerald Energy and Exploration Land Company. As always, we will strive to minimize customer impacts.
- Any potential environmental risk will be mitigated by using best management practices (BMPs) and completing the work in accordance with all local, state, and federal regulations.

Alternatives Considered

The cost associated with each alternative has been updated based on construction bids and actual spend through February 2020.

1. Recommendation: Replacement of Oversized Sections NPVRR: ($000s) $27,955k
   Replace the eight oversized segments of the Magnolia Transmission Lines with like diameter piping. This would make the Magnolia Transmission Lines uniform diameter from end to end. This option would also include the removal of an offset in the Magnolia Transmission Lines that is currently constructed using long radius elbows, which have presented issues during ILI runs in the past. This option includes a capital investment of $6,344k and O&M expenditures totaling $79,887k

2. Alternative #1: Tethered Inspections NPVRR: ($000s) $34,903k
   This option would involve inspecting the Magnolia 16" Transmission Line using the multi-diameter inline inspection tools being developed for use in the Western Kentucky Lines, and to run separate inline inspections on each size pipe in the Magnolia 20" Line. To the extent this is possible, both ends of each 24-inch section of the Magnolia 20" Line would have to be excavated each time an inspection was scheduled, and tethered ILI tools pulled through the pipe. This alternative would require expenditures to date towards engineering the replacement of the oversized sections to be reclassified from CAPEX to OPEX. Inspections would be repeated every seven years to comply with PHMSA regulations. This alternative has no capital investment and has O&M expenditures totaling $127,127k.

3. Alternative #2: 20" Multi-Diameter Tool Development NPVRR: ($000s) $30,763k
   A second alternative considered was to inspect the Magnolia 16-inch Line using the multi-diameter inline inspection tools being developed for use in the Western Kentucky Lines, and to develop similar tools capable of inspecting the 20-inch and 24-inch segments of the Magnolia 20-inch Line. This alternative would require expenditures to date towards engineering the replacement of the oversized sections to be reclassified from CAPEX to OPEX. This alternative has no capital investment and has O&M expenditures totaling $98,091k.

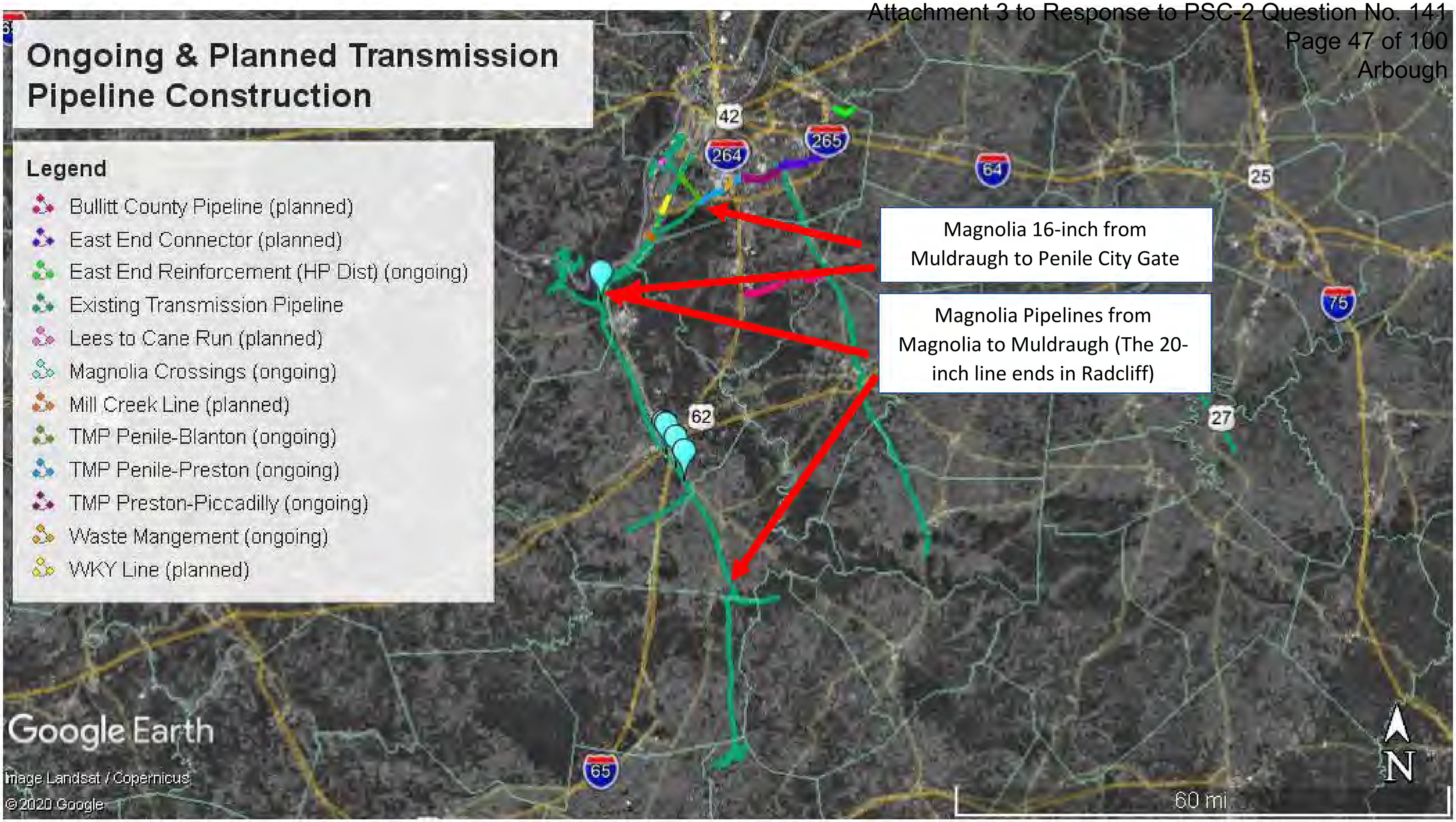
Conclusions and Recommendation

It is recommended that the Investment Committee approve the Magnolia Crossings Project for $6,344k to facilitate successful ILI runs with single diameter tools, supporting compliance and improving the overall safety and reliability of our gas 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	


Ongoing & Planned Transmission Pipeline Construction
Legend
Bullitt County Pipeline (planned)
East End Connector (planned)
East End Reinforcement (HP Dist) (ongoing)
Existing Transmission Pipeline
Lees to Cane Run (planned)
Magnolia Crossings (ongoing)
Mill Creek Line (planned)
TMP Penile-Blanton (ongoing)
TMP Penile-Preston (ongoing)
TMP Preston-Piccadilly (ongoing)
Waste Mangement (ongoing)
WKY Line (planned)
Magnolia 16-inch from Muldraugh to Penile City Gate
Magnolia Pipelines from Magnolia to Muldraugh (The 20-inch line ends in Radcliff)
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Investment Proposal for Investment Committee Meeting on: April 28, 2020

Project Name: Preston Highway High Pressure Reinforcement

Total Capital Expenditures: $2,990k (Including $498k of contingency including $76k of internal labor, if applicable)

Total O&M: $ 0k

Project Number(s): 406000079

Business Unit/Line of Business: Gas Distribution

Prepared/Presented By: Tom Hebbeler/Tom Rieth

Brief Description of Project

This project will install a high pressure gas distribution main extension and regulator station to reinforce the South Jefferson-Bullitt medium pressure gas system. The main extension and regulator station will increase capacity to the system in order to serve current and future residential and small commercial load growth in the area. The scope of work for this project is to install approximately 5,600 feet of 8-inch steel high pressure gas distribution main along Preston Highway and a new regulator station near 1401 Preston Highway. The design and engineering will occur in Spring 2020 with expected construction to start in the Summer/Fall of 2020. The project is planned to be in service by the end of 2020.

Why is the project needed? What if we do nothing?

The high pressure gas distribution main extension and regulator station is needed to reinforce the South Jefferson-Bullitt County area medium pressure gas system. This will increase capacity in order to serve current and future residential and small commercial load growth and maintain reliable gas system pressures in the area. Additionally, this provides a high pressure distribution source in this area that can be integrated with other system reinforcement projects as this area develops. If this project is not completed, load growth on this system is projected to cause system constraints and reliability concerns during high demand periods as soon as the next winter operating season.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	2,990				2,990
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	2,990	-	-	-	2,990
4. Capital Investment 2020 BP					-
5. Cost of Removal 2020 BP					-
6. Total Capital and Removal 2020 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(2,990)	-	-	-	(2,990)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(2,990)	-	-	-	(2,990)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed					-
2. Project O&M 2020 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The project has been funded by reallocations from other capital projects through the Corporate RAC process.

A 20% contingency of $498k was included due to the field probing of an estimated 50% rock along the route. The construction bid reflects that information but actual rock volumes may be higher.

Risks

1. Due to indication that rock is present along 50% of the route, actual construction costs may be higher than estimated.
2. If this project is not completed, load growth in the area is projected to cause system constraints including low pressure during periods of high demand.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 3,896k

   Install high pressure gas distribution main extension and regulator station to reinforce the South Jefferson-Bullitt medium pressure gas system.

2. Alternative #1: Mt. Washington Loop NPVRR: ($000s) 5,931k

   This alternative considered installing a 3/4 mile loop of 8” high pressure gas distribution main from the Mt. Washington High Pressure Distribution Station along Hwy 44 to reinforce the South Jefferson-Bullitt system. This alternative presents many challenges with increased costs such as easement acquisition, presence of hard rock, and limited construction area along a congested highway.

3. Alternative #2: Do Nothing NPVRR: ($000s) 0,000k

   This alternative considered the impacts of operating the gas system without the planned reinforcement. Due to the current and future load growth in the area, this alternative is not recommended because of projected system constraints and reliability concerns during winter operating conditions.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Preston Highway HP Reinforcement project for $2,990k to serve load growth in Southern Jefferson County.

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: April 28, 2020

Project Name: St. Helens Station

Total Capital Expenditures: $7,430k (Including $1,134k of contingency including $151k of internal labor)

Total O&M: $ 0 k

Project Number(s): 141004

Business Unit/Line of Business: Gas Distribution

Prepared/Presented By: Tom Hebbeler / Barry Walker

Brief Description of Project

- Project Summary Description
  This project consists of renovating the St. Helens regulator station which serves as one of the major gas supply delivery points to the urban Louisville area. This station delivers gas from LG&E's Western Kentucky Transmission Pipeline system to the Louisville high pressure distribution system. The project scope includes replacement of piping, regulation equipment, valves, control equipment, electrical systems, emergency electrical power, and buildings on property adjacent to the existing regulator station. A separate project (155539) was created for the adjacent property purchase and demolition of existing infrastructure on that new property. The AIP for that project was opened for $553k and the project was completed in 2019 for $444k.

  This proposed project will increase reliability, provide new gas measurement capabilities, improve pressure control, improve security, replace aging infrastructure, and reduce facility damage risks. The project total cost estimate is $7,430k, the 2020 Business Plan (BP) included funding for this project of $3,121k in 2020. The AIP was opened for $300k in 2016 for engineering design and was revised in 2017 to $621k. To date, a total of $632k has been spent. The economic useful life of this project is assumed to be 40 years.

- Project Scope
  Construction of the new station will occur in 2020 on adjacent property purchased in 2018. The construction will include piping, buildings, controls, electric power, and communications. The existing generator will be reutilized once the existing station is demolished in 2021. Transfer of pressure regulation/control from the existing station must occur during the non-heating season therefore, the existing station will be taken out of service between June 1 and September 1, 2021 and the Western Kentucky A and B pipelines will be transitioned from the existing to the new station one at a time to reduce operational risk. Once the new station is completely operational, the existing station will be demolished. The existing fence around the property (existing station and new property purchase) will be replaced as needed due to poor condition. A no cut/no climb fence will

be constructed around the new station buildings for additional security to critical infrastructure as recommended by Corporate Security. Contingent on approval of the project, bids will be awarded for materials and contractor services.

- Project Timeline
  - 1st Qtr. 2020 – Engineering and design approximately 95% completed
  - 1st Qtr. 2020 – Contractor bidding and selection commences.
  - 2nd Qtr. 2020 – Equipment and material purchasing commences.
  - 3rd Qtr. 2020 – Begin material deliveries.
  - 3rd Qtr. 2020 – Begin construction and equipment installation of new station.
  - 4th Qtr. 2020 – Complete construction of new station.
  - 2nd/3rd Qtr. 2021 – Complete inlet and outlet piping tie-ins.
  - 3rd Qtr. 2021 – Commission new station.
  - 3rd Qtr. 2021 – Demolish existing station.

Why is the project needed? What if we do nothing?

St. Helens Station is located in the Shively area of Jefferson County near Seventh Street Road and Manslick Road. The existing St. Helens Station was originally constructed in the early 1950s and modified in the mid-1960s. This station regulates and controls gas delivered by the Western Kentucky Gas Transmission Pipeline system to the high-pressure gas distribution system (i.e. Beltline System) supplying the urban Louisville distribution system. On peak days approximately 33% of all gas supplied to the Beltline System is supplied through St. Helens Station. Critical equipment within the facility has reached the end of its expected life and is obsolete. The existing St. Helens regulator station is located immediately adjacent to railroad tracks with a risk of severe facility damage from a train derailment incident. A failure of Saint Helens Station during winter operating period could result in up to 89,000 customer outages. Doing nothing would result in increasing risk of station failure during winter operating period resulting in large customer outages.

The recommended upgrade project will provide the following benefits.

- Increased reliability of gas supply to the Louisville high pressure distribution system (i.e. Beltline system) by replacing aging and obsolete equipment.
- Improved pressure control lowering the risk of exceeding maximum allowable operating pressure of Beltline High Pressure System.
- Improved site security and lower risk of facility damage from a train derailment.
- Documentation of maximum allowable operating pressure – current piping and equipment records are incomplete. Upgrade of the regulator facility will enable meeting new records requirements for validation of maximum allowable operating pressures.
- Gas flow measurement capability to quantify amount of gas supplied through St. Helens Station to the Beltline High Pressure System.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	**Pre** 2020	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed	626	5,398	1,196	-	7,220
2. Cost of Removal Proposed	-	-	210	-	210
3. Total Capital and Removal Proposed (1+2)	626	5,398	1,406	-	7,430
4. Capital Investment 2020 BP	621	3,121	-	-	3,742
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	621	3,121	-	-	3,742
7. Capital Investment variance to BP (4-1)	(5)	(2,277)	(1,196)	-	(3,478)
8. Cost of Removal variance to BP (5-2)	-	-	(210)	-	(210)
9. Total Capital and Removal variance to BP (6-3)	(5)	(2,277)	(1,406)	-	(3,688)

Financial Detail by Year - O&M ($000s)	**2020**	**2021**	**2022**	**Post 2022**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The table above shows the 2020 and 2021 expected expenditures. The 2020 BP included $3,121k in 2020 and $0k in 2021. Additional funding amounts of $1,700k and $577k were reallocated to the project in the 2020 March and April Corporate RAC meetings respectively resulting in total 2020 project funding of $5,398k. Proposed 2021 capital spend of $1,406k will be covered within the GDO BP process.

A 20% contingency of $1,134k is included in the estimated cost shown in the table. This contingency is based on the challenging schedule and site conditions.

Risks

- Failure to complete the project outside the heating season resulting in inadequate gas supply to the gas distribution system and customer outages with significant restoration efforts and costs.
- Higher environmental costs if unknown environmental issues are discovered.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $9,332
   This alternative includes renovating the St. Helens Regulator Station on adjacent property. The renovation will include replacement of piping, regulation equipment, valves, control equipment, electrical systems, emergency electrical power, buildings, and the addition of gas measurement equipment. Benefits of this alternative includes; increase reliability through replacement of obsolete equipment, reduced risk of not completing the project outside the heating season, greater distance between critical station equipment and the railroad, and increased site security by providing two fence barriers to the renovated station.

2. Alternative 1 (Do Nothing): NPVRR: ($000s) $10,115
The "Do Nothing" option includes continuing to maintain the existing facility and performing equipment upgrades and replacements over time. This option includes upgrades to meet new regulatory requirements for validating maximum allowable pressure of gas transmission piping, security upgrade to address immediate security concerns, and various equipment/facility upgrades as the facility ages. This alternative includes on-going risk of equipment failures and risk of facility damage from a train derailment that could result in large customer outages. Estimated capital cost for this alterative is $6,962k.

3. Alternative 2 (Renovate Existing Site): NPVRR: ($000s) $11,008
Alternative 2 included renovating the regulator station within the existing property. This alternative would require that the station to be renovated and recommissioned during the non-heating season of June 1 to September 1. Since this alternative would include piping, buildings, controls, electric power, telecommunications and demolition, construction would most likely take longer than the allowable timeframe. Failure to recommission the station before the heating season could impact the gas delivery reliability of the area. This alternative includes on-going risk of a train derailment during winter heating season resulting in large customer outages. Estimated capital cost for this alternative is $7,932k.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the proposed St. Helens Station project for $7,430k to improve gas supply reliability to the high pressure gas distribution by upgrading a critical gas regulation facility that has reached the end of its useful life.

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: April 28, 2020

Project Name: Witherspoon Relocation

Total Capital Expenditures: $3,650k (Including $587k of contingency and $177k of internal labor)

Total O&M: $0

Project Number(s): 406000071

Business Unit/Line of Business: Gas Distribution Operations

Prepared/Presented By: Jim Wade/Chris Fitzgerald/Tom Rieth

Brief Description of Project

The 20" & 16" high pressure (HP) steel main along East Witherspoon Street is experiencing cathodic protection (CP) interference, which threatens the integrity of the pipeline. This project will reroute the HP main, made up of 2,192 ft of 20" steel pipe and 748 ft of 16" steel pipe, with 3,310 ft of 12" HP steel main running down River Road to avoid the area causing CP interference. Gas system modeling verifies that downsizing the diameter of this section of pipeline from 16"/20" to 12" does not have a significant effect on the downstream pressure of our distribution system. There is one industrial customer served by the line being abandoned, so this project also includes the installation of a medium pressure (MP) regulation facility on North Shelby Street to feed this customer with a new plastic service.

Why is the project needed? What if we do nothing?

The relocation is needed because of interference with the galvanic CP system that protects the pipeline. Galvanic CP works by attaching a sacrificial anode to the steel pipeline, which applies a positive electric current to the pipe and causes the anode to erode instead of the steel pipe. When another electric current is present in the ground around the pipe, it can interfere with the CP system and may result in the outside of the pipe corroding. Efforts have been made to locate and mitigate this source of stray current, including multiple investigations by our corrosion department and a survey done by a third-party corrosion specialist. None of these investigations have been able to pinpoint the source of stray current, which has left us with a single remaining option of re-routing the pipeline. The route that has been selected is the only plausible path to re-route the pipeline away from the source of interference when considering the parks and highways in the area.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	3,640				3,640
2. Cost of Removal Proposed	10				10
3. Total Capital and Removal Proposed (1+2)	3,650	-	-	-	3,650
4. Capital Investment 2020 BP	2,733				2,733
5. Cost of Removal 2020 BP	69				69
6. Total Capital and Removal 2020 BP (4+5)	2,802	-	-	-	2,802
7. Capital Investment variance to BP (4-1)	(907)	-	-	-	(907)
8. Cost of Removal variance to BP (5-2)	59	-	-	-	59
9. Total Capital and Removal variance to BP (6-3)	(848)	-	-	-	(848)

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

The increase from the 2020 BP is driven by increased paving costs with bids coming in higher than the BP estimate. Incremental funding for 2020 will be reallocated throught the RAC process.

Risks

The main risk of not completing this project is the threat to the integrity of the HP steel main. Continued operation of the main while CP interference is present could result in the pipe wall corroding and eventually leading to a leak or pipe failure. Additionally, this pipe is located in a highly populated area along East Witherspoon Street, which increases the consequences of a leak or failure.

LG&E will have to prepare a Stormwater Pollution Prevention Plan and obtain a Kentucky Division of Water General Stormwater Permit because the construction will disturb over 1 acre of land. Additionally, any retired pipe that is removed will require hazardous waste disposal due to the potential for asbestos in the coating.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $4,756

   Relocate 12 inch HP pipeline and install MP pipeline
   This option completes the necessary HP pipeline relocation and reinforces the MP distribution system in the area. Much of the excavation and labor required to relocate the HP line will also be used to improve reliability of the MP distribution system.

2. Alternative #1: NPVRR: ($000s) N/A

   Do Nothing
   This option is not possible because the integrity of the pipeline in its current location is threatened by CP interference and mitigation efforts have been unsuccessful.

Compliance

The materials and construction activities will be done in a manner compliant with State and Federal Regulations, Company procedures and construction standards. Materials not ordered on the current pipe, valve and fitting supplier will be specified to meet requirements in 49 CFR 192. [redacted] who will be the pipeline construction contractor has an approved Operator Qualification (OQ) plan and is fully integrated in the Industrial Training Services (ITS) system for OQ. Company procedures have been provided to [redacted]

Conclusions and Recommendation

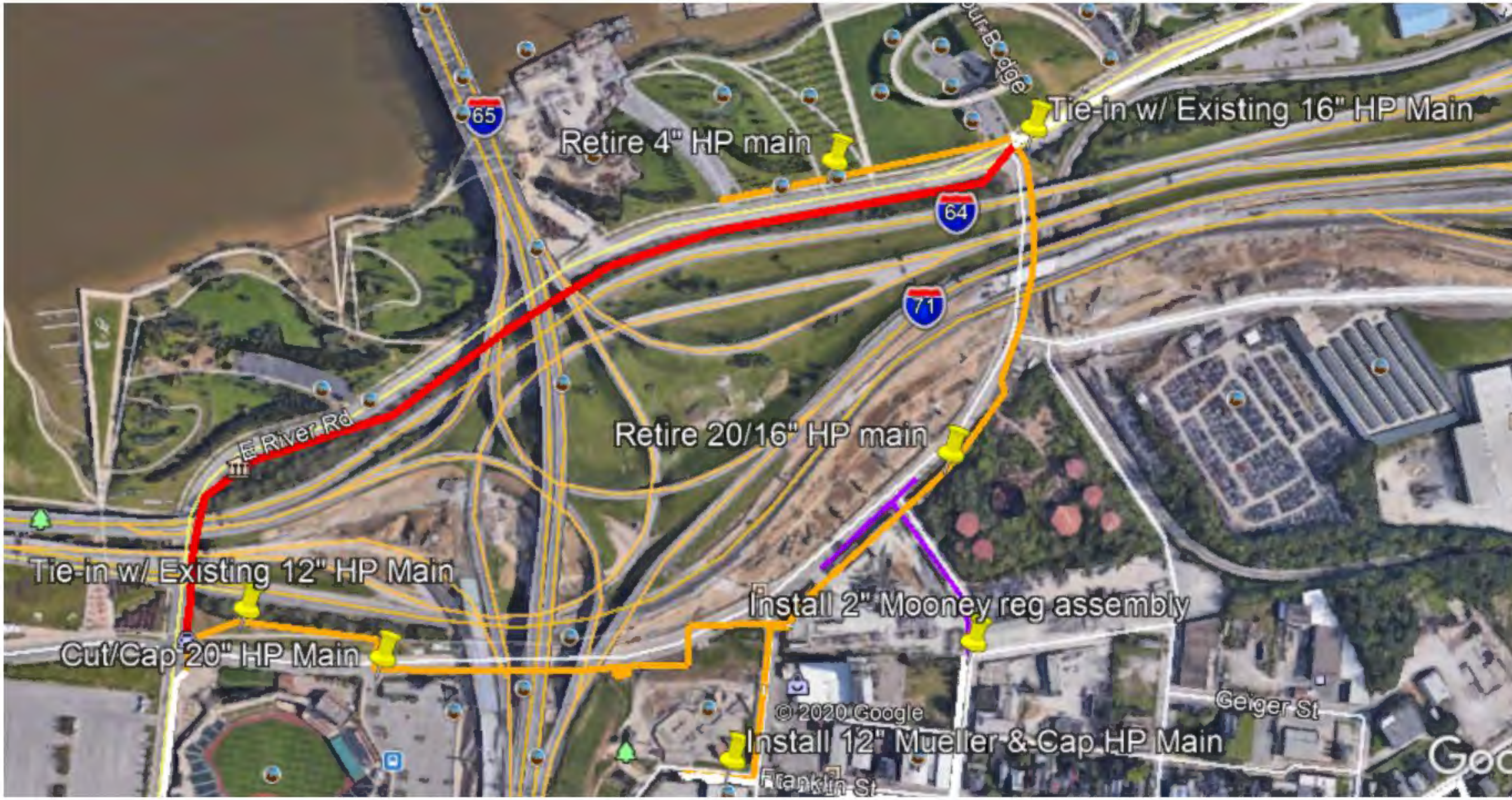
It is recommended that the Investment Committee approve the Witherspoon Relocation project for $3,650k to relocate 3,310 feet of HP pipeline and install a new MP regulation facility on North Shelby Street.

Approval Confirmation for Capital Projects Greater Than $2 million:

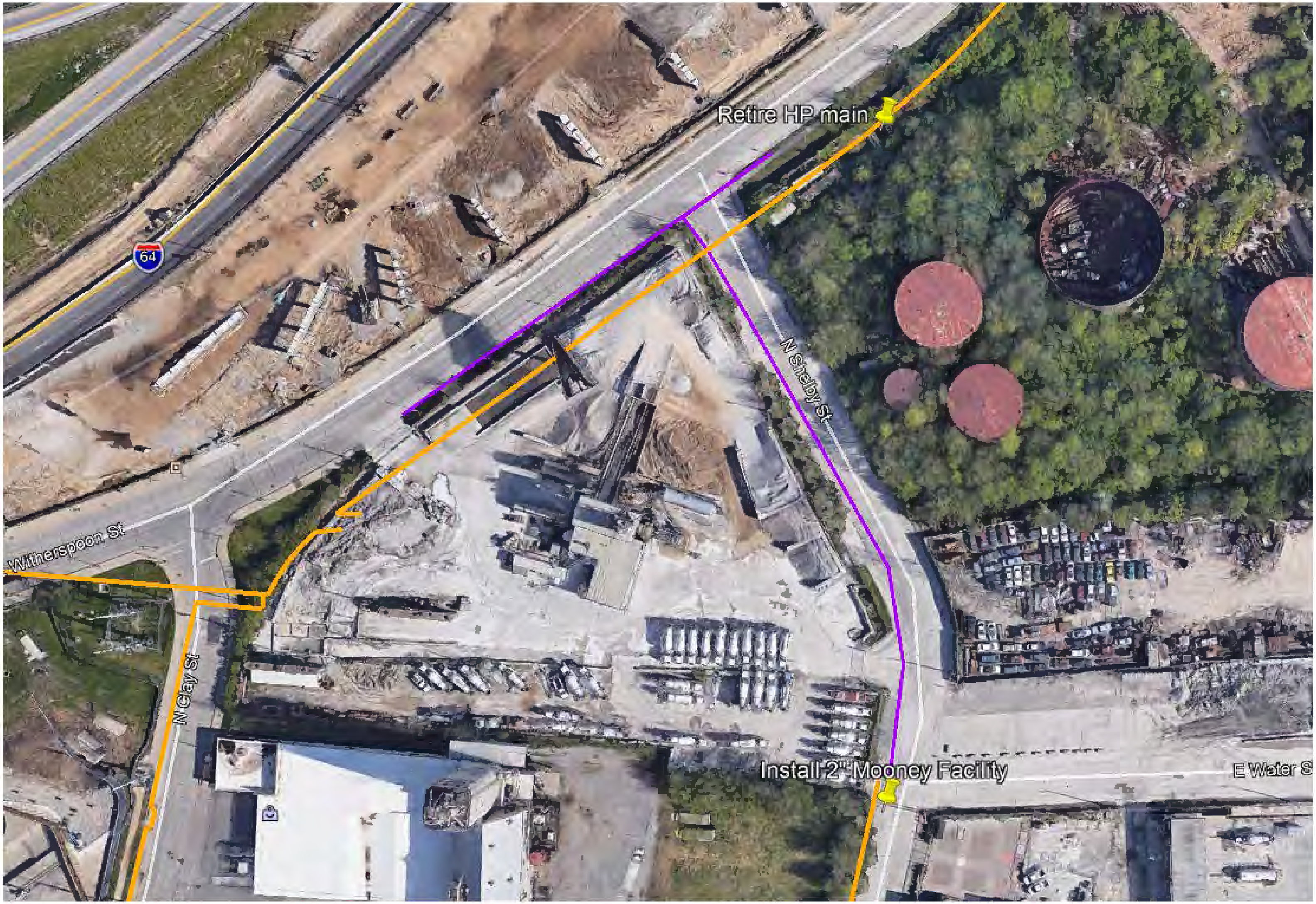
The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Witherspoon Project Overview



Witherspoon MP Pipeline Overview



Investment Proposal for Investment Committee Meeting on: May 26, 2020

Project Name: Bullitt County System Reinforcement

Total Original Capital Expenditures: $10,043k (Approved in February 2019)

Total O&M: $ 0k

Amendment Value: $ 7,606 k

Total Revised Capital Expenditures including Amendment: $17,649k

Project Number(s): 153662

Business Unit/Line of Business: GDO/Gas Operations

Prepared/Presented By: Tom Rieth

<u>Description of Incremental Ask</u>

Original Approved Capital Expenditures		$10,043k
Revised Capital Expenditures Requested including Amendment		<u>$17,649k</u>
Total Amendment Requested		<u>$7,606k</u>

- The Bullitt County Reinforcement project was approved for $3,654k in November 2016 for the engineering, surveying, real estate and right-of-way (ReROW) and other preliminary activities necessary to develop a final pipeline route and detailed design specification and drawings required for submitting applicable permits and creating construction bid documents. This request included expenditures prior to 2017. The total project expenditures through the end of 2017 were $1,669k.
- During the November 2016 Investment Committee approval, it was communicated that the remainder of the project would be brought to the Investment Committee after the pipeline construction costs were bid. Due to volatile steel prices from tariff changes, the project team went to the Investment Committee in August 2018 to request additional authorization of $3,641k to purchase pipe in 2018 in order to mitigate potential higher material costs and needed additional authorization for this expenditure. The Investment Committee approved the request and the project authorization was revised to $7,295k.
- At the time of the August 2018 request it was anticipated that the pipeline construction bids would be received, and the project team would come back to the Investment Committee for full project authorization in November or December 2018. The pipeline construction bidding process was delayed due primarily to real estate issues. The real estate issues delayed work on properties needed for the pipeline construction bid and

additional engineering/design work to modify easement documents. In February 2019 the Investment Committee approved additional authorization of $2,748k ($10,043k total) for work necessary to prepare bid material, bid the construction labor for the project, work on real estate issues and obtain permits.

- The project team is requesting additional authorization to continue work on obtaining the remaining necessary easements and permits along with any additional engineering/survey work necessary to support the real estate and permitting work and rebidding the construction labor. The project team is requesting additional authorization of $7,606 for a revised authorization of $17,649k to support the work described and expects to return to the IC for full project authorization in the first half of 2021. Bids and project costs continue to be refined.
- While the projected costs are trending higher than originally estimated, this project remains the lowest cost option to reliably serve the existing and growing demand for natural gas service in Bullitt County and the surrounding area.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	Pre-2020	2020	2021	Post 2021	Total
1. Capital Investment Proposed	9,248	2,401	6,000		17,649
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	9,248	2,401	6,000	-	17,649
4. Capital Investment 2020 BP	11,665	25,948	24,615		62,228
5. Cost of Removal 2020 BP					-
6. Total Capital and Removal 2020 BP (4+5)	11,665	25,948	24,615	-	62,228
7. Capital Investment variance to BP (4-1)	2,417	23,547	18,615	-	44,579
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	2,417	23,547	18,615	-	44,579

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

The 2020 Budget included the full project scope and envisioned a more accelerated pace than has been able to be achieved. The project is expected to be $26 million behind budget by year-end 2020.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Bullitt County System Reinforcement project for $17,649k to continue acquiring remaining easements, engineering and design work needed to finalize permitting applications, pipeline construction bid documents, and material purchases.

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: May 26, 2020

Project Name: KYTC Blue Lick Road Widening

Total Original Capital Expenditures: $2,500k (Non-reimbursable) (Approved on 06/27/2018)

Total O&M: $ 0 k

Amendment Value: $ 975k

Total Revised Capital Expenditures including Amendment: $3,475k

Project Number(s): 406000030

Business Unit/Line of Business: Gas Construction

Prepared/Presented By: Erin Holton/Tom Rieth

Description of Incremental Ask

Original Approved Capital Expenditures		$2,500k
Revised Capital Expenditures Requested including Amendment		$3,475k
Total Amendment Requested		$975k

The project duration and cost are exceeding original estimates for this project primarily due to underground conflicts. The existing gas facilities are located in the State ROW and the Company will not be reimbursed to relocate the facilities. Some contributing factors include:

- Three underground gasoline tanks had caused contaminated soil requiring the pipe to be rerouted around those sites. Additionally, at least 2 installed water lines conflicted with the route requiring the gas pipeline to be installed at a deeper depth. One of the contaminated areas led to an additional road crossing.
- Additional work due to these issues have led to higher construction costs. It is assumed that construction will be complete in Q3 2020. However, $73k will be included in 2021 to remove pipe if the pipe coating contains asbestos. This is based on KYTC's schedule.
- The extended duration of the project and complexity of the project required additional traffic control resources than originally estimated.
- Inspection costs were higher than estimated. Duration is a contributing factor. The original estimate assumed 1 inspector for the project for one main crew and a service crew. An additional inspector was added when an additional main crew was utilized to help with production in meeting KYTC's timing for the road project.
- Customer interactions were limited but did contribute to delays as well.

- The 2021 cost is for coal tar pipe remediation and disposal by contractor supplied by LG&E, National Environmental Contracting (NEC), based on KYTC's schedule.
- A 10% contingency is included on the remaining spend, due to the uncertainty of the amount of coal tar pipe that will be required to be removed for the KYTC project (i.e., drainage ditches and grade changes). The original IP estimate included 10% contingency.
- It is assumed that the alternative of replacing the pipeline would have had similar delays and cost over-runs resulting in the recommendation still being the least cost alternative.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	Pre-2020	2020	2021	Post 2021	Total
1. Capital Investment Proposed	2,057	1,311	-		3,368
2. Cost of Removal Proposed		34	73		107
3. Total Capital and Removal Proposed (1+2)	2,057	1,345	73	-	3,475
4. Capital Investment 2020 BP	2,470				2,470
5. Cost of Removal 2020 BP	43				43
6. Total Capital and Removal 2020 BP (4+5)	2,513	-	-	-	2,513
7. Capital Investment variance to BP (4-1)	413	(1,311)	-	-	(898)
8. Cost of Removal variance to BP (5-2)	43	(34)	(73)	-	(64)
9. Total Capital and Removal variance to BP (6-3)	456	(1,345)	(73)	-	(962)

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

GDO will cover the additional required 2020 funding through other GDO project reductions. The 2021 spend will be covered by GDO in the 2021BP.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the gas KYTC Blue Lick Road Widening project for $3,475k to relocate pipeline in conjunction with the KYTC project.

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: June 30, 2020

Project Name: Magnolia 16-inch Pipeline Cut Outs

Total Capital Expenditures: $3,505k

Total O&M: N/A

Project Number(s): 161087

Business Unit/Line of Business: Gas Distribution Operations

Prepared/Presented By: Ellen Reynolds & Pete Clyde

Brief Description of Project

The Magnolia 16-inch natural gas transmission pipeline is primarily 16-inch in diameter, but has some 20-inch diameter road crossings and is approximately 40 miles long. It runs from the Magnolia Compressor Station in LaRue County to the Muldraugh Compressor Station property in Meade County. The pipeline was in-line inspected by Rosen in 2019 to satisfy transmission integrity management pipeline safety regulations within 49 CFR 192 subpart O. In response to the report, LG&E completed replacements, including cutting out and replacing 5 short sections of pipe to date. The anomalies replaced consisted of dents containing metal loss and a linear weld anomaly.

An AIP was approved in November 2019 for $200k to replace three short sections of 16-inch pipe prior to additional in-line inspection reports being received. The AIP was revised in December 2019 for a total of $262k to address rock removal and fabrication costs encountered. The AIP was revised in March 2020 for a total of $805k to include nine additional (12 in total) cutouts in response to a new in-line inspection report.

Upon receipt of the preliminary EMAT in-line inspection report, the scope is now being increased to include an additional 14 anomalies (26 in total). Five of the 26 anomalies have been replaced to date. The revised scope brings the total proposed capital expenditures to $3,505k.

Why is the project needed? What if we do nothing?

The replacements are necessary to maintain the integrity of the Magnolia 16-inch gas transmission pipeline and to ensure compliance with federal pipeline safety regulations. The project also enhances reliability of LG&E's gas system.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	250	3,204			3,454
2. Cost of Removal Proposed	11	40			51
3. Total Capital and Removal Proposed (1+2)	261	3,244	-	-	3,505
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)	(250)	(3,204)	-	-	(3,454)
8. Cost of Removal variance to BP (5-2)	(11)	(40)	-	-	(51)
9. Total Capital and Removal variance to BP (6-3)	(261)	(3,244)	-	-	(3,505)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed					-
2. Project O&M 2019 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The funding for this project has been allocated from other projects within GDO and has been approved by the RAC.

Risks

The Magnolia 16-inch gas transmission pipeline is a pipeline which delivers gas from two of LG&E's gas storage fields and compressor stations to other areas of the system. In addition, it traverses various densely populated areas. Not completing the replacements could result in a pipeline failure which would jeopardize public safety and LG&E's ability to meet customer gas demand.

There are six linear longitudinal weld anomalies that will not be cutout as regulations do not require action at this time and it is uncertain if any of them need to be repaired. Those anomalies will be reevaluated once the cutouts in this investment proposal are completed, the pipe samples are analyzed by a laboratory, and pipe material properties are confirmed.

Alternatives Considered

1. Recommendation: NPVRR: $4,306k

2. Alternative #1: Do nothing NPVRR: N/A
   Do nothing is not a viable alternative as replacements are necessary to ensure pipeline safety and regulatory compliance. We will be filing a Safety Related Condition Report to inform federal and state regulatory agencies of situation and will need to follow up with them when replacements are completed.

Conclusions and Recommendation

It is recommended that Management approve the Magnolia 16-inch Pipeline Cutouts project for $3,505k to ensure pipeline safety, system reliability, and regulatory compliance.

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: July 29, 2020

Project Name: Clark Station Road Gas Main Extension

Total Capital Expenditures: $2,142k (Including $379k of contingency)

Project Number(s): 406000075

Business Unit/Line of Business: Gas Distribution

Prepared/Presented By: Erin Holton/Tom Rieth

Brief Description of Project

- The Clark Station Road main extension project includes a new regulator facility and associated inlet and outlet piping, a small uprate for the mains and services on the existing regulator station (less than 1000-feet of main and 4 customers), and installing 6,160 feet of 8 inch medium pressure gas pipeline along Clark Station Road south of Spotswood Lane in eastern Jefferson County. The project will end by installing 1,850 feet of 6-inch medium pressure pipeline to connect to the southern section of Catalpa Farms residential development.
- Construction is planned to start Q3 2020 and be completed in Q1 2021.
- The project will provide capacity to serve Catalpa Farms, Shakes Run and additional development in the area, including houses on Clark Station Lane that do not currently have gas service.
- The new regulator facility and associated inlet and outlet piping will have a maximum allowable operating pressure of 200 psig. The medium pressure pipeline will have a maximum allowable operating pressure of 60 psig.
- Most of the pipe will be installed in easement, necessary easements have been obtained. Where easements were not obtained, the pipe will be installed in the road right of way.
- The technology that will be used to install the new pipeline has been proven and is appropriate for the location of installation and the scope of work.
- Shakes Run Creek is blueline stream and the new medium pressure main will be installed using a bore under this creek. A general floodplain construction permit will be obtained and KYDOW will be notified by LG&E environmental affairs prior to the start of construction. A wetland delineation was completed by [redacted]roup for the route in 2019 and a storm water pollution prevention plan (SWPPP) was provided. LG&E will need to obtain a Metropolitan Sewer District (MSD) site disturbance permit for erosion prevention and sediment control.
- LG&E has a contract in place with the [redacted] to perform main extension projects.
- All piping and associated facilities have been sized to ensure reliable performance and cost effectiveness. Utilizing the system analysis software, the affected system has been reviewed for reliability with the implementation of the proposed changes. Preliminary

design plans have been drawn up for the location of the pipeline, though these are subject to change through the design build process as the project progresses.

- All materials will be procured from [redacted] utilizing the blanket contract.

Why is the project needed? What if we do nothing?

The new main extension is needed to support the planned load growth of the Shakes Run and Catalpa Farms residential developments with safe and reliable gas service.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	700	1,432			2,132
2. Cost of Removal Proposed	10				10
3. Total Capital and Removal Proposed (1+2)	710	1,432	-	-	2,142
4. Capital Investment 2020 BP					-
5. Cost of Removal 2020 BP					-
6. Total Capital and Removal 2020 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(700)	(1,432)	-	-	(2,132)
8. Cost of Removal variance to BP (5-2)	(10)	-	-	-	(10)
9. Total Capital and Removal variance to BP (6-3)	(710)	(1,432)	-	-	(2,142)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed					-
2. Project O&M 2020 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

- The $9k that was spent in 2019 on the environmental study is included above in the 2020 cost and will be moved to this project in August 2020.
- The estimate assumes that 50% of the route will have rock and while the exact amount of rock is not known based on field probing results the 50% estimate appears reasonable. An overall 25% contingency was added to the project cost to cover field changes and additional labor.
- The funding for the 2020 scope of the project is covered by other projects within GDO. The 2021 spend will be covered by GDO throught 2021 BP process.

Risks

- Risks associated with completing the project include delays due to the amount of rock encountered and any associated weather delays.

Alternatives Considered

1. Recommendation: NPVRR: ($000s)$2,686

2. Alternative #1: Installing 6-inch pipeline NPVRR: ($000s) $2,624
   The same scope as recommended, but installing 6,160 feet of 6-inch plastic pipeline. The minimal cost increase to install 8-inch pipe compared to 6-inch pipe is justified by the added hydraulic benefit and increased future growth predicted in the area. With the full build out of Catalpa Farms (approximately 500 homes) the 8-inch option increases the low pressure in the system from 32 psig to 38 psig. Typically an 8-inch pipe will have roughly double the capacity of a 6-inch pipe.

3. Alternative #2: Choose another route NPVRR: ($000s)$3,467
   Hydraulic studies from 10/9/2018 and 2/16/2017 show other routes that were evaluated early in the design phase to have a higher cost for equal or less hydraulic benefit.

4. Alternative # 3: Do Nothing NPVRR: ($000s) N/A
   Approved phases of Catalpa Farm Residential Development joint trench designs cannot be reliably supported by existing infrastructure on a design day.

Conclusions and Recommendation

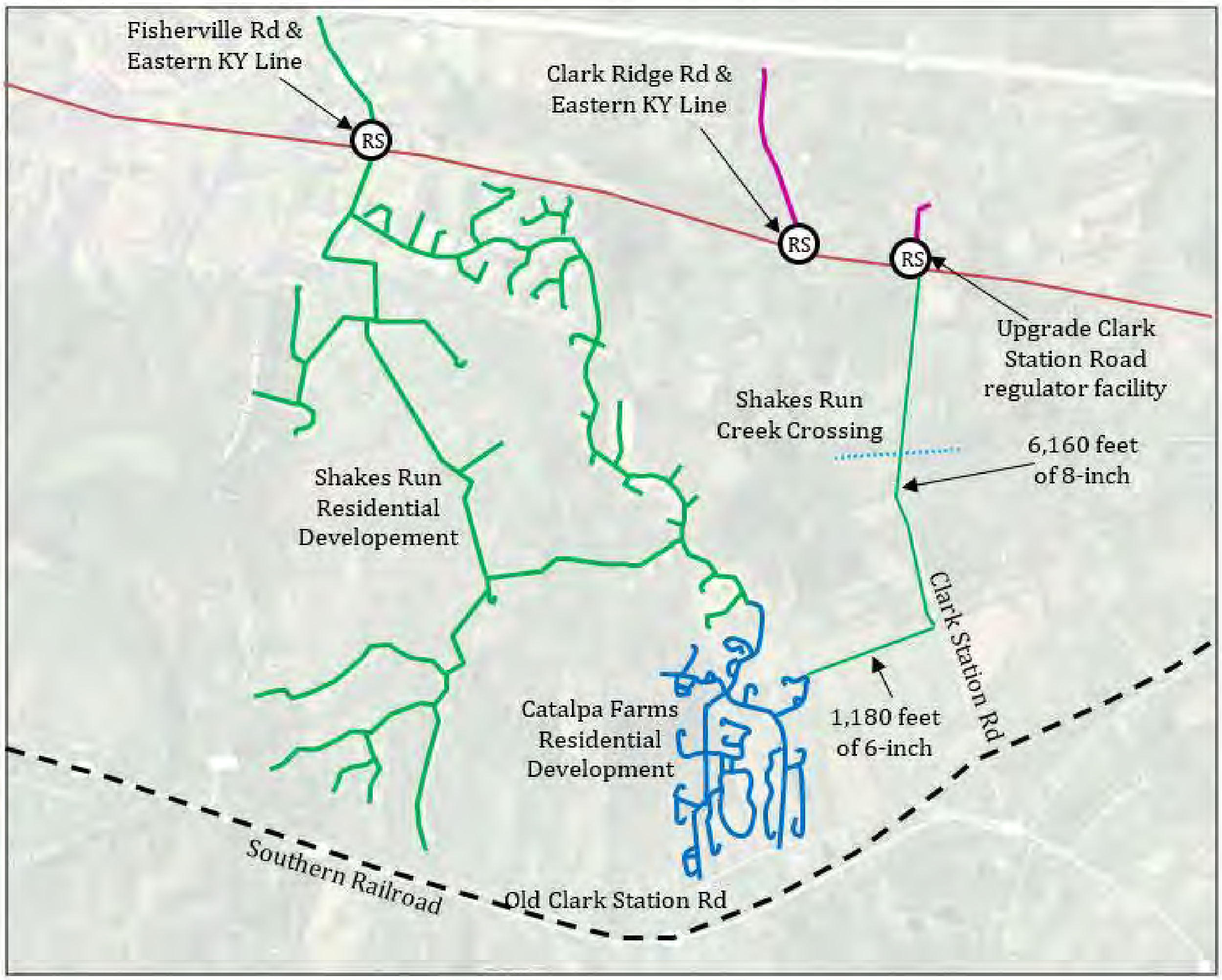
It is recommended that the Investment Committee approve the Clark Station Road Main Extension project for $2,142k to support the residential load growth in Eastern Jefferson County.

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

Project Overview Map



Investment Proposal for Investment Committee Meeting on: August 27, 2020

Project Name: Center Pipeline Cut Outs

Total Capital Expenditures: $2,087k

Total O&M: N/A

Project Number(s): 158237

Business Unit/Line of Business: Gas Distribution Operations

Prepared/Presented By: Mike McIntire & Pete Clyde

Brief Description of Project

The Center natural gas transmission pipeline is 20-inch in diameter and approximately 20 miles long. It runs from the Magnolia Compressor Station to the Center Storage Field in Metcalfe county. The pipeline was In-line Inspected (ILI) by [redacted] during 2018 and 2019. During one of the tool runs in 2018, an ILI tool broke apart in the pipeline, requiring short sections of pipe to be cut out and replaced to retrieve the tool. Additional short sections were cut out and replaced to improve the piggability of the pipeline for the subsequent runs. In response to the ILI reports, LG&E completed cut outs (short replacements) at one location in December 2018, one location in July 2019, and five locations in 2020 to date. Ten additional cut outs are scheduled for 2020. The total number of cut outs will be 19 including the work done to retrieve the broken tool and improve piggability. The anomalies primarilay consist of dents and corrosion features, some of which impacted girth welds and some of which contained metal loss.

The following AIP amounts have been approved on this project for the approximately 120-feet of pipe replaced to date.

- July 2018 for $100k
- August 2018 for a total of $200k
- September 2018 for a total of $354k
- March 2019 for a total of $561k
- August 2019 for a total of $723k
- April 2020 for a total of $1,555k

Through July 2020, $1,043k has been spent on this project. The total project cost to complete the scope of work is now estimated to be $2,087k. The increase in cost from the April 2020 investment proposal to now was driven by the ability to capitalize $160k in metallurgical analysis which is required by federal pipeline safety regulations effective July 1, 2020 as part of a material verification program, $50k in projected temporary gas supply being provided to keep customers in service, and challenging excavations which included a state highway crossing. The revised cost projection includes $170k in contingency, which is 20% of the unspent portion of the proposed project budget.

Why is the project needed? What if we do nothing?

The cut outs are necessary to maintain the integrity of the Center gas transmission pipeline and to ensure compliance with federal pipeline safety regulation 49 CFR 192.619 Maximum Allowable Operating Pressure. This regulation establishes the maximum pressure in which it is safe to operate the pipeline. The project also enhances reliability of LG&E's gas system.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	Pre-2020	2020	Post 2020	Total
1. Capital Investment Proposed	631	1,267		1,898
2. Cost of Removal Proposed	29	160		189
3. Total Capital and Removal Proposed (1+2)	660	1,427	-	2,087
4. Capital Investment 2020 BP	669			669
5. Cost of Removal 2020 BP	3			3
6. Total Capital and Removal 2020 BP (4+5)	673	-	-	673
7. Capital Investment variance to BP (4-1)	38	(1,267)	-	(1,229)
8. Cost of Removal variance to BP (5-2)	(26)	(160)	-	(186)
9. Total Capital and Removal variance to BP (6-3)	13	(1,427)	-	(1,414)

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

The incremental funding in 2020 was reallocated from other Gas projects and approved by the Corporate RAC.

Risks

The Center gas transmission pipeline delivers gas from LG&E's Center Storage Field and the Monroe City Gate to other areas of the system. In addition, it is a source of gas for two smaller communities. Not completing the cut outs could result in a pipeline failure which would jeopardize public safety and LG&E's ability to meet customer gas demand.

There is the potential that additional cut outs will ultimately be required as engineering analysis continues in preparation for regulatory filings and as PHMSA clarifies expectations on how operators should comply with the July 1, 2020 regulations (Mega Rule part 1). Two anomalies are under review currently and PHMSA clarifications could lead to additional work. One of the two anomalies under review is under the Green River.

Alternatives Considered

1. Recommendation: NPVRR: ($000s): $2,434

2. Alternative #1: Replace 7 miles NPVRR: ($000s): $75,501
   In addition to the 9 cut outs completed to date to retrieve the stuck in line inspection tool and address initial anomalies of concern, replace a 3-1/2 mile and 4-mile stretch of the pipeline to address the remaining anomalies of concern which have been identified.

3. Alternative #2: Do nothing NPVRR: ($000s) N/A
   Do nothing was not a viable alternative as repairs were necessary to ensure pipeline safety and regulatory compliance.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Center Pipeline Cut Outs project for $2,087k to ensure pipeline safety, system reliability, and regulatory compliance

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: August 27, 2020

Project Name: Gas Transmission Pipeline Modernization Program

Total Original Capital Expenditures: $82,109k (Approved on 02/28/2018)

Total O&M: $ 0 k

Amendment Value: $ 71,141 k

Total Revised Capital Expenditures including Amendment: $153,250k

Project Number(s): TMPPENBLN, TMPPENPRS, TMPPRSPIC, TMPPROP1, TMPPROP2, TMP-EDO, TMPPNBL-B, TMPPNPR-B, TMPPRPC-B

Business Unit/Line of Business: Gas Distribution Operations

Prepared/Presented By: Gabriel Wood/Tom Rieth

Description of Incremental Ask

Original Approved Capital Expenditures		$82,109k
Revised Capital Expenditures Requested including Amendment		$153,250k
Total Amendment Requested		$71,141k

Gas Distribution Operations (GDO) seeks approval to increase the project authorization of the Gas Transmission Pipeline Modernization Program (TMP) by the amount shown above from the amount previously authorized in 2018. The goal of the TMP is to implement a systematic modernization program of transmission pipelines critical to LG&E's natural gas system in support of regulatory compliance with current regulations. This authorization increase will allow completion of replacement work on three segments of transmission pipeline:

1. Blanton Lane Regulator Station to Penile Gate Station
2. Penile Gate Station to Preston Gate Station
3. Preston Gate Station to Piccadilly Valve Nest

The 2020 BP included $97,859k for the total project, the amended funding level in this document is proposed in the 2021 Business Plan.

- The primary increase in additional cost compared to what was previously authorized is in contract construction labor, which is driven mainly by an unanticipated amount of rock encountered in the Preston-Piccadilly segment. The amount of rock encountered in this section is significantly greater than LG&E encountered at other nearby locations that were utilized to estimate the costs of rock in this segment. The hardness of the rock also contributed to increased time to remove it. The increase in contract construction labor is $43,778k and includes the following:

  - Rock removal costs for conventionally installed portions of the project have been significantly higher than originally estimated, primarily on the Preston to Piccadilly section – approximately $18,556k.
  - Crushed stone and manufactured sand have been higher than originally estimated, with rock removal being the primary driver for the increase in volume of manufactured sand needed. This increase is estimated to be approximately $8,669k.
  - Miscellaneous increases in pressure testing, fabrication work, timber mats, rock shield and erosion control measures along with other items are approximately $6,436k higher than originally estimated.
  - Tree clearing is approximately $4,205k higher than originally estimated. The increase in the amount of new easement required contributed to the number of trees removed.
  - Due to ROW congestion (dense housing around the easement), approximately 1.7 miles of pipe will have to be installed by removing it from the existing trench and then installing the new pipe. Additionally, some Horizontal Directional Drills (HDDs) or conventional bores were lengthened or added due to field conditions (i.e., utility depths conflicting with initial plans and shallow rock in some locations). These installation methods are more expensive and have increased the original estimate by $3,935k
  - The project was bid assuming a 100' right-of-way (ROW) width. Drawings were not available at time of bid and bidders were evaluated on "typical" unit quantities. Once ROW acquisition began, it became clear that we would not be able to obtain 100' of working space on all portions of the project. Due to this, [redacted] was allowed to reprice their pipe installation units ($/ft) after receiving project drawings and final ROW conditions. [redacted] was also asked to provide updated lump sum pricing for the sections of pipe installed by horizontal directional drilling (HDD) after receipt of finalized drill designs which were not available when the project was bid. The changes to these line items raised [redacted] pricing for this portion of the project work by approximately $1,977k.

- Rights of Way (ROW) acquisition costs were higher than originally anticipated by approximately $3,338k due to the following factors:
  - Easement payments are expected to be approximately $2,084k higher due to both higher than expected per-acre costs and more permanent easement being required than originally anticipated. As engineering work progressed, it was determined that the existing easements on most of Penile-Blanton and a portion of Penile-Preston were too congested for an additional pipeline. Other smaller reroutes also increased the acreage of new easements required.
  - Due to the volume of additional easement acquisition work, internal Real Estate & Rights of Way departmental resources were insufficient and a third-party ROW agency [redacted] was brought on to complete ROW acquisition and provide ongoing customer communication during

construction. The additional ROW labor is expected to increase costs by approximately $1,254k.

- Increased project duration has led to higher company labor costs and higher third-party engineering, survey, and inspection costs of approximately $5,882k. This increased duration is primarily related to the amount of rock encountered on Preston-Piccadilly and the hardness of the rock encountered on the HDDs. Another contributor to higher inspection costs has been the need for more inspectors on the project than has historically been LG&E's practice. This is partially due to the number of sites being worked on simultaneously and partially due to increased documentation requirements from the Safety of Gas Transmission and Gathering Pipelines rule issued in October 2019.
- Material costs are expected to increase by approximately $1,754k. Factors contributing to this increase are:
    - Increased scope at the Blanton Lane Regulator Station, Penile Gate Station, and Piccadilly Valve Nest
    - Increases in steel costs
    - Increased amount of pipe ordered with abrasion resistant overcoating for installation by horizontal directional drill
- Other miscellaneous changes account for an increase in project spend of approximately $2,398k. The largest contributors to this category are hard surface restoration ($1,291k) and non-destructive examination of welds ($712k).
- As a result of these changes, allocated capital burdens and overheads assessed against the project have increased by approximately $4,548k.
- As a result of the project lasting more than 12 months, property tax has been added to the project for a total addition of approximately $1,727k.
- A 10% contingency on the remaining estimated spend of the project is included in this analysis of $7,716k.

Background Update

On October 1, 2019, the Pipeline and Hazardous Materials Safety Administration (PHMSA) published the Safety of Gas Transmission Pipelines: Maximum Allowable Operating Pressure (MAOP) reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments also known as the Mega Rule Part 1. The rulemaking established several new sections of federal pipeline safety regulations, including §192.607 Verification of Pipeline Material Properties and Attributes: Onshore steel transmission pipelines and §192.624 Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines. MAOP reconfirmation timeline requirements are as follows.

- Completing 50% reconfirmation of MAOP for applicable pipelines by July 3, 2028
- Completing 100% reconfirmation of MAOP for applicable pipelines by July 2, 2035

Section 192.624(c) provides six methods for reconfirming the MAOP for pipelines.

1. Pressure Test – Estimates for pressure testing range from $538k to $2.2M based on 200 operator pressure test data points (The Interstate Natural Gas Association of America (INGAA), Safety of Gas Transmission Pipeline Rule, Cost Analysis, A Review of the Natural Gas Notice of Proposed Rulemaking (NPRM) and Preliminary Regulatory

Impact Analysis (PRIA), July 7, 2016) Segments could fail the test and then need to be replaced which would be an additional cost. Pressure tests also require taking the pipeline out of service, potential interruption of service to customers, can be destructive, and would not provide quantitative data on the condition of the pipeline nor verification of material properties.

2. Pressure Reduction – This method requires the operator to reduce the pipeline's pressure to the highest sustained operator pressure during the previous 5 years (prior to Oct 1, 2019) and dividing by a minimum of 1.25. The highest sustained pressure must be achieved at a minimum cumulative duration of 8-hours for a continuous 30-day period and must account for upstream and downstream pressure differences. This method will not be a feasible solution in many cases, as it would inhibit the Company's ability to meet system supply requirements and maintain system reliability. In addition, reducing pressure does not provide quantitative data on the condition of the pipeline or provide verification of material properties.
3. Engineer Critical Assessment – This method involves leveraging inline inspection (ILI) data and performing in ditch remediation and investigations. LG&E plans to use this approach to reconfirm MAOP on other pipelines but does not believe this is the best approach for these pipelines as discussed later in this document.
4. Pipe Replacement – is the recommended approach for these pipelines.
5. Pressure Reduction for Pipeline Segment with Small Potential Impact Radius (<150-ft). This method has similar requirements as the Pressure Reduction method (reduction factor is 1.1 instead of 1.25) and requires increased leak survey frequency. This method has the same disadvantages as Method 2.
6. Alternate Technology - Operators may use an alternative technical evaluation process that provides a documented engineering analysis for establishing MAOP. Other than leveraging inline inspection data as discussed in Method 3 Engineer Critical Assessment, there is not currently an alternate technology established to satisfy the requirements.

Replacement of the segments is being proposed rather than reconfirming MAOP through an Engineering Critical Assessment for the following reasons:

- System Reliability
- Pipeline Segment Location
- Remaining project costs

System Reliability

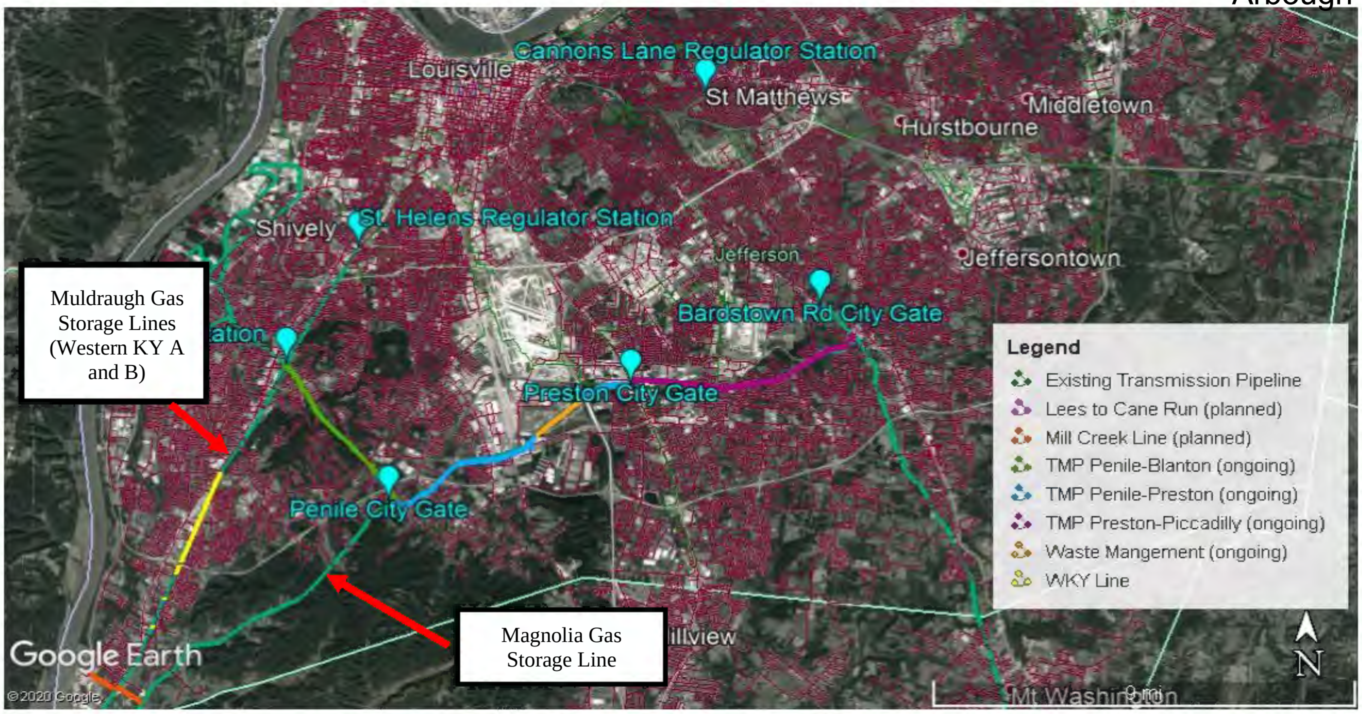
The three transmission pipeline segments proposed to be replaced were installed between 1957 and 1972, using the prevailing materials and construction methods of that time. These pipeline segments are critical for LG&E to reliably serve its customers. The three pipeline segments connect the following major gas supply sources to LG&E's gas distribution system:

- Penile City Gate Station – LG&E's largest city gate station receiving gas supplies from Texas Gas Transmission System
- Bardstown Road City Gate Station – LG&E's 2nd largest city gate station receiving gas supplies from Texas Gas Transmission System.

- Calvary Gas Transmission Pipeline – delivers gas supplies received from Tennessee Gas Transmission Pipeline System thru the Calvary City Gate Station.
- Preston Highway City Gate Station – receives gas supplies from Texas Gas Transmission System
- Magnolia Gas Storage System – delivers gas supplies from Magnolia Upper, Magnolia Deep, and Center gas storage fields.
- Muldraugh Gas Storage Area – delivers gas supplies from Muldraugh and Doe Run gas storage fields.

The Bardstown Road and Penile City Gate Stations have been upgraded in the past 10 years with increased facility capacities. The Preston City Gate Station along with the critical St. Helens (gas regulation facility providing Muldraugh Storage gas supplies to the distribution system) and Cannons Lane regulator stations are scheduled to be upgraded in the next few years. Replacing the three pipeline segments with larger diameter pipe (24-inch vs 20-inch) and increasing the pipeline segments maximum allowable operating pressure (MAOP) allows leveraging increased city gate station and regulation facility capacities from recent and planned upgrade projects to increase overall gas system reliability.

Replacing the three segments in this project will prevent potential unplanned repairs or replacements made in an inefficient manner due to an immediate or emergency basis. Even worse, the emergency repairs or replacements could occur at the very time of the year when these lines are most critical to the reliability of the system. Additionally, replacing the segments in this project increases system operational flexibility to ensure the gas system remains reliable while other transmission pipelines, such as those from Magnolia and Muldraugh Gas Storage, undergo MAOP reconfirmation which could result in temporary pipeline capacity reductions to facilitate remediation of pipeline defects discovered during MAOP reconfirmations. The map below illustrates the strategic location of the three segments in this project in relation to the supply (City Gate Stations and Storage Gas) and regulation assets mentioned in this section. The red lines on the map represent distribution pipelines in the gas system. As a point of reference Muldraugh and Magnolia Gas Storage was scheduled to provide 37% (approximately 220 MMCFD) and 16% (approximately 98 MMCFD) respectively of the 2019/2020 Peak Day Send Out of approximately 599 MMCFD to Firm Sales Customers. Ensuring the three segments in this project are in service and reliable is critical if one of the lines from storage had a pressure reduction or was taken out of service during the MAOP reconfirmation process.



Pipeline Segment Location

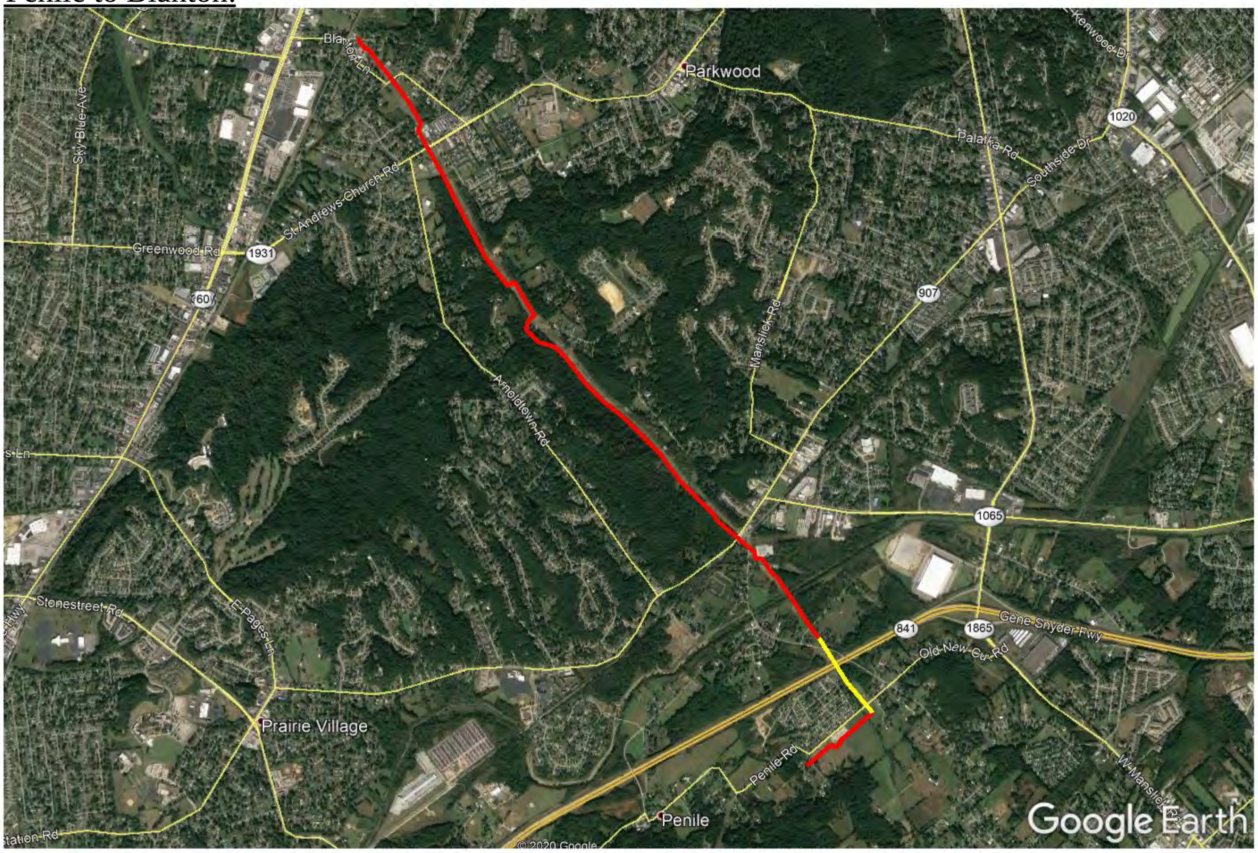
The pipeline segments in this proposal are in some of the most densely populated areas around the Company's natural gas transmission pipelines. This leads to likely higher consequences in the event of an incident on one of these pipeline segments. Of the approximately 15.5 miles originally estimated to be replaced (Approximately 15 miles of pipeline will be installed), roughly 90% is either in High Consequence Area (HCA) or Class 3 location (approximately 38% in HCA and an additional 52% in Class 3).

The map also illustrates the three segments proximity to populated areas as demonstrated by the density of the distribution pipelines (shown in red). The project has required significant new easements to accommodate HDDs that in some cases would be much more difficult to obtain in the future due to the proximity to population and continued growth in the area. The 24-inch pipeline being installed has a wall thickness of 0.469-inches and is designed to operate at 27.9% specified minimum yield strength (SMYS) at its design MAOP of 520 pounds per square in gauge (psig). This design strategy will allow the new pipe to operate below the stress level in which a pipeline is prone to rupture.

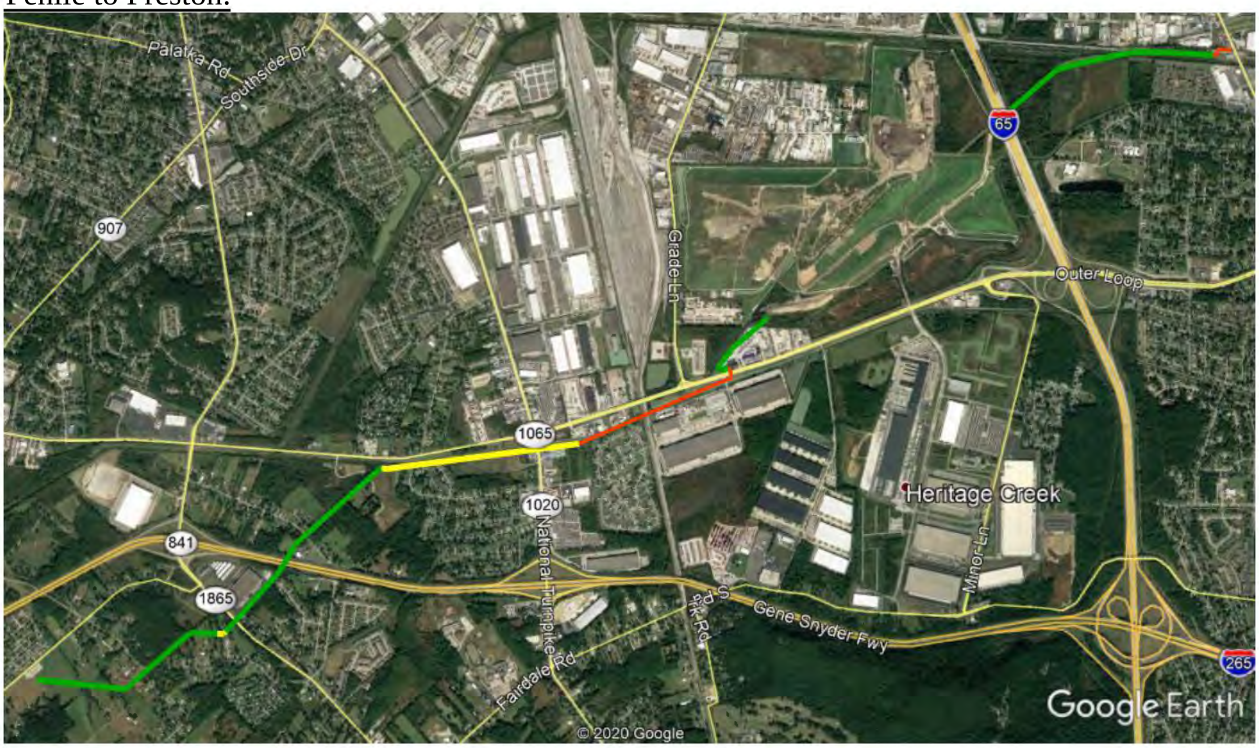
Current Progress

As of mid-August, approximately 5.3 miles of pipeline has been installed. Pipeline installation to date has been on the Penile to Preston and Preston to Piccadilly segments. Work has started on the HDD installations for the Penile to Blanton segment. The progress maps below show completed (green), in-progress (yellow) and remaining (red) sections of the project.

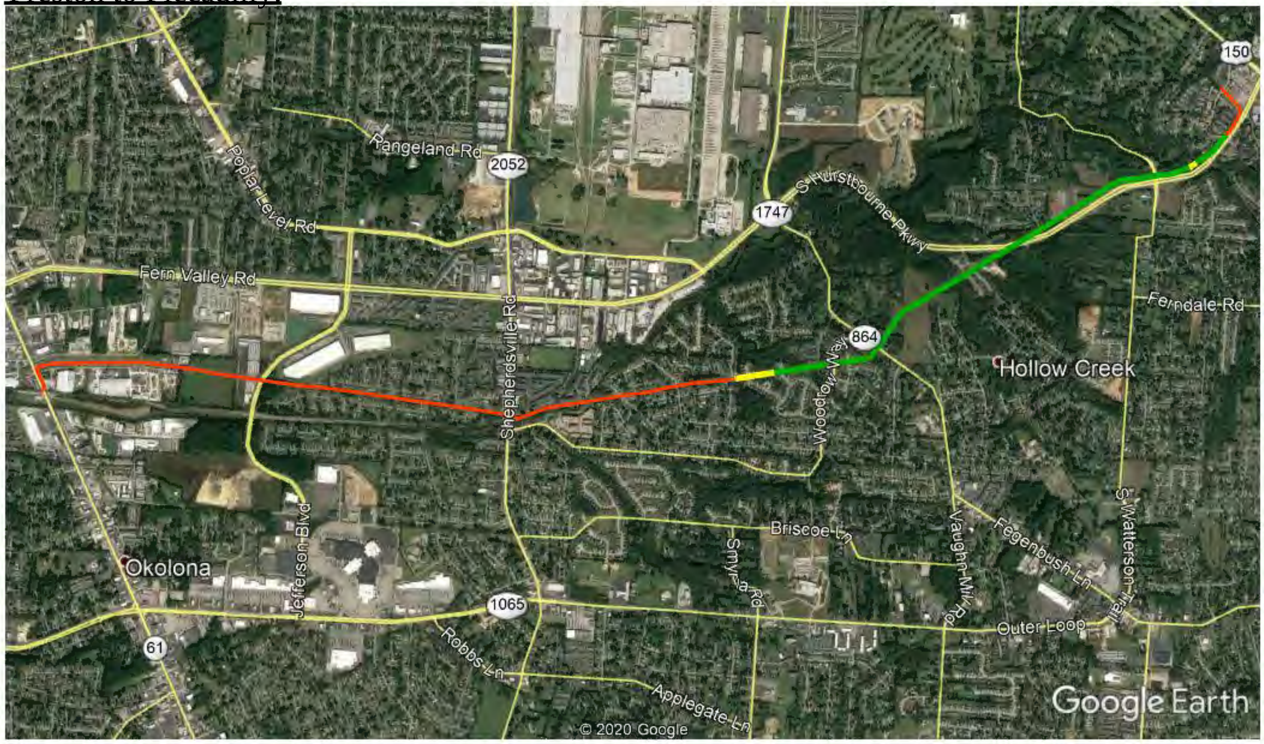
Penile to Blanton:



Penile to Preston:



Preston to Piccadilly:



Project Schedule

An updated project schedule is shown below:

Name	Duration
Perfom Horizontal Directional Drills	25 mons
Perform Conventional Pipeline Construction (trench, bore)	33 mons
Construct Gas Facilities	52 wks
Clean Up & Project Close Out	8 mons

Alternatives Considered

- Recommendation: NPVRR: $164,417k
  The recommended option is to authorize additional funding to complete replacement of the three segments of transmission pipeline. The estimated capital cost of this option is $153,250k.

- Alternative #1: NPVRR: $169,528k
  As presented in 2018, the alternative option was to stop additional construction on the new 24-inch pipeline and subject each of the three existing pipeline segments to hydrostatic pressure testing or other additional inspections to confirm the fitness of the pipeline segments to continue operating at the current MAOP. If defects are identified by these inspections, the Company would be required to take mitigating actions ranging from decreasing the MAOP to unplanned replacement of the pipeline

segment. This option would also require additional work to allow these pipeline segments to be fully inspected by ILI. Unplanned replacement would likely cost significantly more than the planned approach proposed by the recommended option. The alternative option would still not be recommended because it does not provide additional benefits to the recommended option and is a higher cost option. The estimated cost of this option is $7,582k of O&M expenses and $163,855k of capital investment.

- Alternative #2: NPVRR: $170,208k
  An alternative to the recommended option is to complete necessary work so the three segments could be inspected by ILI and then stop additional replacement with the new 24-inch pipeline. This option assumes the development of a suite of four dual diameter 20-inch x 24-inch ILI tools (O&M expense of approximately $11,300k based on contracted costs for two 16-inch x 20-inch tools under development), expense for cancelling the last large pipe order (approximately $4,000k) along with other expense related charges from not completing the project. The pipeline sections not replaced would have their MAOP reconfirmed through Engineering Critical Assessment, which could lead to unplanned replacements for the remaining sections in an unplanned manner, which would likely lead to higher costs for those sections and potentially pressure reductions or sections of the line out-of-service during critical times leading to reliability concerns. The estimated cost of this option is $15,492k of O&M expenses and $163,852k of capital investment.

Budget Comparison & Financial Summary

The annual cash flow in $000s for the entire program is outlined below:

	2017	2018	2019	2020	2021	2022	Total
Penile to Blanton Ln TMPPENBLN	210	1,556	1,626	17,223	21,356	968	**42,939**
Penile to Preston TMPPENPRS	2,230	3,928	13,996	17,769	3,739	0	**41,663**
Preston to Piccadilly TMPPRSPIC	311	2,673	16,920	22,896	24,143	799	**67,742**
Property Penile-Blanton TMPPROP1	257	0	0	4	0	0	**261**
Property Penile-Preston TMPPROP2	0	43	252	0	0	0	**295**
EDO Relocations Penile-Blanton TMP-EDO	0	0	0	350	0	0	**350**
Total	**3,008**	**8,200**	**32,795**	**58,242**	**49,238**	**1,767**	**153,250**

Note: 2017-2019 costs are actual amounts. 2020 costs are based on actual amounts through June 2020 with the remaining months estimated.

Financial Detail by Year - Capital ($000s)	**Pre-2020**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed	44,003	57,501	49,216	1,767	152,487
2. Cost of Removal Proposed	-	741	22	-	763
3. Total Capital and Removal Proposed (1+2)	44,003	58,242	49,238	1,767	153,250
4. Capital Investment 2020 BP	55,258	39,942	1,246	-	96,446
5. Cost of Removal 2020 BP	643	750	21	-	1,414
6. Total Capital and Removal 2020 BP (4+5)	55,900	40,692	1,267	-	97,859
7. Capital Investment variance to BP (4-1)	11,255	(17,559)	(47,970)	(1,767)	(56,041)
8. Cost of Removal variance to BP (5-2)	643	9	(1)	-	651
9. Total Capital and Removal variance to BP (6-3)	11,897	(17,550)	(47,971)	(1,767)	(55,391)

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

Through 30 June 2020, $67,021k has been spent of the original authorization. The higher spend in 2020 has been approved by the Resource Allocation Committee (RAC). The 2021 and 2022 estimates are consistent with the proposed 2021 BP.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Gas Transmission Pipeline Modernization Program project for $153,250k to complete the work already begun.

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 27, 2020

Project Name: Elevated Pressure Replacement Program - 2021

Total Capital Expenditures: $3,000k (Including $273k of contingency, including $190k of internal labor)

Total O&M: $ 0k

Project Number(s): 406000023

Business Unit/Line of Business: Gas Distribution Operations

Prepared/Presented By: David McGuire/Tom Rieth

Brief Description of Project

This proposal is requesting funding for the fourth year (2021) of a systematic program to reinforce areas of the Elevated Pressure (3.0 PSIG Max Allowable Operating Pressure (MAOP)) LG&E Gas Distribution System. Upgrading areas of Elevated Pressure (EP) to Medium Pressure (MP) removes gas load from the burdened EP system. This increases the EP system's overall stability and reliability, effectively reinforcing the existing system. The proposed funding for 2021 will support the installation of approximately 2.9 miles of new main, uprate a short section of polyethylene main (app 300-feet to 400-feet), the installation of approximately 172 new service lines, and the uprate of approximately 128 existing polyethylene service lines. Uprate feasibility will be determined based upon field conditions at the time of construction.

Where reinforcement occurs, existing elevated pressure steel main pipelines will be replaced with plastic (polyethylene) pipelines, which are used in all distribution systems with a MAOP less than 60 psig. Likewise, existing steel service lines will be replaced with new polyethylene service lines. Existing elevated pressure polyethylene main lines and service lines will be uprated to operate at medium pressure. In some instances, existing polyethylene facilities may be replaced when the cost for replacement is less or when construction or customer considerations dictate the need for replacement.

The primary driver for the reinforcement work is to mitigate reliability risks in the elevated pressure system. These risks exist in three major forms: hydraulic constraint in locations with substantial impact, uncertainty in total connected load due to unreported back-up generator installations, and the age of the system components and historical construction practices. The reinforcement work will have additional benefits including improving operational and emergency response flexibility. The majority of the current elevated pressure system is constructed of steel pipeline components with a limited number of valves in the existing system. The steel pipelines and limited valves can result in more costly and time-consuming shutdown techniques in the case of emergency or operational need. Furthermore, the relatively low operating pressure of the elevated pressure system (MAOP of 3 psig) greatly limits the ability to isolate small sections of the system. This could result in either higher customer and system impact or the necessity for a costly and time-consuming by-pass installation when isolations are necessary.

The estimated cost for 2021 is $3,000k which is included in the proposed 2021 Business Plan (BP).

This project will consist of all activities and responsibilities necessary to achieve the following scope:

Scope Item Description	Quantity
Install new 2" Polyethylene Pipeline	4,565 Feet
Install new 4" Polyethylene Pipeline	3,149 Feet
Install new 6" Polyethylene Pipeline	4,490 Feet
Install new 8" Polyethylene Pipeline	3,330 Feet
Install New Service (Customer and Company)	172 Services
Uprate Existing Polyethylene Service	128 Services

In many ways this project will be very similar to both the Priority Main Replacement Program and the Large Scale Main Replacement Program. We have established company procedures and have built a repository of experience and knowledge in this type of work over the past 22 years. The project has been planned in a modular nature to minimize extended restoration times (including street) to reduce the impacts of our work on the surrounding community.

All hydraulic analysis and material specification have been completed for this project. General pipe routes have been selected, and exact locations will be selected in the field based off in-situ conditions and existing utility locations. Preliminary right-of-way and easement research has started. Estimates of necessary man-hours and other logistics have been completed for completion of an estimate.

This project will start construction in January of 2021 and is intended for completion by the end of December 2021. Construction will follow as closely as possible the following timeline:

-Month 1-4: Install or uprate main lines
-Month 5-8: Finish installation of main lines and start and complete service lines
-Month 9-12: Complete restoration of all public and private assets

<u>Why is the project needed? What if we do nothing?</u>
LG&E's Elevated Pressure Distribution System consists largely of four separate hydraulic distribution systems within Louisville. These systems combined contain approximately 150 miles of main pipeline and 13,000 service lines. The customers consist mostly of residential, commercial, and light industrial groups. These four systems all have an operating pressure of 2.0 PSIG and an established MAOP of 3.0 PSIG. The Elevated Pressure is regulated and supplied to the distribution system by fourteen regulator facilities spread throughout the four systems. Customer services have individual service regulators at the meter reducing the pressure to the customer's side of the meter to standard houseline pressure.

Many parts of the elevated pressure system were designed and installed as far back as the 1950s. Over time customer load has increased and through system planning and monitoring several areas of the elevated pressure system have been identified as needing reinforcement to mitigate declining operating pressures, especially during the heating season when demand is generally higher. On very cold days it is possible for pressures in some isolated sections of the system to drop sufficiently to risk customer service outages.

In some portions of the elevated pressure system, the installation of emergency generators without information being provided to LG&E has created potentially significant undocumented transient demand on the elevated system. It is difficult to determine the effect this demand could have on the elevated pressure system if a large-scale electrical disruption were to occur. If such a large-scale electrical disruption were to occur it would activate all of the transient loading associated with the backup generators, which could cause the inability of the elevated pressure system to supply gas to all elevated pressure customers.

Finally, there are reliability concerns related to the age of the existing elevated pressure system. The oldest components of this system date from the early 1950s. Construction practices at the time do not conform to current standards and best practices. The elevated pressure system has a large number of mechanical couplings. Additionally, the older parts of the elevated pressure system have very few mainline or service valves. This limits our ability to quickly isolate a leak in an emergency situation and requires more expensive and time consuming isolation methods to be employed.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed		2,905			2,905
2. Cost of Removal Proposed		95			95
3. Total Capital and Removal Proposed (1+2)	-	3,000	-	-	3,000
4. Capital Investment 2021 BP		3,000			3,000
5. Cost of Removal 2021 BP		-			-
6. Total Capital and Removal 2021 BP (4+5)	-	3,000	-	-	3,000
7. Capital Investment variance to BP (4-1)	-	95	-	-	95
8. Cost of Removal variance to BP (5-2)	-	(95)	-	-	(95)
9. Total Capital and Removal variance to BP (6-3)	-	-	-	-	-

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed		-			-
2. Project O&M 2021 BP		-			-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks

- Poor weather could delay the completion of this project. As a result, financial obligation for restoration would continue into 2021 and the social impact of the project would be extended.
- Lack of contractor resources available to start this project on our proposed schedule could slow or delay the construction and push additional work and cost into 2021.

- Cold winter weather may discourage customers from scheduling their service change over. This will reduce the project efficiency, drive up costs, and possibly delay work and costs into 2021.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $3,909k

2. Alternative #1: NPVRR: ($000s) $4,489k
   Replace recommended Pipeline and Services
   Replace all pipeline, services and components in the section of the elevated pressure system to be reinforced so it can operate at medium pressure (MAOP up to 60 psig). This option would replace plastic pipe and components that are suitable for uprating and compatible with the project design with no additional safety or efficiency benefits.

3. Alternative #2: NPVRR: ($000s) N/A
   Do nothing. This is an option but has considerable risk of service interruption as noted on page 1 of this paper and is not recommended.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Elevated Pressure Replacement Program - 2021 project for $3,000k to increase system reliability and eliminate existing system risks.

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: 10/27/2020

Project Name: Gas Service Line Replacement Program-2020-21 GLT Revision

Total Original Capital Expenditures: $10,028k (Approved on 11/22/2019)

Total O&M: $ 0k

Amendment Value: $ 7,184k

Total Revised Capital Expenditures including Amendment: $17,212k

Project Number(s): 414000002

Business Unit/Line of Business: Gas Distribution Operations/Gas Construction

Prepared/Presented By: Lesley Hill/Tom Rieth

Description of Incremental Ask

Original Approved Capital Expenditures		$ 10,028k
Revised Capital Expenditures Requested including Amendment		$ 17,212k
Total Amendment Requested		$ 7,184k

Gas Distribution Operations instituted a systematic large-scale replacement program of steel gas distribution customer service lines and targeted removal of county loops and steel curbed services. This program began in 2018 and will enhance the safe and reliable delivery of natural gas service to LG&E's customers. Over time, steel gas service lines are susceptible to corrosion, which could lead to gas leaks developing near a home or business. County loops and curbed services would be removed because of an elevated risk of third-party damage due to their physical location.

The Kentucky Public Service Commission approved recovery of this program through the Gas Line Tracker (GLT) Mechanism in 2016. The Company has chosen to end recovery through the GLT at the end of June 2021. From July 2021 forward project expenditures will be recovered through base rates. The additional authorization requested in this revision includes additional funding to cover increased project expenses in 2020 and to add the remaining GLT funding through June 2021.

The project began 2020 with 15 total crews: 9 replacing services, 5 removing curbed company services, and 1 removing high pressure curbed services. The staffing is at a level to help meet service replacement target for the first 5 years of the program along with removing the remainder of the steel curb services in that time frame as well.

Production targets for the customer service line replacement from the original 2020 IP were 2,739 steel customer services and 1,048 steel curbed services (3,787 total services). Revised full year targets are 2,695 steel customer service lines and 1,474 steel curbed services (4,169 total services) resulting in about 400 additional services being completed in 2020 than in the original IP. The shift to higher steel curbed service production was due primarily to managing the contractor work force during the pandemic and targeting to complete removing them by the end of 2021.

Due to the pandemic, work requiring home entry was suspended from mid-March through the end of May. Service crews were shifted to removing steel curbed services or replacing services on inactive meters (did not require home entry, gas was left off at the meter). During this time, crews were on a T&M basis using the labor blended service crew rate since customer steel services requiring home entry were not being replaced at this time. The inactive meters with steel customer services were in scope and billed to the project, inactive meters with plastic customer services were not billed to the project. Shifting crews to this work resulted in lower steel service replacement production and higher cost/service due to the non-unit work. Crews were shifted back to replacing steel customer services on a unit basis when the Company started home entry work again.

On June 1st, 2020 the service crews returned to normal service replacements but continued to schedule the replacements with customers before completing work. Normally from April-October, replacements are not required to be scheduled and can be completed if the customer has been notified. Scheduling replacements has historically shown to decrease productivity and slightly increase costs. June and July data are showing a slight productivity decrease (5% or less vs the same time period last year), but costs per service for June and July are lower. Due to the pandemic it is planned to continue scheduling, productivity and costs will be monitored to evaluate scheduling impacts.

This project will continue following CDC guidelines and scheduling service replacements in 2021. During the remaining months of the GLT tracker, it is estimated that 1,600 steels services will be replaced, and 700 curbed services will be removed. The project expects to remove the majority of curbed services by mid-2021.

Due to the circumstances described above, this revision is seeking $1,697k additional funding through the end of 2020, and $5,487k for project expenses in 2021 under the existing GLT recovery method.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	Pre-2020	2020	2021	Post 2021	Total
1. Capital Investment Proposed		8,812	4,115		12,927
2. Cost of Removal Proposed		2,913	1,372		4,285
3. Total Capital and Removal Proposed (1+2)	-	11,725	5,487	-	17,212
4. Capital Investment 2021 BP		8,812	5,487		14,299
5. Cost of Removal 2021 BP		2,913	-		2,913
6. Total Capital and Removal 2021 BP (4+5)	-	11,725	5,487	-	17,212
7. Capital Investment variance to BP (4-1)	-	-	1,372	-	1,372
8. Cost of Removal variance to BP (5-2)	-	-	(1,372)	-	(1,372)
9. Total Capital and Removal variance to BP (6-3)	-	-	-	-	-

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

The 2021 funding was budgeted under project 414000003.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Gas Service Line Replacement Program-2020-2021 GLT project for $17,212k to continue to replace at risk steel customer service lines and remove targeted curbed services. This replacement program is consistent with the risks and recommendations identified in the LG&E DIMP and will provide a safer, more reliable gas service to customers.

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: November 20, 2020

Project Name: Gas Distribution Blankets - 2021

Total Expenditures: $27,501k

Project Number(s): Various

Business Unit/Line of Business: GDO

Prepared/Presented By: Tom Rieth

Brief Description of Project

Blankets are used to budget and account for annual routine short cycle, high volume work types and infrastructure work in GDO. Capital Blankets are comprised of a multitude of individual small projects necessitating capital investment. GDO subdivides its Blankets into distinct categories for new customer connections, network enhancements, network maintenance, and network repairs. These categories align with primary work drivers for GDO.

Blanket spend is monitored, analyzed, and trended on a monthly basis, using a combination of financial, applicable area economic indicators, and detailed input from area operational managers and other departments. This information, with consideration for known influences on historical trends, is used to develop annual budget allocations.

GDO is requesting approval for $27,501k in Blankets, an increase of $167k from the 2020 Business Plan for 2021.

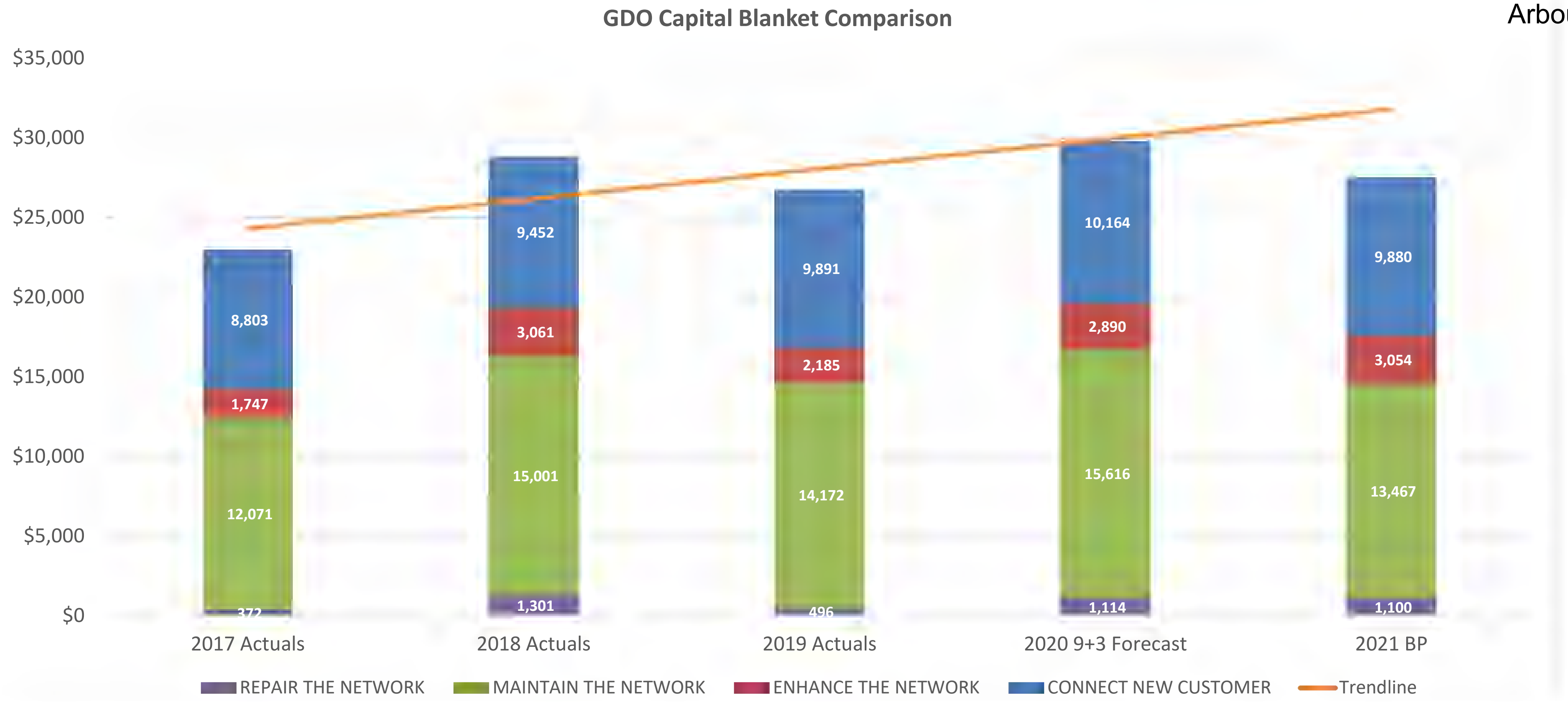
Conclusions and Recommendation

It is recommended that the Investment Committee approve the 2021 GDO Blanket projects for $27,501k to help manage the GDO capital work budgeted for 2021.

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



High Level Variance Explanations:

Connect New Customers - Reduced in anticipation of lower customer growth.
Enhance the Network - the 2021 requested amount is higher than the forecast due to:
- Public Works 2020 forecast funding was reallocated to individual projects that exceeded that blanket threshold.

Maintain the Network - the 2021 requested amount is lower than the 2020 forecast due to:
- Lower Company Service Leak Repairs inline with historical levels.
- Higher Gas Regulator Facility Upgrade costs in 2020 due to additional facilities identified for replacements and system upgrades.
- Lower projected costs in 2021 consistent with historical spend. Amine Replacement project is also expected to reduce costs incurred on this project going forward.

Gas Distribution Operations
2021 Capital Blankets (In Thousands $)

Blanket Project Number/Description	2021 BP	vs. 2020 BP			vs. 2020 Working Forecast			Variance - 2021 BP vs 2020 Forecast
		2020 BP (2021)	Variance Plan over Plan	% Chg	2020 Working Forecast	Variance to 2020 Working	% Chg	
CONNECT NEW CUSTOMER								
CGME406 - Gas Main Extensions	3,048	2,802	-246	-9%	3,067	19	1%	BP based on 5-year historical average.
CNBCS - New Business Customer Service (GLT)	4,892	4,743	-149	-3%	5,074	182	4%	2021 New Business reduced based on the trend from 2017-2019 actuals\ of lower customer growth and inflationary increases through the planning period with new commercial and industrial loads.
CNBGS - New Business Gas	1,825	1,649	-176	-11%	1,943	118	6%	2021 New Business reduced based on the 5-year average from 2015-2019 actuals of lower customer growth and inflationary increases through the planning period with new commercial and industrial loads.
CNBREG - Purchase Regulators New Business	115	115		0%	80	-35	-44%	New business regulator purchases less than expected in 2020
CONNECT NEW CUSTOMER TOTAL	**9,880**	**9,309**	**-571**	**-6%**	**10,164**	**319**	**3%**	
ENHANCE THE NETWORK								
CFTCUS-Gas Control FT Customer Conversions	90	90		0%	29	-61	-210%	
CKYTCR - Public Works - Customer Requests	26		-26	N/A	362	336	93%	2021 BP based on 2019 actuals as these were the only numbers available. BP assumes most all charges are reimbursable, 2020 includes several projects such as Stonebridge and US 150 (Springfield) that are only partially reimbursable.
CPBWK - Public Works Relocations Gas	1,938	2,357	419	18%	1,305	-633	-49%	In the 2020 forecast funding was reallocated to individual projects that exceeded that blanket threshold
CRCST - Relocations Cust Request				N/A	152	152	100%	Not requesting 2021 funding for this blanket.
CSYSEN - System Enhancements Gas	1,000	720	-280	-39%	1,042	42	4%	The 2021 BP reflects similar spending as the 2020 forecast.
ENHANCE THE NETWORK TOTAL	**3,054**	**3,167**	**113**	**4%**	**2,890**	**-164**	**-6%**	
MAINTAIN THE NETWORK								
CACMIT-Regulatory AC Mitigation	800	1,180	380	32%	1,248	448	36%	21 BP funding for 21 adjusted due to project work change and 21BP planning. The 2020 work consists primarily of addressing induced AC on pipelines. The 2021 work consists primarily of addressing AC arcing onto pipelines.
CCAPAC-Gas Regulation Capacity Project	600	607	7	1%	313	-287	-92%	Project scope reduction. Funding and resources shifted to the CREGFC, Gas Regulator Facility Upgrade project.
CCGUPG-Upgrade Facilities at City Gate	50	51	1	2%	138	88	64%	Project scope increase due to additional facilities identified for upgrades/improvements. Funding and resources shifted from other funding sources.
CCOCNT-Replace Controllers at City Gate	60	60		0%	36	-24	-67%	Project work postponed this year due to initial equipment planned to use for upgrade not feasible.
CCPIMP-CP Impressed Current System Improvement		35	35	100%	31	31	100%	Not requesting 2021 funding for this blanket.
CCSO - Replace Existing Customer Service (GLT)	2,775	2,714	-61	-2%	2,576	-199	-8%	2019 company service leaks were up substantially over other years (31% over 2018), lowered to reflect leaks repaired in other years. Trend has not carried into 2020, and reduced 2021 plan to reflect 2020 as well as the 2017-2019 actuals.
CDEFEQ-Storage Equipment Replacement	325	337	12	4%	385	60	16%	Project funding based on historical spend. No additional funding increases anticipated. Amine Replacement project is also expected to reduce costs incurred on this project going forward.
CEBREG & CCAPR -Purchase Regulators Existing Customer	185	120	-65	-54%	156	-29	-19%	21 BP based on 2019 actual.
CHPSRV-High Pressure Gas Service Upgrade	500	1,006	506	50%	804	304	38%	Funding levels increased in 2020, returned to historical levels in the 2021 BP process.
CPLUG-Plug Wells	1,151	1,350	199	15%	1,140	-11	-1%	Project scope decreased from original 2021 estimates in the 2020BP due to resources shifted to completion of Storage Well Integrity Inspection work accelerated into 2020, minimal change from 2020 estimate.
CREGFC-Gas Regulator Facility Upgrade	640	646	6	1%	1,250	610	49%	Project scope increased in 2020 due to additional facilities identified for replacements and system upgrades. 2021 funding kept consistent with original 2020 BP estimates.
CREGST-Upgrade Facilities at Regulator Station	50	50		0%	93	43	46%	Project scope increased in 2020 due to additional facilities identified for replacements and system upgrades. 2021 funding kept consistent with original 2020 BP estimates.

Gas Distribution Operations
2021 Capital Blankets (In Thousands $)

Blanket Project Number/Description		2021 BP	vs. 2020 BP			vs. 2020 Working Forecast			Variance - 2021 BP vs 2020 Forecast
			2020 BP (2021)	Variance Plan over Plan	% Chg	2020 Working Forecast	Variance to 2020 Working	% Chg	
	CRELI-Reline Wells	388	658	270	41%	332	-56	-17%	Project scope depends on results of Integrity Logging results. Wells with excessive corrosion may be relined with new casing/tubing.
	CROTAR - Upgrade Obsolete Rotary Meters	70		-70	N/A		-70	N/A	Project based on previous historical spend in 2017 and earlier. Project was not used in 2019 or 2020.
	CSTATN-Station Blanket	759	621	-138	-22%	804	45	6%	Project funding based on historical spend. No additional funding increases anticipated. Amine Replacement project is also expected to reduce costs incurred on this project going forward.
	CSTOR-Storage Field/Transmission Blanket	1,689	1,716	27	2%	2,184	495	23%	No additional increase anticipated for 2021. Based on historical spend. Project funding used for storage field and transmission piping repairs.
	RRCS - Replace Company Gas Services (GLT)	3,425	2,977	-448	-15%	4,126	701	17%	2019 company service leaks were up substantially over other years (37% over 2018), lowered to reflect leaks repaired in other years. Trend has not carried into 2020, and reduced 2021 plan to reflect 2020 as well as the 2017-2019 actuals.
	MAINTAIN THE NETWORK TOTAL	**13,467**	**14,128**	**661**	**5%**	**15,616**	**2,149**	**14%**	
REPAIR THE NETWORK									
	CTBRD - Trouble Orders Gas	953	581	-372	-64%	960	7	1%	Coupling replacement policy updated in 2019 has driven this number up in recent years. 2021 expected to be consistent with 2020 spending.
	CTPD - Repair 3rd Party Damage	147	149	2	1%	154	7	5%	2021 developed based on 5-year average. No significant changes expected to forecast.
	REPAIR THE NETWORK TOTAL	**1,100**	**730**	**-370**	**-51%**	**1,114**	**14**	**1%**	
	REPORT TOTAL	**27,501**	**27,334**	**-167**	**-1%**	**29,784**	**2,318**	**8%**	

Investment Proposal for Investment Committee Meeting on: January 30, 2019

Project Name: GH CCR Pipe Conveyor Belt

Total Expenditures: $3,089k (Including $403k of contingency)

Project Number(s): 144365

Business Unit/Line of Business: Power Generation

Prepared/Presented By: Vincent Forcellini/Steve Turner

Executive Summary

This project is to replace the Ghent Coal Combustion Residual (CCR) pipe conveyor belt. The pipe conveyor was installed in May of 2014 and is Ghent's primary means of CCR transportation to the landfill. The pipe belt top cover is wearing prematurely and splices are failing at an increasing rate. The project will remove the old belt, install a new belt and relag large diameter pulleys on the pipe conveyor.

Initially, material and labor bids were solicited separately. Material bids were solicited from four vendors [redacted] did not supply a technically acceptable proposal. [redacted] supplied a more competitive proposal through [redacted] Installation and labor bids were solicited from [redacted]. During the review process, the project team determined it would be beneficial to combine the material and installation bids. This approach reduces contractual risk and helps preserve the integrity of the warranty once the installation is complete. Combined material and labor bids were solicited from [redacted] and [redacted]. The Ghent Station project team conducted a thorough technical and commercial review of these proposals. [redacted] proposal provided a technically acceptable belt with a more favorable lead time and competitive price. [redacted] did not show willingness to be the primary warranty holder or primary administrator to support the chosen installation sub-supplier.

The GH CCR Pipe Conveyor Belt project is not under contract at this time. Contract negotiations are underway with the recommended bidder, [redacted] which is the original designer of the Ghent CCR Pipe Conveyor. It should be noted that the original belt material was supplied by a different manufacturer and that the installation and splices were performed by a different contractor than [redacted] proposes to use for this work. For this project, [redacted] proposes to procure belt material from [redacted] and use [redacted] to perform the installation. This project was activated in 2018 for $20k for initial scope development and technical bid analysis. Authorization of $3,089k, inclusive of 15% contingency, is requested for the Ghent Pipe Conveyor Belt replacement. A total of $3,660k is included in the 2019BP.

Background

The Ghent CCR pipe conveyor is the primary means of transporting CCR materials to the landfill at Ghent. In the event the pipe conveyor is out of service, the station air permit allows 1,800 loads utilizing 40 ton trucks to haul CCR material to the landfill on a rolling twelve (12) month calendar. This is approximately 9% of the average total CCR material added to the landfill. Consequently, reliability and availability of the pipe conveyor is critical to the overall station generation.

The Ghent Generating Station CCR pipe belt splice failures began in September of 2016. Originally, the pipe conveyor belt had eleven (11) splices and nine (9) failures have occurred. Depending on the severity of the failures, splices are cut out and replaced (belt shortened) or a saddle installed (2 splices required to add a section of belt). Each time a splice is added, the number of potential failure points in the system increases. Third party belt consultants have reviewed the scan and failed splice data. Failures have been attributed to incorrect installation of the fabric layer, breaks in the steel chords beyond the fabric layer, and failure in the top cover rubber to splice rubber bond. As a result of the analysis performed, the new belting will incorporate a design change to the steel chord layout in the splice area and reduce the number of splices (10 instead of 11). For this project, installation will be performed by a different contractor than the original belt, and a [redacted] technical representative will be onsite during installation to ensure splices are installed and vulcanized correctly. A splice report with vulcanization temperature and time graphs will be submitted for record. Additionally, [redacted] will warranty the splices for 3 years.

Costs for splice repairs and related maintenance increased over the last three years; $34k in 2016, $238k in 2017, and $225k in 2018. When a splice failure occurs, operation of the Ghent Generating Units can be significantly impacted. Repairs can range from a day to over a week depending on the severity of the damage. Additionally, trucking the CCR material from the silos to the landfill must be closely monitored so as not to exceed our emissions limit. The new belt design includes a higher grade of abrasion resistant rubber and improved life characteristics compared to the current belt design. A new pipe conveyor belt will reduce the current risk associated with operation of the pipe conveyor.

- **Alternatives Considered**
    1. Recommendation: Replace Pipe Belt NPVRR: ($000s) $3,996
       In addition to the scope of work described below, the belt will include upgraded rubber compounds to improve the wear of the belt. This is an improvement to the OEM design and has been successfully implemented at other locations.

    2. Alternative #1: Delay Replacement NPVRR: ($000s) $7,691
       This alternative includes estimates for cover maintenance and splice repairs of the pipe conveyor belt before replacement in 5 years.

    3. Alternative #2: Do Nothing NPVRR: ($000s) $26,227
       This alternative includes increasing estimates to perform cover maintenance and splice repairs of the pipe conveyor belt. The belt will eventually catastrophically fail and require replacement.

Project Description

- **Project Scope and Timeline**
  The primary project scope of work is to remove the old belt and install a new pipe conveyor belt. [redacted] was contracted to develop the technical scope requirements, review bids and provide a recommendation. A pipe belt is specifically designed for each application with significant engineering analysis and testing to ensure the system will operate properly with a new belt. The pipe conveyor bidders provided a preliminary design and will provide testing results after the first run of material is manufactured. The new pipe belt will have a higher abrasion resistance rubber compound compared to the original belt. Abrasion resistant rubber compounds are more sophisticated and readily available since the original belt was ordered. Other characteristics of the belt including cables, top breaker fabric, bottom breaker mesh, will be similar to the original belt. The project scope will also include new belt scrapers and upgrading the skirt rubber compound.

  The pipe conveyor installation will require an additional concrete pad to be installed for the contractor to set the new rolls of belt and equipment for pulling the new belt into position. The concrete pad will likely require significant backfill and/or a structural wall to support the equipment and loads generated during installation, and will be installed by the installation contractor. Material supply and installation will be awarded under one contract to minimize risk.

  Lead times for the pipe belt are between 20-24 weeks. Installation is planned to occur during the Unit 2 & 3 fall outage overlap in October 2019. Installation will require an outage of approximately 22 days and work will be around the clock from start to finish.

- **Project Cost**
  A total of $3,660k is included in the 2019BP. The total requested project amount is [redacted] Authorization for detailed scope development ($20k) was approved in 2018. The project includes 15% contingency to address unforeseen challenges as this replacement is the first of its kind at Ghent.

Economic Analysis and Risks

- **Bid Summary ($000's)**

	[redacted]	[redacted]	[redacted]	[redacted]
MBE/WBE	N/A	N/A	N/A	N/A
Rubber Type	[redacted]	[redacted]	[redacted]	Unable to meet specification
Cover Wear Warranty	3 yrs.	5 years/13M Ton	10 years/26M Ton	N/A
Splice Warranty	3 yrs.	5 yrs.	5 yrs.	N/A

Material (Shipping, Testing)	[redacted]	[redacted]	[redacted]	[redacted]
Preform Splice	Not Included	[redacted]	[redacted]	N/A
Spare Belt	Included	[redacted]	[redacted]	N/A
Spare Belt	1,522 ft (464m)	1,522 ft (464m)	1,522 ft (464m)	N/A
Installation Contractor	[redacted]	[redacted]	[redacted]	N/A
Installation Cost	[redacted]	[redacted]	[redacted]	N/A
Material & Installation Cost	[redacted]	[redacted]	[redacted]	N/A
Scraper and Skirt Rubber	[redacted]	[redacted]	[redacted]	N/A
KU Labor	$57k	$57k	$57k	N/A
Overland Scope Development/Review	[redacted]	[redacted]	[redacted]	N/A
Burdens	$45k	$46k	$46k	N/A
Contingency	$403k	$493k	$543k	N/A
Total Cost	[redacted]	[redacted]	[redacted]	N/A

The GH CCR Pipe Conveyor Belt material is not under contract at this time. The technical and project team preference is the [redacted] proposal. The [redacted] is a high abrasion resistance compound specifically formulated for pipe conveyors. [redacted] is responsible for installation including extending the concrete pad for belt winder equipment, which will remain after the project for future belt changes.

Budget Comparison and Financial Summary

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	20	2,919			2,939
2. Cost of Removal Proposed		150			150
3. Total Capital and Removal Proposed (1+2)	20	3,069	-	-	3,089
4. Capital Investment 2019 BP		3,510			3,510
5. Cost of Removal 2019 BP		150			150
6. Total Capital and Removal 2019 BP (4+5)	-	3,660	-	-	3,660
7. Capital Investment variance to BP (4-1)	(20)	591	-	-	571
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(20)	591	-	-	571

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)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$57
Contract Labor:	$599
Materials:	$1,764
Equipment:	$221
Burdens:	$45
Contingency:	$403
Net Capital Expenditure:	$3,089

- **Assumptions**

Recommendation:

This recommendation assumes the new pipe conveyor will last at least 10 years before requiring replacement. The current belt was installed in 2014 and is wearing prematurely, requiring replacement sooner than originally planned due to splice failures and material buildup. Design changes will be implemented with this installation to address the splice failures. In addition, Ghent Station has implemented a weekly shutdown to clean up the pipe conveyor area as well as made significant improvements to the operation of upstream equipment. A new scraper design will be installed on this project which is already in use elsewhere, and successful in minimizing carryover of material.

Alternative #1: Delay Replacement

This alternative assumes at least two or three splice repairs per year. Additional maintenance is required in an attempt to extend the life of the belt.

Do Nothing:

This option isn’t feasible because the pipe conveyor belt is the primary means for transporting CCR material to the landfill area. The pipe conveyor would eventually catastrophically fail and cause significant structural damage, requiring more extensive capital repairs later.

- **Environmental**

This project has been reviewed and approved by the Ghent environmental department.

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	N
#2	Does the project involve equipment that is part of a regulated air emission unit? a. Is change a like-kind or functionally equivalent replacement?	N Y
#3	Does the project increase through-put with any of the material handling systems?	N
#4	Will the project affect the dispatch order or utilization of the unit?	N
#5	Does the project increase the emissions unit's maximum hourly heat input?	N
#6	Does the project increase the emissions unit's electrical output (gross MW)?	N
#7	Has the equipment or component in question been repaired or replaced in the past at this unit? a. Provide frequency or when equipment or component in question was last repaired or replaced.	Y
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	N

#7a. – Several splice repairs since 2016 detailed elsewhere in this paper.

- **Risks**

There are risks of the belt catastrophically failing if the change out is not completed in 2019. The belt is very thin in the middle with an increasing rate of splice failures every year. A catastrophic belt failure could damage structure and other components of the system risking generation capacity of all four units at Ghent.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the GH CCR Pipe Conveyor Belt project for $3,089k to purchase and install a new pipe conveyor belt.

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: February 27, 2019

Project Name: BRCT6 C Inspection (LTSA Update)

Total Capital Expenditures: $18,409k (Including $500k of contingency)

Total O&M: $895k

Project Number(s): CAP: 123906 / 123906LGE; O&M: BR6CINS18

Business Unit/Line of Business: Power Generation / EW Brown

Prepared/Presented By: Greg Wilson

Brief Description of Project

The Investment Committee approved the BRCT 6 & 7 Long Term Service Agreement (LTSA) on 10/25/2017 for $88,440k. On 12/05/2017, LG&E and [redacted] signed the LTSA which encompasses planned and unplanned maintenance services on covered parts associated with the compressor, combustor, and turbine sections of each combustion turbine (CT). KU pays [redacted] through monthly variable and fixed fees as well as milestone payments tied to specific planned events. This document provides an update to the Investment Committee regarding LTSA spend to date, requests authorization to proceed with work to occur within 2019, specifically, the BRCT6 Type C Hot Gas Path Inspection (HGPI), and requests approval for the Capital project in support of the upcoming spring outage.

Why is the project needed? What if we do nothing?

During the first HGPI for BRCT6 under the current LTSA all covered equipment parts will be exchanged with either new or reconditioned parts to allow the unit to operate to the next planned inspection. Various upgrades to non-covered equipment will be implemented during the inspection. Once the inspection is complete, BRCT6 will be released to operate 32,000 equivalent operating hours (EOH) or 1,200 equivalent starts, whichever comes first.

The outage is scheduled to start April 15th, 2019, and is planned for a duration of 6 weeks.

To do nothing and continue to operate without performing the HGPI is not a viable option as it will only lead to a catastrophic failure for the unit. Long term exposure to creep and cyclic fatigue will inevitably lead to a failure of parts. Any failure of a component in the rotating section of the machine would lead to significant collateral damage that would escalate repair costs tremendously. Operating a gas turbine in such manner would be a tremendous safety risk. Additionally, this inspection is a requirement of the LTSA.

Budget Comparison & Financial Summary

To date, [redacted] invoices total $6,915k, and are tracked in a deferred debit account. Included in the deferred account are monthly fixed and variable fees in the amount of $956k for the CT7 overhaul currently planned for 2021. The remaining $5,959k is attributed to CT6, of which $959k is associated with fixed and variable monthly fees, and $5,000k accounts for the first two milestone payments for Covered Equipment parts being delivered to site. (See contract spend to date table on Page 3 for additional detail.) Three additional milestone fees totaling $11,747k will come due at the conclusion of CT6's overhaul this Spring. Also, an additional quarterly invoice, estimated at $189k, for monthly fixed and variable fees tied to CT6 will be charged to the deferred account before the start of the inspection. Based on the above, BRCT6's first HGPI under the current LTSA will be valued at [redacted]. At the conclusion of the BRCT6 HGPI, the deferred account will have a balance of approximately $1,096k for expenses associated with BRCT7's 1st HGPI.

The Capital and O&M referenced above were included in the 2019 BP at $20,892k & $79k, respectively. This paper seeks approval for a total estimated spend of $19,304k, with $18,409k being Capital and $895k being O&M. The Capital portion of this request is 12% lower than budget due to three factors determined after finalization of the 2019 BP. First, the mandatory spare parts that are required as part of the LTSA will be accounted for in an inventory account rather than on the capital project. Second, the first HGPI for each unit will be tax exempt under the new and expanded provision, which deems certain installation of upgraded/modnernized parts exempt from Kentucky sales tax. Third, based on guidance from Financial Planning and Accounting, the Plant adjusted the forecast to a split of 95% Capital and 5% O&M which is consistent with treatment of other LTSA contracts in the fleet. The O&M needed for the first HGPI has increased to $895k, in return reducing the amount of Capital needed. These three changes reduced the amount of Capital needed for BRCT6 HGPI to $18,409k, a favorable variance of $2,483k to the 2019 BP. The O&M portion of this project is $816k unfavorable to the 2019 BP, but will be funded within Power Generation.

Additional expenses of $1,409k outside the LTSA are required to support the outage. The breakdown of the costs are shown in the table below.

Project Cost Build Up ($000)				
Description	**Total**	**CAP**	**O&M**	**Comments**
[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	-Processed to the Contract
Misc. Consumables & Activities	$250	$250		-Scaffolding & Crane inspection.
Company Labor	$100	$100		-I&C and Electrical support
Contingency	$500	$500		-2.6% of total project
Burdens	$559	$559		-Capital burdens
Non-LTSA Spend	**$1,409**	$1,409		
Total Project Spend:	[redacted]	[redacted]	[redacted]	

*Includes Contract Spend to Date (see table below)
**Includes Contract Spend to Date (see table below) and Assumes 1st quarter 2019 LTSA invoice with 2% escalation.

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	17,462				17,462
2. Cost of Removal Proposed	947				947
3. Total Capital and Removal Proposed (1+2)	18,409	-	-	-	18,409
4. Capital Investment 2019 BP	19,945				19,945
5. Cost of Removal 2019 BP	947				947
6. Total Capital and Removal 2019 BP (4+5)	20,892	-	-	-	20,892
7. Capital Investment variance to BP (4-1)	2,483	-	-	-	2,483
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	2,483	-	-	-	2,483

Financial Detail by Year - O&M ($000s)*	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	895				895
2. Project O&M 2019 BP	530				530
3. Total Project O&M variance to BP (2-1)	(365)	-	-	-	(365)

*O&M portion of this project is included in Outage Normalization.

Contract Spend to Date	
Invoice	[redacted]
[redacted]	[redacted]

LTSA Update

At the time of LTSA award, the 2018 Generation Planning Long Term Plan (LTP) forecast yielded a contract spend of $80,400k. The timing of the outages and associated value for each outage presented to the Investment Committee were as follows:

2018 Generation Planning LTP			
Outage	Timing	Trigger	Value($000)
[redacted]	[redacted]	[redacted]	[redacted]

*Does not include 10% contingency that was approved for the contract

Updating the model to reflect changes from the current 2019 LTP increases the amount of spend required for the total contract to [redacted]. As mentioned above, two factors have reduced the spend required for the initial HGPIs for each unit, but the fewer starts forecasted in the current LTP extends the dates for the second HGPIs therefore increasing the total amount of spend required for the contract due to escalation. Changes to the LTSA forecast are summarized in the table below, and the revised buildup of costs is attached as Exhibit 1.

2019 Generation Planning LTP				
Outage	Timing	Trigger	Value($000)	Variance
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]

[1] Removal of sales tax and removal of booking of mandatory spare parts.
[2] Removal of sales tax for new and expanded exemption.
[3] Escalation increase due to significant spend being in later years.
[4] Escalation increase due to significant spend being in later years / booking of mandatory spares parts at completion of last HGPI.

The new forecasted spend for the BRCT 6 & 7 LTSA has increased to [redacted], which is lower than the Investment Committee approved amount of $88,440k. The LTSA Contract Proposal presented to the Investment Committee in October 2017 is included as Appendix A.

Risks

With essentially no support available for the GT24 fleet other than the OEM, an LTSA for the units limits our risk to the maximum extent possible. KU does not have the ability to terminate for convenience until after the completion of the 2nd HGPI of the contract. KU's failure to perform the BRCT6 HGPI would be considered a breach of contract.

Alternatives Considered

In 2017, Plant Staff and Commercial Operations explored the option of replacing the units with gray market combustion turbines, but this alternative did not prove feasible because of the high up-front Capital required for installation. This agreement is the best option available, given the very few alternatives that exist for continued support of these units.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the request to proceed with the BRCT6 2019 C Inspection project for $19,304k ($18,409k capital and $895k O&M) to allow for continued operation of the unit.

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	

CONFIDENTIAL INFORMATION REDACTED

[redacted]

Total Contract: [redacted]

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

Contract Name: BRCT 6 & 7 Long Term Service Agreement

Contract Total Seeking IC Approval [redacted]

Total Contract Expenditures: [redacted].

Business Unit/Line of Business: Generation

Prepared/Presented By: Greg Wilson / Robert Barnett / Joseph Clements / Jeff Fraley

Executive Summary

Approval is requested under this proposal to award a Long Term Service Agreement (LTSA) for the Brown combustion turbines units 6 & 7 to [redacted] The two units, commonly referred to as the Brown GT24s, were installed in the late 1990's.

Combustion turbines (CTs) require routine periodic maintenance to the combustor, turbine, and compressor sections. These inspections, commonly referred to as C-inspections, are required based on the number of operating hours or starts that the CT has incurred. Under this contract, [redacted] is obligated to perform the next two C-inspections for each unit. A C-inspection replaces many of the components in the turbine and combustor sections of the unit, and when complete the unit is released to operate for another service interval. In addition to the requirements for performing covered maintenance of the units, the contract will contain guarantees and warranties that will limit KU's exposure for unplanned maintenance events (e.g., forced openings, failure of covered equipment & collateral damages, combustion tuning) during the service interval.

[redacted] is considered the successful bidder for this contract as it is the only company capable of servicing the units. Efforts were made to look for other suppliers, but with the limited number of units in the GT24 fleet, no other company has developed the capability to perform this service. An engineering study was performed to look at the feasibility of replacing the GT24 units with gray market [redacted] but this too showed that an LTSA with [redacted] was the least cost solution for continued generation.

A financial analysis by Generation Planning determined that, from a net present value perspective, there is a cost benefit of between $28 and $35 million by entering into an LTSA with the Original Equipment Manufacturer (OEM) when compared to performing outages on a transactional basis with the OEM or replacing the units with the gray-market 7FA units mentioned above. A chart summarizing the results of the analysis is attached to this paper as exhibit 2.

Background

Brown combustion turbine units 6 & 7 were installed in the late 1990's under an agreement with [redacted] [redacted] [redacted] ultimately assumed control / ownership of [redacted]. In 2016, [redacted]. The units were installed as GT24 A models, the first of two variants of the GT24, and were found to have significant design flaws very early into commercial operation. Shortly after going commercial with the units, design issues forced KU and [redacted] into a lawsuit. KU was awarded a favorable ruling, and as part of the settlement the two units were placed in an LTSA in which [redacted] was to perform various upgrades to make the units as similar in design to the GT24 B models as possible. Brown CT 6 & 7 are now known as GT24 A/B models. Currently, there are 10 A/B model units operating throughout the world. KU operates the only two units in simple cycle in the entire GT24 fleet, which is comprised of 51 units.

The previous LTSA ended in October 2016. During that agreement, [redacted] performed four planned C-inspections and two forced openings to correct issues with covered parts.

Currently, a C-inspection is performed when the equivalent operating hours (EOH) of a GT24 combustion turbine unit reaches 24,000. EOH are used to estimate the material degradation of a unit's hot gas path parts and are accumulated on a per start basis. During the first C-inspection for each unit under the proposed agreement, [redacted] will install extended life (XL) hardware that will allow each unit to operate a total service interval of 32,000 EOH or 1,200 weighted starts.

BRCT 6 & 7 have 2,386 and 5,877 EOH remaining respectively until their next scheduled C-inspections. The first C-inspections are scheduled to occur in 2019 and 2021 respectively.

Contract Description

The contract will be in effect from the date signed until the completion of the second C-inspection on each unit. The contract has a sunset clause of 25 years, and if a second C-inspection has not been performed at that time, KU will have the option to extend the term, elect to end the term, or pull forward the C-inspection at the expense of a true-up for unpaid EOH fees.

During the term of the LTSA, [redacted] will provide the following:

- Engineering services
- Technical field advisors (TFAs) to support A and B inspections (visual only inspections)
- TFAs and craft labor to support planned C-inspections or covered maintenance events
- Covered parts and associated assembly hardware
- Open and close parts for outages
- Remote monitoring of the units
- Project Manager responsible for coordinating with KU
- Access to its parts pool which gives KU a spare parts inventory for hot gas path parts.

Payment Terms:

The chart below shows the fees associated with the contract. All fixed monthly and variable fees will be invoiced quarterly, and the event / milestone fees will be paid as described in the notes column. Monthly and event fees are subject to escalation per a published CPI index. Annual average U.S. Consumer Price Index – Urban CUUR0000SA0.

Description	Amount	Notes
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Performance Guarantees:

The following performance guarantees will be in effect for the duration of the contract:

- Pre and Post Outage Performance Guarantee
- Heat Rate and Output Degradation Guarantee
- Starting Reliability Guarantee
- Outage Duration Guarantee
- Emissions Guarantee
- Unscheduled Outage Downtime Guarantee

Each guarantee has in place either a make right provision or liquidated damages. Termination rights are in place if [redacted] fails to correct the issue in a given amount of time or attempts.

Termination Rights:

Both parties will have termination rights for default, insolvency, or force majeure. In addition, KU will have termination rights for the following:

- Termination for change in law
- Termination for permanent or indefinite shut down of units
- Termination for failure to meet performance guarantees
- Termination for Owner's Convenience

There is a termination fee calculation within the contract that is dependent upon when termination occurs (mainly relative to when major contract milestones occur and EOH expended), the reason for termination, and who terminates the contract. Termination is written such that KU would receive back a sizable portion of what it has paid and not received value for in parts or services. A large portion of the termination amount is centered on whether or not parts have been delivered. If parts have been delivered, KU does not have the option to return them in the event of termination. To limit KU's exposure it has been written into the contract that parts cannot be delivered to site for the second C inspection until a time that is within a year of the inspection.

Covered Maintenance & Collateral Damage:
During the term of the contract, [redacted] is required to remedy issues regarding covered equipment, including open and close of the unit, at its expense. In the event that issues with covered equipment creates collateral damage, [redacted] will bear the first [redacted] of the cost, up to a maximum of [redacted] in any one calendar year. The collateral damage limit is subject to escalation up to the cap of the lesser [redacted] or KU's deductible for property insurance.

Economic Analysis and Risks

- **Bid Summary**
  Parts and materials needed to support these units will be provided by [redacted] as part of this agreement. Many of the parts required to be replaced are considered proprietary to [redacted], and are not available from other vendors. The lack of supporting documentation does not allow KU to re-engineer or procure these parts elsewhere. Attempts are continually made to locate other suppliers; however, with the limited number of units in the [redacted] fleet, there has not been enough demand to warrant a third party market. It is believed that over 90% of the [redacted] GT24 fleet is in some type of agreement with the OEM for parts and services.

  Efforts were made to lower [redacted] price throughout negotiations. The effort that seemed to have the most effect was the feasibility study performed with Black and Veatch that looked at replacing the GT24 units with gray market [redacted] 7FA units. As a result, [redacted] reduced its pricing on the order by $10 million. In addition, [redacted] included the XL upgrade to extend service intervals, and included additional coverages throughout the term. Final negotiation attempts reduced [redacted] price another $5 million.

- **Financial Summary**
  Variable and milestone LTSA payments will be held on the books in a deferred asset/debit account and portions of those fees will be transferred to capital at the time of the scheduled outages. KU will seek project approval from the Investment Committee prior to the start of a C-inspection. The proposed 2018 BP includes $22,578k in 2019 for the C-inspection on BRCT 6, and $25,739k in 2021 for BRCT 7. The proposed 2018 OPEX BP includes 5% of the variable fees. For BRCT 6 $79k is budgeted in 2019, and $170k has been budgeted in 2021 for BRCT7.

Contract expenses ($k)	2017	2018	2019	2020	2021	Post 2021	Total
2018 BP			$22,578k*		$25,739k*		
Amount requested based on [redacted]			[redacted]		[redacted]	[redacted]	[redacted]
Contingency Amount Requested – 10% Total Contract							[redacted]
Total contract authority requested				For buildup of costs, see the attached Exhibit 1.			[redacted]

*2018 BP includes project burdens and miscellaneous consumables that will be the responsibility of KU. As noted above, the contract payments will be charged to a deferred asset/debit account and then allocated to a capital project at the time the scheduled outage occurs.

**Contingency included in the contract will cover such items as EOH timing, length of contract, discrepancy in assumed CPI escalation, and smaller extra work authorizations during planned inspections. Larger emergent scopes that would not fall under this contingency will be processed on a case to case basis and presented for approval at the required level under a separate project.

***For total contract cost CPI escalation is assumed to be 2%.

- **Risk of Contract**
  With essentially zero support available for the GT24 fleet other than the OEM, an LTSA for the units limits our risk to the maximum extent possible. KU does have the ability to terminate the contract, if desired, with minimum exposure. The fees are escalated per a CPI index, so periods of extreme inflation could increase cost significantly.

- **Other Alternatives Considered**
  Very few alternatives exist for continued support of these units. With that known, the plant staff views this agreement as the best option available for continued support. In an attempt to lower the cost of the contract, the plant staff and commercial operations did explore the option of replacing the units with gray market combustion turbines. This alternative did not prove feasible because of the high up-front capital required for installation, but it did succeed in lowering the overall cost of the contract.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the BRCT 6 & 7 Long Term Service Agreement (Sole Source) contract for [redacted] to [redacted] International Inc. This will allow for continued operation of the units in a very limited market for support, and at a significant benefit when compared to transactional purchases for maintaining them.

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

<u>Approval Confirmation for Contract Authority Greater Than or Equal to $10 million bid, or $2 million sole sourced</u>:

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

DAT for
10-31-17

Kent W. Blake
Chief Financial Officer

Paul W. Thompson
President and Chief Operating Officer

Victor A. Staffieri
Chairman and Chief Executive Officer

AWARD RECOMMENDATION APPROVALS
– Attachment for IC Proposal

SUBJECT:
BRCT 6 & 7 Long Term Service Agreement

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the Brown CT 6 & 7 Long Term Service Agreement contract for [redacted]

Sourcing Leader	N/A	Proponent Greg Wilson Supervisor-Production	Greg Wilson 10/26/2017
Supplier Diversity Manager	N/A	Manager Jerry Arnold Manager-Production	Jerry Arnold 10/27/17
Commercial Operations Bob Barnett Manager – Commercial Operations	Bob Barnett 10/26/17	Commercial Operations Joe Clements Director – Power Gen. Commercial Operations	Joe Clements 10/31/2017
Director Jeff Fraley General Manager, EW Brown	Jeffrey D. Fraley 10/27/17	Vice President Ralph Bowling VP Power Production	Ralph Bowling 10/31/17

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Novak, Lana

From:	Elzy, Tammy
Sent:	Tuesday, October 31, 2017 8:43 AM
To:	Cosby, David; Novak, Lana
Subject:	FW: Delegation Of Authority Notification For KENT BLAKE to DAN ARBOUGH

Tammy Elzy
Sr. Assistant to Kent W. Blake | Chief Financial Officer
LG&E and KU Energy LLC
220 West Main Street, Louisville, KY 40202
O: (502)627-2184
tammy.elzy@lge-ku.com

From: LG&E ERS Website
Sent: Monday, October 30, 2017 9:46 AM
To: Arbough, Dan <Dan.Arbough@lge-ku.com>; Delegation of Authority <doa@lge-ku.com>; Slavinsky, Eric <Eric.Slavinsky@lge-ku.com>; Blake, Kent <Kent.Blake@lge-ku.com>; Schmitt, Mark <Mark.Schmitt@lge-ku.com>; Thompson, Paul <Paul.Thompson@lge-ku.com>; Conroy, Robert <Robert.Conroy@lge-ku.com>; Charnas, Shannon <Shannon.Charnas@lge-ku.com>; Elzy, Tammy <Tammy.Elzy@lge-ku.com>; Scott, Valerie <Valerie.Scott@lge-ku.com>; Oracle Security <oracle@lge-ku.com>; Cash Management <Cash@lge-ku.com>; Bowling, Ralph <Ralph.Bowling@lge-ku.com>; Malloy, John <John.Malloy@lge-ku.com>; Straight, Scott <Scott.Straight@lge-ku.com>; Jessee, Tom <Tom.Jessee@lge-ku.com>; Wolfe, John <John.Wolfe@lge-ku.com>; O'brien, Dorothy (Dot) <Dorothy.OBrien@lge-ku.com>; Quinn, Julie <Julie.Quinn@lge-ku.com>; Whelan, Chris <Chris.Whelan@lge-ku.com>; McFarland, Beth <Beth.McFarland@lge-ku.com>; Sinclair, David <David.Sinclair@lge-ku.com>; Bellar, Lonnie <Lonnie.Bellar@lge-ku.com>; Freibert, David <David.Freibert@lge-ku.com>; Meiman, Greg <Greg.Meiman@lge-ku.com>
Subject: Delegation Of Authority Notification For KENT BLAKE to DAN ARBOUGH

This delegation of authority is effective with the start of the work day 10/30/2017 through the end of the work day 11/3/2017.
The Reason for this delegation of authority is Vacation.

Delegation of Authority for		Authority being delegated to	
Name	KENT BLAKE	**Name**	DAN ARBOUGH
Location	LG&E Center 15th floor	**Location**	LG&E Center 10th floor
Department	Chief Financial Officer	**Department**	Treasurer
Company	LG&E and KU Services Company	**Company**	LG&E and KU Services Company
Phone	502/627-2573	**Phone**	502/627-4956
E-Mail	KENT.BLAKE@LGE-KU.COM	**E-Mail**	DAN.ARBOUGH@LGE-KU.COM
Cell Phone	N/A	**Cell Phone**	N/A
Pager	N/A	**Pager**	N/A

Comments :

Investment Proposal for Investment Committee Meeting on: February 27, 2019

Project Name: TC1 FGD Recycle Pump Piping

Total Capital Expenditures: $2,973k gross, ($2,230k net) (including $266k gross (10%) of contingency)

Total O&M: $0k

Project Number(s): 158623

Business Unit/Line of Business: Generation

Prepared/Presented By: Logan Waller / Laura Mohn

Brief Description of Project

The Trimble County Unit 1 (TC1) Wet Flue Gas Desulfurization (WFGD) is original to the unit and has been in operation for nearly 30 years. The fiberglass piping has been repaired over the years, but is now reaching the end of its expected life. The TC1 WFGD design is unique to the fleet as it contains two tanks, four modules, and five recycle pumps per module. The scope of this project includes the purchase, fabrication, and replacement of all ten "A" side recycle pumps' suction and discharge piping up to the discharge headers. The project milestones are:

○ Award Project to Successful Bidders	March 2019
○ Material Fabrication	April 2019 to August 2019
○ Material Delivered	September 2019
○ Outage Begins	October 14th, 2019
○ Project Complete	November 5th, 2019

Why is the project needed? What if we do nothing?

Over the years, fiberglass piping repairs have been made nearly every outage to fix leaks and repair the piping's protective coating. Expected life of fiberglass pipe in these slurry conditions in the industry is approximately 20 years. A video inspection of the piping in 2015 and 2017 indicated significant deterioration of the corrosion barrier, which is the primary protective layer of the piping. The discharge headers were replaced on all four modules during the TC1 Fall 2017 outage. The replacement of the fiberglass piping is in line with a 2017 [redacted] WFGD condition assessment. The study analyzed the overall health, reliability, and necessary modifications to maintain WFGD performance. This proposed project is one of several that was included in the 2019BP to upgrade the WFGD to meet demands of unit availability and continue to meet emissions requirements. If nothing is done, there is a potential for excessive leaks causing recycle pumps to become unavailable, which will increase sulfur dioxide emissions.

Budget Comparison & Financial Summary

This project is included in the 2019BP with a total budget of $1,483k gross ($1,112k net) over years 2019 to 2021. The expected total cost is $2,973k gross ($2,230k net). The Work has been competitively bid. The most competitive and technically acceptable bid received is $2,560k. Contingency (10%) is $266k and will cover any unknown conditions once the work begins that would be directly related to the scope of the project. The Work will be awarded as lump-sum and any additional work discovered during the project will be completed on a time and material not to exceed basis.

A project (124518) to replace all of the recycle pump suction and discharge piping was included in the 2019BP as a multi-year project over four outages. Therefore, the funding was spread out. However, after reviewing the installation scope, it became apparent that it would be more advantageous to install over two outages to reduce risk and overall project labor costs. The difference in the project cost and what was included in the 2019BP is mainly due to:

- Higher material cost
- Labor to install complex pipe routing
- A more detailed analysis indicated all the pipe supports need replacing

The difference in the project cost and what was included in the 2019BP will be funded by reprioritization and reallocation of other project funds in 2019. This has been reflected in the 0+12 capital forecast approved by the RAC. This project is the first half of an overall plan to replace all TC1 WFGD recycle pump suction and discharge piping. The "B" side suction and discharge piping is planned to be replaced during TC1 Fall 2021 outage.

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	2,040				2,040
2. Cost of Removal Proposed	190				190
3. Total Capital and Removal Proposed (1+2)	2,230	-	-	-	2,230
4. Capital Investment 2019 BP	364	368	380		1,112
5. Cost of Removal 2019 BP					-
6. Total Capital and Removal 2019 BP (4+5)	364	368	380	-	1,112
7. Capital Investment variance to BP (4-1)	(1,676)	368	380	-	(928)
8. Cost of Removal variance to BP (5-2)	(190)	-	-	-	(190)
9. Total Capital and Removal variance to BP (6-3)	(1,866)	368	380	-	(1,118)

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)	-	-	-	-	-

Note: Total amount shown in 2019BP is from placeholder project 124518

Risks

The risks of not completing this project include:

- Once the corrosion barrier has been compromised in fiberglass pipe, small holes or leaks lead to larger holes or leaks. It is difficult to maintain a patch in a WFGD slurry environment. This could lead to a decrease in operational efficiency and unit derates to maintain sulfur dioxide emission limits.
- O&M expenditures will increase due to costs associated with repairing leaks and patching elbows.

The risk of completing the project:

- Delays in installation could cause the outage timeframe to increase. This risk will be mitigated by utilizing experienced contractors with rigging knowledge.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $2,610
2. Alternative #1: Do nothing NPVRR: ($000s) $2,892
   [This alternative should not be considered due to the increased risk of pipe failure. If nothing is done, the piping will continue to deteriorate, unit reliability will decrease, and O&M spending will increase with each outage.]
3. Alternative #2: Complete over two outages NPVRR: ($000s) $2,903
   [This option would replace the A1 module piping in 2019 and the A2 module piping in the 2021 outage. It is assumed that there would be an increase in installation costs by 15% for increased labor. This alternative should not be chosen due to the increased cost and complexity of the tight working spaces. This would also delay the replacement of the "B" side piping, which is not recommended due to the condition of the piping.]

Conclusions and Recommendation

It is recommended that the Investment Committee approve the TC1 FGD Recycle Pump Piping project for $2,973k gross ($2,230k net) to avoid future incremental O&M costs as the existing fiberglass pipe reaches the end of its service life. This is also to ensure environmental compliance and long term unit reliability.

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: 03/27/2019

Project Name: GH4 AH Basket Repl 2020

Total Expenditures: $2,488k (includes $118k contingency)

Total O&M: $0k

Project Number(s): 156629

Business Unit/Line of Business: Generation

Prepared/Presented By: Steven Straight/Steve Turner

Brief Description of Project

The Ghent Unit 4 Air Heater Basket project is a replacement-in-kind and includes the purchase of new hot and cold-side basket elements, and hot and cold-side seals. Additionally, the project includes labor to remove the old basket materials and install these new materials in both of the Unit 4 Air Heaters. These components have reached the end of their useful life. Replacement of the air heater baskets and associated seals will eliminate the risk of steady fragmentation and loss of the basket elements which can lead to air heater basket pluggage, increased pressure differential, overall performance loss and pluggage in the air heater hopper discharge line.

The project materials and labor have been competitively bid as part of separate fleet-wide RFQs. The project materials will be purchased and fabricated in 2019 and the removal and installation labor will be completed during the Unit 4 eight week 2020 spring outage.

Why is the project needed? What if we do nothing?

The current basket elements have been steadily deteriorating over the past several years. The causes for this deterioration are corrosion and soot blowing. The life expectancy of the hot-side elements is approximately ten (10) years and the life expectancy of the cold-side enamel-coated elements is approximately six (6) years. The hot-side elements will be sixteen (16) and the cold-side elements will be eight (8) years old in 2020.

If this project is not completed during the 2019 outage, continued degradation of the hot-end and cold-end baskets will occur. Forced outages to clean the Air Heaters and possible derates associated with air heater pluggage or lost performance will occur and increase with frequency the longer the Unit operates with the existing basket elements and seals. The Unit's heat rate and efficiency will worsen as the elements degradation continues.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	1,386	1,004	-	-	2,390
2. Cost of Removal Proposed		98	-	-	98
3. Total Capital and Removal Proposed (1+2)	1,386	1,102	-	-	2,488
4. Capital Investment 2019 BP	1,496	900	-	-	2,396
5. Cost of Removal 2019 BP	-	98	-	-	98
6. Total Capital and Removal 2019 BP (4+5)	1,496	998	-	-	2,494
7. Capital Investment variance to BP (4-1)	110	(104)	-	-	6
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	110	(104)	-	-	6

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)	-	-	-	-	-

This project is included in the 2019BP with a total budget of $2,494k. The expected total cost is $2,488k. The material and labor have been competitively bid as part of separate fleet-wide RFQs. The material cost is $1,519k and the labor is $608k. Burdens are estimated to be $243k. Contingency (5%) is $118k and will cover any unknown conditions within the Air Heater once the work begins that would be directly related to the scope of the Project. The labor will be awarded as lump-sum and any additional work discovered during the Project will be completed on a T&M basis.

Risks

- If this project is not completed, the existing air heater baskets will continue to deteriorate causing increased pressure differentials, overall performance loss and potential forced outages to clean the air heater baskets and hoppers.
- This project is utilizing proven equipment and technology.
- This project has been reviewed and approved by Environmental Affairs.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $2,849

2. Alternative #1: Do Nothing NPVRR: ($000s) $5,391
   This alternative should not be chosen because the existing hot-end and cold-end Air Heater baskets are beyond their expected life and have exhibited signs of damage for several years. Heat rate impacts were not accounted for in the model. If nothing is done, forced outages, derates, and loss of efficiency will result at an increasing rate for every year that action is not taken.

3. Alternative #2: Replace with [redacted] Baskets NPVRR: ($000s) $3,097
   This alternative should not be chosen based on previous experience with [redacted] basket elements. The plant installed a sector of [redacted] baskets in 2011 as a test and had to replace them with [redacted] baskets within a year due to constant plugging and the resulting loss of air flow and efficiency.

4. Alternative #3: Delay to 2021 NPVRR: ($000s) $3,351
   This alternative should not be chosen because the existing hot-end and cold-end Air Heater baskets are beyond their expected life and have exhibited signs of damage for several years. This alternative will require additional labor and material costs due to the shortened outage window and the delayed procurement of the basket elements.

Conclusions and Recommendation

Approval of the GH4 AH Basket Replacement 2020 project is recommended for $2,488k to minimize the potential of derates, forced outages, and loss of heat rate due to poor Air Heater performance caused by further degradation of basket elements and seals.

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: 3/27/19

Project Name: MC 3 Generator Stator Bars (Installation)

Total Capital Expenditures: $2,973k (Including $229k of contingency)

Total O&M: $0k

Project Number(s): 142399

Business Unit/Line of Business: Power Generation/ Mill Creek Station

Prepared/Presented By: Paul Hunter/Joe Didelot

Brief Description of Project

Mill Creek Unit 3 is equipped with a [redacted] water-cooled generator that went into service in 1978. Authority is being requested to install new stator bars in the MC3 generator. The bars were purchased from [redacted] in 2013.

[redacted] introduced water-cooled generator windings in the early 1960's and has approximately 500 units of this type in service worldwide. In May 1991, [redacted] issued a service bulletin, TIL-1098, which identified several types of cooling system leaks within these units. The leaks defined in the TIL ranged from simple copper plumbing leaks to stator bar clip-to-strand connection leaks. The stator bar clip-to-strand leak is of greatest concern as it will allow water to migrate between a bar and its ground wall insulation. Bar insulation that is wet will age much faster and eventually lead to an electrical stator bar failure resulting in a forced unit outage.

The bars were purchased in 2013 with the intent to have a spare set of stator bars onsite in case of failure since it is a long lead time item. Since [redacted] predicts a high probablility of a bar failure, it was determined the next scheduled eight week outage was the optimal time to install the new bars.

The scope for this project includes opening, cleaning, closing the generator, inspecting and testing the generator field, and replacing the existing stator bars with the new stator bars purchased in 2013.

Key Milestones:

Unit Offline	10/4/19
Mechanical Completion	11/28/19
Unit Online	11/30/19

Why is the project needed? What if we do nothing?

Of the cooling system leaks identified in the [redacted] bulletin, clip-to-strand leaks present the highest risk as this type of leak allows water to migrate between a bar and its associated ground wall insulation. The wet insulation ages faster, leading to electrical stator bar failures necessitating a stator rewind.

The failure mechanism for a clip-to-strand leak is crevice corrosion and occurs when the water chemistry of the stator bar clip area attacks the copper and braze alloy (phosphorus) of the clip-to-strand joint. Crevice corrosion is occurring in all [redacted] water-cooled generator stator bars manufactured before 2005. In 2006, [redacted] developed a stator bar clip with phosphorus free braze.

There is no accurate method to predict the development of a stator bar leak. However, [redacted] world-wide experience and the previous stator bar leaks within the LG&E/KU fleet emphasize the level of risk associated with operating water cooled stators. A leak is an unavoidable occurrence at some point in the life of the water cooled stator resulting in a forced unit outage.

Due to the age of the generator, industry experience, and leaks experienced across the industry and the LG&E/KU fleet it is recommended to install new stator bars on Mill Creek 3.

Budget Comparison & Financial Summary

The stator bar bid was part of the larger major turbine overhaul bid. Below is the cost summary of the major overhaul bids:

	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

The total cost for the stator bar project from the low bidder [redacted]

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	2,477				2,477
2. Cost of Removal Proposed	496				496
3. Total Capital and Removal Proposed (1+2)	2,973	-	-	-	2,973
4. Capital Investment 2019 BP	2,477				2,477
5. Cost of Removal 2019 BP	496				496
6. Total Capital and Removal 2019 BP (4+5)	2,973	-	-	-	2,973
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)	-	-	-	-	-

Risks
There is no accurate method to predict the development of a stator bar leak. However, [redacted] world-wide experience and the previous stator bar leaks within the LG&E/KU fleet emphasize the level of risk associated with operating water cooled stators. The risks associated with the alternatives presented are increased possibilities of unplanned outages due to stator bar failures.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $3,476
2. Do Nothing: NPVRR: ($000s) $15,920
   The risk involved with do nothing is having a wet bar and having to install the stator bars during an eight week forced outage.
3. Delay until next 8-week outage: NPVRR: ($000s) $5,027
   This risk involved with delaying until the next scheduled 8 week outage (2027) is having an 8 week forced outage for wet bars. Both the Do Nothing and Delay alternatives assume a 10% probability of developing a wet bar, with the probability increasing 3% per year.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the MC 3 Generator Stator Bars (Installation) project for $[redacted]to maintain reliability.

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: March 27, 2019

Project Name: MC 854G Dozer #1 Replacement

Total Capital Expenditures: $2,198k

Total O&M Expenditures: $0k

Project Number(s): 132976

Business Unit/Line of Business: Power Generation / Mill Creek

Prepared/Presented By: Don Van Winkle / Joe Didelot

Brief Description of Project

This project is to replace the current [redacted] 854G dozer with a new [redacted] 854K, incorporating a trade-in credit of $110k. The 854K dozer has 904 gross horsepower with a 58 cubic yard blade and has the most recent EPA emission requirements (Tier 4). The scope includes dozer setup and operator training for the Mill Creek coal handling personnel. This dozer purchase will increase the reliability of Mill Creek coal handling operations. This project is included in the 2019 Business Plan for $2,200k. The project cost is $2,198k. No contingency is included due to firm fixed price and sales tax credits associated with Tier 4 equipment.

Key milestone dates are:

Purchase Award	April 10, 2019
Dozer Delivery	September 1, 2019

Why is the project needed? What if we do nothing?

To ensure the continued reliability of the coal handling equipment fleet and the ultimate reliability of plant operation, the Mill Creek Station requests to purchase a new [redacted] 854K Wheel dozer. Mill Creek currently utilizes two [redacted] 854G's to support coal unloading, coal reclaim, and coal pile construction/compaction operations. This project will replace the #1 dozer which was purchased in 2002 and has exceeded its recommended service life of 18,000 hours by 25%. The size of the coal pile, the 3.8 million ton annual burn rate, and the variety of unloading and operational functions necessitates the reliable use of at least two large dozers. This project will help ensure two functioning dozers to maintain reliability as the dozers are critical for sustaining proper coal pile construction, compaction and fugitive dust control at the plant.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	$2,308	-	-	-	$2,308
2. Cost of Removal Proposed	($110)	-	-	-	($110)
3. Total Capital and Removal Proposed (1+2)	$2,198	-	-	-	$2,198
4. Capital Investment 2019 BP	$2,200	-	-	-	$2,200
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	$2,200	-	-	-	$2,200
7. Capital Investment variance to BP (4-1)	($108)	-	-	-	($108)
8. Cost of Removal variance to BP (5-2)	$110	-	-	-	$110
9. Total Capital and Removal variance to BP (6-3)	$2	-	-	-	$2

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)	-	-	-	-	-

Risks

The primary risk is a major component failure that renders the 854G dozer unavailable for an extended period. The secondary risk is rapidly escalating cost and difficulties for the station to maintain the dozer due to age. The station requires the use of two dozers, so the sole reliance on one station dozer is not a viable option. Long term use of a rental dozer would be required if a dozer failure occurred. There is no project risk as the price is fixed.

Alternatives Considered

1. **Recommendation**
   Purchase New 854K NPVRR: $2,665k
   Purchase new [redacted] 854K Dozer at a cost of $2,198k (total cost of $2,256k - $110k (credit for the 854G) + burdens ($52k at current rate of 2.4%)). New purchase provides maximum long-term value by improving availability and performance. [redacted] has offered the extended 48 month/7,000 hour [redacted] warranty. Project is being submitted with tax included in the cost, however commercial is exploring potential tax credits associated with Tier 4 equipment.

2. **Alternative #1**
   [redacted] **Certified Rebuild of Existing Dozer** NPVRR: $3,069k
   This option would include completely new critical components (motor, transmission, cab, etc.) except for frame. Any frame repairs would be an additional expense. In March 2018 a rebuild cost of $1,748k (inclusive of taxes and burdens) was provided, and has been increased by 3% for 2019 dollars. Under a rebuild condition, any issues

discovered during the rebuild would incur additional cost, and the rebuild does not include any replacement or major repairs to the front and rear frames. Due to the uncertainty of additional repairs, 15% contingency is included in the CEM. The rebuild would take 3-4 months in which two D8 dozers would need to be rented at a cost of $50k/month plus additional labor to operate the equipment at $19k/month. Also, the upgrade would not include updating to EPA Tier 4 standards. The rebuilt machine would come with a 12 month warranty and incremental maintenance costs starting at $25k/year escalated over 10 years.

3. **Alternative #2**
   Postpone Project NPVRR: $3,307k
   This is not a viable long-term option due to the age and condition of the current dozer. Intermittent major component failure on the existing dozer would occur at increasing annual costs. The CEM assumes the rental of two D8 dozers for two months/year at a total cost of $100k/year. Maintenance costs are included at $50k/year and additional labor is also included at $38k/year. O&M costs are escalated at 3% each year. Continued use at the current duty cycle will significantly shorten any remaining lifespan of the 854G and hasten the need for a complete rebuild or new machine. Imminent risk of major failure is projected in the next three years. CEM model shows a rebuild cost in 2022 at $1,800k (2019 dollars) escalated 3% each year = $1,967k + 15% contingency for reasons listed above = $2,262k.

4. **Purchase Alternate Dozer** NPVRR: N/A
   Purchasing an alternate Make/Model dozer was not considered in the Capital Evaluation Model. The equipment specifications were competitively bid with no comparable equipment available. The key requirement is the equipment must be a wheeled dozer versus a track dozer, in which no competitors offer the size similar to the existing dozer. The wheels provide superior compaction of the coal pile which minimizes fugitive dust and erosion.

Conclusion and Recommendation

It is recommended that the Investment Committee approve the Mill Creek 854G dozer #1 replacement project for $2,198k to maintain reliable and cost effective coal handling operations at the station.

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: 3/27/2019

Project Name: Mill Creek 2 Lower Slope

Total Capital Expenditures: $3,186k (Including $150k of contingency)

Total O&M: $0k

Project Number(s): 147056

Business Unit/Line of Business: Power Generation

Prepared/Presented By: Michael Kjelby / Joe Didelot

Brief Description of Project

This project is to mitigate boiler tube failures (BTF's) on Mill Creek Unit 2 (MC2) lower slope due to sliding ash erosion, thermal fatigue, and deformation caused by falling slag impacts. The project will replace the front and rear lower slope panels with thicker tubing and include nickel/chrome overlay to the areas of highest wear. The weld overlay will mitigate the effects of sliding ash erosion on the tubes and increased wall thickness will provide protection against falling slag impacts.

Milestones:

Labor Bids Received	September 2018
Material Bids Received	March 2019
Project Approved	April 2019
Material PO Issued	April 2019
Material Delivery	February 2020
Installation	March 2020

Total cost of the project is $3,186k with $150k contingency included. The project is included in the 2019 Business Plan at $870k for material in 2019 and $1,898k in 2020. The project is seeking $418k additional funding in 2020 than originally budgeted. The increase is due to higher than anticipated labor bids, increased tubing costs, and the inclusion of beams to support furnace scaffolding.

Project 151578 MC2 Air Tips will fund $243k. The remaining $175k will be funded from project 154379 MC1 & MC2 PM Probe.

Why is the project needed? What if we do nothing?

MC2 is a Combustion Engineering boiler placed into commercial service in 1973. The lower slope, excluding the corner panels, was replaced in 1999 with 0.195" minimum wall thickness (MWT) tubes in place of the original 0.188" MWT tubes. The existing slope has been deformed from years of falling slag and thinned by erosion, causing multiple leaks.

Inspections of the lower slopes have been conducted during maintenance outages. Each inspection has identified new gouges in the tubes that have been repaired with pad welds and dutchmen. A 2016 inspection revealed sliding ash erosion damage on the outer most tubes of each slope, with tubes eroded to 0.085” wall thickness on each slope (44% of MWT).

This project will eliminate previous damage and field repairs made to the slope. The weld overlay on the outer tubes will increase the slope’s resistance to sliding ash erosion. Leaving the slope in its current condition will increase unit EFOR due to BTF’s.

Budget Comparison & Financial Summary.

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	870	2,118			2,988
2. Cost of Removal Proposed		198			198
3. Total Capital and Removal Proposed (1+2)	870	2,316	-	-	3,186
4. Capital Investment 2019 BP	870	1,700			2,570
5. Cost of Removal 2019 BP		198			198
6. Total Capital and Removal 2019 BP (4+5)	870	1,898	-	-	2,768
7. Capital Investment variance to BP (4-1)	-	(418)	-	-	(418)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	(418)	-	-	(418)

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)	-	-	-	-	-

Contingency for the project is $150k, 5% of the estimated expenses for the project. Bid information is included in Appendix A.

Risks

Not completing this project will increase EFOR due to BTF’s. Forced outage repairs will be more frequent and require more time to complete. Deferral of this project will impact the feasibility of future projects within the boiler, since work overhead of the slope will need to be restricted. Suspension of other boiler projects will also cause an increase in BTF’s and unit EFOR.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $3,570
2. Next Best Alternative: NPVRR: ($000s) $3,603
    - The Next Best Alternative is delaying the project until 2022
    - Inflation of 2% a year is considered.
3. Do Nothing: NPVRR: ($000s) $3,798
    - The Do Nothing alternative is not completing this project.

- In the Next Best Alternative and Do Nothing options, it is assumed that each tube leak on the lower slope will cause an outage forty-eight (48) hours long. It is assumed that two tube leaks per year will occur on the lower slope starting in 2020, then the number of tube leak per year will increase in 2021 and 2024.

The Spring 2020 outage is the most ideal timeframe to complete this project since the outage is six weeks and no other boiler work is scheduled to be completed overhead of the slope. The Do Nothing alternative would allow continued BTF's.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the Mill Creek 2 Lower Slope project for $3,186k to ensure continued, reliable operation of the Mill Creek 2 boiler.

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	

Appendix A

The labor to replace the lower slope was bid in September of 2018. Bids were received [redacted]. The three lowest bids are shown in the table below. The proposed project cost of [redacted] is based on the price from [redacted], the second lowest bidder. [redacted] will not be considered for the this project due to historically poor performances during boiler work at Mill Creek and the lack of acceptable supervision for projects.

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

The material bids for the lower slope material were received in March of 2019. Bids were requested from [redacted] did not submit a bid. [redacted] was the lowest bid for the base scope of an in kind replacement, but an options for larger outside diameter (OD) tubes was not provided. A request was issued to [redacted] for a bid with an option with larger OD tube, the new bid is due on March 20th 201 and the bids will be evaluated at that time. The panels on the corner of each slope will be sole sourced to the OEM, [redacted] due to the complex geometry of the tubes in the area.

Investment and Contract Proposal for Investment Committee Meeting on: 4/24/2019

Project Name(s): GH1 Cooling Tower Complete Rebuild & GH4 Cooling Tower Complete Rebuild
Contract Name (Good/Service): GH1 and GH4 Cooling Tower Replacements 2020-2021

Selected Vendor(s): [redacted]

Contract Authorization Requested: $19,841k (Including $945k or 5% contingency)

Contract Term: May 2019 through September 2021

Total Capital Expenditures Requested: $23,547k (Including $1,282k of contingency)

Project Number(s): 121GH & 220GH
Business Unit/Line of Business: Generation

Prepared/Presented By: Jared Kelley & Steven Straight/Steven Turner

Brief Contract/Project Description

These projects are for the complete rebuilds of the Ghent Unit 1 and Ghent Unit 4 Cooling Towers (CTs). The scope of these projects includes the design, engineering, fabrication, procurement, demolition, disposal, construction, and performance testing required to replace the entire Unit 1 and Unit 4 CTs. In addition to the full replacement of the towers, the circulating water distribution piping of both CTs will be re-located from the top of the cooling tower to the ground, decreasing the weight supported by the structure. These projects will emulate the Ghent Unit 3 complete rebuild project which was successfully installed by [redacted] during the 2018 fall outage.

The request for proposal (RFP) was issued to four (4) contractors specializing in this type of work: [redacted] A pre-bid meeting was conducted on December 12, 2018. [redacted]

In addition to pricing, proposals were evaluated based on technical approach, proposed warranty, liquidated damages, conformity to the scope of work, proposed material suitability, relevant experience, commercial terms, and safety. Overall, [redacted] was found to have the preferable bid based on input from the Commercial, Maintenance, Operations, and Planning Departments. The [redacted] proposal is technically and commercially acceptable. It includes significant schedule and performance liquidated damages to be verified by third party performance testing, as well as a fifteen (15) year material and workmanship warranty on the structure and a five (5) year material and workmanship warranty on the mechanical equipment.

Why is the project needed? What if we do nothing?

The cooling towers are inspected annually during the outage and areas of concern are noted and corrected to ensure the reliable operation of the cooling tower for the next year. Typically the cooling tower fill material, which occupies a majority of the internal volume of the tower, is not removed and the inspection focuses on the external and mechanical areas. Following the collapse of cell 4-1 in 2013 and cells 4-2 and 4-3 of the Unit 4 cooling tower during the summer of 2016, a thorough inspection of the Unit 3 cooling tower was conducted, which revealed 54 structural columns that had split at the corners and failed throughout the 8 fiberglass cells.

Since the collapse of several cells on the Unit 4 cooling tower and the discovery of the split structural posts on the previous Unit 3 cooling tower, the plant has conducted a thorough inspection and removed fill material from cells in order to inspect the columns which typically cannot be seen. The thorough inspections have spotlighted the poor condition of the existing structures. This resulted in a revision to the station's cooling tower replacement strategy from individual cell replacements, to more comprehensive rebuild projects. The rebuild projects include the mechanical and piping components and electrical upgrades with the installation of variable frequency drives (VFDs) to control fan speed.

These projects include demolition and disposal of the entire existing cooling tower down to the concrete basin, installation of a new cooling tower structure, new mechanical equipment, re-routing the large distribution piping from the top of the structure to ground elevation, new electrical and control cables, VFDs for the fan motors, and third party testing of the new tower's thermal performance. These projects must be completed during major turbine-generator outages due to the schedule requirements and therefore cannot be delayed without greatly increasing the risk associated with the existing CTs. Comprehensive rebuild projects, matching the successful project for Ghent Unit 3 in 2018, will help prevent future structural failures resulting in forced outages, and ensure plant personnel remain safe while near or in the cooling tower.

Contract Bid Summary

The request for proposal (RFP) was issued to four (4) contractors specializing in this type of work: [redacted] A pre-bid meeting was conducted on December 12, 2018. [redacted]

In addition to pricing, proposals were evaluated based on technical approach, proposed warranty terms, schedule and performance liquidated damages (LDs), conformity to the scope of work, proposed material suitability, experience, relevant references, commercial terms, and safety. Overall, [redacted] was found to have the preferable bid based on input from the Commercial, Maintenance, Operations, and Planning Departments. [redacted] proposal includes significant schedule LDs, acceptable performance LDs which will be verified by third party performance testing, materials that match the recently re-built Unit 3 cooling tower completed by [redacted] a fifteen (15) year material and workmanship warranty on the structure and a five year material and workmanship warranty on the mechanical equipment.

[redacted] lowest cost proposal was eliminated due to the major areas of concern listed below:

- [redacted] execution plan combined with their proposed man-hours (see table below) raise concerns regarding their ability to successfully complete the work in the scheduled outage, their ability to safely perform the work, and the increased risk of submitted change orders to complete the work. [redacted] execution plan for Unit 1 includes stick building large portions of the structure, rather than the pre-built bent building method [redacted] used on Unit 3 in 2018 and is proposing for Units 1 and 4. Stick building the tower will require more labor than the pre-built bent method, which is not consistent with their proposal. A normalization of this labor disparity is shown in the table below.
- [redacted] did not include any site preparation work or costs in their proposals.
- References supplied by [redacted] have experienced structural vibration and performance issues following rebuilds completed by [redacted] Two of the three references stated that the [redacted] towers did not meet their performance guarantees.
- Only one of the reference cooling tower rebuilds provided by [redacted] was a complete rebuild which included the replacement of the entire structure and all associated mechanical equipment.
- [redacted] did not include the required dedicated safety person in their proposal.
- [redacted] cannot provide the requested full access to the fan gear reducers to ensure maintenance access and personnel safety.
- [redacted] proposal for Unit 1 would result in an addition of approximately 7 feet of pump head, 3 more feet than the [redacted] tower.
- [redacted] proposed schedule LDs of $20k per day are half of [redacted]s proposed LDs.

Pricing Sheet		Enexio US LLC			EvapTech Inc.		
Item #	Item Description						
1	GH4 Labor & Equipment	1	EA	$ [redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	TOTAL BASE BID			**$** [redacted]			**$** [redacted]
7	**Man-Hours to Complete Rebuild of Unit 4 (N2)**	[redacted]			[redacted]		
8	**Man-Hours to Complete Rebuild of Unit 1 (N2)**	[redacted]			[redacted]		
9	**Labor Normalization Based on Man-Hour Differential (N3)**	$ [redacted]			$ -		
Total Normalized Bid		$ [redacted]			$ [redacted]		
Notes		N1. [redacted] 2017 contract amount for the Unit 3 rebuild minus all electrical scope items was a total of [redacted] less than their current Unit 4 proposal. N2. [redacted] provided man-hour estimates favorably compare to the actual man-hours [redacted]equired for the Ghent Unit 3 rebuild that they performed. [redacted] provided man-hours are concerning when compared to the aforementioned Unit 3 rebuild. N3. [redacted] provided T&M labor rate average [redacted] The most common daily subsistence rate is $106.00/day. By assuming ten hour work days, the calculated comprehensive average hourly rate is [redacted]. In taking the difference between the provided man-hours for each unit and multiplying it by the comprehensive average price/hr., a conservative estimate can be calculated for the potential labor cost differential.					

Contract Financial Summary

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted],841

The ‘GH1 and GH4 Cooling Tower Replacements – 2020-2021’ contract is covered under two projects found in the current business plan. The allocated totals found in the business plan for GH1 and GH4 are $10,723k and $11,536k, respectively. The contract cost is $8,997k for GH1 and $9,899k for GH4. The recommended contingency value is five percent (5%) of the total contract value, or $945k. This contingency is based upon previous experience with [redacted] Inc. on the ‘GH3 Cooling Tower Replacement – 2018’ project. The majority of the change orders incurred on the aforementioned project were related to the electrical portion of the Scope of Work, which has been removed from this project and will be bid separately. The Scope of Work reduction, combined with the previous experience performing similar work at the Ghent Generating Station, was used to calculate the requested contingency with reference to the total cost of the contract. The contract cost is firm, fixed pricing and does not require built-in escalators.

Project Financial Summary– GH4 (Project# 220GH)

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	1,976	8,996	-		10,972
2. Cost of Removal Proposed		989	-		989
3. Total Capital and Removal Proposed (1+2)	1,976	9,985	-	-	11,961
4. Capital Investment 2019 BP	1,436	9,111	-		10,547
5. Cost of Removal 2019 BP		989	-		989
6. Total Capital and Removal 2019 BP (4+5)	1,436	10,100	-	-	11,536
7. Capital Investment variance to BP (4-1)	(540)	115	-	-	(425)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(540)	115	-	-	(425)

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)	-	-	-	-	-

Project Financial Summary– GH1 (Project# 121GH)

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	-	2,188	8,899		11,087
2. Cost of Removal Proposed		-	499		499
3. Total Capital and Removal Proposed (1+2)	-	2,188	9,398	-	11,586
4. Capital Investment 2019 BP	-	3,217	7,007		10,224
5. Cost of Removal 2019 BP		-	499		499
6. Total Capital and Removal 2019 BP (4+5)	-	3,217	7,506	-	10,723
7. Capital Investment variance to BP (4-1)	-	1,029	(1,892)	-	(863)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	1,029	(1,892)	-	(863)

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)	-	-	-	-	-

The amount required in 2019 for the Unit 4 cooling tower will be funded internally within the Ghent capital plan and reflected in the 3+9 RAC forecast. These projects are a high priority for long term reliability for the Ghent station, and as such, variances for both projects in 2020 and 2021 will be managed in the 2020BP prioritization process.

Risks – Common to Both GH4 and GH1

- The Credit Department has conducted a credit review and approved of conducting business with [redacted]
- Failure to completely rebuild the cooling towers will lead to increased operational, equipment and personnel safety risks. If a portion of the cooling tower structure fails it will result in at least a week long unplanned outage and large unforecasted O&M costs.
- A complete cooling tower rebuild can only be accomplished during an eight (8) week major turbine-generator outage due to the amount of work required. If the projects are delayed they will each have to be delayed by seven (7) years and the operational and safety risks will continue to increase.
- The rebuilt cooling towers will meet existing air permits regarding drift rates and will not require any changes to the existing air permit(s).
- These projects have been reviewed and approved by Environmental Affairs.

Project Alternatives Considered – GH4 (Project# 220GH)

1. Recommendation: [redacted] Award NPVRR: ($000s) 13,292
2. Alternative #1: Do Nothing NPVRR: ($000s) 17,982
   This alternative should not be chosen because the cooling tower has exhibited signs of damage throughout the structure and poses a risk to operations and personnel safety. If nothing is done the potential for catastrophic failure will increase.

3. Alternative #2: Delay to 2027 NPVRR: ($000s) 13,585
   This alternative should not be chosen because the cooling tower has exhibited signs of damage throughout the structure and recent inspections recommend replacement of several cells in the near future. This alternative would not address the known operations and personnel safety risks associated with the potential collapse of the structure.

Project Alternatives Considered – GH1 (Project# 121GH)

1. Recommendation: [redacted] Award NPVRR: ($000s) 12,899
2. Alternative #1: Do Nothing NPVRR: ($000s) 18,327
   This alternative should not be chosen because the cooling tower has exhibited signs of damage throughout the structure and poses a risk to operations and personnel safety. If nothing is done the potential for catastrophic failure will increase.
3. Alternative #2: Delay to 2028 Outage NPVRR: ($000s) 13,341
   This alternative should not be chosen because the cooling tower has exhibited signs of damage throughout the structure and recent inspections recommend replacement of several cells in the near future. This alternative would not address the known operations and personnel safety risks associated with the potential collapse of the structure.

Conclusions and Recommendation

Investment Committee approval of the GH1 Cooling Tower Complete Rebuild project for $11,586k and the GH4 Cooling Tower Complete Rebuild project for $11,961k is recommended to ensure long term reliability and safety of the Ghent 1 and Ghent 4 cooling towers. Additionally, approval is recommended for the GH1 and GH4 Cooling Tower Replacements 2020-2021 contract for [redacted]

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced:

The Capital project spending and contract authority requests included in this Investment Proposal have 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 the capital project and contract authority requests.

Kent W. Blake Date	Paul W. Thompson Date
Chief Financial Officer	Chairman, CEO and President

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
GH1 and GH4 Cooling Tower Replacement

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the GH1 and GH4 Cooling Tower Replacements 2020-2021 contract for [redacted]

Sourcing Leader		Proponent/Team Leader	
Supplier Diversity Manager		Manager	
Manager - Supply Chain or Commercial Operations		Director – Supply Chain or Commercial Operations	
Director		Vice President	

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Investment Proposal for Investment Committee Meeting on: May 29, 2019

Project Name: GH3 Waterwall Panel Repl 2019

Total Capital Expenditures: $2,127k (Approved on 07/05/2018)

Total O&M: $0k

Total Revised Capital Expenditures: $2,792k

Project Number(s): 151366

Business Unit/Line of Business: Power Generation

Prepared/Presented By: Benjamin Zeigler

Description of Incremental Ask

Original Approved Capital Expenditures		$2,127k
Revised Capital Expenditures Requested		$2,792k
Total Increase Requested		$665k

This project was originally approved on July 5th, 2018. At that time, the project cost was developed using budgetary estimates for labor that had been received from contractors. Recently, the installation labor for this project was formally bid with two other boiler projects that are to take place during the same outage. The execution of these projects will need to be awarded to a single contractor to minimize risk, as coordination of multiple boiler activities is crucial to mitigating safety risks. The recommended contractor has presented a very tactful and well developed plan to accomplish the scope of work. Although the labor cost from the recommended bidder resulted in an increase in this project, it is relevant to note that the contractor will also be replacing the GH3 center division panel during this outage. The cost of the center division panel replacement will be recovered via a settlement agreement with another contractor resulting from negligence during the fall 2018 outage. The selected contractor for this project is the low bidder for the center division panel replacement, making this a prudent selection.

The alternative of field-applied weld overlay is no longer a viable option, due to the emergent work to replace the center division panel. Field-applied weld overlay requires extensive surface preparation via grit blasting and has a high chromium content in the weld overlay metal. These two factors eliminate the possibility of other simultaneous work in the gas path. In addition, the potential safety and reliability benefits of replacing existing tubing with other defects will not be realized if field-applied weld overlay is employed.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	Pre-2019	2019	2020	Post 2020	Total
1. Capital Investment Proposed	198	2,080			2,278
2. Cost of Removal Proposed		514			514
3. Total Capital and Removal Proposed (1+2)	198	2,594	-	-	2,792
4. Capital Investment 2019 BP	200	1,675			1,875
5. Cost of Removal 2019 BP		252			252
6. Total Capital and Removal 2019 BP (4+5)	200	1,927	-	-	2,127
7. Capital Investment variance to BP (4-1)	2	(405)	-	-	(403)
8. Cost of Removal variance to BP (5-2)	-	(262)	-	-	(262)
9. Total Capital and Removal variance to BP (6-3)	2	(667)	-	-	(665)

Financial Detail by Year - O&M ($000s)	Pre-2019	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)	-	-	-	-	-

The incremental authority for this project will be funded by a reduction in project 158949, GH3 #3 Boiler Division Wall Rpl, resulting from the settlement agreement previously referenced in this document. The revised project total includes $94k of contingency (3.4% of total project). Contingency in the original approved project was $183k. None of this contingency has yet been spent, but higher than expected labor bids have required this project revision. The contingency identified with this revision is reasonable since firm pricing has been established for material and labor.

Conclusions and Recommendation

Investment Committee approval of the GH3 Waterwall Panel Repl project for $2,792k is recommended to prevent future forced outages and maintain unit availability.

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
Chief Financial Officer

Paul W. Thompson — Date
Chairman, CEO and President

Investment and Contract Proposal for Investment Committee Meeting on: June 26, 2019

Project Name: GH1 Reheat Pendant Assy Repl
Contract Name (Good/Service): GH1 Reheat Pendant and Left Reheat Outlet Header Replacement

Selected Vendor(s): [redacted]

Contract Authorization Requested: $6,631k (Including $603k of contingency)

Contract Term: Three years (2019, 2020, and 2021)

Total Capital Expenditures Requested: $12,749k (Including $1,032k of contingency and $32k of internal labor)

Total O&M: $ 0k

Project Number(s): 131978
Business Unit/Line of Business: Power Generation

Prepared/Presented By: Benjamin Zeigler / Brenton Motley

Brief Contract/Project Description

The scope of this project is replacement of the GH1 front and rear reheat pendants as well as the left reheat outlet header. Replacing these components will achieve the goals of replacing existing tubing which is approaching its end of life, mitigating heavy slag accumulation in this portion of the GH1 reheater, and replace an original seam welded high temperature header with a new seamless header. Routine boiler inspection has revealed significant tube wall loss in the existing pendant tubing as a result of erosion and corrosion associated with boiler slag. Slag accumulation in this area is due to gas lane spacing between assemblies which were originally designed for specific fuel characteristics which have changed over time. This slag results in carburization on the tube surface and requires increased sootblower activity to remove. Both of these are mechanisms that cause tube failures in this area. The left reheat outlet header is original and is fabricated from seamed piping. These seam welds are known to experience creep damage over time and eventually fail. The right reheat outlet header was replaced on a prior project; replacing the left one reduces the risk of creep-related seam weld failures. The new reheater pendants will be redesigned to allow for wider gas lane spacing near the bottom of the front pendants. This new design will not affect boiler efficiency, but will decrease the potential for slag accumulation in this area. This project scope also includes provisions for weld overlay on the bottom portion of the pendants to protect the tubing against the corrosive environment. These measures will ensure continued reliability of the GH1 boiler. The economical useful life of this project is an estimated 30 years.

Funding for the project was included in the 2019 Business Plan, and has been revised for the current amount in the current RAC approved forecast and proposed 2020 Business Plan. The project funding request is based on a firm proposal for materials, as well as two budgetary estimates for installation labor. The larger of these estimates was used for funding development, although the two estimates were within 5% of each other.

This Contract schedule spans three years (2019, 2020, and 2021) due to engineering and manufacturing lead time. All new tubing assemblies are planned for delivery in February 2021 and installation during the GH1 2021 spring outage. The amount requested for this Contract Proposal is $6,631k (inclusive of $603k contingency). The Contract includes a milestone payment structure with net 30 payment. The Contract Proposal request is a sole source purchase to be awarded to [redacted], the OEM supplier, who has previously performed a redesign on this scale for Ghent Station. The general premise of this recommendation is to increase reliability of the existing GH1 boiler design. The contract includes liquidated damages for delayed delivery of materials as well as failure to achieve defined performance targets.

Why is the project needed? What if we do nothing?

This project is necessary to prevent future tube failures in the area of the GH1 reheater. When slag accumulates in this area, it bridges between assemblies and fills the cavity directly above the nose arch. Sootblowers are used to clean this area but are not always effective. Excessive sootblower activity causes wear on the tubing. The sulfur and chlorine content in the fuel add to the corrosion potential of the slag that is in contact with the tube surface. It is difficult and expensive to gain access to this area of the boiler, which limits ability to inspect the reheat pendants. Upon inspection during the GH1 spring 2019 outage, tubing was found with only 30% remaining wall thickness. Although local repairs were completed, this is evidence of the corrosion and erosion damage in the GH1 reheater. If this project is not completed, such damage will continue, and the risk of tube failures will increase.

Contract Bid Summary

The KU Ghent engineering team considered sourcing components from competing major boiler suppliers. Ultimately it was decided that a design with components procured from [redacted] provided significant advantages and reduced the risks associated with designs from non-OEM suppliers. As the OEM, [redacted] owns the original design for the Unit 1 boiler and has previously demonstrated capabilities to accurately design and model revisions to major boiler components, giving KU confidence to pursue this project with [redacted]. Utilizing [redacted] design will minimize unplanned outages due to boiler tube failures. Choosing an alternative supplier would introduce significant risks to this project. Failure to meet original boiler performance criteria could cause loss of efficiency, and risk equipment damage and ultimately unit derates.

The total firm fixed contract value for the recommended Sole Source Agreement is $6,631k (inclusive of a 10% ($603k) contingency) and covers the material purchase, design, engineering, manufacture, and delivery of the front and rear pendant reheater and left reheat outlet header for GH1. Material delivery is required by February 2021. Contingency is included to cover any unforeseen costs during the execution of the contract. The contract will be governed by the prevailing General Services Agreement (GSA) with [redacted] signed December 10, 2010, now a wholly owned subsidiary of [redacted] [redacted] proposal meets all technical and schedule expectations presented for the GH1 reheater redesign, and includes liquidated damages for delayed delivery of materials as well as failure to achieve defined performance targets. [redacted] will provide a three year warranty provision for all purchased material.

Contract Financial Summary

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

This Contract schedule spans three years (2019, 2020, and 2021) due to engineering requirements and manufacturing lead-time. To meet a spring 2021 outage schedule, the OEM requires an 86-week lead-time to complete delivery by February 2021. Funding for the contract is $6,631k (inclusive of $603k contingency). The project is included in the RAC approved forecast with a total of $1,111k (including material burdens) in 2019, and is in the proposed 2020BP with a total of $4,516k in 2020 and $7,122k in 2021.

Project Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	1,111	4,516	4,777		10,404
2. Cost of Removal Proposed			2,345		2,345
3. Total Capital and Removal Proposed (1+2)	1,111	4,516	7,122	-	12,749
4. Capital Investment 2019 BP	459	4,176	3,733		8,368
5. Cost of Removal 2019 BP			823		823
6. Total Capital and Removal 2019 BP (4+5)	459	4,176	4,556	-	9,191
7. Capital Investment variance to BP (4-1)	(652)	(340)	(1,044)	-	(2,036)
8. Cost of Removal variance to BP (5-2)	-	-	(1,522)	-	(1,522)
9. Total Capital and Removal variance to BP (6-3)	(652)	(340)	(2,566)	-	(3,558)

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)	-	-	-	-	-

Previous estimates for this project were based on a like-kind design of the reheat pendants. The proposed project cost includes a redesign to address the slagging issues as described above as well as the addition of corrosion resistant weld overlay to address fireside corrosion. The incremental cost of the weld overlay is estimated to be $2,500k. The project total includes $1,032k of contingency, which is approximately 10% of the raw project costs.

Risks
If this project is not completed or delayed, the risk of unplanned outages increase significantly due to the present corrosion and the rate that the tube thickness lessens. Environmental Affairs has reviewed and approved this project.

Project Alternatives Considered

1. Recommendation: Replace GH1 reheater in 2021 NPVRR: ($000s) $13,844

2. Alternative #1: Delay project until 2028 NPVRR: ($000s) $15,392
   This alternative explores the option of delaying the project to the next planned outage of sufficient length to complete the work. The cost evaluation model assumes 3% inflation for this option. From 2019 to 2021, the model assumes an increasing probability of a single tube failure that requires 4 days to repair. Beginning in 2021, it is assumed that the degraded condition of the equipment results in increasingly more forced outages each year until replacement.

3. Alternative #2: Do nothing NPVRR: ($000s) $26,562
   If this project is not completed, the probability of a four day forced outage increases as time progresses. Beginning in 2021, it is assumed that the degraded condition of the equipment results in increasingly more forced outages each year. Alternatives #2 and #3 both assume $130k for startup costs and $50k to repair a tube failure in this area. The model also assumes a one-time O&M cost in 2023 of $400k to make partial repairs that will mitigate immediate risk.

Conclusions and Recommendation

Investment Committee approval of the GH1 Reheat Pendant Assy Repl project for $12,749k as well as the GH1 Reheat Pendant and Left Reheat Outlet Header Replacement contract to [redacted] Steam Power for $6,631k is recommended to prevent future forced outages and maintain unit availability.

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced:

The Capital project spending and contract authority requests included in this Investment Proposal have 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 the capital project and contract authority requests.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
GH1 Reheat Pendant and Left Reheat Outlet Header Replacement

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the GH1 Reheat Pendant and Left Reheat Outlet Header Replacement contract for [redacted]

Sourcing Leader		Proponent	
Supplier Diversity Manager	N/A	Manager	
Manager - Commercial Operations		Director –Commercial Operations	
General Manager		Vice President	

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Investment Proposal for Investment Committee Meeting on: June 26, 2019

Project Name: GH2 CT Cell Rebuilds 2019

Total Capital Expenditures: $2,844k (Including $259k of contingency)

Total O&M: $0k

Project Number(s): 159105

Business Unit/Line of Business: Generation

Prepared/Presented By: Stephen Nix/Steve Turner

Brief Description of Project

This project is to structurally rebuild four (4) Ghent Unit 2 cooling tower cells during the 2019 fall outage. The inspection of these cells in December 2018 found these remaining wood cells to be in poor condition with structural weaknesses and signs of deterioration that require immediate attention. Replacement of the wood structure was recommended as soon as possible. The wood structure is to be replaced with polyester fiberglass. Major mechanical and electrical components including the fan blades and fan stacks will be reused.

The original treated Douglas Fir cooling tower went into service in 1977. These four cells were previously rebuilt as like-kind with wood in 2003 and 2004. The other eight (8) cells were rebuilt with fiberglass structural components in the months following the 2008 partial collapse.

Material and installation for this project was competitively bid and will be awarded as a firm fixed price contract to [redacted] for $2,486k. The total cost for this project including other expenses, burdens and contingency is $2,844k. As this project is emergent based on recent findings, funding was not in the 2019BP. However, funding of $2,000k was approved by the RAC in the 1+11 forecast, and an additional $844k is included in the 5+7 RAC forecast.

Why is the project needed? What if we do nothing?

The 2018 inspection revealed that the top deck has become weak and personnel access has been restricted to a grated walk path. Drift eliminators have fouled with mud, delaminated and become brittle. Fan mechanicals are in need of realignment. Fill support members have rolled and some fill has collapsed. As a result, multiple bays of fill have been removed to relieve stress. Approximately 90% of the wetted structure was estimated to have rotted members. There is concern that further deterioration or a strong wind could cause a failure event similar to the one in 2008 when the south side of five (5) cells collapsed. Collapse of part or all of the Unit 2 cooling tower would result in a loss of all generation from Ghent 2 until repairs could be made. It also presents a safety risk to employees and contractors working in the area.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed *	2,161				2,161
2. Cost of Removal Proposed	683				683
3. Total Capital and Removal Proposed (1+2)	2,844	-	-	-	2,844
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)	(2,161)	-	-	-	(2,161)
8. Cost of Removal variance to BP (5-2)	(683)	-	-	-	(683)
9. Total Capital and Removal variance to BP (6-3)	(2,844)	-	-	-	(2,844)

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)	-	-	-	-	-

*The total project cost includes 10% contingency, which is included in the financial summary above.

Risks

The risks include forced outages of one (1) week if cells collapse before the unit can be returned to service in a derated capacity. Emergency costs for rebuilds are more than the capital cost of scheduled cell rebuilds and include collateral damage to adjacent cells. Operating personnel and contractors are at risk if working around the cooling tower.

Alternatives Considered

1. Recommendation: Rebuild Four (4) Cells NPVRR: ($000s) $3,325

   This Recommendation to Rebuild Four (4) Cells has the lowest NPVRR of the alternatives considered.

2. Alternative #1: Do Nothing NPVRR: ($000s) $4,685

   Do Nothing evaluates the risk of a forced outage and the risks of emergency rebuild costs each year that the project is not performed until the budgeted rebuild occurs in the year 2026. This alternative should not be chosen because these four (4) cells in the Unit 2 cooling tower have exhibited signs of damage throughout the structure.

3. Alternative #2: Rebuild Cell by Cell NPVRR: ($000s) $4,336

   Rebuild Cell by Cell evaluates rebuilding one cell each year starting in the fall of 2019. The capital costs of the planned yearly cell rebuilds plus the risk of forced outages and the risk of emergency rebuild costs each year were included in the cost analysis. This alternative should not be chosen because these four (4) cells in the Unit 2 cooling tower have exhibited signs of damage throughout the structure. The uncompleted structure may still collapse due to the slower pace of rebuilds. The total capital costs of individual rebuilds are greater than capital cost for the recommended project.

Assumptions:

- All historical and projected costs were adjusted 2%/year for inflation.
- The collapse of part of any wood cell would trigger emergency replacement of all wood cells due to the shock on the weakened structure and causes collateral damage to an adjacent fiberglass cell.
- Unavailability is for one (1) week after a collapse while temporary measures restore partial circulating water flow. Derates continue for the following weeks and diminish as rebuilt cells are put into service.
- Probability of collapse is based on the degrading condition of the structure in areas of the cooling tower cells inaccessible for inspection and repairs. Probability is 10% in 2020 and increases 1.5%/year.
- The capital investment cost for the alternatives includes, as applicable, the cost of multiple mobilizations and planned rebuilds and, the probability of collapse times the emergency cost to rebuild the wood cells in service plus half of the adjoining fiberglass cell. The emergency cost is based on applicable costs of the 2008 collapse.
- Anticipated O&M costs for wood cells rise 5%/year due to accelerated degradation.

Conclusions and Recommendation

Investment Committee approval of the GH2 CT Cell Rebuilds 2019 project for $2,844k is recommended to improve safety and reliability of Ghent Unit 2.

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: June 26, 2019

Project Name: TC F Coal Conveyor Floor Panel Replacement

Total Capital Expenditures: $6,264k gross ($4,698k net) (Including $569k gross ($427k net) of contingency)

Total O&M: $0k

Project Number(s): 155443LGE/155443KU

Business Unit/Line of Business: Power Generation

Prepared/Presented By: Grant Phelps, Caroline Miller

Brief Description of Project

The Trimble County Generating Station consists of two coal fired units. There is a system of conveyors used for transporting coal from barges on the river to the coal pile and the crusher building. From the crusher building, the F conveyor transports the coal into the plant where it fills the silos for both Units 1 & 2. The F Conveyor Gallery structure slopes from ground level at the north end to an approximate height of 180 feet at its south end. The Gallery contains three elevated conveyor frames with two of those being utilized for Units 1 & 2. The elevated portion of the structure is approximately 870 feet long and 50 feet wide, and consists of structural steel framing that supports a precast concrete floor system. The F Conveyor Gallery was built in the late 1980's as part of the construction of Unit 1. The floor system consists of precast concrete panels supported by underlying structural steel framing. Each precast concrete panel is nominally 2 feet wide (in the direction of the conveyors) and varies in length from approximately 3 to 6 feet (in the transverse direction) to match the spacing of the underlying conveyor framing. The existing precast panels have a channel-shaped cross-section.

Figure 1. General overview of F coal conveyor gallery structure.

The existing precast concrete panels have experienced widespread deterioration which has affected the overall integrity of the floor system. The floor panels can no longer support their design load. LG&E has temporarily installed grating supported by the steel structure for access to the conveyor. An evaluation of the existing precast concrete floor system was performed in June 2017 where it was recommended that the entire floor system be replaced with new precast panels of uniform thickness.

The removal of the existing floor panels and installation of the new concrete floor system will be a large, complex project. Due to the uncertainties in the scope and cost of overall floor replacement project, a pilot project was conducted during the 4th quarter of 2018. This pilot project consisted of replacing the floor panels in span three (3) of the eleven (11) spans that make up the F Conveyor Gallery. The lessons learned from the pilot project was used to bid out the remaining scope of work.

This project is spread across 2019 and 2020 due to the constraints of working around the operating conveyor. The contractor will be limited to an 8-10 hour shift per day including a 2-hour Lockout Tagout (LOTO) period as the conveyor gallery must be used to provide coal to both units. The proposed schedule begins in the summer of 2019 and completes in the fall of 2020. The major project milestones include:

Award Contract	July 2019
Fabrication of precast concrete panels	August 2019
Delivery of precast concrete panels	October 2019
Begin installation of panels	October 2019
Project completion	September 2020

Why is the project needed? What if we do nothing?

The deterioration of the existing precast concrete floor panels were first observed in 2017. At that time, a third party firm who has prior experience with this concrete floor system was hired to perform a condition assessment of the F Coal Conveyor Gallery Floor System. The assessment revealed that the deterioration of these panels was widespread and even those with little visible deterioration were subject to severely compromised strength. These panels are a safety issue as stated in their report, "continuing deterioration could eventually cause planks [panels] to fall from self-weight alone." These concrete panels provide the flooring system which is used for maintenance access along the entire length of the F coal conveyors. Temporary safety measurements have been put in place including grating supported off structural steel along with netting and scaffold boards to collect any falling debris from the panels.

If we do nothing, these floor panels along with the integrity of the structural steel are subject to failure. Based on the failure mechanism of these concrete panels and the knowledge of previous cases with similar deterioration, these panels are at risk of collapsing. The chance of failure is increased with applied load on these panels such as coal building up on the sides of the conveyors or personnel walking across them for maintenance access in the gallery. One of the attributing factors to the deterioration of this concrete includes a failed sealant between these panels. This failed sealant has allowed leakage to the bottom side of the panels and has caused a light surface corrosion on the top of the steel beam framing system which supports the entire gallery structure.

If this corrosion continues, it will eventually put the structural integrity of the entire steel framing system into question. This has the potential to cause operational downtime for Units 1 & 2 if the coal cannot be conveyed into the silos.

Budget Comparison & Financial Summary

The total project cost is $6,264k gross ($4,698k net). A total of $5,401k gross ($4,051k net) was included in the 2019BP. The balance will be funded from the reallocation of another Trimble County capital project (153080LGE) as part of the 2020BP.

The Work has been competitively bid. The bids are under review and an award will be issued in the month of July. There are two bids being considered at this time so the higher bid has conservatively been used to calculate costs. These bids were within 7% margin of each other. A 10% contingency of $569k gross ($427k net) has been added to this cost and will cover any unknown conditions such as lead paint abatement, steel coating refurbishment, etc. The Work will be awarded as lump-sum and any additional work discovered during the project will be completed on a time and material not to exceed basis.

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	1,418	2,352			3,769
2. Cost of Removal Proposed	236	692			929
3. Total Capital and Removal Proposed (1+2)	1,654	3,044	-	-	4,698
4. Capital Investment 2019 BP	1,629	2,421			4,050
5. Cost of Removal 2019 BP					-
6. Total Capital and Removal 2019 BP (4+5)	1,629	2,421	-	-	4,050
7. Capital Investment variance to BP (4-1)	211	69	-	-	281
8. Cost of Removal variance to BP (5-2)	(236)	(692)	-	-	(929)
9. Total Capital and Removal variance to BP (6-3)	(25)	(623)	-	-	(648)

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)	-	-	-	-	-

Note: Net values shown in above table.

Risks

The major risk of not completing this project is the continued deterioration of the concrete floor panels eventually leading to the panels falling from self-weight alone which has the potential to become a safety hazard. The temporary measures for the F conveyor gallery will suffice for the present time, but these measures should not be considered for permanent use.

There were several different options considered when evaluating the replacement for these precast concrete panels for the gallery floor. This evaluation included utilizing grating as used for the temporary flooring system. After further review, this option was eliminated since the coal is being transported from the crusher building; an open floor would make this gallery an opportune location for fugitive dust emissions.

The new concrete floor panels that will be installed as part of this project have many advantages over the previous generation of panels that will be removed. These advantages include uniform thickness, additional rebar, upgraded rebar material, and a waterproof sealant and coating. All of which will combat the failure mechanisms of the old panels and provide improved strength and service life for the gallery floor.

Alternatives Considered

1. Recommendation: Uniform Thickness Concrete Panels NPVRR: ($000s) $6,141

2. Alternative #1: Structural Steel Plates NPVRR: ($000s) $6,435
   [This alternative should not be considered due to the increased amount of weight that it would add to the structural steel load of the conveyor gallery which would require additional engineering evaluation and potential structural steel improvements. These plates would weigh about 25 percent more than the uniform-thickness concrete panels. They would require more work to install due to the necessity of welding to the structural steel and adjacent plates.]

3. Alternative #2: Do nothing NPVRR: ($000s) $7,729
   [This alternative should not be considered due to the high risk of a safety incident. These concrete panels will continue to deteriorate long term until whole panels begin to fall. This will create a safety hazard to both equipment and personnel working within the conveyor gallery area and on the ground below.
   There is also the risk of continued corrosion of the steel framing which would cause operational downtime if F conveyors for Units 1 & 2 must be taken out of service.]

Conclusions and Recommendation

It is recommended that the Investment Committee approve the TC F Coal Conveyor Floor Panel Replacement project for $6,264k gross ($4,698k net) to avoid the continual deterioration of these precast concrete floor panels and ensure the safety of all personnel working in the area. This project will provide long-term safe and reliable maintenance access to the conveyors to avoid operational downtime.

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	

Appendix

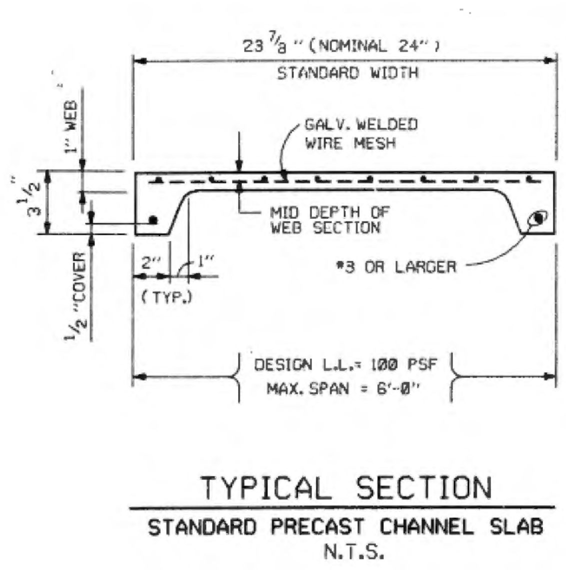


Figure 2. Cross-section of typical existing floor panel.

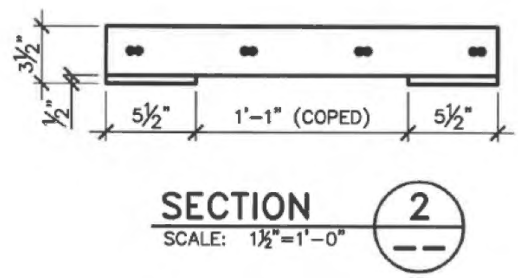


Figure 3. Cross-section of typical new design floor panel.

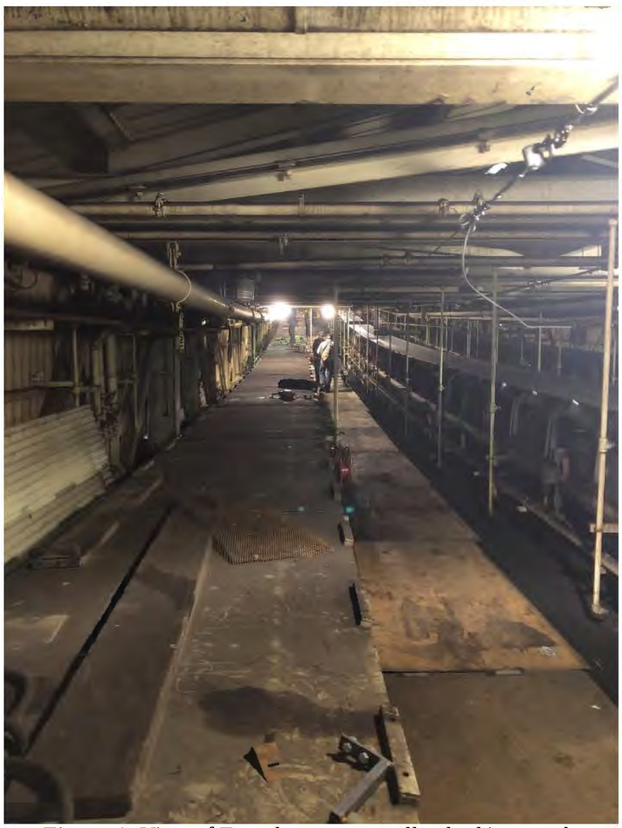


Figure 4: View of F coal conveyor galley looking south.

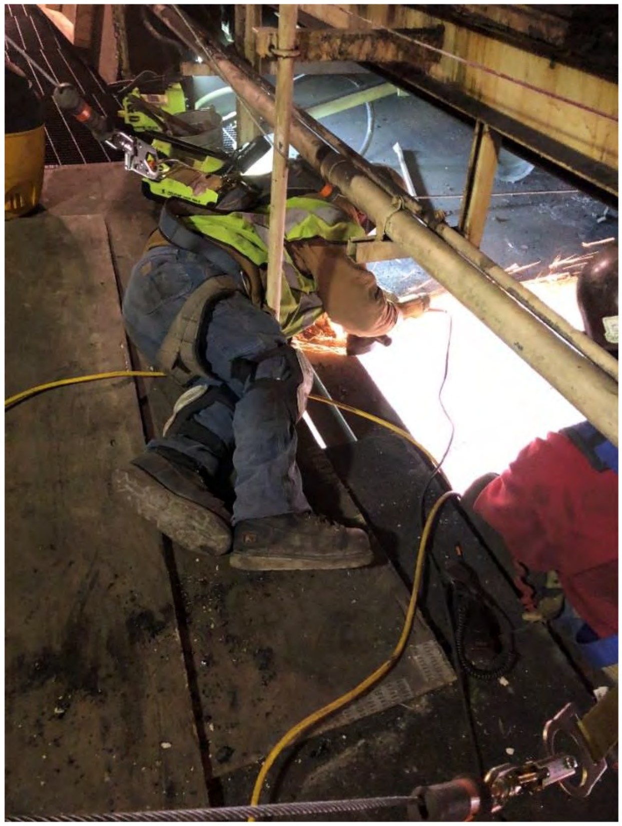


Figure 5. Employee grinding beneath F2 conveyor to install new panels.

Investment Proposal for Investment Committee Meeting on: June 26, 2019

ProjectProject Name: TC2 SCR Catalyst L1

Total Capital Expenditures: $2,332k gross ($1,749k net) (Including $212k gross ($159k net) of contingency)

Total O&M: $0k

Project Number(s): 153080LGE/153080KU

Business Unit/Line of Business: Power Production/Trimble County 2

Prepared/Presented By: Haley Turner, Laura Mohn, Mike Buckner

Brief Description of Project

The scope of this project includes the purchase of a new layer of catalyst modules which will replace the layer currently installed on Layer 1 of the Trimble County Unit 2 (TC2) Selective Catalytic Reduction System (SCR). This will occur during the planned Spring 2020 outage for TC2. The supply of new catalyst modules was competitively bid fleet-wide and an order will be placed in June 2019. The catalyst material will be delivered at least one month prior to the start of the outage. A total of 182 modules (91 per reactor) will be removed from Layer 1 and replaced with new modules.

The labor for removal and installation was bid as part of a fleet-wide initiative and was awarded last year. Industrial cleaning of the SCR and disposal of the old layer of catalyst will be included in this project. Additional seals and miscellaneous material will be purchased in 2020 for the catalyst replacement project.

The following details the expected project timeline:

- April 2019 — Bids received for catalyst material
- June 2019 — Issue PO for new catalyst material, progress payment
- 4th Quarter 2019 — Issue PO for Industrial cleaning of the SCR
- March 2020 — Outage start, catalyst replacement/door install completed
- April 2020 — Used SCR catalyst shipped for disposal
- June 2020 — Tune SCR to optimize ammonia distribution

Why is the project needed? What if we do nothing?

The TC2 SCR was placed in service when the unit was commissioned and is designed to hold three catalyst layers. The top two layers were filled with catalyst initially, and the third, taller layer was added in 2012 due to boiler outlet NOx exceeding system design due to poor burner performance.

In the Spring of 2014, the top layer (layer 1) of catalyst was replaced with brand new catalyst in order to meet SCR performance requirements and outage scheduling. The middle layer (layer 2) of catalyst was replaced in 2016 by the regenerated original layer 1. The bottom layer (layer 3) of catalyst was replaced in 2018. The top layer (layer 1) needs to be replaced in spring of 2020 in order for the TC2 SCR to meet NOx removal requirements and avoid unplanned outages due to ammonia slip plugging the air heater.

The current catalyst management plan, based on continued catalyst sampling and testing, shows a need for Layer 1 to be replaced in 2020 during the planned outage for TC2. Due to the results of the continued catalyst sampling and testing program, regeneration is not a viable option to ensure the catalyst management plan can be maintained. Sample testing results have shown that the regenerated catalyst modules are not performing to the guaranteed levels. This poor performance reduces the useful life of the catalyst for NOx removal and ammonia slip resistance. For these reasons, regeneration has been removed as a viable option for the TC2 catalyst management plan and, therefore, only new catalyst modules will be considered in the future for catalyst replacement projects.

Installation of a new layer of catalyst in Layer 1 will allow the unit to continue operating as necessary for NOx removal rates and reducing ammonia slip to the air heater which poses risk of air heater fouling if not controlled and minimized.

<u>Budget Comparison & Financial Summary</u>

A total of $1,035k gross ($776k net) and $3,035k gross ($2,276k net) is included in the 2019BP for spend in 2019 and 2020, respectively. It is recommended that the project be approved in order to meet the target NOx emission, reduce ammonia slip, avoid unplanned outage, and improve safety and time for future catalyst replacement projects. The total requested project funding is $2,332 k gross ($1,749k net) with 10% contingency. This varies from the 2019BP due to the costs for catalyst, labor and disposal being unknown and variable at that time.

Financial Detail by Year - Capital ($000s) Net	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed	753	922			1,675
2. Cost of Removal Proposed		74			74
3. Total Capital and Removal Proposed (1+2)	753	996	-	-	1,749
4. Capital Investment 2019 BP	776	2,201			2,977
5. Cost of Removal 2019 BP		75			75
6. Total Capital and Removal 2019 BP (4+5)	776	2,276	-	-	3,052
7. Capital Investment variance to BP (4-1)	23	1,279	-	-	1,302
8. Cost of Removal variance to BP (5-2)	-	1	-	-	1
9. Total Capital and Removal variance to BP (6-3)	23	1,280	-	-	1,303

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)	-	-	-	-	-

Risks
The risks of *not completing* this project include:

Exceeding NOx emissions target: NOx removal performance will decrease as the catalyst layer deactivates with age. Without the replacement of a new catalyst layer in the TC2 SCR, the NOx emissions will increase and will risk exceeding the Unit's NOx limit. Operating at the necessary NOx removal rate will become more critical due to compliance regulations associated with the finalization of CSAPR-II.

Forced Unit Outages: Without replacement of a new catalyst layer in the TC2 SCR, the amount of un-reacted ammonia leaving the system will increase. This ammonia will then be available to form ammonia bisulfate which deposits in the air heater. The deposits will build-up over time and will require a unit outage for air heater cleaning which will increase O&M costs and negatively impact unit availability

Alternatives Considered

1. Recommendation: Install new layer NPVRR: ($000s) $1,984
   The purchase and installation of a new layer in the 2020 outage is the recommended option. This plan is least cost over the life of the project and avoids the probability of air heater wash outages, unit derates, and decreases in NOx removal efficiency.

2. Alternative #1: Delay Project One Year NPVRR: ($000s) $2,230
   Delay of the catalyst layer change-out one year to the next planned unit outage presents two large risks: decreased NOx removal efficiency and risk of air heater wash outages due to ammonia slip. As catalyst activity deteriorates past the recommended replacement year the NOx removal efficiency declines. Additionally, the increasing ammonia slip would foul the air heaters faster than typical and poses risk of forced air heater wash outages. This alternative is not recommended due to the above risks and unfavorable NPVRR.

3. Alternative #2: Do Nothing NPVRR: ($000s) $7,976
   This alternative is not recommended as this would be extremely detrimental to unit operation and condition with high probability of unit derates/forced outages.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the TC2 SCR Catalyst L1 project for $2,332 k gross ($1,749k net) including 10% contingency to ensure NOx removal continues to meet target removal rates and environmental regulations and to avoid forced outages and/or derates due to ammonia slip or NOx emission issues.

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: September 25, 2019

Project Name: CR7 2020 Hot Gas Path (HGP) & Update of Long Term Program Contract (LTPC)

Total Capital Expenditures: $22,496k

Total O&M: $1,184k

Project Number(s): 144542 / 144542KU

Business Unit/Line of Business: Power Generation / Cane Run

Prepared/Presented By: Dave Tummonds

Brief Description:
The Investment Committee approved the CR7 Long Term Program Contract (LTPC) on 10/29/2012 for [redacted]). On 1/3/2013, LG&E and [redacted] signed the LTPC which provides for planned and unplanned maintenance on the covered parts associated with the compressor, combustor, and turbine sections of each CR7 combustion turbine (CT) which LG&E pays for through initial, annual, and variable fees. This document provides an update to the Investment Committee (IC) regarding LTPC spend to date, requests authorization to proceed with work to occur within 2020, and discusses LTPC considerations for the current Business Plan (BP) and BP's to follow. The most recent update was provided to the IC on March 29, 2017.

At present, the deferred account described in the 2017 update remains a deferred debit by $21,648k inclusive of all [redacted] LTPC invoices, associated taxes and the booking of the 2017 Combustor Inspection (CI) assets. During the spring 2020 outage, [redacted] will conduct the next planned LTPC outage on both CT's. The "2020 LTPC Work Scope" section discusses the scope of this Hot Gas Path (HGP). Based on the methodology discussed in Appendix B, completion of these HGP's will relieve the deferred debit account of $23,680k ($22,496k to CAPEX/$1,184k to OPEX). The company expects to process additional invoices totaling ≈$4,000k prior to conduct of the referenced work. These forecasted invoices, the current balance of the deferred account, and the forecasted booked assets for the referenced work will net $1,968k (still deferred debit) following completion of this work.

The Capital and O&M for this 2020 HGP project were included in the 2020 BP.

Contract Spend to Date

Per the Table below, paid invoices and associated tax currently total [redacted]

Year	CT1 Fees ($000's)					CT2 Fees ($000's)					Total
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

- [redacted]
- [redacted]

Netting the $8,688k asset booked in 2017 for the Combustor Inspection (CI), this deferred account stands at $21,648k (debit) presently.

2020 Long Term Program Contract (LTPC) Work Scope

- **Project Scope and Timeline**

  Based on current accumulation of Equivalent Base Hours (EBH's) and immediate forecast, both CR7 CT's will trigger their initial HGP in December 2019. [redacted] has provisionally agreed to delay this trigger to February (scheduled outage) as it falls within the normally acceptable 5% trigger deviation.

  This HGP involves the following scope:

  - Replacement of combustor components (transitions, fuel nozzles, baskets, and transition seals)
  - Replacement of rows 1 & 2 turbine blades and vanes and ring segments
  - Inspection of rows 3 & 4 blades (potential for replacement of both rows 3 and 4 blades and vanes – ring segments will likely just require inspection)
  - Inspection of compressor inlet guide vanes and variable guide vanes
  - Inspection of compressor last row outlet guide vanes
  - Inspection of inlet manifold and exhaust

  Although not typical for a HGP, [redacted] will also implement their latest recommended remediation for the current Variable Guide Vanes (VGV's) issue on both CT's (if not executed as determined by boroscopic inspections in the Fall 2019 Planned Outage). This scope will include removing both the upper and lower compressor casings and completion of the following:

  - Inspection of the VGV rows 2 & 3 (replacement of any VGV vanes with indications), along with a visual of all exposed compressor blades / vanes
  - Change out rows 2 & 3 VGV bushings to Rev.3
  - Change out rows 2 and 3 VGV lip seals
  - Modify the lower half inner rings on rows 2 and 3 VGV (upper half already modified in 2018)
  - Clean compressor blades (the plant may have to assist in this effort)

This incremental scope will require additional time which the plant has coordinated with Generation Planning. However, the additional scope will not impact cost for this outage per the LTPC.

The following describes the expected timeline:

- May 31, 2018 – Phase 1 Total Maintenance Solutions (TMS) Meeting (Budgetary Planning)
- August 30, 2018, December 5, 2018, March 20, 2019, July 30, 2019, November 12, 2019 – Phase 2 TMS Meeting(s) (Outage Planning)
- Mid to late January 2020– Phase 3 TMS Meeting (Readiness Review)
- Week of February 18, 2020 – Program Parts and Tool Kits On-Site
- Week of February 18, 2020 – Inspection Parts Kits On-Site
- February 22 – March 30, 2020 – HGP & Incremental Scope Planned Outage
- Late April Early May 2020 – Phase 4 TMS Meeting (Lessons Learned)

<u>**Business Plan Considerations**</u>

The 2017 update outlined the drivers and cost impacts of the multiple assumption differences from original contract (2012) to the initial LTPC outage in 2017. At the time of that update, the LTPC outage calculation yielded outage schedules and projected costs as follows:

Outage		Year	Updated Total Cost ($000's)
1	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Following both the 2017 CI (which booked $8,688K against the deferred account) and the interim runtime on CR7, the LTPC outage calculation yields the following outage timing and projected costs for remaining outages. The 2020 BP includes these projected costs.

Outage		Year	Updated Total Cost ($000's)
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Less than forecasted runtime in 2017 (primarily due to steam turbine blade issues) has led to the change in projected outage years which drive slightly higher projected costs due to additional annual payments with escalation.

Additional invoices in the interim between calculation for the 2020 BP and execution of the referenced HGP outages will drive some discrepancy between the $23,680k referenced herein and the actual asset booked against the deferred account. The combined effect of actual runtime and actual indexed escalation (relative to BP assumptions) will drive this discrepancy which is expected to be minor.

General LTPC Update

Although not specific to the HGP scope of work, please note the following relative to execution of the LTPC:

- The broader [redacted] gas turbine fleet has experienced an alarming number of inlet guide vane failures over the last three years. Inspection of both CR7 gas turbines have revealed that it is not immune to this issue. Regular inspections (every six months) and potential mitigating actions have been covered by the LTPC as the guide vanes are "covered parts." [redacted] has communicated the completion of design for permanent mitigation and has committed to install this mitigation during the HGP outage.
- [redacted] has communicated to the company that Combustor Inspections (CI's) may no longer be required. Although not yet proposed, I expect that prior to the next update, the company will need to evaluate a likely recommendation to no longer conduct CI's on these gas turbines in exchange for reduced LTPC fees. The plant and Commercial Operations will ensure the management team is aware of and involved in this potential option.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the CR7 2020 Hot Gas Path project for $22,496k to proceed with the OEM recommended maintenance for which LKE has already paid via the LTPC payment terms and deferred account activity discussed.

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	

Contract Proposal
Confidential

Contract Proposal for Investment Committee Meeting on: October 29, 2012
Contract Name: Cane Run 7 Long Term Program Contract
Sole Source Seeking IC Approval $176,418k
Total Contract Expenditures: [redacted]
Business Unit/Line of Business: Energy Services / Cane Run Station
Prepared/Presented By: Robert Barnett / Joseph Clements / Steven Turner

Executive Summary

Authority is requested under this proposal to award a Long Term Program Contract (LTPC) to [redacted] The Cane Run 7 Natural Gas Combined Cycle station will include two [redacted] SGT6-5000F (5) Efficiency Enhanced combustion turbines. Combustion turbines (CTs) require regular scheduled maintenance of the combustor, turbine and compressor sections. These maintenance inspections are required at periodic intervals based on the number of hours or starts that the CT has been operated or incurred respectively. The contract includes inspection and replacement of the major parts associated with the CTs. In addition, a key provision of the contract is that warranties are provided for the parts and services.

[redacted] CTs were offered by the successful bidder for the engineering, procurement and construction (EPC) agreement for the CR7 station. Currently [redacted] is the only company capable of performing these services and furnishing parts. The proposed LTPC is a result of negotiations between LKE and [redacted]

A financial analysis (Exhibit 1) by Generation Planning determined $50,000k-$110,000k in NPVRR savings is realized using the LTPC when compared to purchasing the parts and services outside the LTPC. In addition, the LTPC ensures that parts and services are available by placing the responsibility for maintaining the Program Parts inventory (Exhibit 2) on [redacted].

The LTPC has a provision for the utilization of minority, women, disadvantaged and local business enterprises during the performance of the work. There are no companies however that could be considered as a direct supplier for the CTs or these services. Efforts will be made with [redacted] to promote the use of minority, women, disadvantaged and local business enterprises at lower tiers over the term of the LTPC.

Background

The three distinct scheduled maintenance outages; combustor inspection (CI), hot gas path inspection (HGPI) and major inspection (MI) are required at defined intervals. These intervals are determined by the equivalent base hours (EBH) the CTs are operated or the equivalent starts (ES) that the CTs incur as shown in the following table.

Outage Type	Interval*
Combustor	16,600 EBH or 1,200 ES
Hot Gas Path	33,200 EBH or 1,200 ES
Major	66,400 EBH or 2,400 ES

*These are the current maintenance intervals per [redacted] Service Bulletin and Addendum C-1.

LKE may either perform these inspections under the proposed LTPC or utilize individual transactional contracts with [redacted] at the time a scheduled maintenance outage is required. Due to the high temperatures and thermal stresses under which CTs operate, not performing these inspections will compromise the integrity and reliability of the station.

The LTPC utilizes quarterly payments based on EBH or ES versus transactional payments for parts and services.

Experience with [redacted] new part lead times has been 12-18 months. Without an inventory of spare parts or use of an LTPC, LKE would plan on refurbishing existing parts during HGPI and MI outages. Based on the most recent Paddys Run 13 MI outage, 21 weeks were required to receive refurbished blades. An additional risk under this approach is that some parts may not meet the requirements for refurbishment. In lieu of entering into an LTPC and to ensure unit availability, an initial spare parts purchase of $54,000k would be required and recommended. The [redacted] LTPC utilizes a pool of parts across the fleet of [redacted] units. In the LTPC, [redacted] will furnish new or reconditioned Program Parts.

Contract Description

PPL [redacted] negotiated a LTPC with [redacted] in 2011, and this information was very beneficial as a basis for negotiation format and terms. The contract term is from [redacted] through the earlier of the second major inspection or 32 years (Sunset Date). [redacted] is expected in late 2014. There is an option to extend the Sunset Date an additional three years. Therefore considering the maximum term, the contract could end in 2049.

[redacted] obligations under the LTPC are to furnish services (management, engineering, installation, etc), Program Parts and open/close hardware associated with each inspection. [redacted] will assign a program manager that will coordinate all activities with LKE. In addition, [redacted] will provide a remote monitoring system that will be used to monitor the performance and operating conditions of the units. LKE's responsibilities can be summarized as complying with the operating instructions specified by [redacted] and participating in the planning of scheduled outages. LKE will be responsible for all other non-program parts and maintenance.

Contract Pricing Structure
The contract includes initial, annual, and variable fees as described below. The contract fees are subject to an escalation factor which is a published CPI index.

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	
[redacted]	[redacted]	

Liquidated Damages
The contract includes a provision to apply liquidated damages if [redacted] fails to execute and complete scheduled outages within the durations summarized below.

- Combustor Inspection – 240 hours (10 days)
- Hot Gas Path Inspection – 504 hours (21 days)
- Major Inspection – 672 hours (28 days)

The liquidated damage fee is [redacted] per hour per CT, limited to [redacted]k per year for both CTs. In addition, the contract includes "Unscheduled Outage Downtime Warranty Liquidated Damages" of [redacted] per hour per CT if the CTs collectively accrue 264 hours of unscheduled downtime in a calendar year, limited to $[redacted] per year. The total limit for liquidated damages through the term of the contract is [redacted]

Termination Rights
Both parties will have termination rights for default and non-performance. In addition, LKE will have the right to cancel the agreement for convenience prior to [redacted] and after the initial six years during the term. In the event of termination, LKE will receive a refund or credit (depending on the termination reason) for all variable fees since the last scheduled outage or since the [redacted] if there has not been a scheduled outage. Both parties will make the other whole for any cancellation costs and transfer of ownership of parts. In addition, [redacted] will provide a $1000k credit per CT if the termination is due to their default.

[redacted] may terminate the LTPC if [redacted] (Guaranteed Effective Date) has not occurred by May 1, 2018. In this case, LKE pays $1,000k per CT to [redacted]. The expected [redacted] is November 1, 2014.

LKE's cost to terminate prior to First Fire is summarized as follows:

- LTPC execution date to June 30, 2013 - $0.
- July 1 to December 31, 2013 - [redacted] per CT.
- January 1, 2014 to Expected First Fire - [redacted]k per CT.
- Expected First Fire plus one year - [redacted] per CT.
- Thereafter to Guaranteed Effective Date, May 18, 2018 - [redacted] per CT.

During the Term, LKE may also terminate for following reasons:

a) Convenience after the first six years. LKE does however retain the right to terminate within the first six years and thereafter if operational conditions outside its control (e.g. available fuel conditions change) cause [redacted] to suspend warranties, thereby reducing the value of having an LTPC in place.
b) The station is permanently shut down for economic reasons.
c) LKE is forced to shut down because of failure to maintain necessary operating permits or regulatory approvals.
d) Change in Applicable Law prevents operating the station.
e) Force Majeure persisting six months or longer.
f) Long Term Performance deficiencies occur.

If LKE terminates for inability to perform, default or (a), (b), (c) above, there is an additional fee of $1,000k per CT, plus a refund of 25% of any previously paid property damages by [redacted]. The total of the fee and refund cannot exceed $2,500k per CT. In addition, if the contract term expires prior to the second MI, LKE will receive a credit for the variable fees paid since the last outage, to be used for the purchase of any [redacted] generation equipment for seven years. There are no fees associated with termination caused by (d), (e), or (f) above.

Property Damage
In the event a program part fails and causes downstream or consequential property damage, [redacted] will be responsible to repair or replace the failed part. Their responsibility to cover other property damage is limited to [redacted] per event and [redacted] per calendar year. The contract limit is $12,500k through the term and post term periods.

Warranty
The Program Parts and associated services are covered during the term and Program Parts until the earliest of the following during the post term:

- 18 months from the date of last installation.
- 450 ES from the date of last installation.
- 12,500 EBH from the date of last installation.
- 30 months from the date of last delivery to the station.

[redacted] also included an extension of the warranty in the EPC contract for Non-Program Longitudinal Parts. These parts are listed in Exhibit 3.

The contract was negotiated using both in-house and outside legal counsel [redacted] In addition to the provisions described above, the contract contains standard contractual issues addressed in LKE's General Services Agreements or Master Agreements (e.g. Safety, NERC compliance, Title and Risk of Loss, Force Majeure, Indemnification, Insurance, Compliance with Laws, permits, Regulated Waste, Intellectual Property, Confidential and Proprietary

Information, Limitation of Liability, Applicable Law and Dispute Resolution, Assignment and Transfer, Audit, Liens, Code of Business Conduct).

Economic Analysis and Risks

- **Bid Summary** – The EPC RFP included a request for information on a long term CT maintenance agreement, but no formal bid process was developed specifically for one. [redacted] will supply the CTs and currently there is no other source for [redacted] parts and services. [redacted] also submitted bids under the EPC RFP and its Contractual Services Agreement (CSA) is approximately [redacted] LTPC. However, the overall evaluated cost of the [redacted] bid including the LTPC, Capital, and Production costs was [redacted] (see attached presentation as Exhibit 1)

  [redacted] protects its pricing schemes from being published. Efforts were made by LKE's Rates and Regulatory group to research PSC filings by other [redacted] customers, but were unsuccessful. The PPL [redacted] contract allowed LKE to verify that the order of magnitude for the variable fees is consistent in what is included in this contract. LKE's experience with the transactional [redacted] prices associated with PR 13 validates the prices for purchasing the Program Parts outside of the LTPC.

  [redacted] an engineering firm with extensive background in combined cycle gas turbine projects, has reviewed the contract terms and fees and finds them to be at or under market for similar projects.

- **Financial Summary**

  The approved 2012 OPEX LTP included \$25,000k in 2016 for CR7 of which [redacted] was for an LTPC. The proposed 2013 Business Plan includes OPEX of \$18,000k. Also included in the plan are the first two scheduled outages (CI 2017 and HGPI 2019) which are budgeted as capital. This is primarily based on replacement of the designated hot gas path components.

  Initial and annual LTPC payments will be accounted for through a deferred debit account and portions will be transferred to capital at the scheduled outage intervals. This accounting treatment will be consistent with how EW Brown and Trimble County fund CT outage expenses. Estimated transfers and timing will be coordinated with financial planning as part of the business plan process.

  Generation Planning calculated the life cycle cost of the LTPC using 24 scenarios. The range of payments to [redacted] under these scenarios is [redacted]. The NPVRR forecast model only looks forward to 2040. However, for the purpose of the LTPC, conservative estimates of 1,281 EBH and 127 ES are used in years 2041-2049. The actual value of the LTPC is a function of natural gas prices and how the station is operated. Scenario 11 is the model being used as the expected mode of operation and the basis for the budgeting methodology over the LTPC life. This scenario anticipates CR7 will be replaced by additional, more efficient CTs in the fleet in the out years. It does not consider the reduced dependence on existing coal fired units. The payments to [redacted] for the LTPC in scenario

11 through 2049 are [redacted] In this scenario, CR7 will run significant hours per year (60%-90% capacity factor) through 2021 and then significantly less through 2049.

The estimated contract expenditures for IC approval are calculated based on scenario 11 as follows:

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

***As noted above the contract payments will be charged to a deferred debit account and then allocated to a capital project at the time the scheduled outage occurs.**

***[redacted] escalated 2% / yr through 2049.**

- **Risk of Contract**

The LTPC balances the risk evenly between the parties. Both parties have obligations to perform and adhere to the conditions of the LTPC. LKE does have the ability to cancel or terminate the LTPC, and the process and costs are defined. In addition to the risk associated with the EPC contract, the term of the LTPC is significant in duration. The prices are escalated by a CPI index. Periods of extreme inflation could drive the cost significantly higher than predicted. Although the [redacted] SGT6-5000F CTs have a proven record, these are the initial two Efficiency Enhanced models. Having an LTPC mitigates some of the risks associated with newer technology.

- **Other Alternatives Considered**

  Foregoing entering into a LTPC with [redacted] places the risk of spare parts availability on LKE. The initial cost for recommended spare parts would be [redacted] In lieu of carrying spare parts, long lead times would be associated with each outage, and LKE would be subject to the then current market pricing from [redacted]

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Cane Run 7 Long Term Program (Sole Source) Contract for [redacted] to [redacted] due to the significant savings realized when compared to the cost of transactional purchases of spare parts and individual contracts for each CT inspection.

Robert Barnett
Mgr. Commercial Operations, CR

D. Ralph Bowling
VP Power Production

10/29/12
Joseph Clements
Director Pwr. Gen. Comm. Ops.

11/1/12
Paul W. Thompson
Senior VP Energy Services

Steven Turner
Gen. Mgr. Cane Run & Comb. Turbines

Kent W. Blake
Chief Financial Officer

Victor A. Staffieri
Chief Executive Officer

APPENDIX B – CALCULATION OF DEFERRED ACCOUNT ACTIVITY

As noted, the deferred account currently carries a deferred debit of $21.6M. Estimating runtime through the conduct of the 2020 HGP yields an estimated deferred debit account value of ≈$25.6M at the time of execution. The methodology below determines the amount of deferred debit account relief following completion of this planned LTPC outage.

1. Determine total expected contract spend as the total of the contract spend to date and the expected remaining spend through contract expiration. The current Generation Planning Forecast indicates that the contract will expire in 2032 following the completion of the second Major Outage on each CT. That Generation Planning forecast and an estimated annual escalation of 2% result in expected annual and variable (hours based) fees through the end of the contract.
2. 4.26% of the result above is added to account for sales tax based upon [redacted] input that contract value is split 71% parts and 29% labor yielding the 4.26% assessment of sales tax.
3. 10% of (1) above is also added as contingency to account for potential volatility in the Generation Planning forecast which may lead to greater total contract spend as well as potential differences between future planned and actual escalation.
4. The sum of items 1-3 comprise the total expected contract spend.
5. Item 4 less the total previously assessed against the deferred account results in the forecasted total remaining to be split against the remaining planned outages.
6. Item 5 is then spread across the remaining LTPC outages using the relative value of what each outage would have cost at the forecasted execution time had the company conducted the outages outside of an LTPC. The resultant LTPC outage values are then split 95% to CAPEX and 5% to OPEX with each of those being 71% material and 29% services based upon [redacted] input at the time of entering into the LTPC.

Total Value ($000's)	Capital (95%) ($000's)				O&M (5%) ($000's)			
	Material (71%)	Sales Tax[1]	Labor (29%)	Total	Material (71%)	Sales Tax[1]	Labor (29%)	Total
23,680	15,320	919	6,257	22,496	806	48	329	1,184

[1] The company pays 4.26% (6% X 71% material) of each [redacted] invoice to the KY State Treasurer.

For continued clarity, the contract approved by the Investment Committee in 2012 (Appendix A) authorizes spend to date and ongoing spend which comprise the deferred debit account. This document serves to memorialize how this 2020 work scope will impact that deferred debit account.

Investment and Contract Proposal for Investment Committee Meeting on: September 25, 2019

Project Name: TC2 Turbine Last Stage Buckets

Contract Name (Good/Service): TC2 Turbine Last Stage Buckets Goods and Alternate Services

Selected Vendor(s): [redacted]

Contract Authorization Requested: [redacted]

Contract Term: October 2019 through June 30, 2023

Total Capital Expenditures Requested: $8,056k net ($10,741k gross) (Including $235k net ($313k gross) of contingency)

Total O&M: $0k

Project Number(s): 152104LGE / 152104KU

Business Unit/Line of Business: Trimble County / Power Generation

Prepared/Presented By: Laura Mohn/Mike Buckner, Bob Barnett/Joe Clements

Brief Contract/Project Description

Trimble County Unit 2 (TC2) was commissioned in 2011 and had its first major turbine overhauls in 2018 and 2019. The high pressure (HP) and intermediate pressure (IP) sections of the turbine were overhauled in the spring of 2018, while the low pressure (LP) sections were overhauled in the spring of 2019. During the 2019 overhaul and inspection, it was noted that each row of the last stage buckets (L-0) showed an increase in erosion on the leading edge that was first noted in 2012 during the one-year inspection. (See Figures in the Appendix)

During the 2019 outage, [redacted] was consulted on the condition of the buckets and said that the unit could go back into operation with the L-0 buckets in their existing condition based on the level of erosion seen and the non-destructive examination. [redacted] recommended checking the L-0 erosion in the next one to two years and purchasing new buckets to prepare for replacement.

This project will include the purchase of the turbine end (TE) and generator end (GE) L-0 buckets and associated hardware. While the project includes the material purchase only, the contract contains two alternatives for installation as detailed below.

The parties to the contract will be LG&E and [redacted] (a wholly owned subsidiary of [redacted]). The base scope is for the purchase of four rows of L-0 turbine buckets and associated installation hardware. There are a total of 320 buckets, and at 40 inches long are considered large by industry standards. The price for the buckets is firm. The listed delivery schedule is 96 weeks from execution of the contract. [redacted] has the right to make an earlier delivery if LG&E is given at least a 90-day notice before an agreed to delivery window. The contract will include progress payments including an initial payment of $2,770k plus the cost of a security letter of credit to be invoiced upon full execution of the contract. [redacted] will be required to furnish subsequent letters of credit in the amounts equal to or greater than cumulative payments made. Charges for cancellation for LG&E's convenience of the base scope are listed and begin following execution of the contract. [redacted] and LKS are signatory to a negotiated GSA that has been updated through several amendments. The limits of liability and insurance requirements are consistent with the current 2019-21 contract with [redacted] that includes four major and six smaller valve and/or pump outages.

There are two alternative lump sum prices in the contract for installing the new buckets on the rotor. One includes performing the work at the station. The other is for shipping the rotors to [redacted] shop in [redacted]. Both are based on the installation occurring in the spring of 2023. If the outage shifts, there could be a minor adjustment to these alternative prices. The alternative prices do not include removing and reinstalling the rotor in the machine. That work will be included in the next cycle of fleet turbine/generator maintenance efforts.

Change orders will be managed on a lump sum, unit prices or at hourly rates in a negotiated master agreement with [redacted].

Why is the project needed? What if we do nothing?

TC2 is at risk if the materials are not ordered and available due to the unique design and extremely long lead times. If a bucket were to fail and spares were not available, the unit would be unavailable for approximately a year and a half to two years.

According to [redacted], the L-0 buckets are at end of life when the erosion depth reaches 6 mm. The erosion depth measured during the Spring 2019 outage was 66% of end of life and if the erosion rate is constant, the buckets would need to be replaced as early as the end of 2022.

Contract Bid Summary

A formal request for proposals was issued through [redacted]. [redacted] and [redacted] the only companies deemed viable were notified. [redacted] did not register in [redacted] and [redacted] did not respond. There are no known diverse suppliers that can supply these materials. Both [redacted] and [redacted] would need to reverse engineer the buckets in order to manufacture them. Both companies were given the opportunity during the recent TC2 spring outage. [redacted] Hitachi is the manufacturer of the TC2 Steam Turbine. [redacted] Therefore [redacted] price was suspected to be higher than market and was challenged. Using the information on the alloy composition buckets obtained from Hitachi during the initial purchase of TC2, an estimate of the alloy cost was made. In addition, comparing these buckets to the recent purchase of 33" buckets for MC3 provided a basis for price comparison. [redacted] initial proposal was $10,160k. Following initial negotiations, the price is $9,226k. Additional negotiations are in process at this writing in an effort to achieve further price reductions.

($000s Gross)	[redacted]	[redacted]	[redacted]
		No Bid	No Bid
Base Price – 4 rows of L0 buckets	[redacted]		
Alternative 2* – Install the buckets at [redacted]	[redacted]		
Cost for Letters of Credit (estimated)	[redacted]		
Total Cost – includes Base Price ***plus Option 2 and LOCs***	[redacted]		
Alternative 1* – Install the buckets at the station	[redacted]		

*Neither alternative price includes disassembly and reassembly of the machine. That work will be bid out with the next cycle of the fleet T/G outage contracts.

<u>Contract Financial Summary</u>

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The contract is required due to the condition of the buckets that was observed during the recent spring outage. The long lead time at 96 weeks requires that the contract be awarded at this time even though immediate replacement is not expected.

Project Financial Summary
(Expenses below are net, burdened costs for the project.)

Financial Detail by Year - Capital ($000s Net)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	2,390	3,615	2,051		8,056
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	2,390	3,615	2,051	-	8,056
4. Capital Investment 2019 BP				3,850	3,850
5. Cost of Removal 2019 BP					-
6. Total Capital and Removal 2019 BP (4+5)	-	-	-	3,850	3,850
7. Capital Investment variance to BP (4-1)	(2,390)	(3,615)	(2,051)	3,850	(4,206)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(2,390)	(3,615)	(2,051)	3,850	(4,206)

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)	-	-	-	-	-

This project is included in the proposed 2020BP and the RAC has approved 2019 funding. A contingency of $235k net ($313k gross), which is 3%, is included due to unforeseen changes to the scope.

Risks
If a bucket were to fail and spares were not available, TC2 would become unavailable. Although it is difficult to predict the end of life for the existing buckets, the expectation is that it will occur within the next three to five years. The current lead time for the buckets is 96 weeks. Not purchasing the buckets within the next year, puts the unit at more risk as the unit continues to run and time passes.

Due to the value of the contract and the inclusion of large progress payments, the LKS credit department performed a credit risk assessment of [redacted] and recommended a Parent Guarantee be obtained. We know from previous contracts with [redacted] that a parent guarantee is not the best option because of their [redacted] ownership. Therefore the contract will require a letter or progress letters of credit equal to or greater than payments made.

Project Alternatives Considered

1. Recommendation: NPVRR: ($000s) $ 9,864

2. Alternative #1: Do Nothing NPVRR: ($000s) $ 53,797

   The Do Nothing alternative is to not purchase spare L-0 buckets, but to include them as part of the 2026 LP turbine overhaul, which was the plan in the 2019BP. This is not recommended due to the potential down time associated with the unit at even a low probability of failure in the first few years.

3. Alternative #2: Begin Purchase in 2021 NPVRR: ($000s) $ 14,159

   An alternative is to begin the purchase of the buckets after inspection in 2021. This is not recommended due to the potential down time associated with a failure.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the TC2 Turbine Last Stage Buckets project for $8,056k net ($10,741k gross) as well as the TC2 Turbine Last Stage Bucket Purchase contract including an alternative for installation in 2023 at [redacted] gross due to [redacted] at a negotiated contract price.

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced:

The Capital project spending and contract authority requests included in this Investment Proposal have 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 the capital project and contract authority requests.

Kent W. Blake Date	Paul W. Thompson Date
Chief Financial Officer	Chairman, CEO and President

CONFIDENTIAL INFORMATION REDACTED

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
(TC2 Turbine Last Stage Bucket Purchase contract)

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the TC2 Turbine Last Stage Bucket Purchase contract including an alternative for installation in 2023 at $10,648k gross due to [redacted] at a negotiated contract price.

Sourcing Leader [If applicable; the approvers for this table can be modified as needed]	N/A	Proponent/Team Leader [If applicable]	N/A
Supplier Diversity Manager [If applicable]	N/A	Manager [If applicable]	
Manager - Supply Chain or Commercial Operations		Director – Supply Chain or Commercial Operations	
Director [If applicable]		Vice President [If applicable]	

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Appendix

Figure 1. Comparison of bucket leading edge erosion from 2012 to 2019

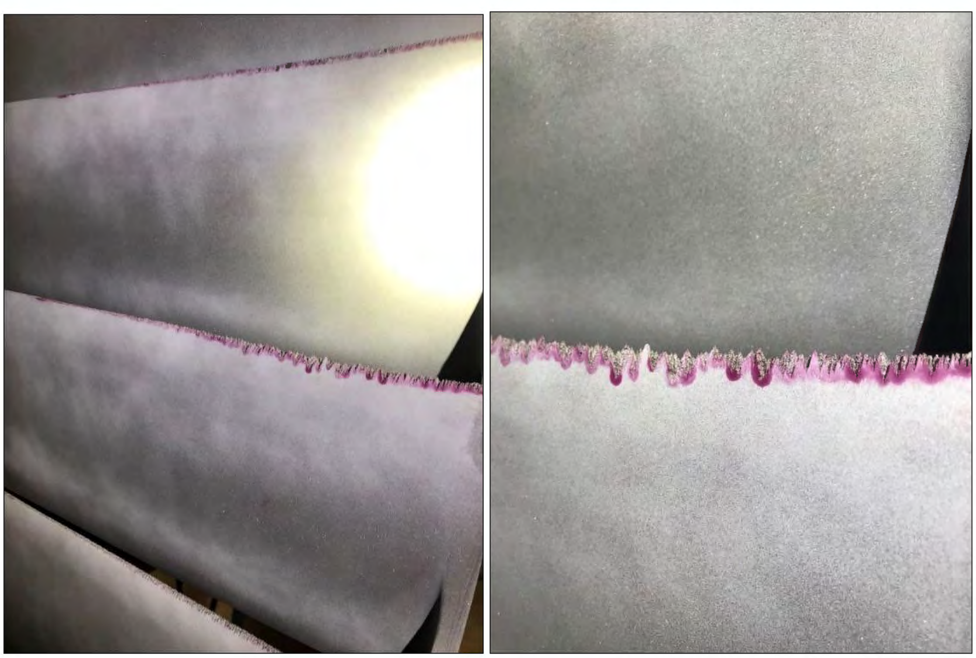


Figure 2. Leading edge erosion in 2019

Figure 3. LP rotors on stands for inspection during 2019 spring outage

Investment Proposal for Investment Committee Meeting on: November 1, 2019

Project Name: Cane Run 7 Kettle Boiler Replacement

Total Capital Expenditures: $2,350k, including $233k of contingency (11%)

Total O&M: $0

Project Number(s): 158876

Business Unit/Line of Business: Power Generation / Cane Run

Prepared/Presented By: Zach Springer / David Tummonds

Brief Description of Project

Kettle Boiler Purpose

Each of the two gas turbine units at Cane Run 7 is equipped with a shell and tube heat exchanger referred to as a “Kettle Boiler” or, in some instances, a “Rotor Air Cooler.” The primary purpose of the Kettle Boilers is to cool compressed air which is bled from the associated gas turbine. The air is returned to the gas turbine and utilized to cool turbine hot-end rotating components. The secondary purpose of the Kettle Boiler is to take advantage of the heat removed from the rotor cooling air by generating intermediate pressure steam in parallel with the station’s heat recovery steam generators (HRSGs). The steam is ultimately utilized in the station’s steam turbine for power generation.

Kettle Boiler heat exchangers are utilized at combined cycle plants throughout the industry, but are not the most common means for accomplishing gas turbine rotor air cooling. Among installed Kettle Boilers, there is considerable design variation depending on the vintage and position in the steam cycle. Due to the limited number of installations and this large variation in design, there is no appreciable industry data to predict failures or quantify expected failure rates.

Existing Kettle Boiler Issues

Outside of an issue on CT2’s Kettle Boiler identified and mitigated during commissioning in 2015, both Kettle Boilers had performed as expected prior to the fall 2018 inspection. That inspection revealed a concerning increase in leaks identified in each Kettle Boiler. The intermediate pressure feedwater and steam in the Kettle Boiler’s shell is higher pressure than the rotor cooling air inside the tubes. Therefore, when a leak develops, water enters the rotor cooling air circuit creating potential for corrosion of gas turbine components downstream. Corrosion debris can plug the small cooling passages, leading to overheating and significant damage to turbine blades.

[redacted] the gas turbine manufacturer, has specifically identified Kettle Boiler leaks as a cause of foreign material damage to their gas turbines in a service bulletin published in late 2018.

Industry photos of leaking Kettle Boilers and corrosion debris in rotor cooling air piping from [redacted] service bulletin.

Because of the risk of gas turbine damage, leak detection instrumentation is installed in the cooling air piping just upstream and downstream of the Kettle Boilers. When a leak is detected, the gas turbine must be shut down so the leak can be investigated and repaired by plugging the tube. The CR7 Kettle Boilers are designed to meet their heat transfer requirement with up to 50 tubes (10%) plugged. Plugging tubes beyond this allowance will reduce cooling capacity and increase pressure loss in the Kettle Boilers, resulting in permanent gas turbine load reductions to prevent overheating.

The leak history of the CR7 Kettle Boilers is summarized in the table below:

Date	Event
Spring 2015 (Commissioning)	Repetitive leaking of Unit 2's Kettle Boiler during commissioning. The parties involved agreed to replace all tubes onsite so commissioning activities could continue. LKE Generation Engineering personnel performed destructive analysis on some of the failed tubes, which indicated stress corrosion cracking initiating from the inside diameter of the tubes was the failure mechanism. The factors leading to this failure mechanism were the subject of debate between the parties involved and no definitive root cause was determined.
October 2016 (Planned Outage)	Planned outage non-destructive examination (eddy current testing) performed on all accessible tubes of both Kettle Boilers. Four tubes in Unit 2's Kettle Boiler were identified to have significant wall loss (not yet leaks) and were plugged.
August / October 2018 (Planned Outage)	During normal operation in August 2018, leaks were detected in both Kettle Boilers by drain water level monitoring instrumentation. The drain valves were opened to remove the accumulated liquid, clearing the alarms which did not return. During outage visual inspections in October, leaking tubes were discovered in both Kettle Boilers – 7 in Unit 1, 15 in Unit 2. Leaking tubes were inspected with a borescope but no obvious cause of the leaks was found. The leaking tubes were plugged.

Due to time constraints and the difficulty in extracting failed tubes for destructive analysis, no definite root cause has been determined for recent failures. However, the industry at large is familiar with two major failure mechanisms in Kettle Boilers:

1. Stress Corrosion Cracking (SCC) – development of very small cracks in a member under stress in a corrosive environment at an elevated temperature. In the case of Kettle Boilers, the corrosive environment is most likely created by the concentration of chlorine from the feedwater in crevices through evaporation. 304 stainless steel, the currently installed tube material, is particularly susceptible to this phenomenon in the presence of chlorine. Finally, SCC was determined to be the cause of the Unit 2 commissioning failures, providing evidence that the materials used in the Kettle Boiler are indeed susceptible to this failure mechanism.

2. Fatigue – failures caused by repetitive stresses on components. In Kettle Boilers, the high temperature rate of change during startups, loads from connecting piping or foundation constraints which can hinder thermal expansion or impart excessive forces onto the vessel, and flow-induced vibration of tubes are stressors that can lead to fatigue failures. Fatigue failures will almost certainly increase in frequency and severity if Cane Run 7 is cycled as designed.

Circumstantial evidence discovered during the inspection and repair of the Kettle Boiler leaks cannot rule out either of these mechanisms.

Finally, the station has identified the following additional concerns with the existing Kettle Boilers:

- The use of seamed tubing material instead of seamless. The welded longitudinal seams may have residual stresses which make the tubes more susceptible to the stress corrosion cracking mechanism mentioned above.

- Inadequate support of the outlet end of the vessel, which may cause sagging that puts excessive stress on the tubes. The tubes were observed to be bowed during the borescope inspections performed in 2018, consistent with inadequate support.

- Review of the Kettle Boiler design by the station’s preferred heat exchanger manufacturer has revealed the tube sheet to shell and inlet/outlet channels are not sufficient to withstand the stresses associated with the rapid thermal expansion the vessels must endure during unit startup and shutdown.

Following the relatively good results of the non-destructive examination performed in 2016, the station resolved to repeat the examination during all longer outages, approximately every four years. However, the sudden increase in leaks in 2018 is alarming and suggests the damage mechanism is accelerating. This increase in observed failures, the susceptibility to known industry issues, and concerns with the quality of the tube replacement in Unit 2’s Kettle Boiler during commissioning culminate in the decision that Kettle Boiler design changes are necessary to minimize the ongoing risks of unavailability and turbine damage.

Project Scope and Timeline

The proposed project will replace the Kettle Boilers on both gas turbines at Cane Run 7. The new heat exchangers will be specified, designed, and constructed to be resistant to the failure mechanisms and additional concerns noted on page 3 and observed with the existing Kettle Boilers and elsewhere in the industry. A service life of 15 years is expected from the new Kettle Boilers.

Specifically, the project scope includes the following:

- Turnkey design, fabrication, delivery, and installation of two new Kettle Boiler heat exchangers. This contract will be awarded by 12/1/2019 with delivery of the new Kettle Boilers in time for installation during the Spring 2021 outage.
- Procurement and installation of replacement ancillary components (valves, instruments, etc.) to improve reliability.
- The Spring 2021 outage is currently scheduled to be one week in duration, beginning on 4/26/2021. This outage will need to be extended to three weeks to accommodate installation of the Kettle Boilers. The plant is working with Generation Planning to revise the Planned Outage Schedule accordingly. All work will be complete at the conclusion of this outage.
- The original Kettle Boilers will be scrapped.

As the plant identified the concerning increase in leaks following submission of the 2019 Business Plan (BP), this project is not included in the current BP. At the time of 2020 BP submission, the plant forecasted a project total of $1,807k ($672k in 2019 and $1,135k in 2020). This assumed project completion during the spring 2020 outage. The RAC approved the $650k forecasted for 2019 in the 1+11 forecast. Following that forecast, plant personnel and the contractor selected for the Kettle Boiler repair scope identified that the presumed design would require modification to properly allow for thermal growth. This modification required additional design and sourcing time as well as incremental funding relative to the $1,807k total referenced above. The net effect is that the replacement installation will now be completed during the spring 2021 outage (as noted) and that the new project scope drives a budget of $2,350k with the following detail:

- 2019: $384k (RAC approved $650k in 1+11 and then approved reduction to $350k in 8+4)
- 2020: $603k (reduced $532 from 2020 BP submission of $1,135k)
- 2021: $1,363k (incremental to submitted 2020 BP)

<u>Why is the project needed? What if we do nothing?</u>

The recently discovered increase in Kettle Boiler failures along with understanding of Kettle Boiler issues throughout the industry lead to substantial concern associated with either or both of the following failure types:

- Incremental tube failures properly identified through online leak detection and/or prudent inspection practices. To date, this is the failure type observed at Cane Run and is most likely. This failure type will result in approximately a 3 day outage (likely forced) and repair costs of approximately $10k per event to plug the leaking tube or tubes. Once greater than 10% of the tubes have been plugged, incremental de-rates will impact the unit due to inadequate cooling of the turbine blading.

- Gas turbine blading failure as a result of corrosion debris plugging cooling passages of turbine blading. This failure type is not common and all Kettle Boilers have safety mechanisms to avoid this. However, this has occurred within the industry despite those mechanisms. This failure type will result in effectively conducting an unscheduled Major Outage on the affected gas turbine. The outage scope and the unplanned nature of it would likely result in approximately 3 months of downtime with the costs likely near $2.5M as the LTPC does not cover damage resulting from the Kettle Boiler.

Future failure rates are not easily predicted with available data. Given CR7's placement in the current and foreseen dispatch order, the Capital Evaluation Model (CEM) for this project assumes a moderate 25% growth rate in tube failures annually. Additionally, the Alternatives Considered section of this proposal includes a table of variable growth rates and their associated NPVRR to demonstrate sensitivities associated with this unknown.

The Kettle Boiler Replacement project will improve Cane Run 7's expected reliability and availability by reducing the need for unplanned outages to perform Kettle Boiler leak repairs, reducing the potential for permanent unit de-ratings due to reduced Kettle Boiler cooling capacity from plugged tubes, and reducing chances of catastrophic gas turbine damage from water induction into the cooling circuit as a result of leaks. Doing nothing will leave the unit susceptible to such unplanned outages and corresponding repair costs.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed	384	603	1,263		2,250
2. Cost of Removal Proposed			100		100
3. Total Capital and Removal Proposed (1+2)	384	603	1,363	-	2,350
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)	(384)	(603)	(1,263)	-	(2,250)
8. Cost of Removal variance to BP (5-2)	-	-	(100)	-	(100)
9. Total Capital and Removal variance to BP (6-3)	(384)	(603)	(1,363)	-	(2,350)

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)	-	-	-	-	-

Proper mitigation of this risk will avoid the O&M costs associated with tube plugging outages that will likely become a routine occurrence if not mitigated via this project. However, since the concern was not known prior to submission of the current BP, the BP does not include these likely costs. As such, there are no O&M savings in reference to the current BP.

Contingency is included in the estimate. It is calculated as an additional 11% over the estimated taxed and burdened subtotal for the project.

Risks

The risks of not completing project include continued Kettle Boiler leaks leading to unit unavailability associated with unplanned outage time necessary to conduct repairs and ultimately the permanent and increasing de-ratings which will commence when the maximum number of Kettle Boiler tubes are plugged. Corrosion from slow undetected leaks or sudden catastrophic failure may result in gas turbine damage.

The nearest outage of sufficient duration for installation following the earliest possible delivery of replacement Kettle Boilers is not unit 2024. Instead of waiting until this time to execute this project, the station has concluded that it is prudent to replace the Kettle Boilers as soon as possible. This minimizes the amount of time the unit is exposed to the risks described above.

By taking advantage of industry experience gained since 2014 to develop relevant specifications and design requirements and through contracting with a heat exchanger manufacturer with Kettle Boiler construction experience, the risks of continued leaks following replacement are minimized.

Environmental Affairs (EA) has reviewed this project and determined that the Kettle Boiler replacement does not present an NSR risk. Completed EA analysis is available on the EA SharePoint site.

Alternatives Considered

1. Recommendation: Replacement in 2021 NPVRR: ($000s) $2,472

   Modify the Kettle Boilers during the spring 2021 planned outage as described above.

2. Alternative #1: Do Nothing NPVRR: ($000s) $ 99,810

   Continue to operate with the existing Kettle Boilers. The NPVRR for this alternative is estimated in consideration of the following costs:

   - Leak repairs require gas turbine shutdowns three days in duration at a forecasted frequency of two events per year, resulting in lost availability.
   - A corresponding de-rating will commence when more than the allowable number of tubes are plugged, resulting in a further availability reduction. There is uncertainty in forecasting the magnitude and timing of this reduction, with industry experience suggesting the annual rate of tube failures will grow over time. NPVRR for this alternative is shown as a function of the annual increase in tube failures in the table below:

Annual Tube Failure Rate Increase (%)	NPVRR ($000s)
10	42,837
20	80,975
30	112,642
40	126,270
50	143,877

The NPVRR listed for this alternative assumes an average course where tube leaks will initially develop at a rate of 5 tubes per year in each Kettle Boiler, with the number of additional leaking tubes increasing by 25% each year.

- Material and labor costs associated with leak repair work.

The estimated NPVRR does not include the cost associated with potential gas turbine damage previously described. Although a substantial concern, this failure type is far too unpredictable to place into the CEM with any veracity.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Cane Run 7 Kettle Boiler Replacement project for $2,350k to replace both Kettle Boilers at Cane Run 7, reducing the risk of unplanned availability and gas turbine damage.

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: November 1, 2019

Project Name: GH1 SH Pendant Platen Replacement

Total Capital Expenditures: $4,775k

Total O&M: $0k

Project Number(s): 144312

Business Unit/Line of Business: Power Generation

Prepared/Presented By: Jesse Chipman\Steve Turner

Brief Description of Project

The scope of the GH1 SH Pendant Platen Replacement project is to replace all 23 superheat pendants in their entirety, including new tubing extending to a new weld line in the penthouse. These components were previously replaced in 2000, but have reached the end of their useful life due to corrosion and erosion from fuels with higher sulfur and chlorine contents. The new pendants will be similar to components replaced on Ghent 2 in 2012, with respect to utilization of stainless steel. However, the proposed Ghent 1 pendants will have a substantial amount of Alloy 72 weld overlay to combat coal ash corrosion and graphitization.

Materials have been bid, and the scope of work for the labor is being developed to support competitive bidding. Delivery of the tubing will occur in early February 2021 in advance of the Spring 2021 Unit 1 planned outage. Project execution will occur during the Spring 2021 Unit 1 outage which starts on March 6th and ends May 8th, 2021. This project is included in the 2019BP and proposed 2020 BP for execution in 2021. This project is not considered ECR or GLT recoverable and KPSC approval is not required. The useful economic life of this project is 30 years.

Why is the project needed? What if we do nothing?

During the Spring 2019 outage, portions of a total of 75 tubes were replaced in the GH1 Superheat Platens due to corrosion and erosion which had resulted in tube wall loss. While these replacements addressed the immediate EFOR risk, the effects of corrosion and erosion from higher sulfur and chlorine fuels are widespread through these components. Application of Alloy 72 weld overlay to the full circumference of the bottom half of the new pendants will greatly reduce the rate of corrosion and erosion wall loss. Strategic application of weld overlay in the upper portion of the pendants will protect the tubing from sootblower erosion.

Failing to complete this project will result in increased risk of forced outages on Ghent 1 as the existing pendants experience continued wall loss. Due to the pendant spacing and the type of failure that usually occurs, significant secondary damage is common, which increases cost and duration of forced leak repairs. There are no compliance or safety related concerns. The successful completion of this project will ensure that our exceptional customer experience is maintained by the reliable operation of Ghent Unit 1.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	309	1,544	2,305		4,158
2. Cost of Removal Proposed			617		617
3. Total Capital and Removal Proposed (1+2)	309	1,544	2,922	-	4,775
4. Capital Investment 2019 BP	287	1,524	2,129		3,939
5. Cost of Removal 2019 BP			669		669
6. Total Capital and Removal 2019 BP (4+5)	287	1,524	2,797	-	4,608
7. Capital Investment variance to BP (4-1)	(22)	(21)	(176)	-	(219)
8. Cost of Removal variance to BP (5-2)	-	-	51	-	51
9. Total Capital and Removal variance to BP (6-3)	(22)	(21)	(125)	-	(167)

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)	-	-	-	-	-

This project is included in the 2019BP and proposed 2020BP for execution in 2021. The incremental funds in each year will be funded internally within the Ghent Capital Budget.

Risks

Failure to complete this project during the Spring 2021 outage would result in the risk of a tube leak or leaks prior to the replacement during the next outage of proper duration. Given the rate of wall loss due to corrosion and erosion, a delay is a major risk to unit reliability. The next outage of equal duration is in 2028. The Ghent Environmental Supervisor and Environmental Affairs have reviewed and approved this project.

Alternatives Considered

1. Recommendation: Replace SH Pendants in 2021 NPVRR: ($000s) $5,087

2. Alternative #1: Replace SH Pendants in 2028 NPVRR: ($000s) $6,581
   This alternative includes delaying the replacement of the SH Pendant Platens until the next outage of adequate duration. Prior to completing this project, the probability of a forced outage caused by a tube leak increases. An expected duration for such a leak is 4 days. Operation beyond 2021 without full replacement makes multiple failures per year likely. Maintenance in the form of tube replacements would have to also occur each outage in order to maintain two tube leaks per year.

3. Alternative #2: Do Nothing NPVRR: ($000s) $7,650
   The corrosion and erosion will continue to occur and multiple tubes leaks per year would be expected. In addition, maintenance repairs in the form of tube replacements during each outage would have to occur.

Conclusions and Recommendation

Investment Committee approval of the Ghent 1 SH Pendant Platen Replacement project for $4,775k is recommended to maintain the reliability of the Ghent Unit 1 boiler.

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: 11/22/2019

Project Name: Mill Creek 1 Front Lower Slope

Total Capital Expenditures: $2,294k (Including $110k of contingency)

Total O&M: $0k

Project Number(s): 147053

Business Unit/Line of Business: Power Generation

Prepared/Presented By: Michael Kjelby / Joe Didelot

Brief Description of Project

The purpose of this project is to mitigate risk of boiler tube failures (BTF's) on Mill Creek Unit 1 (MC1) front lower slope due to sliding ash erosion, thermal fatigue, and deformation caused by falling slag impacts. The project will replace the front lower slope panels with thicker tubing, including nickel and chrome alloy overlay to the areas of highest wear. Weld overlay reduces sliding ash erosion. Thicker tubing provides improved protection against falling slag impacts.

Milestones:

Project Approved	January 2020
Material Bids Received	March 2020
Material PO Issued	April 2020
Labor Bids Received	April 2020
Material Delivery	February 2021
Installation	March 2021

This project is included in both the 2019 BP and the proposed 2020 BP, though the scope of this projected has been reduced relative to the 2019 BP to accommodate changes to the outage schedule. This project is included in the 2020 BP at $1,837k. Total cost of the project is now estimated at $2,294k, including a $110k contingency, based on recent bids received for materials and labor on Mill Creek Unit 2 for similar work. The $2,294k cost is $457k more than budgeted in the 2020 BP, with all additional costs incurred in 2021. This increase will be funded within the Generation capital plan during the 2021 BP process.

Why is the project needed? What if we do nothing?

MC1 is a [redacted] boiler placed into commercial service in 1972. The original lower slope tubes were 0.188" minimum wall thickness ("MWT") tubes. These tubes, excluding the corner panels, were replaced in 1999. The existing slope has deformed due to falling slag, and thinned by erosion, causing multiple BTF's.

Inspections of the lower slope tubes are conducted during maintenance outages. Each inspection identified new gouges and additional erosion, requiring tube repair welds and replacements. Due to sliding ash erosion, outer tubes of the lower slope measured 0.108” MWT during a 2017 inspection. A 0.108” MWT represents a 45% erosion of MWT.

This project will eliminate previous damage and field repairs made to the front slope. The weld overlay on the outer tubes will increase the slope’s resistance to sliding ash erosion. Thicker tubing provides improved protection against falling slag impacts. If this project is not performed, the slope will continue to deteriorate in both MWT and repaired gouges, increasing the likelihood of BTF’s, thus increasing the unit EFOR.

Budget Comparison & Financial Summary.

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed		320	1,774		2,094
2. Cost of Removal Proposed			200		200
3. Total Capital and Removal Proposed (1+2)	-	320	1,974	-	2,294
4. Capital Investment 2019 BP		855	1,586		2,441
5. Cost of Removal 2019 BP			312		312
6. Total Capital and Removal 2019 BP (4+5)	-	855	1,898	-	2,753
7. Capital Investment variance to BP (4-1)	-	535	(188)	-	347
8. Cost of Removal variance to BP (5-2)	-	-	112	-	112
9. Total Capital and Removal variance to BP (6-3)	-	535	(76)	-	459

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)	-	-	-	-	-

Contingency for the project is $110k, 5% of the estimated expenses for the project.

Risks

Not completing this project will increase EFOR due to BTF’s. Forced outage repairs will become more frequent and require more time to complete. Deferral of this project will impact the feasibility of future projects within the boiler, since work overhead of the slope will need to be restricted. Suspension of other boiler projects will further increase BTF’s and unit EFOR.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $2,542

2. Next Best Alternative: NPVRR: ($000s) $3,026
   - The Next Best Alternative is delaying the project until 2023
   - Inflation of 3% a year is considered.

3. Do Nothing: NPVRR: ($000s) $6,904
   - The Do Nothing alternative is not completing this project.

In the Next Best Alternative and Do Nothing options, the model assumes that each BTF on the lower slope will cause a forty-eight (48) hour outage, with three BTF's per year commencing on 2021 and increasing BTF's in subsequent years.

The Spring 2021 outage presents the best opportunity to complete this project. This outage is the only planned outage of at least four weeks until spring of 2023, by which time MC1 is assumed to suffer several BTF's. The Do Nothing alternative would allow continued BTF's.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Mill Creek 1 Lower Slope project for $2,294k to increase the reliability of the Mill Creek 1 boiler.

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 and Contract Proposal for Investment Committee Meeting on: 12/19/2019

Project Name: BRCT8 C Inspection & Parts Reconditioning

Contract Name (Good/Service): BRCT8 [redacted] Parts and Services

Selected Vendor(s): [redacted]

Contract Authorization Requested: $6,200k (Including $211k/3.5% of contingency)

Contract Term: NA

Total Capital Expenditures Requested: $9,452k (Including $500k of contingency, including $150k of internal labor.)

Total O&M: $0k

Project Number(s): 147950

Business Unit/Line of Business: Generation

Prepared/Presented By: Greg Wilson

Brief Contract/Project Description

This proposal seeks approval for the capital required to perform a C-inspection on Brown Combustion Turbine Unit 8 (BRCT8), along with approval for a sole source award to [redacted] for the purchase of parts and materials to support the outage. The aforementioned scope of work will be performed under project 147950.

The Brown 11N2 combustion turbines were installed in the mid-1990's. Brown CT8 is currently 20,794 Equivalent operating hours (EOH) into its 24,000 EOH maintenance cycle. This is the second C inspection for the unit so total lifetime EOH at the time of the inspection is estimated to be 44,683.

EOH is the factor used to estimate material degradation of the unit's hot gas path parts. Turbine starts, trips, and fired hours all have a fixed number of EOH associated with them, and the accumulation of 24,000 EOH is considered the point where many of the hot gas path parts need to be replaced to avoid increased risks for failures.

A C-inspection replaces many of the components in the turbine and combustor sections of the unit. With this being a second interval C inspection (approx. 48K EOH) later stages of turbine blades and vanes will need to be replaced. When completed, the unit will be capable of another 24,000 EOH cycle.

Capital project 147950, BRCT8 C-inspection is included in the 2020 BP with $2,303k in 2020 and $8,387k in 2021. After successful negotiations with [redacted] for a significant discount on new parts if awarded an order this year, and reconditioned parts if [redacted] is awarded a contract for field services in 2020, $9,452k is being requested for the project. In order to secure the [redacted] discount to new parts, a purchase order will need to be issued this year for procurement of parts required to support the outage. A milestone payment is due upon [redacted] receipt of order. To cover this milestone payment, $700k will need to be pulled forward from 2020 into 2019. The 2019 payment was approved by the RAC in the 10+2 forecast. The 2020 forecast will be reduced to $200k. During next year's budget cycle, 2021 will need to be increased to $8,552k to match the new $9,452k total project cost.

Why is the project needed? What if we do nothing?

Material degradation of gas turbine parts can mainly be attributed to two factors, creep & thermal cycle fatigue. The first, creep, is attributed to long term exposure to the high temperatures created in the combustion process. The second, thermal cycle fatigue, is caused by the continual on/off cycling of the unit that creates thermal stresses in components. In both cases, degradation of the parts is very predictable. Exceeding the manufacturer's recommendation significantly increases the risk of failure.

Parts in the gas turbine requiring the most attention are those associated with the combustion process and those exposed to high temperatures from the hot gases discharged. These parts are called the hot gas path components, and include blades, vanes, liners, burners, and casings. These parts get replaced during a C-inspection in order to meet manufacturer's recommendation, maintain unit reliability, reduce risk of failure and safeguard insurability at reasonable premiums.

This is the second C-inspection for BRCT8. BRCT11 underwent an overhaul in 2018 where most of the hot gas path components were taken out of service and replaced. The components that were capable of being refurbished for another cycle will be reconditioned within the scope of this project, and will be placed in service on BRCT8. Likewise, the parts that are removed from BRCT8 that can be refurbished will be placed in service on BRCT9 during its overhaul, currently scheduled in 2025. The hot gas path component's proximity to the combustion process typically determines how many maintenance cycles a part can remain in service, and once it is taken out of service, whether it can be reconditioned or will need to be purchased new.

The following components from BRCT11 will be reconditioned and placed in service on BRCT8. Currently, the assets are assigned to BRCT11, and will need to be transferred to in-service assets on BRCT 8 after this project.

- Row 2 & 3 vanes; row 1, 2 blades
- Entry segments A & B
- Hot gas casing
- Lower Combustor Insert

Significant Milestones associated with this project are as follows:

Dec 2019:	Seek Investment Committee approval.
Dec 2019:	Place order to [redacted] for parts associated with C-inspection.
Fall 2020:	Competively bid services. Enter into contract for field services.
Fall 2021:	Perform a C-inspection on BRCT8 (8 week outage)

Contract Sole Source Authorization

Parts and materials needed to support the outage will be purchased from [redacted] under a sole source contract. The value of this contract is $6,200k, which includes $2,11k/3.5% in contingency. Many of the parts required to be replaced are considered proprietary to [redacted] and are simply not available from other vendors. The lack of supporting documentation does not allow us to re-engineer, or procure these parts on our own. We continue to make attempts to look for other providers, but with the limited number of units in the [redacted] fleet there has not been enough demand to facilitate a third-party market.

These parts will be purchased via a contract referencing a previously negotiated GSA that includes commercial terms.

[redacted] has offered to perform outage field services work for $1,610k. This amount is not included in the contract authorization portion of this paper. Station management and the commercial team prefer to qualify multiple bidders for field services, and plan to do so in the coming months. If it is determined that viable field services competitors to [redacted] exist, that work will be competitively bid in late 2020. Following these efforts, contract authorization will be requested to cover field services.

Project Financial Summary

The total cost for the project is expected to be $9,452k.

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	700	200	8,252		9,152
2. Cost of Removal Proposed			300		300
3. Total Capital and Removal Proposed (1+2)	700	200	8,552	-	9,452
4. Capital Investment 2020 BP		2,303	8,227		10,530
5. Cost of Removal 2020 BP			160		160
6. Total Capital and Removal 2020 BP (4+5)	-	2,303	8,387	-	10,690
7. Capital Investment variance to BP (4-1)	(700)	2,103	(25)	-	1,378
8. Cost of Removal variance to BP (5-2)	-	-	(140)	-	(140)
9. Total Capital and Removal variance to BP (6-3)	(700)	2,103	(165)	-	1,238

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

$500k (6%) in contingency has been included in the project to cover extra work or parts that may be required for findings after the unit is opened and an assessment is performed.

Risks

Risks associated with executing the project include potential additional funding to correct any unforeseen issues internal to the unit. Recent inspections have not indicated such problems, but with limited internal access the possibility exists.

Environmental Affairs has reviewed the project and has no issues from an NSR perspective.

Project Alternatives Considered

1. Recommendation: Perform C Inspection NPVRR: ($000s) $9,623

2. Alternative #1: Do Nothing NPVRR: ($000s) $14,068
   Do nothing and continue to operate without performing an inspection. This is not a viable option and will lead to catastrophic damage to the unit. Hot gas path component's long-term exposure to creep and cyclic fatigue will inevitably lead to a failure. Any failure of a component in the rotating part of the machine would lead to significant collateral damage that would escalate repair costs tremendously. We estimate the costs of returning the unit to service after such an event would be two times the costs of a C-inspection. In addition to this, it would likely take up to a year to return the unit to service. The capital evaluation model predicts that this will occur in 2025.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the BRCT8 C-inspection project for $9,452k to ensure the reliability and dependability of the generating asset going forward, along with the sole source award to [redacted] for parts and materials of $6,200k.

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced:

The Capital project spending and contract authority requests included in this Investment Proposal have 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 the capital project and contract authority requests.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
BRCT8 C Inspection & Parts Reconditioning

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the BRCT8 C Inspection & Parts Reconditioning contract for $6,200k that will cover a term of two years (December 2019 to December 31, 2021) to [redacted]

Sourcing Leader [If applicable; the approvers for this table can be modified as needed]		Proponent/Team Leader [If applicable]	
Supplier Diversity Manager [If applicable]		Manager [If applicable]	
Manager - Supply Chain or Commercial Operations		Director – Supply Chain or Commercial Operations	
Director [If applicable]		Vice President [If applicable]	

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Investment Proposal for Investment Committee Meeting on: December 19, 2019

Project Name: GH1 PJFF Bag Replacement 2021

Total Capital Expenditures: $3,176k (Including $96k of contingency and $14k of internal labor) [$2,590k is ECR under Project 135277 / $586k is non-ECR under Project 161247]

Project Number(s): 135277 / 161247

Business Unit/Line of Business: Power Generation

Prepared/Presented By: Jen Price

Brief Description of Project

The Ghent Unit 1 (GH1) pulse jet fabric filter (PJFF), designed by [redacted] has been in service since May 2015. The PJFF is comprised of two casings (1-1 and 1-2) each containing ten compartments. Each compartment holds 864 filter bags, totaling 8,640 bags per casing, and 17,280 bags for the entire system. The filter bags, which are woven fiberglass finished with an acid resistant polytetrafluoroethylene (PTFE) membrane, serve as the filtering medium for the boiler flue gas. Each bag is 6" in diameter and 26'-9" in length.

Beginning in the spring of 2016, in-service bags have been sampled from GH1 during unit outages. Third party testing has been performed in order to establish and monitor the bag life cycle; thirty-six (36) bags have been analyzed to date. In addition to sending off bags for analysis, leak tests utilizing fluorescent powder (identical to the original equipment startup activities) have been conducted during unit outages to identify bag failures. No bag failures have been detected to date and although bag analysis results have shown a decline in endurance/durability values, overall the bags have given good service. Based on the most recent results, the GH1 bag replacement was pushed out one (1) year from 2020 to 2021.

In order to ensure continued reliability of the unit, it is recommended to replace the filter bags during the 2021 spring outage. At that time, the bags will have been in service for 6 years, exceeding the expected 5-year life span. It is also recommended to replace the current cages. During the most recent inspection, every cage that was removed in order to obtain a sample bag was deemed to be in poor condition. One (1) cage from each compartment was inspected, for a total of twenty (20) cages. All cages had widespread surface corrosion, were bright orange in color and the surface was very rough to the touch. Cages in good condition are usually silver/gray in color and smooth to touch. It is not recommended to re-install the current cages as they could potentially scratch the inside of new bags after being re-inserted. As a result, new bags would be more susceptible to failing due to the roughness of the cages creating weak spots from the inside out.

Installation of new bags and cages will allow the unit to continue operating as necessary to comply with particulate matter (PM) emissions limits.

Ghent Unit 1 work is scheduled to be performed during the spring 2021 outage. At the earliest, the PJFF can be accessed beginning on March 15, 2021. All work, including the leak test and final inspections, is to be complete by May 7, 2021. The below scope items were competitively bid as part of a fleet wide initiative; [redacted] was awarded both the bag purchase and installation services. It is expected that the purchase of cages will be sole-sourced to [redacted] who holds a US patent on LG&E-KU's current cage design, more specifically the twist-lock mechanism that holds together the two-piece cage.

The project scope includes the following:

- New filter bag fabrication
- Inspection of pulse air components including pulse air piping, headers, and j-pipes
- Removal of existing bags and cages
- Disposal of used bags and cages
- Installation of new bags and cages
- Replacement of various gaskets; top hatches, pulse air pipe compression couplings, hopper doors, etc. (labor only, not material)
- Leak test with fluorescent powder to ensure proper installation

The expected project milestones are as follows:

- January 2019 — RFQ released
- March 2019 — Bids received
- July 2019 — Contract awarded
- January 2020 — Bag substrate material notice to proceed
- June 2020 — Release PO for cage purchase/production
- November 2020 — Delivery of new bags and new cages
- March 2021 — Pre-outage mobilization activities, outage starts, work begins
- May 2021 — Work complete

The total project cost, discussed in more detail in the *Budget Comparison & Financial Summary*, is estimated to be $3,176k. Approximately $2,590k will be spent prior to April 30, 2021 and is ECR recoverable. The remaining $586k will be non-ECR. A total of $3,100k is included in the 2020BP. The increased project cost is based on updated estimates for the purchase of cages and additional labor costs for cage disposal and installation which was not part of the original bid package.

Why is the project needed? What if we do nothing?

In order to continue to meet PM emissions limits set forth by the Environmental Protection Agency (EPA), it is recommended to replace the GH1 fabric filter bags and cages in 2021 before bags begin to fail. Once bag failure occurs, it will continue at an exponential rate and ultimately cause forced outages due to not being able to maintain PM compliance.

If bags are not replaced during the 2021 spring outage, the unit runs the risk of forced outages. If the project is continuously delayed, the probability of forced outages increases each year. The option to change bags in select compartments upon failure while the unit is online not only jeopardizes unit reliability, but also decreases the life of new bags due to the majority of the gas flow going through the new, more permeable bags. Changing bags online also poses safety risks because of increased temperatures in the work area and compartments not being fully isolated due to small imperfections in the inlet and outlet dampers.

By replacing all the GH1 PJFF filter bags as they near closer to end of life, as well as replacing the cages which have been deemed to be in poor condition, we are safeguarding the reliability of the equipment and the unit, as well as minimizing operations and maintenance costs which would likely be spent if this work was not complete.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed		2,566	321		2,887
2. Cost of Removal Proposed			289		289
3. Total Capital and Removal Proposed (1+2)	-	2,566	610	-	3,176
4. Capital Investment 2020 BP		2,598	331		2,929
5. Cost of Removal 2020 BP			171		171
6. Total Capital and Removal 2020 BP (4+5)	-	2,598	502	-	3,100
7. Capital Investment variance to BP (4-1)	-	32	10	-	42
8. Cost of Removal variance to BP (5-2)	-	-	(118)	-	(118)
9. Total Capital and Removal variance to BP (6-3)	-	32	(108)	-	(76)

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

The 2021 shortfall will be funded internally within the Ghent capital plan. A contingency of $96k is planned for this project and is prudent given that firm pricing has been secured for the major materials and labor for the project.

Risks

Failure to meet particulate emissions limit: If the filter bags are not replaced, there is a risk that particulate emissions will increase and pose a risk to the unit's reliability.

Forced outages: If the bags are not replaced there is a risk that the particulate emissions will not meet compliance regulations and the unit will be forced to take outages to replace sections of broken bags.

Changing bags online: The bags could be changed one compartment at a time while the unit remains online, however, the life expectancy of the new bags would be greatly affected due to gas flow taking the path of least resistance through the new, clean bags. Also, changing the bags online constitutes a higher risk in safety.

Alternatives Considered

1. Recommendation: Purchase/Install New Bags — NPVRR: ($000s) $3,707k
2. Alternative #1: Delay Project One (1) Year — NPVRR: ($000s) $3,732k
3. Alternative #2: Do Nothing — NPVRR: ($000s) $6,931k

Recommendation – Purchase/Install New Bags

The purchase and installation of new bags in 2021 is the recommended option. This plan is least cost over the life of the project, avoids the probability of unit outages, and ensures PM emissions compliance.

For the recommended project, the following assumptions were made:

- All materials purchased and delivered to site in 2020
- Capital spend in 2021 is KU labor, contractor labor, and contingency

Alternative #1 – Delay Project One (1) Year

Delaying the project one (1) year to the next planned unit outage presents multiple risks. These risks include decreased PM removal efficiency and risk of unit outages due to inability to maintain environmental compliance. As bags start to fail, the failure will accelerate exponentially leading to PM compliance issues and potentially multiple unit outages to replace failed filter bags. This alternative is not recommended due to the above risks and unfavorable NPVRR.

For alternative #1, the following assumptions were made:

- Capital spend occurring in 2021 and 2022; all materials purchased and delivered to site in 2021
- 2% inflation rate
- 25% probability of a four (4) day forced outage in 2021 due to replacing failed bags
- Incurred costs include labor and material for replacing bags in two (2) total compartments if a failure occurred. Incurred costs were calculated as 10% of [redacted] bid plus $10k of miscellaneous plant support and KU supplied materials.

Alternative #2 – Do Nothing

This alternative is not recommended as this would yield a high probability of forced unit outages due to inability to meet PM emissions requirements and would be unfavorable to unit operations.

For alternative #2, the following assumptions were made:

- 25% probability of a four (4) day forced outage starting in 2021 and increasing by 25% each year; the probability would be 100% by 2024
- Incremental costs for 2021-2024 are the same as alternative #1, including 2% inflation each year
- 100% probability of a one (1) week forced outage starting in 2024
- Incremental costs for 2024 and beyond include labor and material for replacing bags in four (4) total compartments, including 2% inflation each year

Conclusions and Recommendation

It is recommended that the Investment Committee approve the GH1 PJFF Bag Replacement 2021 project for $3,176k to continue to meet particulate matter emission limits and avoid forced unit outages.

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: January 29, 2020

Project Name: GH DTLS & Pipe Conveyor Recons

Total Capital Expenditures: $6,500k

Total O&M: $0k

Project Number(s): 161436

Business Unit/Line of Business: Power Generation

Prepared/Presented By: Steve Turner

Brief Description of Project

The Ghent Dual Truck Loading Station (DTLS) is part of the Coal Combustion Residuals (CCR) management facilities at the Ghent Station, commonly called the CCRT. This facility houses equipment to receive CCR materials (flyash, bottom ash, and gypsum) from the pipe conveyor and transfer it to trucks for hauling to the landfill. On November 20, 2019, the DTLS facility sustained a fire that caused significant damage to the pipe conveyor, the DTLS building, and associated equipment. The cause of the fire is currently under investigation, and as a result of the fire, the DTLS and pipe conveyor are currently out of service.

The Ghent pipe conveyor is approximately 1.5 miles long and conveys material from the CCRT to the DTLS building. Utilization of the pipe conveyor and DTLS provides the benefits of reduced hauling distance for CCR materials to be placed in the landfill, reduced cost of CCR placement, and reduction of fugitive dust emissions associated with hauling by truck from the CCRT. In fact, the current site air permit for Ghent allows less than 10% of the total annual CCR production to be hauled by truck from the CCRT to the landfill.

The scope of this project will be to conduct a thorough investigation of the cause of the fire, complete an evaluation of the remaining structure to determine what must be replaced, and execute the cleanup, demolition, and re-construction of the facility. In early 2019, Ghent initiated project 144365 to replace the pipe conveyor belt due to age and condition. Prior to the fire, major materials had been delivered but were not yet installed, and thus were not impacted by the fire. Given that a portion of the belt was damaged in the fire, the new belt will be installed simultaneously with the DTLS reconstruction. Costs associated with the belt replacement will be captured by project 144365, while the remaining DLTS reconstruction costs will be captured with project described in this paper. It is anticipated that this work will be completed in the Summer of 2020. The project is ECR recoverable and has a useful life of 30 years.

Why is the project needed? What if we do nothing?

Reconstruction of the Ghent DTLS and pipe conveyor will provide the least-cost process for transporting CCR material to the Ghent landfill, as well as allow for operation within the current Ghent air emissions permit. Using present contracted rates for CCR hauling and applying a 2%

annual inflation, transporting CCRs to the landfill from the DTLS is $90 million less expensive over the 30-year life of the facility.

In addition, the shorter truck haul of CCR materials to the landfill from the DTLS reduces fugitive dust emissions associated with hauling from the CCRT. The current Ghent air emissions permit places an annual limit on the quantity of trucks which can haul from the CCRT to the landfill due to dust emissions from gravel roads around the CCR facilities. This limit is less than 10% of the total CCR production at Ghent. As a result of the current fire damage, CCR materials are being beneficially reused for ash pond closure, thus avoiding hauls to the landfill. However, operation within the current air emissions permit would not be possible in the future once ash ponds are closed unless the DTLS and pipe conveyor are in service or significant investments are made in road paving.

Once the root cause is determined and general cleanup completed, a third-party engineering firm will provide direction on specific structural components which require replacement. In addition, portions of the pipe conveyor structure, loadout conveyors, and shuttle conveyor will require replacement. Based on initial review of the damaged facility, the cost of reconstruction for the DTLS and pipe conveyor is estimated at $6,500k. The work is anticipated to be complete in Summer 2020. The Company will make a claim with insurance for recovery of the cost, though a $2,500k deductible applies. Additionally, upon completion of a root cause and origin study, a claim with a third party contractor may be made. The pipe conveyor belt was previously planned for replacement under project 144365. At the time of the fire, the replacement belt material had been received, but not installed. The installation of the belt will be made along with the DTLS reconstruction, though installation costs will be allocated to the original project.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed		4,000			4,000
2. Cost of Removal Proposed		2,500			2,500
3. Total Capital and Removal Proposed (1+2)	-	6,500	-	-	6,500
4. Capital Investment 2020 BP					-
5. Cost of Removal 2020 BP					-
6. Total Capital and Removal 2020 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	-	(4,000)	-	-	(4,000)
8. Cost of Removal variance to BP (5-2)	-	(2,500)	-	-	(2,500)
9. Total Capital and Removal variance to BP (6-3)	-	(6,500)	-	-	(6,500)

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

Total project costs remain as estimates at this point until cleanup and engineering analysis can be completed. Funding of $10,000k was authorized by emergency activation approval of the Investment Committee on November 26, 2019.

Risks

As this project seeks to reconstruct existing CCR handling facilities essentially in-kind, the technology is proven, and the risks associated with executing the project are minimal. Failing to complete the project will result in significantly higher operating expenses associated with CCR disposal, as well as an inability to comply with the current air emissions permit. The project will be reviewed by Environmental Affairs and the Ghent Environmental Department, but as a like-kind replacement is unlikely to require any special review or permitting.

Alternatives Considered

1. Recommendation: Rebuild DTLS and Pipe Conveyor NPVRR: $7,603k

The recommendation for this project is to complete reconstruction of the DTLS and pipe conveyor structure to minimize future CCR disposal costs and comply with the current air emissions permit.

2. Alternative #1: Haul CCRs from CCRT to Landfill NPVRR: $43,320k

This alternative reflects the incremental costs of hauling CCR materials to the landfill from the CCRT area over hauling from the DTLS due to the longer travel distance. This alternative should not be chosen as ongoing O/M costs for CCR disposal will be significantly higher than the recommended case. Additionally, this alternative is not possible within the current air emissions permit.

Conclusions and Recommendation

Investment Committee approval of the GH DTLS & Pipe Conveyor Reconstruction project for $6,500k to restore optimal operation of the Ghent CCR disposal process is recommended.

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: Click here to enter text.

Project Name: Mill Creek 2 Lower Slope

Total Capital Expenditures: $3,186k (Approved on 04/04/2019)

Total O&M: $ 0 k

Total Revised Capital Expenditures: $4,120k

Project Number(s): 147056

Business Unit/Line of Business: Power Generation

Prepared/Presented By: Michael Kjelby

Description of Incremental Ask

Original Approved Capital Expenditures		$3,186k
Revised Capital Expenditures Requested		$4,120k
Total Increase Requested		$934k

The revision of the Mill Creek 2 Lower Slope project is due to changing the labor contractor at additional costs for the project. The project was initially bid as part of the fleet boiler craft labor, which covered Spring 2019 through Spring 2020 outages. Initial bids were received in September of 2018.

Mill Creek received three bids for the work, from [redacted] has prior performance issues at Mill Creek. [redacted] was new to LG&E, and [redacted] bid price was substantially higher than the other two. Therefore, LG&E elected not to award the work until [redacted] demonstrated its capabilities on the Spring 2019 Ghent hot reheat pipe project. [redacted] was marginally successful on the hot reheat pipe project.

Due to the marginal success of [redacted], and in hopes of obtaining a better price from [redacted], the project was bid again. Bids were received from [redacted] in early September 2019. [redacted] submitted bids of approximately $1.8M and $1.9M, respectively. [redacted] submitted a bid for $2.4M. Since none of the bids received were competitive with the existing bid from [redacted], Mill Creek intended to award the work to [redacted]. Shortly after, however, [redacted] failed to perform at Trimble County during its outage and was ultimately terminated for cause on November 7, 2019.

Mill Creek immediately resumed discussions with [redacted] was not able to provide an acceptable supervisor for the work. [redacted] informed Mill Creek on December 6, 2019 that it would not be able to perform the work. Mill Creek then began discussions with both [redacted], the two remaining viable bidders.

Mill Creek favored award of the contract to [redacted], the lower of the two bidders. However, on January 9, 2020, two weeks after receipt of a draft contract for the work, [redacted] informed Mill Creek that its owners were discontinuing work in the power generation business and therefore [redacted] would not be able to sign the contract. [redacted] remains interested and committed to performing the work.

Deferral of the project to the next Mill Creek Unit 2 planned out in 2022 has been evaluated but is not the best course of action because of other planned MC2 boiler work. Deferral would increase the risk of BTF's in the lower slope as well as other areas of the boiler and make future outage schedules more difficult to manage. Continuing with the project is recommended over delaying the project or not completing the project. Not completing the project will increase EFOR due to increased boiler tube failures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	Pre-2020	2020	2021	Post 2021	Total
1. Capital Investment Proposed	467	3,403	-	-	3,870
2. Cost of Removal Proposed	-	250	-	-	250
3. Total Capital and Removal Proposed (1+2)	467	3,653	-	-	4,120
4. Capital Investment 2020 BP	802	1,700			2,502
5. Cost of Removal 2020 BP		198			198
6. Total Capital and Removal 2020 BP (4+5)	802	1,898	-	-	2,700
7. Capital Investment variance to BP (4-1)	335	(1,703)	-	-	(1,368)
8. Cost of Removal variance to BP (5-2)	-	(52)	-	-	(52)
9. Total Capital and Removal variance to BP (6-3)	335	(1,755)	-	-	(1,420)

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

Contingency for the project is $200k, 5% of the revised expenses for the project. The incremental $1,755k over the 2020 Business Plan will be funded within the Mill Creek capital plan and is included in the 0+12 RAC Forecast.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $4,556

2. Next Best Alternative: NPVRR: ($000s) $4,568
   - The Next Best Alternative is delaying the project until 2022
   - Inflation of 2% a year is considered.

3. Do Nothing: NPVRR: ($000s) $4,623
   - The Do Nothing alternative is not completing this project.
   - In the Next Best Alternative and Do Nothing options, it is assumed that each tube leak on the lower slope will cause an outage forty-eight (48) hours long. It is assumed that two tube leaks per year will occur on the lower slope starting in 2020, then the number of tube leaks per year will increase in 2021, 2024, and 2028.

The Spring 2020 outage is the most ideal timeframe to complete this project since the outage is six weeks and no other boiler work is scheduled to be completed overhead of the slope. The Do Nothing alternative would allow continued BTF's.

Conclusions and Recommendation

It is recommended that the Mill Creek 2 Lower Slope project be executed in 2020 to ensure continued, reliable operation of Mill Creek 2 boiler. In the event this cannot take place, increased boiler tube failures, repairs, and inspections will take place on both the lower slope and other boiler components.

It is recommended that the Investment Committee approve the Mill Creek 2 Lower Slope project for $4,120k to ensure continued, reliable operation of the Mill Creek 2 boiler.

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: 3/31/2020

Project Name: GH4 Generator Stator Rewind

Total Capital Expenditures Requested: $4,250 k

Total O&M: $ 0 k

Project Number(s): 162409

Business Unit/Line of Business: Power Generation / Ghent Station

Prepared/Presented By: Dylan Staples / Steven Turner

Brief Description of Project

This purpose of this project is to rewind (replace the stator bars) the Ghent Unit 4 generator during the spring 2020 outage. This is an emergent project and is recommended due to results of generator electrical testing conducted in the spring 2020 outage which revealed an unacceptable level of degradation in the generator stator electrical insulation. The rewind will utilize the set of replacement stator bars previously purchased for the Ghent Units. Failure to execute this rewind would sustain a significant risk of a generator electrical failure and resultant unit forced outage. Completion of the stator rewind project is required to maintain generator reliability.

The anticipated schedule for execution of the rewind is six weeks from notice to proceed. Although mitigation plans are being developed, prudent practices around COVID-19 prevention could slow the project. The six-week completion schedule would result in outage completion within one week after the original outage completion date.

[redacted] is presently on-site conducting the planned inspection and overhaul work. In order to minimize outage disruption, best utilize existing resources, and utilize OEM technical knowledge base, execution of the Ghent 4 stator rewind by [redacted] is proposed. Additionally, with the outbreak of the COVID-19 virus, minimizing additional contract personnel on-site is preferred. Since [redacted] is on-site, fewer additional personnel are required to perform the rewind relative to awarding the work to another contractor.

The 2020 Ghent 4 outage turbine and generator inspection work was competitively bid and awarded to [redacted] through the Investment Committee process in December 2018. A copy of the December 2018 approval is attached. While sufficient authority currently remains under the December 2018 approval to perform the Ghent 4 Stator Rewind, a revised contract authorization request will be forthcoming in the latter part of 2020.

Why is the project needed? What if we do nothing?
[redacted] released Technical Information Letter [redacted] in May 1991 identifying several types of leaks for [redacted] water cooled generators such as Ghent Unit 4. One common type of leak is a stator bar clip-to-strand joint leak. This type of leak allows water to migrate between the stator bar and its ground wall insulation and cause the insulation to age much faster.

There have been multiple instances of clip-to-strand leaks on GH4 including those found in 2008, 2014, and 2019. An additional leak has been found in the 2020 outage. In each of these instances, DC Leakage Testing, also known as Generator Hi-Pot Testing, has been performed to verify the integrity of generator stator insulation. Recent tests have revealed elevated amounts of leakage current in the left phase. Elevated leakage current is a common indication of damaged insulation due to the stator bar leaks described above. During the spring 2020 outage, the DC Leakage Test was aborted due to an additional step increase in leakage current. Had the test been allowed to proceed, damage to the generator would have been possible.

As an additional benefit, [redacted] which recommends [redacted], will be addressed during this stator rewind. The flexible leads provide a mechanical and electrical connection between the stator winding and the rest of the generator circuit. Replacing the flexible leads and associated hardware reduces the risk of joint fatigue and potential electrical fault. The flexible lead kit is included in the spare parts for the stator rewind.

There is a high level of forced outage risk associated with continuing to operate GH4 in its current condition due to a stator bar failure. This project is required to maintain generator reliability.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	2,833				2,833
2. Cost of Removal Proposed	1,417				1,417
3. Total Capital and Removal Proposed (1+2)	4,250	-	-	-	4,250
4. Capital Investment 2020 BP					-
5. Cost of Removal 2020 BP					-
6. Total Capital and Removal 2020 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(2,833)	-	-	-	(2,833)
8. Cost of Removal variance to BP (5-2)	(1,417)	-	-	-	(1,417)
9. Total Capital and Removal variance to BP (6-3)	(4,250)	-	-	-	(4,250)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed					-
2. Project O&M 2020 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks

There is no accurate method to predict the failure of stator bar insulation. However, the results of the DC Leakage Test and [redacted] experience within the LG&E/KU fleet emphasize the level of risk associated with continuing to operate GH4 in its current condition. The risks associated with the alternatives presented are increased possibilities of forced outages due to stator bar failures.

If this project is not completed now, the potential for stator bar insulation failure increases with time. The next available outage window for a project of this duration is in 2027. The probability of GH4 experiencing a forced outage is assumed to increase each year by 5% and is expressed in the alternatives considered below.

This project has been reviewed with the Ghent Station Environmental Supervisor and there are no risks associated with this project.

Contractually, as an amendment to the existing three-year, turbine/generator contract with [redacted] the risk mitigation provisions of that contract will apply. These included heightened insurance requirements negotiated with assistance of and approved by [redacted], heightened limits of liability to allow access to the insurance, and a parent guarantee from [redacted], reviewed and approved by Credit & Contract Administration and Legal.

Project Alternatives Considered

1. Recommendation: NPVRR: ($000s) 4,971

2. Alternative #1: Delay until 2027 outage NPVRR: ($000s) 5,102

   Alternative #1 contemplates a delay of the project until the next outage of sufficient duration and incurs the risk of a forced outage until that time. The CEM assumes the risk of a forced outage increases 5% per year until project execution.

3. Alternative #2: Do nothing until failure NPVRR: ($000s) 6,590

   Alternative #2 contemplates not executing the project and would result in not mitigating the known risk of an electrical fault in the generator. This alternative also assumes a 5% probability of stator bar insulation failure, with the probability increasing 5% each year until reaching 100% probability of failure. At that point, a generator rewind would be required to restore availability of the unit.

Conclusions and Recommendation

Investment Committee approval of the GH4 Generator Stator Rewind project for $4,250k to maintain generator reliability is recommended.

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	

Contract Proposal for Investment Committee Meeting on: December 19, 2018

Contract Name: Turbine / Generator Major 2019-2021

Contract Total Seeking IC Approval $44,898k

Total Contract Expenditures: [redacted]

Business Unit/Line of Business: Power Generation

Prepared/Presented By: Bob Barnett / Ross Lerch / Kenny Noonan

Executive Summary

This contract proposal includes labor, equipment and material required for 15 scopes during the 2019-21 outage cycle. These include 6 turbine/generator major and 9 feed pump turbine (FPT) / valve outages. The stations involved are EW Brown, Ghent, Mill Creek, and Trimble County. The contract includes specific scopes funded by OPEX and Capital. The base recommendation is to divide the award between [redacted] The authority requested under this scenario is $44,898k which includes a [redacted] contingency and the incremental premium of $597k for the transactional purchase of the E.W. Brown 3 (EWB 3) blades. A transactional Purchase Order (PO) in the amount of [redacted] for the EWB 3 turbine blades may be issued to [redacted] prior to the final contract with [redacted] This transactional PO includes a [redacted] premium based on blade supply only by [redacted] versus material and installation both being provided by [redacted]. If a final agreement is reached with [redacted] that allows for both material supply and installation on EWB 3, a discounted blade price will be in the final contract price.

All three companies are certified contractors. However, additional risk mitigation has been recommended by LKE's insurance consultant when work involves turbines and generators. Both [redacted] and [redacted] have met our request and will accept higher limits of liability including risk associated with property damage. To date, [redacted] has been reluctant to accept these higher limits. Competitive bids were solicited through a formal request for proposal process. If LKE cannot reach terms with [redacted], the contract expenditures for contracts divided between [redacted] and [redacted] is [redacted] including the transactional PO to [redacted] for the blades.

Four contractors were invited to bid both the major and FPT/valve outages. Those are [redacted]. Three additional contractors [redacted] were invited to bid only the FPT/valve scopes. [redacted] is an incumbent and woman owned business.

Background

Power Generation's strategy over the last decade, with respect to planned turbine/generator outage work, has involved contracting through a competitive bid process for a consolidated scope across the LKE fleet. This approach benefits both LKE and the contractor(s) by securing skilled labor well ahead of the outages. In addition, budget forecasts can be managed according to the contracts negotiated. The strategy deployed during the 2016-18 cycle included 4 major and 7 FPT / valve outages. [redacted] and [redacted] just completed the last major and valve outages respectively. The outages associated with TC2 2018 – 19 were managed as a separate contracting effort and those scopes awarded were divided between [redacted] and [redacted]

The outages included in this effort are:

2019	2020	2021
	Majors	
Mill Creek 1 major S19	Ghent 4 major S20	Ghent 1 major S21
Ghent 2 major F19		
Mill Creek 3 major F19		
EW Brown major F19		
	FPT/Valve	
Ghent 4 valve S19	Ghent 1 valve S20	Mill Creek 1 valve S21
Ghent 1 FPT S19	Trimble Co 2 FPT/valve S20	Trimble Co FPT F21
Trimble Co. 1 valve F19	Mill Creek 2 valve S20	
	Ghent 3 valve F20	

Scheduled major overhauls of steam turbine / generator machines is an industry recognized standard practice due to normal wear and tear associated with the conditions of service. The stations and LKE's manager of turbine and generator maintenance in coordination with generation planning develop and agree to the schedule of these inspections and overhauls.

Contract Description

The contracts will include fixed prices for the work defined in each outage scope. The contracts will become effective during the fourth quarter of 2018 and continue through the end of the final outage in each respective contract. The prices are firm through the duration of the contract unless an outage schedule shifts to a future year. Escalation, if applicable, will be limited by the annual change in the Bureau Labor Statistics Employment Cost Index for private industry workers in the [redacted] contract. Both [redacted] and [redacted] have agreed to a 1.5% cap on price escalation. Although highly unlikely on these units, cancellation fees have been agreed to with each contractor in the range of 2.5-4.0%. These contracts include a specific division of responsibilities between LKE and the contractor.

Progress payments will be made during each outage based on submittal and acceptance of detailed outage plans, mobilization, disassembly, reassembly and final report.

Each contract will include negotiated hourly rates for emergent work and allow for emergent work to be performed using these rates or to negotiate change orders on a lump sum or unit rate basis. Liquidated damages have been included in each contact for late completion. No harm / No foul was proposed by each contractor, but negotiated out of the final contracts. LKE retains the right to terminate for breach even in the event a contractor is subject to liquidated damages.

Each contract will include a specified “discovery date”. This date, typically 21 days into the major outages and 7 days into the FPT/valve outages, is a date that the contractor should have completed all inspections and reported material defects in the major components of the machines. If emergent work discovered after the discovery date results in an outage extension, each contract includes a provision that requires the contractor to provide significant discounts on its labor associated with the extension and emergent work.

All three contractors are signatory to negotiated General Services and/or Master Agreements. The contracts with [redacted] and [redacted] contain added property damage coverage and higher limits of liabilities as discussed below under Risks. [redacted] has been reluctant to agree to these provisions to date.

Economic Analysis and Risks

- **Bid Summary**

  Two request for proposals were issued to prospective bidders. One included the 6 major and 9 FPT/valve outages and was sent to four major turbine / generator contractors [redacted] and [redacted]. All four responded and bid on all the scopes with the exception of SEI, which only bid the EWB 3 and Ghent 1 outages [redacted] The second RFP was issued on the same date to three other prospective bidders [redacted] This RFP only included the FPT/Valve scope. These contractors were deemed capable of performing the smaller scopes. [redacted] declined to bid. The team thought there may be some savings by including smaller contractors for work outside the majors. [redacted], an incumbent and a WBE, submitted bids for each FPT/Valve outage, but was only competitive on one scope by about [redacted] on a [redacted] outage out in 2020. The team determined the benefits associated with awarding that scope in a larger contract to one of the recommended contractors with respect to risk outweighed the small cost difference.

  All bidders are certified with the exception of [redacted] and [redacted] Both have been pursuing business from LKE. [redacted] declined to bid without reason. Individual negotiation meetings were held with [redacted] on clarifications to the scope and specifications. Multiple negotiations over the GCA were held with [redacted] but fell through on the issues of liability limits and property damage. The team plans to continue negotiation on a GCA with [redacted] beyond this effort. In addition, multiple negotiations with [redacted] and [redacted] were successful with respect to both accepting greater level of risk. If similar negotiations with [redacted] fall through, then [redacted] will only be awarded the purchase of the blades as mentioned above.

The following table summarizes the evaluated costs and recommended contract values. The recommendation is based on the least cost to LKE for each scope except if a contract cannot be agreed to with [redacted] Attachment 1 provides the summary of recommended award by scope.

	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total *Evaluated* Cost <u>All</u> Work (1, 2, 3)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total *Evaluated* Cost All Work Split (1,2,3)		[redacted]			
Total *Contract* Split with [redacted] awarded both the blade supply and install on EWB 3 (3)	[redacted]	[redacted]	[redacted] (8)	N/A	N/A
		Total [redacted] ***(10)***			
Total *Contract* Split with [redacted] awarded install and [redacted] awarded blade supply on EWB 3 (3)	[redacted]	[redacted]	[redacted]	N/A	N/A
	Total [redacted] (9,10)				

Notes –
1 Includes using [redacted] premium blade prices in [redacted]
2 Includes using [redacted] packing prices in [redacted]
3 Does not include contingency but does include est. [redacted] steam path repairs per major
4 Includes [redacted] evaluation adder to [redacted] for 8 days extra at EWB
[redacted] only bid EWB 3 & Gh 1 major and Gh 1 FPT and Valve
6 LKE could not reach an agreement on terms and conditions with [redacted]
7 [redacted] only bid the FPT and valve scopes.
8 Includes discounted blade price for EWB blades
9 Includes EWB 3 premium blade price of [redacted]
10 The variance between [redacted] and [redacted] is the [redacted] premium for [redacted] to supply only the blades on EWB 3. Negotiations are not finalized, and this premium is based on the line provided in the bid submittal

Financial Summary

The following table projects spend by year over the contract period. The requested 20% contingency is supported by recent outages. The actual condition of a machine following 8 years of operation is difficult to pinpoint. However, it appears that due to the increased use of generation fueled by gas, emergent work associated with solid particle erosion has increased. The emergent work experienced in the 3 most recent outages is as follows.

- Mill Creek 2 S18; [redacted] 16 change orders @ 15% over base price
- Trimble Co. 2 S18; [redacted] 15 change orders @ 15% & [redacted] 7 change orders @ 69% over base price.
- Ghent 3 F18; [redacted] 24 change orders @ 19% over base price.

Contract expenses ($k)	2018	2019	2020	2021	2022	Post 2022	Total
Amount requested based on contract award estimates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Contingency Amount Requested	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Incremental PO for EWB blades	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total contract authority requested	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Risk of Contract

During this contracting cycle LKE engaged [redacted] as its risk management contractor. Their recommendations include increasing the insurance requirements for turbine / generator components. The team identified what it considers the single worst case damage scenario; a generator rotor valued at $10M. This required the current GSA's to be amended with respect to the limits of liability wording previously agreed to. This will allow LKE to have access to that insurance. Both [redacted] and [redacted] have responded positively through negotiations to amended contract terms. [redacted] has not as evidenced by the table below.

	[redacted]	[redacted]	[redacted]
LKE - Property Damage (PD)			
Property Damage – Turbine Components	[redacted]	[redacted]	[redacted]
Umbrella Insurance	[redacted]		

In addition, the team consulted LKE's credit and contract administration department. They studied the financial information provided by each contractor which has resulted in the following contract inclusions.

- [redacted] letter of credit through the term of the warranty of the final outage.
- [redacted] Parent Guarantee through the term of the warranty in the final outage.

- [redacted] – Parent Guarantee still under consideration.

With the consolidation of T/G manufactures in recent years, these three contractors represent the majority of companies that can actually perform the major work on LKE machines. LKE is currently conducting significant business with each. Speculation around what will happen with [redacted] is mitigated by a strong "Assignment" provision in the GSA. The team believes it has minimized the risks to LKE in these contracts [redacted] and [redacted]. Should the team be unsuccessful with [redacted] then the work will be divided between [redacted] and [redacted]. Each contractor will use subcontracts. The contracts include provisions protecting LKE for any liabilities the subcontractors cause. They also require the subcontractors to adhere to all LKE safety and environmental policies.

Other Alternatives Considered

The work required under these contracts is required for the safe, reliable and continuing operation of these machines. Delaying or not performing the work will ultimately result in the machines being unavailable for production. LKE has historically contracted this work due to the long interval when a large internal specialized work force is required. The only alternative being considered is the contract award for the EWB 3 scope.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Turbine / Generator Major 2019-2021 contracts for $44,898k (inclusive of [redacted] contingency for emergent work and the [redacted] because this results in the lowest overall cost to LKE and provides appropriate contract terms for the work being performed. This approval allows for contracts to be awarded to only [redacted] should final negotiations with [redacted] fail.

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

Approval Confirmation for Contract Authority Greater Than $10 million bid, or $2 million sole sourced:

The contract authority request 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 contract authority request.

DocuSigned by: Kent Blake C055E669F1EB443...	12/21/2018 | 10:05 AM PST	DocuSigned by: Paul Thompson 37E11AF682314EE...	12/26/2018 | 7:03 AM PST
Kent W. Blake Chief Financial Officer	Date	Paul W. Thompson Chairman, CEO and President	Date

AWARD RECOMMENDATION APPROVALS
– Attachment for IC Proposal

SUBJECT:
Turbine / Generator Major 2019-2021

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the Turbine / Generator Major 2019-2021 contracts for $44,898k (inclusive of [redacted] contingency for emergent work and the [redacted] ecause this results in the lowest overall cost to LKE and provides appropriate contract terms for the work being performed. This approval allows for contracts to be awarded to only [redacted] and [redacted] should final negotiations with [redacted] fail.

Contracts Administrator Ross Lerch Date 12/18/2018 | 10:19 AM EST	DocuSigned by: F24A367FDB0E4F7...	General Manager Mill Creek Joe Didelot Date 12/18/2018 | 9:51 AM PST	DocuSigned by: JMDidelot 74B3803FAB724DC...
Commercial Operations Manager Bob Barnett Date 12/17/2018 | 8:48 AM EST	DocuSigned by: Bob Barnett BE2121BBD7EA431	General Manager Trimble County Mike Buckner Date 12/18/2018 | 7:44 AM PST	DocuSigned by: Michael a Buckner CF839BC5CADD4A1
Manager Turbine / Generator Maint. KR Noonan Date 12/17/2018 | 9:43 AM EST	DocuSigned by: KR Noonan 42D1C1830E654F9...	General Manager EW Brown Jeff Fraley Date 12/18/2018 | 12:58 PM EST	DocuSigned by: Jeff Fraley F830E2617BEE4A0
Director – Supply Chain/Commercial Operations Date 12/18/2018 | 10:49 AM EST	DocuSigned by: Joe Clements 3BE4B989FEA84C9	General Manager Ghent Steve Turner Date 12/18/2018 | 7:[illegible]6 AM PST	DocuSigned by: Steven B. Turner 8AD647306F3F4A0
Director -Generation Services Mike Drake Date 12/18/2018 | 3:08 PM EST	DocuSigned by: Michael Gosekamp doa for Mike Drake 6D27173501AD4A6	Vice President Power Production Ralph Bowling Date 12/18/2018 | 3:16 PM EST	DocuSigned by: Ralph Bowling 901D57ABEB06435

Attachment 1 - Fleet T/G Contract Amount Summary

	[redacted]	[redacted]	[redacted]	
2018 incremenatl blade			[redacted]	
2019				
Mill Creek 1 - Major	[redacted]			
KU Ghent 2 Major with Valve	[redacted]	[redacted]		
LG&E Mill Creek 3 Major with Valve	[redacted]			
KU EW Brown 3 Major with Valve & FPT	[redacted]		[redacted]	
incremntal blade				
Ghent 1 FPT	[redacted]			
Ghent 4 Valve		[redacted]		
Trimble County 1 Valve		[redacted]		
2020				
KU Ghent 4 Major	[redacted]	[redacted]		
Ghent 1 Valve	[redacted]			
Trimble County 2 FPT and valve				
Ghent 3 Valve				
Mill Creek 2 Valve		[redacted]		
2021				
Ghent 1 Major	[redacted]			
Trimble County 1 FPT	[redacted]			
Mill Creek 1 Valve		[redacted]		
Summary [redacted] Awarded EWB 3				
	[redacted]	[redacted]	[redacted]	**Total**
2018			[redacted]	[redacted]
2019				
subtotal cap + Opex + SP repairs	[redacted]	[redacted]	[redacted]	[redacted]
Total Contingency	[redacted]	[redacted]	[redacted]	[redacted]
2020				
subtotal cap + Opex + SP repairs	[redacted]	[redacted]		[redacted]
Total Contingency	[redacted]	[redacted]		
2021				
subtotal cap + Opex + SP repairs	[redacted]	[redacted]		[redacted]
Total Contingency	[redacted]	[redacted]		
total contract	[redacted]	[redacted]	[redacted]	[redacted]
total contingency	[redacted]	[redacted]		
[redacted]				
total rounded				[redacted]
[redacted]				
Total Contract	[redacted]	[redacted]		[redacted]
Total Contingency	[redacted]	[redacted]		[redacted]
				[redacted]

PPL companies

Date: December 18, 2018

To: Mike Buckner, General Manager Trimble County
Joe Didelot, General Manager Mill Creek
Jeff Fraley, General Manager E.W. Brown
Steve Turner, General Manager Ghent
Mike Drake, Director Generation Services
Joe Clements, Director, Commercial Operations
Ralph Bowling, VP Power Production
Kent Blake, CFO
Paul Thompson, Chairman, CEO, and President

From: Bob Barnett, Manager Commercial Operations

RE: Contract Award Recommendation
Fleet Turbine Generator Contract 2019-21

The attached Investment Committee proposal was approved on December 17, 2018.

The total authority is $44,898k.

In accordance with the company authority matrix, your approval is required.

Please sign the document via DocuSign.

The contract includes 6 major outages and 9 valve and/or feed pump turbine outages.

From: LG&E ERS Website
Sent: Monday, December 17, 2018 12:15 PM
Subject: Delegation Of Authority Notification For MICHAEL DRAKE to MICHAEL GOSEKAMP

This delegation of authority is effective with the start of the work day 12/18/2018 through the end of the work day 12/21/2018.
The Reason for this delegation of authority is Vacation.

Delegation of Authority for	
Name	MICHAEL DRAKE
Location	LG&E Center 8th floor
Department	Dir Generation Services
Company	LG&E and KU Services Company
Phone	502/627-4075
E-Mail	MICHAEL.DRAKE@LGE-KU.COM
Cell Phone	N/A
Pager	N/A

Authority being delegated to	
Name	MICHAEL GOSEKAMP
Location	LG&E Center 8th floor
Department	Dir Generation Services
Company	LG&E and KU Services Company
Phone	502/627-2312
E-Mail	MICHAEL.GOSEKAMP@LGE-KU.COM
Cell Phone	6033722015
Pager	

Comments :

Investment Proposal for Investment Committee Meeting on: April 28, 2020

Project Name: GH1 SCR Catalyst Rpl21

Total Capital Expenditures: $2,165k (Including $100k of contingency and $12k of internal labor)

Project Number(s): 144327

Business Unit/Line of Business: Power Generation

Prepared/Presented By: Jen Price / Steve Turner

Brief Description of Project

The Ghent Unit 1 (GH1) selective catalytic reduction (SCR) system, designed by [redacted], has been in service since March 2004. The SCR is composed of two (2) reactors each containing three (3) layers of catalysts. Each layer contains one-hundred fifty-six (156) modules across both reactors. The modules house plate catalysts which react with anhydrous ammonia to reduce nitrogen oxides (NO_x) in the boiler flue gas.

Beginning several years ago, in-service catalyst plates from each layer have been sampled during annual unit outages. Third party testing has been performed on the samples in order to monitor catalyst activity and remaining life. Based on 2019 test results and LG&E-KU's internal analysis, the next recommended action for the GH1 SCR is to replace Layer 2 in the spring of 2021 with new catalyst. Layer 2 was originally installed in March 2014 and has operated as expected, and will have reached seven (7) years of life and over 50,000 operating hours at the time of replacement. Installation of the new layer will ensure continued reliability of the unit by ensuring compliance with NO_x emission limits.

The SCR catalyst replacement on Ghent Unit 1 is scheduled to be performed during the spring 2021 outage. The project scope includes the following:

- Industrial cleaning of SCR reactors
- Removal and disposal of one-hundred fifty-six (156) catalyst modules
- Purchase and installation of new bolt-on-style catalyst loading/access doors
- Purchase and installation of new catalyst modules and seals
- Post-replacement ammonia injection tuning
- Third-party catalyst testing for new layer performance guarantees

The expected project milestones are as follows:

- May 2020 Issue Contract for new catalyst material
- June 2020 Issue PO for new bolt-on-style catalyst loading/access doors
- 3rd Quarter 2020 Issue Contract for removal/installation labor
- 4th Quarter 2020 Issue Contract for industrial cleaning
- February 2021 Delivery of catalyst modules, doors, seals, miscellaneous material
- March 2021 Outage start, work beings
- April 2021 Work complete
- May 2021 Post-replacement SCR ammonia tuning

Bids have been received for the purchase of the catalyst modules. Nothing has been awarded to date, but the received bids are being used to assist with the estimated project cost. Labor for removal and installation is anticipated to be competitively bid in Summer 2020, while the industrial cleaning will be competitively bid later this year. The bolt-on-style catalyst loading doors, seals, and other miscellaneous material will be purchased in both 2020 and 2021 in order to meet the proposed spend each year.

The total project cost, discussed in more detail in the *Budget Comparison & Financial Summary*, is estimated to be $2,165k. A total of $2,165k is proposed in the 2021BP for spend in 2020 and 2021.

<u>Why is the project needed? What if we do nothing?</u>

In order to continue to meet NO_x emission limits, it is recommended to replace the GH1 Layer 2 SCR catalysts before catalyst deactiviation results in NO_x removal rates dropping below an undesirable level. Catalysts are not capable of regaining activity, therefore, performance levels will continue to decline until the layer is replaced. As catalyst activity declines, the opportunity for ammonia to travel to downstream equipment (ammonia slip) also increases. This poses a risk of air heater fouling, ductwork corrosion, and issues with coal combustion residual (CCR) operations.

If the specified layer is not replaced during the 2021 spring outage, the unit runs the risk of forced outages due to environmental non-compliance and required air heater washes. If the project is continuously delayed, the probability of forced outages increases each year until the unit is no longer able to operate during ozone season. Installation of a new catalyst layer will allow the unit to continue operation at target NO_x removal rates and minimize ammonia slip.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	899	1,007			1,906
2. Cost of Removal Proposed		259			259
3. Total Capital and Removal Proposed (1+2)	899	1,266	-	-	2,165
4. Capital Investment 2020 BP	891	1,006			1,897
5. Cost of Removal 2020 BP		108			108
6. Total Capital and Removal 2020 BP (4+5)	891	1,114	-	-	2,005
7. Capital Investment variance to BP (4-1)	(8)	(1)	-	-	(9)
8. Cost of Removal variance to BP (5-2)	-	(151)	-	-	(151)
9. Total Capital and Removal variance to BP (6-3)	(8)	(152)	-	-	(160)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed					-
2. Project O&M 2020 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

A contingency of approximately $100k is included in the project and is prudent given pricing has been received for the major materials. This project is included in the 2020BP, and although there is a shortfall of $160k in the 2020BP, the additional amount in 2020 is included in the 3+9 RAC forecast. The additional amount in 2021 is funded within the Ghent portion of the proposed 2021BP.

Risks

Failure to meet NO_x emission limit: If the proposed catalyst layer is not replaced, there is a risk that NO_x emissions will increase and pose a risk to the unit's reliability.

Forced outages: Without replacement of a new catalyst layer, there is a risk that NO_x emissions will not meet compliance regulations and the unit will be forced offline annually during ozone season. Also, as ammonia slip increases, it can cause air heater fouling which may require unexpected unit outages for cleaning.

Alternatives Considered

1. Recommendation: Purchase/Install New Catalyst — NPVRR: ($000s) $2,453k
2. Alternative #1: Delay Project One (1) Year — NPVRR: ($000s) $2,460k
3. Alternative #2: Do Nothing — NPVRR: ($000s) $41,463k

Recommendation – Purchase/Install New Catalyst
The purchase and installation of a new catalyst layer in 2021 is the recommended option. This plan is least cost over the life of the project, avoids the probability of unit outages, and ensures NO_x emissions compliance.

For the recommended option, the following assumptions were made:

- Several progress payments on the catalysts and some additional material purchased in 2020
- Capital spend in 2021 is remaining material costs, KU labor, contractor labor, and contingency

Alternative #1 – Delay Project One (1) Year

Delaying the project one (1) year to the next planned unit outage presents multiple risks. These risks include decreased NO_x removal efficiency and increased ammonia slip which could lead to forced unit outages and derates due to the inability to maintain environmental compliance and/or due to air heater fouling. This alternative is not recommended due to these risks and unfavorable NPVRR.

For alternative #1, the following assumptions were made:

- Capital spend occurring in 2021 and 2022
- 2% inflation rate
- 75% probability of a two (2) day forced outage in 2021 due to an air heater wash
- Incurred costs include labor to perform the air heater wash and unit startup expenses, mainly the price for fuel oil

Alternative #2 – Do Nothing

This alternative is not recommended as this would yield a high probability of forced unit outages and would be unfavorable to unit operations.

For alternative #2, the following assumptions were made:

- 75% probability of a two (2) day forced outage due to an air heater wash starting in 2021 and increasing to 100% the following year. Incremental costs are the same as alternative #1, including 2% inflation in 2022.
- 100% probability of a four (4) day forced outage due to two (2) air heater washes in 2023 and 2024. Incremental costs are doubled from 2022 for the additional days offline, including 2% inflation each year.
- 100% probability of the unit being unavailable during ozone season beginning in 2025 due to NO_x emissions non-compliance

Conclusions and Recommendation

Investment Committee approval of the GH1 SCR Catalyst Layer Rpl21 project for $2,165k is recommended, ensuring GH1 continues to meet NO_x emission limits and avoids forced unit outages.

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 Chief Financial Officer	Paul W. Thompson Date Chairman, CEO and President

Investment and Contract Proposal for Investment Committee Meeting on: April 28, 2020

Project Name: TC5 CT MAJOR INSP
Contract Name (Good/Service): Trimble County CT5 Major Inspection Fall 2020 – Spring 2021

Selected Vendor(s): [redacted]

Contract Authorization Requested: $ [redacted] of contingency)

Contract Term: 2020-2021

Total Capital Expenditures Requested: $ 13,438 k (Including $640k of contingency including $70k of internal labor)
Total O&M: $0k

Project Number(s): 153083LGE / 153083KU
Business Unit/Line of Business: Generation – Trimble County Station

Prepared/Presented By: Chris Baer / Mike Buckner / Francisco Maldonado / Adam Ball

Brief Contract/ Project Description

Trimble County Generating Station has six (6) [redacted] Frame 7FA single-fuel gas combustion turbines designated TC5 through TC10. TC5 ("Unit 5") was commissioned in 2002 and since its commissioning, Unit 5 has been operated as a peaking unit to support megawatt demand throughout LG&E's fleet. Being a peaking unit, Unit 5 is expected to reach its factored start limit for both the combustion and hot gas path parts and the combined compressor and turbine rotor in the Fall of 2024. Typically, upon hitting this factored start milestone, the Unit will go through a Major Inspection in which many of the Units parts are reconditioned to extend their life. However, due to a known design flaw on TC5 and TC6 the station is taking proactive measures to correct the issue before a catastrophic failure occurs.

This project is expected to be completed in approximately 6-8 months over the course of Fall 2020 into Spring of 2021. The proposed contract with [redacted] is a lump sum / fixed price contract who, being [redacted] has experience performing this particular scope on similar units in its fleet. This Investment Committee proposal recommends and requests approval for both the contract amount of [redacted] and Capital Expenditures of $13,438k to perform the Major and the Rotor Inspection on Unit 5. The difference in the contract requested amount and the project requested amount is due to the additional monies needed for items to be completed by LG&E outside of [redacted] scope. The total request for the project is included in Trimble County's business plan.

Why is the Project needed? What if we do nothing?

A [redacted] Technical Information Letter (TIL) 1972-R2 made us aware of potential cracking concerns on several stages on the rotor compressor. Thus, one of the main drivers for the project is to assess and address the known cracking issues on stages 12-17 on the rotor compressor. The cracking has been identified on TC5 during annual borescope inspections and the severity of the cracking will continue to progress over time, driven by start / stop cycles. Once the cracking progresses to a point where the structural integrity of the wheel comes into question the unit will no longer be useable unless a Rotor Life Extension (RLE) has been completed to address the configuration issue and replace the affected compressor wheels with an upgraded configuration. [redacted] is aware of the issue and has provided and upgraded design from Flat Slot Bottom (FSB) to Round Slot Bottom (RSB) connections to mitigate the cracking issues. During the RLE process, the rotor is removed, sent offsite, disassembled and inspected. Based off the inspection, various components are replaced, repaired or re-used as needed to extend the serviceable life to 7,400 rotor factored starts (lifetime total not additional). Once we achieve the 7,400 rotor factored starts the rotor becomes condemned and a new rotor must be purchased.

There are two additional scope items that were included in the bidding process outside the standard Major Inspection scope. The first is the completion of a compressor upgrade, which involves replacing specific stationary and rotating blades within the compressor along with software enhancements. All the changes are to enhance the robustness of the compressor to reduce the risk of catastrophic failure that has occurred with other units in the [redacted] 7FA fleet. The Rotor Inspection is the ideal time to perform these upgrades since the affected parts are already exposed. The second additional scope item included is a full generator stator re-wedge. TC9 required a stator re-wedge in 2016 and TC5 is exhibiting similar signs that warrant the need to re-wedge the unit. Addressing the wedges now will reduce the risk of damage to the stator bars, which would be a substantially more expensive repair. It is important to note that we would typically do two (2) Hot Gas Path Inspections and then a Major Inspection, which is an expanded scope that includes all the items a Hot Gas Path Inspection includes. The first Hot Gas Path Inspections resulted in emergent work that ended up meeting the Major Inspection scope, thus our next Major Inspection wouldn’t necessarily be due this outage, but the next. However, the need to pull the rotor out for the RLE provides the access needed to complete the major inspection this year as well. Given the fact that emergent work was found during the first Hot Gas Path inspection it is prudent to perform that inspection and repair scope during this outage time frame.

Contract Bid Summary

The bid process sought to test the competitive 7FA frame market to determine if third-party vendors were capable and situated in a way that would provide an acceptable selection of bids. After discussion with Trimble County's plant proponents, three firms were identified and selected to participate in the competitive bid process. The three firms selected were [redacted] and [redacted] is a firm that has been used by LG&E and KU for successful steam turbine / generator overhaul labor services in the past and they have performed work on LG&E's Paddy's Run 13 combustion turbine. [redacted], who once was owned by [redacted], is a new vendor to LG&E but they have quite a bit of experience with [redacted] 7FA units and have developed their own solutions / designs for common 7FA concerns. The last bidder was [redacted] who without question has experience performing this scope on 7FA's.

[redacted] did not provide a technically complete bid as they could not perform all of the requested scope and, further, their limited scope was significantly higher than the other two vendors.[redacted], at first glance, provided what appeared to be a competitive bid but upon further review, their bid was approximately [redacted] than that of [redacted]

	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Contract Financial Summary

Contract expenses ($k)	2020	2021	Total
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

* Includes an additional contingency of 5%.

[redacted] based on the bid provided that included our desired options, is recommended for the award of the Trimble County TC5 Major & Rotor Inspection contract.

Project Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	5,517	7,921			13,438
2. Cost of Removal Proposed	-	-			-
3. Total Capital and Removal Proposed (1+2)	5,517	7,921			13,438
4. Capital Investment 2020 BP	-	34,294			34,294
5. Cost of Removal 2020 BP	-	-			-
6. Total Capital and Removal 2020 BP (4+5)	-	34,294			34,294
7. Capital Investment variance to BP (4-1)	(5,517)	26,373			20,856
8. Cost of Removal variance to BP (5-2)	-	-			-
9. Total Capital and Removal variance to BP (6-3)	(5,517)	26,373			20,856

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-			-
2. Project O&M 2020 BP	-	-			-

* Contingency is 5% of expected [redacted] contract and LG&E scope totals. The 2020 BP was based on purchasing new parts as opposed to using refurbished parts.

Risks

In lieu of providing LG&E with audited financials, [redacted] is going to provide LG&E with a Parent Guaranty.

Project Alternatives Considered

1. Recommendation: Inspection in 2020 NPVRR: ($000s) $14,866
   Perform the Major and Rotor Inspections as outlined with [redacted] as the contractor in 2020.

   Alternative #1: Purchase and Install Refurbished Rotor NPVRR: ($000s) $17,258
   Purchase an assembled refurbished rotor instead of removing the existing rotor and refurbishing it.

2. Alternative #2: Do Nothing NPVRR: ($000s) $0
   If nothing is done, Unit 5 would reach a point where the Flat Slot Bottom (FSB) cracking would put the structural integrity of the rotor in question and the unit would not be useable, making this not a viable option.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the TC5 CT MAJOR INSP project for $13,438k as well as the Trimble County CT5 Major Inspection Fall 2020 – Spring 2021 Contract for [redacted]

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced:

The Capital project spending and contract authority requests included in this Investment Proposal have 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 the capital project and contract authority requests.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
Trimble County CT5 Major Inspection Fall 2020 – Spring 2021

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the Trimble County CT5 Major Inspection Fall 2020 – Spring 2021 contract for [redacted] inclusive of contingency (6-8 month contract term) to [redacted] International, Inc.

Sourcing Leader [If applicable; the approvers for this table can be modified as needed]		Proponent/Team Leader [If applicable]	
Supplier Diversity Manager [If applicable]		Manager [If applicable]	
Manager - Supply Chain or Commercial Operations		Director – Supply Chain or Commercial Operations	
Director [If applicable]		Vice President [If applicable]	

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Investment Proposal for Investment Committee Meeting on: May 26, 2020

Project Name: OF DCS UPGRADE

Total Capital Expenditures Requested: $ 2,488 k (Including $118k of contingency and $160k of internal labor)

Total O&M: $0k

Project Number(s): 151980

Business Unit/Line of Business: Generation – Ohio Falls Station

Prepared/Presented By: Brian Sumner / Mark Payne / Sam Mudd / Alan Crone

Brief Project Description

Ohio Falls Generating Station has eight units and a common balance of plant (BOP) system. The currently installed [redacted] distributed control system (DCS) was installed as part of the multi-year rehab project which began in 2005 at Ohio Falls. The manufacturer has obsoleted this system, making the procurement of replacement components an increasingly large risk to plant equivalent forced outage rate (EFOR) as resupply takes substantially longer and some parts will soon have no availability. The proposed [redacted] is comparable to the current DCS installed on Cane Run 7 and elsewhere throughout the Generation fleet. The project will replace all controllers, input/output (I/O) cards, workstations, servers, networking equipment, and speed & vibration monitoring equipment.

This project will take 10-12 months starting in the second half of 2020 and finishing following the Ohio Falls Spring 2021 Outage. In 2019, [redacted] was contracted to assist in writing the bid scope due to its complexity. The request for the project is included in the Ohio Falls 2020 Business Plan.

Why is the project needed? What if we do nothing?

[redacted] stopped supplying the controllers required by the current control system in 2015 and stopped supporting the controllers in 2018. Currently, product supply for these controllers is limited to available inventory from the manufacturer which has been substantively reduced over the last five years. In addition to concerns over controller supply and support, vendor support for the I/O cards end in 2022. This project proactively replaces the DCS before parts and support become unavailable to the extent of causing prolonged unit or plant outages. Most removed equipment will become spare for similar systems on Paddys Run 11 & 12. The amount of removed equipment should suffice to provide any spares needed for those units for the remainder of their useful lives. In 2019, an engineering firm was contracted to assist in writing the bid scope for this project, which is included in this budget.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	33	1,192	1,263		2,488
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	33	1,192	1,263	-	2,488
4. Capital Investment 2020 BP	40	-	3,295		3,335
5. Cost of Removal 2020 BP					-
6. Total Capital and Removal 2020 BP (4+5)	40	-	3,295	-	3,335
7. Capital Investment variance to BP (4-1)	7	(1,192)	2,032	-	847
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	7	(1,192)	2,032	-	847

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed					-
2. Project O&M 2020 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

* Contingency is 5% of expected [redacted] contract and LG&E scope totals. The 2020 BP was based on internal estimates prior to receiving bids. Incremental funding of $1,192k is needed in 2020; of which $1,100k was approved by the RAC in the 3+9 forecast. The additional $92k will be funded in the 4+8 forecast within the Ohio Falls/Cane Run capital plan.

Risks

Overall risks associated with this project are minimal and LG&E has negotiated favorable terms that are contained in both the General Services Agreement and a Master Service Agreement that have been incorporated into the primary contract.

Project Alternatives Considered

1. Recommendation: [redacted] NPVRR: ($000s) 3,481

2. Alternative #1: [redacted] NPVRR: ($000s) 3,735
   The first alternative to the discussed recommendation is to have an alternative supplier [redacted] conduct very close to the same work scope (see Appendix A for bid information). This alternative requires slightly less initial investment but requires notable additional O&M expense over the analyzed life of the project, ultimately resulting in a less favorable analysis for this alternative relative to that of the recommendation. This alternative also fails to deliver the unmodeled benefit of similarity with the CR7 control system. Adding this alternative system at Ohio Falls will ultimately require additional annual training and familiarity not necessary with the recommendation.

3. Alternative #2: Do nothing NPVRR: ($000s) 13,062
   This "do nothing" alternative exposes the plant to prolonged unit or plant outages as replacement part supply and service becomes increasingly unavailable. While unmodeled, the perceptual risk of prolonged outages to the company's largest source of renewable generation is particularly concerning.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the OF DCS UPGRADE project for $2,488k to ensure continued availability of the Ohio Falls Generating Station units.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending requests included in this Investment Proposal have 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 the capital project and contract authority requests.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Appendix A

Bid Summary

The bid process sought to test the main DCS vendors that LG&E and KU utilize at other stations and situated in a way that would provide an acceptable selection of bids. The two companies selected were [redacted] and [redacted]. [redacted] is used by LG&E and KU at Cane Run, Trimble County, Ghent stations. [redacted] is the current vendor at Ohio Falls as well as Mill Creek station. Both companies have experience in retrofitting hydro-electric generating station distributed control systems.

[redacted] at first glance, provided what appeared to be the lesser of the two bids but upon further review, their bid did not include the first year of support that the [redacted] bid included. Furthermore, the [redacted] solution did not include an anti-virus solution and their E-Server solution relies on LG&E supplied equipment. This equates to making the bids virtually identical in cost. Another benefit of selecting [redacted] is that the Ohio Falls DCS support is provided by the Control Specialist at Cane Run. The proposed [redacted] system at Ohio Falls will match the current DCS installed at CR7. This will also help reduce the amount of procedures/solutions needed to maintain cyber security standards.

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

As referenced in Alternative #1 in the Risks section of this proposal, the total cost reflected in this table does not account for additional future O&M expense for the [redacted] option, which is not required for the [redacted] recommendation. The CEM reflects this expense. The detailed table below depicts the incremental training and service agreement associated with Alternative #1:

$k	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Ongoing [redacted] Training for Control Specialists		$12	$9	$9	$9	$9	$12	$9	$9	$9	$9	$12	$9	$9	$9	$9
Ongoing [redacted] Service Agreement	$45	$45	$45	$45	$45	$45	$45	$45	$45	$45	$45	$45	$45	$45	$45	$45
Ongoing [redacted] Service Agreement	$0	$29	$29	$29	$29	$29	$29	$29	$29	$29	$29	$29	$29	$29	$29	$29
[redacted] Spare Parts	$15															
[redacted] Spare Parts	$0															

Investment Proposal for Investment Committee Meeting on: 6/30/2020

Project Name: MC3 Rear Slope & Lower Waterwall Headers

Total Capital Expenditures: $3,092k (Including $150k of contingency)

Total O&M: $ 0k

Project Number(s): 147060

Business Unit/Line of Business: Power Generation

Prepared/Presented By: Michael Kjelby/Joe Didelot

Brief Description of Project

This project is to mitigate boiler tube failures (BTF's) on Mill Creek Unit 3 (MC3) lower slope due to sliding ash erosion, thermal fatigue, and deformation caused by falling slag impacts. The project will replace the Mill Creek 3 boiler rear lower slope tubes with supply headers, sidewall tubing including sidewall headers, and lower dead air space structural steel. The scope will replace 207 lower slope tubes and 66 sidewall tubes. The new lower slope will incorporate thicker tubing, nickel/chrome overlay, and new structural steel to ensure reliable operation.

Project Milestones:

Material Bids Received	June 2020
Project Approved	July 2020
Material PO Issued	July 2020
Labor Bids Received	February 2021
Material Delivery	September 2021
Installation	October 2021

Total cost of the project is $3,092k with $150k contingency included. The project is included in the 2020 BP for $2,854k. The incremental $238k will be funded within the Generation capital plan in the 2021 BP. There is $860k for material in 2020 with the remaining $2,232k included in 2021.

Why is the project needed? What if we do nothing?

MC3 is a [redacted] boiler placed into operation in 1978. The lower slope is original and is deformed from years of falling slag and thinned by erosion. The slag impacts on the slope have bowed the support steel and sheered attachment hardware off the tubes.

Past inspections of the lower slope have identified gouges from slag impacts that require weld metal buildup repairs. The most recent inspection of the lower slope revealed sliding ash erosion damage on the outer most tubes of the slope, with tubes eroded down to sixty-five (65) percent of the original minimum wall thickness.

The original design of MC3 had a submerged ashpit, exposing the slope tubes, welds, and headers to cold water. After 40 years of service the headers and welds have become thermally fatigued and suffered quench cracking. The ashpit was replaced in 2019 with a new, dry bottom ash conveying system mitigating future thermal fatigue damage.

This project will eliminate previous damage and field repairs made to the slope. The weld overlay will increase the slope's resistance to sliding ash erosion. Leaving the slope in its current condition would increase unit EFOR due to BTF's.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	860	2,033			2,893
2. Cost of Removal Proposed		199			199
3. Total Capital and Removal Proposed (1+2)	860	2,232	-	-	3,092
4. Capital Investment 2020 BP	860	1,795			2,655
5. Cost of Removal 2020 BP		199			199
6. Total Capital and Removal 2020 BP (4+5)	860	1,994	-	-	2,854
7. Capital Investment variance to BP (4-1)	-	(238)	-	-	(238)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	(238)	-	-	(238)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed					-
2. Project O&M 2020 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Contingency for the project is $150k, 5% of the estimated expenses for the project.

Risk

Not completing this project would increase EFOR due to BTF's. Forced outage repairs would be more frequent and require more time to complete. Deferral of this project would impact the feasibility of future projects within the boiler, since work overhead of the slope would need to be restricted.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 3,464
2. Next Best Alternative: NPVRR: ($000s) 3,652
   - The Next Best Alternative is delaying the project until 2023.
   - Inflation of 2% a year is considered.
3. Do Nothing: NPVRR: ($000s) 4,671
   - The Do Nothing alternative is not completing the project.

In the Next Best Alternative and Do Nothing options, it is assumed that each tube leak on the lower slope will cause a forty-eight (48) hour long outage. It is assumed that two tube leaks per year will occur on the lower slope starting in 2021, then the number of tube leaks per year will increase in 2022, 2025, 2035, and 2041.

The Fall 2021 outage is the most suitable timeframe to complete this project since the outage is six weeks and minimal boiler work is scheduled to be completed overhead of the slope. The Do Nothing alternative would result in continued BTF's.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Mill Creek 3 Rear Lower Slope & Lower Waterwall Headers project for $3,092k to ensure continued, reliable operation of the Mill Creek 3 boiler.

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: July 27, 2020

Project Name: GH4 Reheat Outlet Terminal Tube Replacement

Total Capital Expenditures: $2,047k, including $160k contingency

Total O&M: $ 0k

Project Number(s): 155014

Business Unit/Line of Business: Power Generation

Prepared/Presented By: Jesse Chipman\Dave Tummonds

Brief Description of Project

The scope of the GH4 Reheat Outlet Terminal Tube replacement project is to replace 464 of 756 terminal tubes across the Reheat Outlet header. Doing so will achieve the objective of replacing the overheated terminal tubes and header nipples. The terminal tubing was installed in 2002 with a reheater component replacement, while the header nipples are original to the unit, commissioned in 1984. At this time, no tube leaks have occurred in the terminal tubes. However, visual inspections, oxide scale readings, a full header condition assessment completed in 2020, and metallurgical data gathered from the same pressure part on Ghent Unit 3 show that the terminal tubes have less than ten (10) years of remaining life and the horizontal sections of the hotter zones have three (3) or fewer years of remaining useful life. Therefore, replacement of these tubes will effectively mitigate the risk associated with the overheated, thin and aged tubing and will maintain Ghent Unit 4's reliability.

Materials and labor for this project are currently out for bid and will be awarded shortly after project activation. Delivery of the tubing will occur in February in advance of the Spring 2021 Unit 4 planned outage. Project execution will occur during that outage which starts on April 3rd and ends May 1st, 2021. This project is not considered ECR or GLT recoverable and KPSC approval is not required. The useful economical life of this project is 30 years.

Why is the project needed? What if we do nothing?

A terminal tube is any tube that either starts or ends at a header and penetrates through the outer wall of the header. Approximately 7% of the 756 terminal tubes were replaced in 2008 due to overheating. Some of these same tubes were found to have transverse cracks during the inspection conducted in the 2020 outage. This project is the next step in mitigating the risk of overheated and subsequently thin terminal tubes as well as removing the terminal tubes that were installed in 2008. The 464 tubes replaced on this project are broken down as indicated on the following table:

Configuration of Reheat Outlet Terminal tubing to be replaced on project 155014

Tube termination configuration	Tube count
Upstream of 2002 pendant installation weld (Grade 22) to Reheat Outlet Header	201
Upstream of 2002 pendant installation stainless steel dissimilar metal weld (DMW) to Reheat Outlet Header	255
Selected backpass horizontal legs (known to be overheated) from 2020 pendant installation to Reheat Outlet Header	8
Total	**464**

To fully define the project scope, a full inspection was completed during the Spring 2020 outage. In addition, results from a sample tube taken from Ghent Unit 3's identical reheat outlet section, which is one year newer than the same component on Unit 4, were evaluated. A total of 400 terminal tubes were replaced on a separate project on Ghent 3 in 2019. Using the 2020 Ghent 4 inspection, as well as the sample data from Ghent 3, a total of 464 terminal tubes were identified for replacement on Unit 4 under this project. The scope identified through these processes is the primary driver for the cost increase over the budgeted amount for this project in the 2020BP. This project is required to maintain reliability of the Ghent Unit 4 boiler. There are no compliance or safety related concerns. The successful completion of this project will ensure that our exceptional customer experience is maintained by the reliable operation of Ghent Unit 4.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	**2020**	**2021**	**2022**	**Post 2022**	**Total**
1. Capital Investment Proposed	108	1,757			1,865
2. Cost of Removal Proposed		182			182
3. Total Capital and Removal Proposed (1+2)	108	1,939	-	-	2,047
4. Capital Investment 2020 BP	108	1,009			1,117
5. Cost of Removal 2020 BP		155			155
6. Total Capital and Removal 2020 BP (4+5)	108	1,164	-	-	1,272
7. Capital Investment variance to BP (4-1)	-	(748)	-	-	(748)
8. Cost of Removal variance to BP (5-2)	-	(27)	-	-	(27)
9. Total Capital and Removal variance to BP (6-3)	-	(775)	-	-	(775)

Financial Detail by Year - O&M ($000s)	**2020**	**2021**	**2022**	**Post 2022**	**Total**
1. Project O&M Proposed					-
2. Project O&M 2020 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The incremental amount for this project in 2021 is proposed in the 2021BP and funded within the Generation capital plan. The requested amount for this project includes $160k contingency and is based on installation labor prices from the similar Ghent Unit 3 project in 2019, with escalation.

Risks

Failure to complete this project during the Spring 2021 outage would result in the risk of a tube leak or leaks until the project is completed. Given the relatively short remaining life of some of this tubing, a delay is a significant risk to unit reliability. The next outage of equal duration isn't until 2022, and the next major outage isn't until 2028. To mitigate risk with foreign material supply, the raw material for the terminal tubes will be sourced from [redacted]. Lastly, the Ghent Environmental Supervisor and Environmental Affairs have reviewed and approved this project.

Alternatives Considered

1. Recommendation: Replace tubes in 2021 NPVRR: ($000s) $2,254

2. Alternative #1: Replace tubes in 2022 NPVRR: ($000s) $2,367
   This alternative includes delaying the replacement of the terminal tubes until the next outage of adequate duration. Until this project is completed, the probability of a forced outage caused by a tube leak is elevated. An expected duration for such a leak is 5 days. These tubes are located outside of the unit which increases the safety risk.

3. Alternative #2: Do Nothing NPVRR: ($000s) $9,187
   If this project is not completed in 2021 then the probability of a tube leak occurring continues to increase. After 2024, the frequency of forced outages is expected to increase to at least 2 forced outages per year (10 days). After 2029, at least 3 forced outages per year are expected. Alternatives #1 and #2 both assume $130k for startup costs and $55k to repair a tube failure in this area.

Conclusions and Recommendation

Investment Committee approval of the Ghent 4 Reheat Outlet Terminal Tube replacement project for $2,047k to maintain the reliability of the Ghent Unit 4 boiler is recommended.

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: August 27, 2020

Project Names: GH Spare Stator Bars, TC Generator Rewind

Total Capital Expenditures: GH: $3,882k (Including $184k of contingency)

TC Net: $2,906k (Including $139k of contingency)
TC Gross: $3,875k (Including $185k of contingency)

Total O&M: $0

Project Number(s): 162631 (GH), 131995 (TC)

Business Unit/Line of Business: Generation

Prepared/Presented By: Dylan Staples, Mason Smith / Dave Tummonds, Mike Buckner

Brief Description of Project

The purpose of this project is to purchase two (2) Generator Stator Bar Rewind Kits to continue fleet-wide mitigation of systemic cooling water leak risk associated with water cooled [redacted] generators manufactured between January 1975 and January 1990. Specifically, [redacted] communicated that Ghent 2-4, Trimble County 1, and Mill Creek 1-4 were at risk of failure. In 2010, the fleet purchased two (2) stator bar kits to mitigate this risk – one set designed for use in any of the three affected Ghent units and another set of different design for use in either TC1 or MC4 – each of improved design from original installation. In the interim, offline inspections and online monitoring have triggered the replacement of the GH4 and MC4 bars. Respective plant management expects that these replacements have mitigated the [redacted] concern on both GH4 and MC4, but have depleted the capital spares purchased in 2010 which, again, exposes the remaining units (GH2, GH3, and TC1) to long material lead times should those units develop cooling leaks. Mill Creek 1-3 have three unique designs, so they were not mitigated through the 2010 purchase. However, these units have been mitigated since.

The first rewind kit recommended in this proposal will mitigate risk for GH2 and GH3 (can be used on either). The second rewind kit will mitigate the same risk on TC1. Although unlikely, the first set can also be used on GH4 in the event of unexpected failure. Similarly, the second set can be used on MC4 in the event of an equally unexpected failure.

The stator bar rewind kits will be stored at Ghent and Trimble County upon delivery. Delivery is anticipated in the second quarter of 2021, based on the current project activation, contract development, and production schedule. The rewind kits will remain in storage until needed.

Why is the project needed? What if we do nothing?

LG&E/KU owns and operates eight [redacted] water-cooled generators associated with our large coal fired steam fleet. These generators include Mill Creek 1-4, Ghent 2-4, and Trimble County 1. In 1991, [redacted] issued Technical Information Letter ([redacted] identifying numerous cooling system leaks ranging from copper plumbing to clip-to strand connections.

Clip-to strand issues present the highest risk as this type of leak allows water to migrate between a bar and its associated ground wall insulation. This wet insulation will age appreciably faster leading to electrical stator bar failure necessitating generator rewind. A planned rewind can be completed in six weeks, assuming materials are purchased in advance. However, [redacted] indicates that the lead time for a replacement set of stator bars is approximately 26 weeks, even on an expedited basis. Thus, an unplanned event (as potentially caused by wet insulation) would result in a significant period of unavailability for the affected unit, should a spare set not be available.

Although purchasing these rewind kits does not enhance generator reliability, it would allow the generating facilities to perform an emergency stator rewind without potentially experiencing long material lead times. The spare stator bars previously purchased by LGE-KU proved to be valuable when Ghent Unit 4 required an emergency stator rewind during the Spring 2020 outage due to a failed hi-pot test. The failed hi-pot test was caused by multiple clip to strand leaks over an extended period of time. Having the spare stator bars onsite and readily available made it possible to perform the rewind with minimal outage extension time.

Budget Comparison & Financial Summary - GH

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	749	3,133			3,882
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	749	3,133	-	-	3,882
4. Capital Investment 2020 BP					-
5. Cost of Removal 2020 BP					-
6. Total Capital and Removal 2020 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(749)	(3,133)	-	-	(3,882)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(749)	(3,133)	-	-	(3,882)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed					-
2. Project O&M 2020 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project is not included in the 2020 BP. 2020 spend has been fully funded by the RAC in the 6+6 forecast. The 2021 project spend is funded withing the Generation capital plan in the proposed 2021BP.

Budget Comparison & Financial Summary – TC (Net costs)

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	564	2,342			2,906
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	564	2,342	-	-	2,906
4. Capital Investment 2020 BP					-
5. Cost of Removal 2020 BP					-
6. Total Capital and Removal 2020 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(564)	(2,342)	-	-	(2,906)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(564)	(2,342)	-	-	(2,906)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed					-
2. Project O&M 2020 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project was not included in the 2020 BP. 2020 spend has been fully funded by the RAC in the 6+6 forecast. The 2021 project spend is funded withing the Generation capital plan in the proposed 2021BP. Contingency of 5% is included in each project; bids have been received and negotiation with the preferred vendor is underway.

Risks

There is no accurate method to predict the failure of stator bar insulation. However, the replacements on both GH4 in 2020, and MC4 in 2014, validate both the impetus for the 2010 risk mitigation plan and the utilization rate of spare bars. Completing this project now remains consistent with this established and validated risk mitigation plan on the noted generators. If this project is not completed and a failure occurs on an unplanned basis, there will be significant loss of generation until a replacement set of stator bars can be manufactured, likely at higher cost due to expediting of materials.

The referenced technology is proven by the success of GH4 and MC4 as noted. This project has been reviewed and approved by each generating facility's Environmental Supervisor.

Alternatives Considered - Ghent

1. Recommendation: NPVRR: ($000s) $5,438
   Alternative #1: Do Nothing NPVRR: ($000s) $35,094

   Alternative #1 contemplates not procuring a spare set of stator bars and ends at the point 100% probability of a leak is reached. The CEM assumes the risk of an extended forced outage if a spare set of bars is not purchased, using historical data on stator leak probability from across the industry. The cost of a generator rewind utilizing a spare set is not included and would be addressed at the time a rewind is needed.

Alternatives Considered - Trimble County

1. Recommendation: NPVRR: ($000s) $4,494
   Alternative #1: Do Nothing NPVRR: ($000s) $37,042

   Alternative #1 contemplates not procuring a spare set of stator bars and ends at the point 100% probability of a leak is reached. The CEM assumes the risk of an extended forced outage if a spare set of bars is not purchased, using historical data on stator leak probability from across the industry. The cost of a generator rewind utilizing a spare set is not included and would be addressed at the time a rewind is needed.

Conclusions and Recommendation

Investment Committee approval of the GH Spare Stator Bars project for $3,882k and the TC Generator Rewind project for $2,906k (net) to mitigate extended outage lengths associated with a stator bar failure is recommended.

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: 8/27/2020

Project Name: MC2 COOLING TOWER REBUILD

Total Capital Expenditures: $4,650k (Including $200k of contingency)

Total O&M: $ 0 k

Project Number(s): 147046

Business Unit/Line of Business: Power Generation

Prepared/Presented By: Vince Cecil/Joe Didelot

Brief Description of Project

The eight cell Mill Creek Unit 2 (MC2) cooling tower began operation in 1974. The tower was rebuilt over two outages with the A-D cells being completed in 2001 and the E-H cells being rebuilt in 2003. The cooling tower was returned to the original design standards, using treated wood as the primary structural members. Various component replacements, including tower distribution header and fan stacks, were completed in 2012.

This project comprises the complete rebuild of the MC2 Cooling Tower. Recent inspections revealed degradation in several forms throughout the tower including rot in the load bearing structural members. The replacement tower will incorporate the modern standard in cooling tower technology, utilizing fiberglass structural members in place of wood. The scope of this project includes the engineering, fabrication, procurement, demolition, construction and testing required to replace the entire Unit 2 Cooling Tower.

Milestones:

Project Approved	August 2020
Material/Labor Bids Received	July 2020
Material-Labor PO Issued	August 2020
Material Delivery	February 2021
Installation	March 2021

The total cost of the project is $4,650k with $200k of contingency included. The project was originally funded in the 2016 Business Plan for $6,500k in 2020. The project is included in the 2020 Business Plan for $7,031k with spend in 2025 and 2026. Additional structural inspection findings combined with changes in outage schedules resulted in the project being shifted into 2020 and 2021 in the proposed 2021 Business Plan at a cost of $4,650k.

Why is the project needed? What if we do nothing?

The MC2 cooling tower was originally constructed in 1974. It was completely replaced over the course of two outages in 2001 and 2003 by [redacted]. The tower itself is a cross flow rectangular structure, with the primary structural members being made from treated wood. The tower is exhibiting structural concerns including rot in the load bearing structural members. The tower is currently operating beyond its original design life and inspections confirm that a replacement is warranted to mitigate operational risks and maintain a safe work environment.

The replacement of the MC2 Cooling Tower is recommended to reduce the likelihood of a forced outage from a catastrophic failure. The new tower will utilize fiberglass in the structural members similar to other towers within the LG&E-KU Fleet. The new cooling tower will facilitate continued reliable and efficient operation of the generating unit.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	400	3,750			4,150
2. Cost of Removal Proposed	-	500			500
3. Total Capital and Removal Proposed (1+2)	400	4,250	-	-	4,650
4. Capital Investment 2020 BP	-	-	-	6,531	6,531
5. Cost of Removal 2020 BP	-	-	-	500	500
6. Total Capital and Removal 2020 BP (4+5)	-	-	-	7,031	7,031
7. Capital Investment variance to BP (4-1)	(400)	(3,750)	-	6,531	2,381
8. Cost of Removal variance to BP (5-2)	-	(500)	-	500	-
9. Total Capital and Removal variance to BP (6-3)	(400)	(4,250)	-	7,031	2,381

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed					-
2. Project O&M 2020 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Contingency for the project is $200k, 5% of the estimated expenses for the project. The 2020 spend was funded by the RAC in the 4+8 forecast.

Risks

Based on inspections and lessons learned within the LG&E-KU Fleet, not completing this project could lead to a higher unit EFOR. Outage maintenance cost would increase to mitigate reliability, safety, and performance issues.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 5,193
2. Structural Refurbishment: NPVRR: ($000s) 5,619
3. Do Nothing (Run until failure): NPVRR: ($000s) 5,773

- The structural refurbishment of the tower would include the addition of new load bearing members and replacement of deteriorated structural components. This scope would reduce the probability of a structural collapse but require additional maintenance activities to maintain cooling tower reliability.

- The Do Nothing alternative will allow continued reliability issues, increase safety concerns, increase maintenance spend and result in multiple cell failures.

Conclusions and Recommendation

It is recommended that Management approve the MC2 Cooling Tower Rebuild project for $4,650k to ensure long term reliability and safety of the Mill Creek Unit 2 Cooling Tower.

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: 8/27/2020

Project Name: MC3 WATERWALL PANEL

Total Capital Expenditures: $2,500k (Including $141k of contingency)

Total O&M: $ 0 k

Project Number(s): 159972

Business Unit/Line of Business: Power Generation

Prepared/Presented By: Michael Kjelby/Joe Didelot

Brief Description of Project

This project is to mitigate boiler tube failures (BTFs) on Mill Creek Unit 3 (MC3) waterwall panels due to corrosion caused by sulfidation. This project will replace 2,316 square feet of existing thermal spray coated tubing on the center of the sidewalls at the burner elevations of the MC3 boiler with nickel/chrome weld overlay tubes to protect against corrosion. The project supports transitioning from shorter-lived thermal spray, typically a six-year life, to more durable nickel/chrome weld overlay with a twenty-year life.

Milestones:

Material Bids Received	July 2020
Project Approval	September 2020
Material PO Issued	September 2020
Labor Bids Received	February 2021
Material Delivery	June 2021
Installation	October 2021

The total cost of the project is $2,500k with $141k in contingency included. The project is included in the 2020 Business Plan at $2,000k in 2021 and the proposed 2021 BP, with $350k in 2020 and $2,150k in 2021. The $350k in 2020 was funded by the RAC in the 3+9 forecast, and the incremental $150k in 2021 has been funded within the Generation capital plan in the proposed 2021 BP.

Why is the project needed? What if we do nothing?

MC3 is a [redacted] boiler placed into service in 1978. The waterwalls have experienced corrosion and resulting wall loss since the installation of low-NOx burners in 2002. The waterwalls have had several applications of protective thermal spray applied to mitigate corrosion. Inspections have revealed unacceptable life from thermal spray in this application which has led to a shift to installing weld overlay tubing.

This project will replace corroded tubing with new weld overlay tubing. The weld overlay will provide protection against corrosion. Failure to complete this project would result in an increased number of BTFs and EFOR.

Budget Comparison & Financial Summary

The labor will be included in a fleet wide Boiler Craft Labor Request for Proposal.

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	350	1,950			2,300
2. Cost of Removal Proposed		200			200
3. Total Capital and Removal Proposed (1+2)	350	2,150	-	-	2,500
4. Capital Investment 2020 BP	-	1,800			1,800
5. Cost of Removal 2020 BP	-	200			200
6. Total Capital and Removal 2020 BP (4+5)	-	2,000	-	-	2,000
7. Capital Investment variance to BP (4-1)	(350)	(150)	-	-	(500)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(350)	(150)	-	-	(500)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed					-
2. Project O&M 2020 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Contingency for the project is $141k, 6% of the estimated expenses for the project.

Risks

Not completing this project would increase EFOR due to BTFs. Forced outage repairs would be more frequent and require more time to complete as corrosion continues to reduce the wall thickness of waterwall tubes. Deferral of this project would impact the feasibility of completing future projects due to interference within the boiler, increasing unit EFOR.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 2,818

2. Next Best Alternative: NPVRR: ($000s) 2,859
   - The Next Best Alternative is delaying the project until 2023.
   - Inflation of 3% a year is considered.

3. Do Nothing: NPVRR: ($000s) 3,054
   - The Do Nothing alternative is not completing the project.

In the Next Best Alternative and Do Nothing option, it is assumed that each tube leak on the waterwalls would cause a forty-eight (48) hour long outage. It is assumed that one tube leak per year will occur on the waterwalls starting in 2021, and then the number of tube leaks per year will increase in 2025, and 2027.

Deferring until 2023 for installation will result in tube leaks and a resulting increase in unit EFOR. The Do Nothing alternative would result in continued BTFs.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the MC3 Waterwall Panel project for $2,500k to ensure continued, reliable operation of the Mill Creek 3 boiler.

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: November 20, 2020

Project Name: TC CT MKVIe PHASE 2-3 CT5-10

Total Capital Expenditures: $2,178k (Including $56k of contingency, $40k of internal labor and $212k of burdens)

Total O&M: $ 0 k

Project Number(s): 156865LGE / 156867LGE / 156869LGE / 156871LGE / 156873LGE / 156875LGE

Business Unit/Line of Business: Generation – Trimble County Station

Prepared/Presented By: Chris Baer / Mike Buckner / Francisco Maldonado / Adam Ball

Brief Description of Project

Trimble County Generating Station has six (6) [redacted] Frame 7FA single-fuel gas combustion turbines designated TC5 through TC10. The original control platform across all six units was the [redacted] Mark VI. This control platform entered the legacy phase of its lifecycle at the end of 2018. This phase means no new parts are manufactured and support is offered on a "best effort" basis. To begin to address this obsolescence and enable more advanced combustion control software the first of three phases was completed to migrate from the [redacted] Mark VI platform to the currently supported [redacted] Mark VIe platform. This first phase was completed across all six units from 2016 to 2019. This project is to complete the final two phases of the migration to MKVIe to have all six units on a fully supported control platform. The plan is to complete the migration on four units the Fall of 2021 with completion of the final two the Spring of 2022.

Why is the project needed? What if we do nothing?

The project is needed to address obsolescence of the existing [redacted] VI controls. New parts are not manufactured currently thus over time replacement parts and support will become increasing more difficult to obtain. This puts the units at a greater risk of extended outage if a control system part fails.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Total
1. Capital Investment Proposed	406	1,569	203	2,178
2. Cost of Removal Proposed	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	406	1,569	203	2,178
4. Capital Investment 2021 BP	-	2,616	-	2,616
5. Cost of Removal 2021 BP	-	-	-	-
6. Total Capital and Removal 2021 BP (4+5)	-	2,616	-	2,616
7. Capital Investment variance to BP (4-1)	(406)	1,047	(203)	438
8. Cost of Removal variance to BP (5-2)	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(406)	1,047	(203)	438

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Total
1. Project O&M Proposed	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-

Savings realized from other capital projects will allow us to initiate this project in 2020, as such, 19% of the project will be funded this year within the Trimble County capital plan in the 10+2 forecast. Due to conflicts with another project occurring in Spring of 2021(TC5 Major & Rotor Inspections) completion of the final two units will be pushed into Spring of 2022 moving 9% of the project into 2022. Contingency is 3% of contract total to [redacted]. The project is fully funded in the proposed 2021BP and the excess funds will be reprioritized in the 0+12 RAC forecast. The variance in 2022 will be funded from other projects within Trimble County's capital plan.

Risks

Risk of not completing the project is the potential of an extended outage if parts or support could not be obtained for an unexpected failure within the control systems. The risk of completing the project is minimal as this is a proven technology across the [redacted] gas turbine fleet. No environmental impacts or concerns.

Alternatives Considered

1. Recommendation: Migration in 2021-2022 NPVRR: ($000s) $2,383
   Perform the final two phases of the control platform migration in 2021 and 2022.

2. Alternative #1: Do Nothing NPVRR:($000s) $0
   The Do Nothing alternative was not considered because when parts or support can't be obtained the unit can no longer operate resulting in an extended outage while the system is upgraded. Furthermore, as the current controls platform becomes obsolete the security measures and software updates will follow suit. This presents a vulnerability to our OT cyber security.

Switching to a different control platform was not considered as this would introduce substantial switching costs and technical issues.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the TC CT MKVIe PHASE 2-3 CT5-10 project for $2,178k to ensure the Trimble County combustion turbines are on a fully supported controls platform.

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: November 20, 2020

Project Name: TC1 SCR CATALYST L3

Total Capital Expenditures: $2,273k gross, $1,705k net (Including $206k gross of contingency)

Total O&M: $ 0 k

Project Number(s): 153078

Business Unit/Line of Business: Power Production/Trimble County 1

Prepared/Presented By: Haley Turner, Francisco Maldonado, Mike Buckner

Brief Description of Project

The Trimble County Unit 1 (TC1) selective catalytic reduction (SCR) system, designed by [redacted] has been in service since April 2002. The SCR was originally composed of two (2) reactors each containing two (2) layers of catalysts. A third layer was added in 2005. Each layer contains one-hundred forty-four (144) modules across both reactors. The modules house plate catalysts which react with anhydrous ammonia to reduce nitrogen oxides (NO_x) in the flue gas stream.

In-service catalyst plates from each layer are sampled during annual unit outages. Third party testing is performed on the samples in order to monitor catalyst activity and remaining life. Based on 2019 test results and LG&E-KU's internal analysis, the recommended action for the TC1 SCR is to replace Layer 3 in the fall of 2021 with new catalyst. The current Layer 3 is comprised of regenerated catalyst which were installed in October 2015 and will have reached six (6) years of post-regenerated life at the time of replacement. These modules were thoroughly cleaned and re-dipped in a chemical bath to regenerate catalytic activity. However, as catalyst sampling and testing continued, it was determined that regeneration was not performing as predicted. In order to maintain the catalyst management program and control catalyst life and performance, it became evident that the Trimble County catalyst management plan had to be transitioned from using regenerated catalyst modules to using new catalyst modules. In 2017, Layer 1 received new catalyst modules in accordance with the updated program. Layer 2 received new catalyst modules in 2019. Installation of the new catalyst for Layer 3 in Fall 2021 will maintain consistency in the layers and will aide in compliance with NO_x emission limits.

Bids have been received for the purchase of the catalyst modules. The evaluation process of the bids is still ongoing. Labor for removal and installation is anticipated to be competitively bid and awarded 1st quarter of 2021. Industrial cleaning will also be competitively bid early 2021.

The total project cost, discussed in more detail in the *Budget Comparison & Financial Summary* section, is estimated to be $2,273k gross ($1,705k net).

Why is the project needed? What if we do nothing?

Catalysts are not capable of regaining activity; therefore, performance levels will continue to diminish until the layer is replaced. Additionally, as catalyst activity declines, the opportunity for ammonia to travel to downstream equipment (ammonia slip) also increases. This poses a risk of air heater fouling, ductwork corrosion, and issues with coal combustion residual (CCR) operations. For these reasons it is recommended that the TC1 Layer 3 SCR catalysts be replaced before catalyst deactivation occurs and NO_x removal rates drop below an unacceptable level.

If the specified layer is not replaced during the Fall 2021 outage, the unit runs the risk of forced outages due to required air heater washes. If the project is continuously delayed, the probability of forced outages increases each year. Installation of a new catalyst layer will allow the unit to continue operation at target NO_x removal rates and minimize ammonia slip.

The SCR catalyst replacement on Trimble County Unit 1 is scheduled to be performed during the Fall 2021 outage. The project scope includes the following:

- Industrial vibratory cleaning of SCR reactors
- Removal and disposal of one-hundred forty-four (144) catalyst modules
- Removal of existing soot blower system and purchase and installation of new sonic horn system
- Purchase and installation of new catalyst modules and seals
- Post-replacement ammonia injection tuning
- Third-party catalyst testing for new layer performance guarantees

The expected project milestones are as follows:

- October 2020 Bids received for catalyst material
- December 2020 Issue contract for new catalyst material
- 1st Quarter 2021 Issue PO for new sonic horns and associated material
- 1st Quarter 2021 Issue PO for catalyst and sonic horn installation
- 2nd Quarter 2021 Issue PO for Industrial cleaning of the SCR
- 2nd Quarter 2021 Purchase seals and other miscellaneous material for outage
- August 2021 Delivery of catalyst modules, seals, sonic horns and other material
- September 2021 Outage start
- November 2021 Outage work complete
- December 2021 Used SCR catalyst shipped for disposal
- December 2021 Tune SCR to optimize ammonia distribution

Budget Comparison & Financial Summary (Net costs)

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	219	1,086			1,305
2. Cost of Removal Proposed		400			400
3. Total Capital and Removal Proposed (1+2)	219	1,486	-	-	1,705
4. Capital Investment 2021 BP	219	1,994			2,213
5. Cost of Removal 2021 BP					-
6. Total Capital and Removal 2021 BP (4+5)	219	1,994	-	-	2,213
7. Capital Investment variance to BP (4-1)	(0)	908	-	-	908
8. Cost of Removal variance to BP (5-2)	-	(400)	-	-	(400)
9. Total Capital and Removal variance to BP (6-3)	(0)	508	-	-	508

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed					-
2. Project O&M 2021 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The total cost of the project is estimated to be $2,273k gross ($1,705k net), which includes $206k gross contingency (10%) for contract labor and materials. The project was fully funded in the 2020BP and is included in the 2021BP with the excess in 2021 to be reprioritized as part of the 0+12 forecast in January. The variance to the 2021 plan is driven by receipt of material bids after the plan was submitted, lower labor costs expected and the assumption that disposal costs will remain consistent to last year's costs.

Risks

If the proposed catalyst layer is not replaced, there is a risk that NO_x emissions will increase and pose a risk to the unit's reliability. Additionally, there is a risk that NO_x emissions will not meet compliance regulations and the unit will be forced offline annually, during ozone season. Also, as ammonia slip increases, it can cause air heater fouling which will require unexpected unit outages for cleaning.

Alternatives Considered

1. Recommendation: Purchase/Install New Catalyst NPVRR: ($000s) $1,884k

This plan is least cost over the life of the project, avoids the probability of unit outages, and aides in NO_x emissions compliance.

2. Alternative #1: Delay Project Two (2) Years NPVRR: ($000s) $2,079k

Delaying the project two (2) years presents multiple risks. These risks include decreased NO_x removal efficiency and increased ammonia slip which could lead to forced unit outages and derates. This alternative is not recommended due to these reasons.

3. Alternative #2: Do Nothing NPVRR: ($s) $2,676k

This alternative is not recommended as this would yield a high probability of forced unit outages and would be detrimental to unit operations and equipment.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the TC1 SCR Catalyst L3 replacement project for $2,273k gross ($1,705k net) to ensure TC1 continues to meet NOx emission limits and reduce risks of forced outages.

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: December 2020

Project Name: GH DTLS & Pipe Conveyor Reconstruction

Total Original Capital Expenditures: $6,500k (Approved on 2/13/2020)

Amendment Value: $ 800 k

Total Revised Capital Expenditures including Amendment: $7,300k

Project Number(s): 161436

Business Unit/Line of Business: Generation

Prepared/Presented By: Vincent Forcellini

Description of Incremental Ask

Original Approved Capital Expenditures		$ 6,500 k
Revised Capital Expenditures Requested including Amendment		$7,300 k
Total Amendment Requested		$800 k

Additional funds are requested to complete project 161436 (GH DTLS & Pipe Conveyor Reconstruction). Below are detailed reasons for the increase in authorization amount. The incremental spend will be fully reimbursable through the active insurance claim yielding an unchanged net of $2,500k after finalization of the insurance claim.

- [redacted] was contracted to perform the DTLS building inspection. Due to the detailed nature of evaluating the structure, more time was required to perform the inspection than originally anticipated.
- During the building structural steel demolition, additional structural steel members were identified requiring repair or replacement. This steel was not included in the third-party structural evaluation/inspection report. The entirety of the fourth floor is required to be removed to refurbish six columns not identified in the inspection report. Original design drawings show building connections are bolted. Actual building construction includes both bolted and welded connections requiring additional labor for removal and installation to return it to original connection condition.
- The pipe conveyor was ultimately dislocated more than originally noted after the event. This movement required additional conveyor relocation cost and structural analysis of some load bearing members to ensure the additional movement did not cause further damage.

This recommendation remains the best evaluated alternative after updating the expected capital cost. The DTLS contains a critical set of equipment for the Ghent Generating Station. Hauling

CCR materials to the landfill from the CCRT area compared to hauling from the DTLS has significant incremental O/M costs. Additionally, changing the hauling distance is not possible within the current air emissions permit.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	Pre-2020	2020	2021	Post 2021	Total
1. Capital Investment Proposed		4,352	448		4,800
2. Cost of Removal Proposed		2,500			2,500
3. Total Capital and Removal Proposed (1+2)	-	6,852	448	-	7,300
4. Capital Investment 2021 BP		4,000			4,000
5. Cost of Removal 2021 BP		2,500			2,500
6. Total Capital and Removal 2021 BP (4+5)	-	6,500	-	-	6,500
7. Capital Investment variance to BP (4-1)	-	(352)	(448)	-	(800)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	(352)	(448)	-	(800)

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

- The revised capital project amount of $7,300k will provide the necessary budget for anticipated project spend of $7,200k. Contingency is reduced from $500k to $100k. As previously stated, the entirety of the additional project cost is anticipated to be reimbursed to the company through the insurance claim.

Conclusions and Recommendation

Investment Committee approval of the GH DTLS & Pipe Conveyor Reconstruction project for $7,300k to provide for reconstruction of the GH DTLS and Pipe Conveyor is recommended.

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
Chief Financial Officer

Paul W. Thompson Date
Chairman, CEO and President

Investment Proposal for Investment Committee Meeting on: 12/18/2020

Project Name: GH1 Cooling Tower ComplRebuild

Total Original Capital Expenditures: $11,586k (Approved on 4/24/2019)

Total O&M: $ 0 k

Amendment Value: $ 1,107 k

Total Revised Capital Expenditures including Amendment: $12,693k

Project Number(s): 121GH

Business Unit/Line of Business: Generation

Prepared/Presented By: Roy Arnold/Dave Tummonds

Description of Incremental Ask

Original Approved Capital Expenditures		$11,586k
Revised Capital Expenditures Requested including Amendment		$12,693k
Total Amendment Requested		$1,107k

Project 121GH was approved on April 24, 2019 for $11,586k to complete a rebuild of the GH1 cooling tower. Subsequent to the original project and contract approval, two scope modifications have been identified to ensure successful completion of the project. To meet the performance specifications of the cooling tower, the fan power requirements for the new tower are greater than the original tower, requiring an upgrade to the transformers and switchgear supplying the cooling tower. In addition, an error in the original scope development made replacement of the cooling tower bypass line an option. The condition of the cooling tower bypass line requires replacement. The combination of these two items drives the project increase of $1,107k.

Revision of the original Capital Evaluation Model with the revised requested project authority holds that the original recommendation of project completion remains the preferred alternative.

Budget Comparison & Financial Summary

- The revised project expenses are $2,232k in 2020 and $10,461k in 2021

Financial Detail by Year - Capital ($000s)	Pre-2020	2020	2021	Post 2021	Total
1. Capital Investment Proposed		2,232	9,961		12,193
2. Cost of Removal Proposed			500		500
3. Total Capital and Removal Proposed (1+2)	-	2,232	10,461	-	12,693
4. Capital Investment 2021 BP		2,176	8,878		11,054
5. Cost of Removal 2021 BP			499		499
6. Total Capital and Removal 2021 BP (4+5)	-	2,176	9,377	-	11,553
7. Capital Investment variance to BP (4-1)	-	(56)	(1,083)	-	(1,139)
8. Cost of Removal variance to BP (5-2)	-	-	(1)	-	(1)
9. Total Capital and Removal variance to BP (6-3)	-	(56)	(1,084)	-	(1,141)

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

There are no O&M costs associated with this project. All major material and labor contracts have been bid or executed, therefore a small contingency of $150k is included in this revised project authority request. The incremental funds requested in excess of the proposed 2021BP will be funded from within the Ghent capital plan.

Conclusions and Recommendation

Investment Committee approval of the GH1 Cooling Tower ComplRebuild project for $12,693k to provide for rebuild of the GH1 Cooling Tower with the recommended upgrades is recommended.

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 and Contract Proposal for Investment Committee Meeting on: October 27, 2020 Project Name: GH1 Burner Corner Tube Replacement Contract Name (Good/Service): GH1 Burner Corner Tube Material Contract (SSA) Selected Vendor(s): [redacted] Contract Authorization Requested: [redacted] of contingency) Contract Term: November 2020-February 2022 Total Capital Expenditures Requested: $ 6,563 k (Including $597k of contingency and $86k of internal labor) Project Number(s): 140222 Business Unit/Line of Business: Power Generation Prepared/Presented By: Jesse Chipman/Jonathan Scarborough/Dave Tummonds

Brief Contract/Project Description

The GH1 Burner Corner Tube Replacement project will replace all four original burner corner tube panels, the associated pilot torch air ducts, and structural steel members. In addition, all four separated overfire air (SOFA) tube panels will be replaced. The original burner and SOFA tube panels have reached the end of their useful life due to corrosion fatigue as well as erosion. The new tubing will be a like-kind replacement in terms of physical arrangement, but the new tubing will have a higher allowable stress. The new panels will include Inconel 622 weld metal overlay to mitigate corrosion concerns associated with burning relatively high chlorine and sulfur content Illinois basin coals with a low NOx firing system.

Due to the complexity of the burner and SOFA panel tube geometry and windbox attachment design detail, a sole-source authorization (SSA) for material procurement from the boiler [redacted], [redacted] is recommended. [redacted] has recently supplied several major pressure part components under competitively bid and SSA contracts for LG&E and KU. This contract has a total price of [redacted] contingency) and will span three years (2020-2022).

The Scope of Work (SOW) was developed by GH Engineering in communication with [redacted] is aware of the requirements in the SOW, deliverables, and the expected timeline for completion. Final delivery of the materials would occur in February 2022 in advance of the spring 2022 GH1 planned outage, scheduled to start on March 12th and end April 30, 2022. Installation labor will be competitively bid in spring 2021. This project is not considered ECR or GLT recoverable and KPSC approval is not required.

Why is the project needed? What if we do nothing?

Corrosion fatigue is a failure mechanism initiated on the inside of the tube which results from a combination of mechanicalstress, thermalcycles, and corrosion. Typically, this occurs on the cold side of the tube (boiler exterior) at an attachment point, making the burner corner tube panels an area of concern. During the Spring 2015 outage, Generation Engineering conducted a corrosion fatigue study of the GH1 boiler waterwalls, which included the burner corner tubes. As a result of that study, tubes presenting an immediate EFOR risk were replaced. Replacement of the burner corner panels on GH1 will mitigate latent corrosion fatigue concerns. Because the corrosion fatigue mechanism tends to affect the cold side of the tube, resultant tube leaks can be external, creating a personnel safety concern as well as a forced outage.

The application of Inconel 622 on the new tube panels will minimize future corrosion and erosion. A similar project was completed on E.W. Brown Unit 3 in 2015, and has performed well since then. Thatprojectincluded replacementcorner panels with partial Inconel 622 overlay,which were supplied by [redacted], proving successful OEM supply of these panels.

Failing to complete this projectwill result in increased risk of forced outages on GH1 as the current corrosion fatigue cracks and corrosion/erosion would remain unmitigated. Corrosion fatigue cracks will continue to grow in depth and length as time and stress continue. The successful completion of this project will ensure continued safe and reliable operation of GH1.

Contract Bid Summary

KU elected to sole source the material purchase from [redacted] due to the complexity of the tube bends and physical arrangement of these components. As the OEM, [redacted] owns the original, proprietary design and fabrication information for the GH1 boiler. Supply by a non-OEM vendor would carry considerable fit-up and constructability risks.

The total firm, fixed contract value for the recommended SSA is [redacted] (inclusive of a [redacted] contingency) and covers the material purchase, design, engineering, manufacture, and delivery of four burner corner tube panels with their associated pilot torch air ducts, structural steel members, and four SOFA tube panels. Material delivery is required in February 2022. The contingency is included to cover any unforeseen costs during the execution of the contract. All Work will be governed by the negotiated General Services Agreement dated December 10, 2010. [redacted] proposal meets all technical and schedule requirements. [redacted] is not an MBE/WBE designated supplier. Payment terms will follow a milestone schedule, with Final Completion scheduled for February 2022, upon delivery of materials to Ghent Station. This is prior to the removal and installation during the GH1 2022 spring outage. The contract includes a three-year material warranty and liquidated damages of $20k/day for schedule delay beyond the required delivery date.

Contract Financial Summary

Contract expenses ($k)	2020	2021	2022	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

There are no built-in escalators in this contract. This Contract schedule spans three years (2020 - 2022) due to engineering requirements and manufacturing lead time to support the February 2022 delivery. The contingency requested is reasonable given the f irm, fixed proposal and previous commercial history with [redacted]

Project Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	226	1,825	3,432		5,483
2. Cost of Removal Proposed			1,080		1,080
3. Total Capital and Removal Proposed (1+2)	226	1,825	4,512	-	6,563
4. Capital Investment 2021 BP	225	2,799	3,197		6,221
5. Cost of Removal 2021 BP			1,231		1,231
6. Total Capital and Removal 2021 BP (4+5)	225	2,799	4,428	-	7,452
7. Capital Investment variance to BP (4-1)	(1)	974	(235)	-	738
8. Cost of Removal variance to BP (5-2)	-	-	151	-	151
9. Total Capital and Removal variance to BP (6-3)	(1)	974	(84)	-	889

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed					-
2. Project O&M 2021 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project is included in the 2020BP and proposed 2021BP for execution in 2022. Incremental funding in 2020 is included in the 9+3 RAC forecast. Variances to the proposed 2021BP in 2021 and 2022 will be reallocated within the Ghent Capital Budget in the 2021 0+12 RAC forecast. Project contingency of $597k (approximately 10%) is included and is reasonable given the complexity of the project.

Risks

Failure to complete this project during the Spring 2022 outage would result in increasing risk of tube leaks prior to the replacement during the next outage of sufficient duration in 2029. Given inspection results and age of the tubing, a delay in completingthe projectis a risk to unit reliability and personnel safety. A similar project was successfully completed in 2015 on E.W. Brown Unit 3, proving the technology and project methodology. Both the Ghent Environmental Supervisor and Environmental Affairs havereviewed andapprovedthis project. A risk review was conducted by the Credit Department and [redacted] was found to be within financial risk requirements. [redacted] has agreed to provide a Parent Guarantee within 30 days of contract execution.

Project Alternatives Considered

1. Recommendation: Replace Panels in 2022 NPVRR: ($000s) $6,872

2. Alternative #1: Replace Panels in 2029 NPVRR: ($000s) $9,142
   This alternative considers delaying the replacement of the Burner Corner and SOFA Tube panels until the nextoutage of adequate duration. Prior to completingthis project, the probability of a forced outage causedby a tube leak increases. An expected duration for such a leak is 3 days. Operation beyond 2022 without full replacement makes multiple failures per year likely. In addition, outage expenditure would be required for emergent tube replacement.

3. Alternative #2: Do Nothing NPVRR: ($000s) $7,310
   The corrosion fatigue cracks will continue to grow in size and quantity and multiple leaks per year would be expected. In addition, outage expenditure would be required for emergent tube replacement.

Conclusions and Recommendation

Investment Committee approvalof the GH1 Burner Corner Tube Replacement projectfor $6,563k as well as the SSA GH1 Burner Corner Tube Material Contract for $2,382k to support the continued reliability of the GH1 boiler are recommended.

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced:

The Capital project spending and contract authority requests included in this Investment Proposal have 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 the capital project and contract authority requests.

Kent W. Blake Chief Financial Officer	Date	Paul W. Thompson Chairman, CEO and President	Date

AWARD RECOMMENDATIONAPPROVALS – Attachment for IC Proposal

SUBJECT:
Ghent 1 Burner Corner Tube Material Contract

Please see the attached Investment Proposalfor information related to this contractauthorityrequest and additional approvals.

RECOMMENDATION/APPROVAL The signatures belowrecommendthat Management approve the SSA Ghent 1 Burner Corner Tube Material Contract for [redacted] (inclusiveof $113kcontingency) to [redacted].

Sourcing Leader		Proponent/TeamLeader	
Supplier Diversity Manager		Manager	
Manager, Commercial Operations		Director – Commercial Operations	
General Manager		Vice President	

Note: For Contract Proposals greater than$10 million bid, or greater than$2 million sole sourced, additional required approvals are includedas part of the attached Investment Proposal.

Investment Proposal for Investment Committee Meeting on: 12/18/2020

Project Name: GH1 Cooling Tower ComplRebuild

Total Original Capital Expenditures: $11,586k (Approved on 4/24/2019)

Total O&M: $ 0 k

Amendment Value: $ 1,107 k

Total Revised Capital Expenditures including Amendment: $12,693k

Project Number(s): 121GH

Business Unit/Line of Business: Generation

Prepared/Presented By: Roy Arnold/Dave Tummonds

Description of Incremental Ask

Original Approved Capital Expenditures		$11,586k
Revised Capital Expenditures Requested including Amendment		$12,693k
Total Amendment Requested		$1,107k

Project 121GH was approved on April 24, 2019 for $11,586k to complete a rebuild of the GH1 cooling tower. Subsequent to the original project and contract approval, two scope modifications have been identified to ensure successful completion of the project. To meet the performance specifications of the cooling tower, the fan power requirements for the new tower are greater than the original tower, requiring an upgrade to the transformers and switchgear supplying the cooling tower. In addition, an error in the original scope development made replacement of the cooling tower bypass line an option. The condition of the cooling tower bypass line requires replacement. The combination of these two items drives the project increase of $1,107k.

Revision of the original Capital Evaluation Model with the revised requested project authority holds that the original recommendation of project completion remains the preferred alternative.

Budget Comparison & Financial Summary

- The revised project expenses are $2,232k in 2020 and $10,461k in 2021

Financial Detail by Year - Capital ($000s)	Pre-2020	2020	2021	Post 2021	Total
1. Capital Investment Proposed		2,232	9,961		12,193
2. Cost of Removal Proposed			500		500
3. Total Capital and Removal Proposed (1+2)	-	2,232	10,461	-	12,693
4. Capital Investment 2021 BP		2,176	8,878		11,054
5. Cost of Removal 2021 BP			499		499
6. Total Capital and Removal 2021 BP (4+5)	-	2,176	9,377	-	11,553
7. Capital Investment variance to BP (4-1)	-	(56)	(1,083)	-	(1,139)
8. Cost of Removal variance to BP (5-2)	-	-	(1)	-	(1)
9. Total Capital and Removal variance to BP (6-3)	-	(56)	(1,084)	-	(1,141)

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

There are no O&M costs associated with this project. All major material and labor contracts have been bid or executed, therefore a small contingency of $150k is included in this revised project authority request. The incremental funds requested in excess of the proposed 2021BP will be funded from within the Ghent capital plan.

Conclusions and Recommendation

Investment Committee approval of the GH1 Cooling Tower ComplRebuild project for $12,693k to provide for rebuild of the GH1 Cooling Tower with the recommended upgrades is recommended.

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: December 18, 2020

Project Name: TC1 FGD Recycle Pump Piping

Total Capital Expenditures: $2,525k gross, $1,894 Net (including $250k gross of contingency)

Total O&M: $ 0 k

Project Number(s): 124518

Business Unit/Line of Business: Generation

Prepared/Presented By: Logan Waller

Brief Description of Project

The scope of this project includes the purchase, fabrication, and replacement of all ten "B" side recycle pumps' suction and discharge piping up to the discharge headers. The "A" side was replaced in 2019, as such, this project is a continuation of that replacement effort. The Trimble County Unit 1 (TC1) Wet Flue Gas Desulfurization (WFGD) is original to the unit and has been in operation for nearly 30 years. The fiberglass piping has been repaired over the years but is now reaching the end of its expected life. The TC1 WFGD design is unique to the fleet as it contains two tanks, four modules, and five recycle pumps per module.

The replacement of the fiberglass piping is in line with a 2017 Burns and McDonnell WFGD condition assessment. The study analyzed the overall health, reliability, and necessary modifications to maintain WFGD performance. This proposed project is one of several that was included in the 2018BP and 2019BP to upgrade the WFGD to meet demands of unit availability and continue to meet emissions requirements. As a continuation of this effort this project was included in the approved 2020 BP and is included in the proposed 2021BP.

The project is scheduled to take place during the TC1 2021 fall outage. Costs are estimated to be $2,525k gross. At this time the material portion has been bid out but not awarded. The labor portion of this project is expected to be bid out in the 1 st quarter of 2021.

Why is the project needed? What if we do nothing?

Over the years, fiberglass piping repairs have been madenearly everyoutage to fix leaks and repair the piping's protective coating. Expected life of fiberglass pipe in slurry conditions in the industry is approximately 20 years. A video inspection of the pipingin 2015 and 2017 indicated significant deterioration of the corrosion barrier, which is the primary protective layer of the piping. The discharge headers were replaced on all four modules during the TC1 Fall 2017 outage. The "A" side discharge piping was replaced during the TC1 Fall 2019 outage. The replacement of the fiberglass piping is in line with a [redacted] condition assessment. The study analyzed the overall health, reliability, and necessary modifications to maintain WFGD performance. This proposed project is one of several that were included in the 2018BP and 2019BPto upgrade the WFGD to meetdemands of unitavailability and continueto meetemissions requirements. If nothing is done, there is a potential for excessive leaks causing recycle pumps to become unavailable, which will increase sulfur dioxide emissions.

Project Milestones are as follows:

- Award Project Material — December 2020
- Award Labor — February 2021
- Material Fabrication — April 2021 to August 2021
- Material Delivered — August 2021
- Outage Begins — September 18th, 2021
- Project Complete — October 21st, 2021

Budget Comparison & Financial Summary

This project is included in the approved 2021BP and will be fully funded. This project is divided into two parts; material supply and installation. The most competitive and technically acceptable material bid received is $990k gross. Installation cost of $1,285k gross is estimated based on the 2019 "A" side installation project. Contingency (10%) is $250k gross and will cover any unknown conditions once the work begins that would be directly related to the scope of the project. The Work will be awarded as lump-sum and any additional work discovered during the project will be completed on a time and material not to exceed basis.

The lower funding request compared to the business plan is due to several factors. Material pricing received was more favorable than 2019 material pricing. The project was initially put into the business plan as a multi-year project. Material and labor bids were lower than budgetary estimates.

Financial Detail by Year - Capital ($000s)	2021	2022	2023	Post 2023	Total
1. Capital Investment Proposed	1,597				1,597
2. Cost of Removal Proposed	297				297
3. Total Capital and Removal Proposed (1+2)	1,894	-	-	-	1,894
4. Capital Investment 2021 BP	2,421				2,421
5. Cost of Removal 2021 BP					-
6. Total Capital and Removal 2021 BP (4+5)	2,421	-	-	-	2,421
7. Capital Investment variance to BP (4-1)	824	-	-	-	824
8. Cost of Removal variance to BP (5-2)	(297)	-	-	-	(297)
9. Total Capital and Removal variance to BP (6-3)	527	-	-	-	527

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed					-
2. Project O&M 2021 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks

The risks of not completing this project include:

- Once the corrosion barrier has been compromised in fiberglass pipe, small holes or leaks lead to larger holes or leaks. It is difficult to maintain a patch in a WFGD slurry environment. This could lead to a decrease in operational efficiency and increased unit derates to maintain sulfur dioxide emission limits.
- O&M expenditures will increase due to costs associated with repairing leaks and patching elbows.

The risk of completing the project:

- Delays in installation could cause the outage timeframe to increase. This risk will be mitigated by utilizing experienced contractors with rigging and previous project knowledge.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $2,253

2. Alternative #1: Do nothing NPVRR: ($000s) $3,763
   This alternative should not be considered due to the increased risk of pipe failure. If nothing is done, the piping will continue to deteriorate, unit reliability will decrease, and O&M spending will increase with each outage. Assumed $25k per year increase in repair costs and 1.5 weeks to make repairs.

3. Alternative #2: Complete over two outages NPVRR: ($000s) $2,312
   This option would replace the B1 module piping in 2021 and the B2 module piping in the 2023 outage. It is assumed that there would be an increase in installation costs by 15% for increased labor and material costs. This assumption is made because of the intricacy of potential interferences between the new and old piping. The contractor will also have fixed costs each outage such as crane rental, material staging, and office trailers. This alternative should not be chosen due to the increased cost and complexity of the tight working spaces. Assumed station would incur costs until project complete.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the TC1 FGD Recycle Pump Piping project for $2,525k ($1,894k net) gross to avoid future incremental O&M costs as the existing fiberglass pipe reaches the end of its service life. This is also to ensure environmental compliance and long-term unit reliability.

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: 3/27/19

Project Name: OTN Extension EKY Ring

Total Capital Expenditures: $2,266k (Including $114k of contingency* and $140k of internal labor)

Total O&M: $244k

Project Number(s): IT0453B

Business Unit/Line of Business: IT Infrastructure & Operations

Prepared/Presented By: Jason Finn/Dan Reffett

Brief Description of Project

This is a two-year IT capital project to extend LKS's Optical Transport Network (OTN) into the Eastern Kentucky communication backbone sites. Optical Transport Network technology was chosen in 2013 to be LKS's network transport technology due to its bandwidth capacity, flexibility to carry multiple different networks and robust encryption. OTN is expected to provide a minimum expected useful life of between 10 and 15 years. To date, OTN has been deployed in Louisville, Simpsonville, Lexington, Dix Dam and Danville. This project will continue OTN deployment into Eastern Kentucky sites. OTN deployment will provide several benefits in LKS's Eastern Kentucky communication backbone sites, including:

- Upgrade in bandwidth for corporate network from shared 1 gigabit ring to dedicated 10 gigabit for Pineville to better support the call center there as well as its use as our remote data backup location (Data Domain).

- Upgrade in bandwidth for corporate network, from shared 1 gigabit ring to dedicated 1 gigabit per site for Winchester, Richmond, Somerset, London offices and store rooms.

- Improve grade of service to these locations, with dedicated links back to the BOC and Simpsonville Data Center cores, and provide faster, transport-level protection switching to eliminate service disruptions requiring switching/rerouting.

- Provide transport-level strong encryption of all networks at these locations.

- Facilitate easier replacement in these areas for end-of-life Nokia DMX SONET and Infinera DNX-88 DACS network equipment. LKS does not have access to additional fiber in the Eastern Kentucky backbone, and OTN's capability to carry multiple parallel networks simultaneously will allow for a smoother replacement of equipment by first "underlaying" the OTN network.

- Expand LKS's fiber footprint "virtually" in Eastern Kentucky (where we are severely fiber-constrained), providing access to separate wavelengths along the fiber route for adding separate networks/services as needed.

Project key deliverables and target dates:

Project approved and opened	4/6/19
Site assessments/surveys	7/31/19
Initial fiber optic characterization	8/30/19
Ciena OTN equipment delivery to system build/test location	7/12/19
Sites preparations	3/28/20
Fiber remediation	3/28/20
OTN equipment installation	7/1/20
OTN commissioning	8/28/20
Cutover of corporate network to OTN	9/30/20
Project documentation turnover & signoff	10/30/20

Why is the project needed? What if we do nothing?

Network traffic has grown over the past several years and is projected to continue to grow due to corporate applications, site security and video, anticipated substation IP SCADA and telemetry, Data Domain and other sources. OTN is needed to provide bandwidth capacity to meet these requirements. It will improve data security in the transport network, and allow for an easier transition to the next generation network that replaces the end-of-life SONET and DACS equipment. OTN rollout in Eastern Kentucky is needed for these reasons, as well as to further our efforts to improve cyber-security/data confidentiality with respect to this part of the LKS network.

*Contingency to cover issues that arise requiring more resources than originally scoped, such as additional site or fiber optic remediation, equipment changes to overcome site or fiber deficiencies, etc. Past OTN deployment projects have been successfully executed with a 5% contingency budgeted.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	1,636	630			2,266
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	1,636	630	-	-	2,266
4. Capital Investment 2019 BP	1,386	880			2,266
5. Cost of Removal 2019 BP					-
6. Total Capital and Removal 2019 BP (4+5)	1,386	880	-	-	2,266
7. Capital Investment variance to BP (4-1)	(250)	250	-	-	-
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(250)	250	-	-	-

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	49	49	49	97	244
2. Project O&M 2019 BP	24	55	64	135	278
3. Total Project O&M variance to BP (2-1)	(25)	6	15	38	34

*O&M estimate based on 5 years of support. Approximately $250k was shifted from 2020 into 2019 for this project, in order to take advantage of a $400k discount being offered by the equipment manufacturer for the purchase of the balance of OTN equipment (approved by RAC).

Risks

Fiber remediation issues – Although this project's network design makes it less sensitive to fiber issues compared to some of the previous projects' architectures, OTN does in general require better fiber plant characteristics than does SONET. Our fiber provider for most of the fiber on this project (Windstream) has filed for chapter 11 bankruptcy, and is in the process of securing the cash needed to meet its operational needs. We don't expect a halt in our normal course of business with them (processing splice requests, fiber remediation, etc.), but this is something to watch closely.

Fiber characterization, required to determine where remediation is required, and final circuit cutover will be done during business hours. Work will be done on one side of the ring at a time. This will pose some risk to network traffic downstream of the work due to lack of redundancy. This will be required in order to complete the work while minimizing weekend and overtime work by both internal and external resources. We will manage and monitor to minimize impacts.

Contention for internal engineering & technician resources due to high work volume over the next several years – OTN is a proven technology with a good service record in LKS's deployment. Since the project is planned for two years, there is very little risk of not completing within the allotted time. There are no environmental risks nor permits required to complete this project.

Alternatives Considered

1. Recommendation: OTN in Eastern Kentucky NPVRR: ($000s) $2,848

2. Alternative #1: Do Nothing NPVRR: ($000s) $0

Alternative 1 is not recommended because we will not obtain the additional network capacity needed for traffic growth, it will make the upcoming DACS & SONET equipment replacement much more difficult, with potentially more service disruptions to critical functions such as EMS, and it does not provide encryption on transport links that are a part of LKS's cyber-security strategy.

3. Alternative #2: Ethernet Private Lines NPVRR: ($000s) $3,181

Alternative 2 is not recommended because total cost of ownership is higher. This alternative includes acquiring two private Ethernet service feeds per KU location of the Eastern Kentucky fiber ring, from a carrier. One gigabit per second services would be obtained for all locations on the ring except for Pineville, which would get 10 gigabit per second services.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the OTN Extension Eastern Kentucky Ring project for $2,266k to support network capacity, DACS/SONET replacement, and data security needs in the Eastern Kentucky backbone.

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 and Contract Proposal for Investment Committee Meeting on: April 24, 2019

Project Name: PowerPlan v2018 Upgrade
Contract Name (Good/Service): PowerPlan v2018 Upgrade

Selected Vendor(s): PowerPlan

Contract Authorization Requested: $2,622k (including $379k of contingency)

Contract Term: 1 year

Total Capital Expenditures Requested: $4,106k (including $519k of total project contingency and $1,316k of internal labor)

Total O&M: $52k (one-time training expense) which is part of the contract amount.

Project Number(s): IT0458K/IT0458L/IT0458CG
Business Unit/Line of Business: Accounting/Finance/IT

Prepared/Presented By: Heather DiEnno / Heidi Konynenbelt / Matt Smith

Brief Contract/Project Description

Support for the current version of PowerPlan 2015.1.3.0 ends June 30, 2019. PowerPlan has agreed to continue support beyond June 30, 2019, provided we are actively upgrading the system. The PowerPlan suite of products is a critical financial system providing Fixed Asset, PowerTax, Tax Repairs, Property Tax, Tax Provision, Budget/Forecasting, and Lease functionality. In addition to continuing support for the product, the upgrade will provide improvements to system performance, add enhanced functionality to each of the modules, and process efficiencies including:

- Reduction of customizations to become more cloud-ready, anticipating PowerPlan’s move to a cloud-only version.
- Reduction of manual workarounds and automation of manual tasks.
- Upgrade to newest lease version, which includes functionality lacking in current version.
- Enhanced regulatory reporting capabilities.
- Enhanced features and functionality associated with the upgraded version of PowerPlan.

A six week detailed assessment was completed with PowerPlan and the impacted business proponents to prepare for this upgrade. With the assessment phase complete, this proposal requests the funds needed to complete the project.

The sole source contract with PowerPlan is to upgrade to the most current version (2018), create or update required interfaces, and enhance modules to enable improved or new functionality. The contract will require PowerPlan to provide the following implementation services: Initiate, Design, Build, Test, Deploy, Sustain, and Project Management. The agreement will be a time and materials contract for a total estimated amount of $2,243k, including travel expenses and training/job aids. A 20% contingency will be included on the contract price for a total of $2,622k. The term of the contract is expected to be through April 2020. The project will provide a phased implementation that delivers core functionality and the technical upgrade by February 2020 and additional features by April 2020.

Why is the project needed? What if we do nothing?

If the PowerPlan system is not upgraded, we will lose support for the product on June 30, 2019. The system is needed to provide information to prepare financial statements, budgets, forecasts, tax support, and rate case materials. Failure to upgrade and enhance the system could result in being unable to close the books timely and accurately for financial reporting purposes and could negatively impact financial planning. The table below highlights the risk events, causes, and potential results of not implementing the project that could result in a material financial impact to the Company.

Risk Event	Cause	Result
Inaccurate/delayed information for decision making	Human error/manual processes	• Suboptimal strategic planning decisions based on inaccurate forecasted financial statements • Inaccurate cost of service assumptions resulting in incorrect rate for customers • Brand damage
Incorrect SEC financial statements	Human error/manual processes	• Rework required for restatement • Additional external audit fees • Control failures • Brand damage
Inability to close the books	Technical issue(s) cannot be resolved in-house and PowerPlan support has expired	• Delayed reporting to PPL • Increased manual workarounds • Delayed issuance of SEC financial statements • Brand damage
Inaccurate rate case information	Human error/manual processes	• Brand damage • Incorrect cost recovery, potentially to the detriment of customers • Rework required to correct filings

In addition to avoiding potential costs related to identified risks, the project will provide approximately 1,190 hours annually in operational efficiencies across 9 departments. These efficiency gains will defer the need to add incremental headcount to manage increasing workloads and reduce overtime.

The upgrade will have updated functionality across all modules and will eliminate a significant amount of customizations in the Lease and Budget modules. The enhancements will provide increased capabilities in mining O&M savings of approximately $500k and tax savings of approximately $250k each year from 2021 through 2025. The following additional enhancements have been identified in each module to address existing system limitations and offer additional value.

Budgeting/Forecasting: Current limitations in the budget module include:

- Manual workarounds, which are labor intensive and increase risk of error.
- A large number of customizations, which creates challenges in moving to a future cloud product.
- Inability to report information without manual intervention.
- Manual preparation of the depreciation forecast outside of the system, which is labor intensive and increases risk of error.
- Manual performance of LKE allocations outside of the system, which can lead to inaccuracies between companies and inefficiencies.
- Manual performance of Trimble County partner allocations outside of the system, which can lead to inaccuracies between companies and inefficiencies.
- Manual export and upload is performed between systems rather than utilizing a more efficient interface process.
- Current functionality does not work as intended, reducing usability of the system and creating inefficiencies.

The upgrade with enhancements is estimated to save 700 hours annually of operational efficiencies related to the Budget/Forecast module, and will include the following key functionality:

- Support regulatory filing requirements - Enhances labor budgeting using a position level labor build-up, which will reduce risk of error and streamline processes across the Company, and allow for better tracking across budget versions.
- Automate calculations and improve performance - Allows for automated system allocations and the ability to complete the depreciation forecast systematically.
- Streamline data input and extract - Increases system usability by correcting current functionality, improving system performance, and providing access to historical budget and forecast versions.
- Improve controls over administrative processes - Reduces rework on overlapping processes.
- Simplify forecast reporting - Creates interfaces between other systems and additional queries, reducing manual effort.

Lease Module: The current version of the lease module does not contain full functionality as the product has matured in version releases since our current version. Limitations in the current version of the module include:

- Limited functionality for applying payments to lease schedules, resulting in manual workarounds.
- Inability to perform re-measurement, resulting in manual journal entries.
- Reports used for reconciliation include multiple sets of books instead of one, requiring manual adjustment to the reports to reconcile.
- Limited system approval points, requiring manual evidencing of controls.
- Significant customizations.

The upgrade is estimated to save approximately 250 hours annually in operational efficiencies related to the Lease module and will include the following functionality:

- Remove lease system customizations - Remove customizations that are now included in the base version to prepare for a future cloud product and allow for better support from PowerPlan.
- Leverage new upgrade functionality - Greater flexibility in applying payments to lease schedules and adds re-measurement functionality, reducing manual efforts.
- Enhanced reporting - Accurate reconciliation reports and better reporting to facilitate external audit review.
- Additional lease process controls - Includes more system approval points.
- Leverage new usability improvements - Additional functionality now included in the base module to improve usability of module.

Fixed Asset: Limitations in the Fixed Asset module include:

- Current configuration for auto unitization does not always provide accurate retirement information for financial reporting, requiring a more labor intensive process.
- Manual reversal journal entries are required to correct for FERC entries no longer needed, and preliminary retirement and account 106 reversals are recorded to the wrong account by the system.
- An unused company must be closed each month because it is still active in the system, adding unnecessary work to the close process.
- Timing of certain validations can cause closing issues, requiring manual journal entries and possible delays in closing the books.
- Lack of defined logic to ensure that all LOB projects are handled consistently, causing manual effort to ensure correct reporting.

The upgrade is expected to gain an estimated 180 hours of efficiency annually related to the Fixed Asset module, and will include the following functionality:

- Fix configuration to optimize retirements - More fully utilize system functionality increasing accuracy and reducing manual efforts.
- Correct transactional accounting - Provides greater accuracy and reduces manual efforts; changes timing of validations to allow for more effective and efficient close process.
- Streamline project unitization accuracy - Improves consistency between projects to improve reporting and reduce manual efforts.
- Remove unnecessary processes from monthly workflow - Reduces manual journal entries.

Tax: Current limitations in the Tax modules are as follows:

- Tax depreciation forecast must be completed using manual Excel import sheets, which is labor intensive, more at risk for error, and less efficient.
- Plant deferred tax reconciliations, repairs deduction review analysis, and property tax CWIP/RWIP reporting is performed using manual spreadsheets, which is labor intensive, more prone to errors, and less efficient.

- The current Tax Basis Balance Sheet (TBBS) process in the tax module lacks functionality and requires the completion of the TBBS to be performed in spreadsheets outside the system.

Enhancements to the Tax modules are estimated to gain approximately 60 hours in efficiency each year and will achieve the following:

- Streamline integrations - Streamlined TBBS process using functionality only available in upgraded version and will allow for the completion of the TBBS to be performed within the tax module; integration of tax depreciation forecast with the Budget module will increase accuracy and efficiency.
- Automate manual calculations and systematize reporting - Will allow current processes, such as plant deferred reconciliation, repairs deduction review, and property tax reporting that is currently being performed in spreadsheets to be performed systematically.
- System clean-up - Provides improved system performance.

General Environment: The current PowerPlan environment experiences the following:

- Slowing performance causing user delays, which could ultimately impact timeliness of closing the books and preparing budgets and forecasts.
- Limited usability of the cost repository for information and analysis due to uncorrected historical data.
- Complex security structure which is labor intensive to administer and increases the risk of SOX issues.

The upgraded system will:

- Include data archival for improved system performance.
- Cleanup of the cost repository (CR) to improve accuracy and usefulness.
- Simplify and streamline system security, which will reduce administrative burden and provide strengthened controls for SOX compliance purposes.

Contract Bid Summary

The agreement is sole sourced because the code is developed and owned by PowerPlan. The upgrade is performed by PowerPlan with support by LKE for testing, technical environment support, and integration support. The company has chosen not to bid out for other products for these services at this time due to the cost and time associated with re-implementing a new product. The level of integration between PowerPlan and Oracle would require a significant and costly effort if PowerPlan were to be replaced. PowerPlan has met the Company’s needs since 2008 and it continues to add value as we expand our use to include additional modules. PowerPlan continues to invest in their product, adding functionality, greater integration capabilities, and the ability to scale.

According to Gartner research, PowerPlan provides “an asset focused solution that enables users to develop fact based, strategic capital planning decisions with individual asset strategies and align the investment portfolio with corporate objectives.” In contrast to peers identified by Gartner, PowerPlan is headquartered in the United States, with the majority of their clients in the country. Recent surveys conducted by EEI showed the majority of respondents were PowerPlan users[1]. PowerPlan has a key focus on the utility industry and is knowledgeable on U.S. utility specific issues.

While other systems such as Oracle and UIPlanner offer some functionality, PowerPlan continues to provide a full suite of capital management and budgeting services for the utility industry at a competitive cost. A switch to a different platform at this time was not considered feasible and did not indicate business value or advantage.

Contract Financial Summary

Contract expenses ($k)	2019	2020	2021	2022	2023	Post 2023	Total
Amount requested based on contract award estimates	$1,495	$748					$2,243
Contingency Amount Requested	$126	$253					$379
Total contract authority requested	$1,621	$1,001					$2,622

A breakdown of contract costs is summarized below (in $000s):

System Upgrade/Enhancements	$1,898
Training	52
Travel Expenses	293
Contract Contingency	379
Grand Total	$2,622

[1] "*PowerPlan Software*" survey conducted August 2018 and "*Fixed Asset Accounting Systems*" survey conducted December 2018

Project Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	2,344	1,762			4,106
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	2,344	1,762	-	-	4,106
4. Capital Investment 2019 BP	1,240	1,592			2,832
5. Cost of Removal 2019 BP					-
6. Total Capital and Removal 2019 BP (4+5)	1,240	1,592	-	-	2,832
7. Capital Investment variance to BP (4-1)	(1,104)	(170)	-	-	(1,274)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(1,104)	(170)	-	-	(1,274)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed*	52	-	(750)	(3,000)	(3,698)
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	(52)	-	750	3,000	3,698

*Note: Includes $250k of annual tax savings.

A breakdown of the total project cost by component follows.

PowerPlan Contract with contingency	$2,622k*
Internal Labor	$1,316k
Non Contract Project Contingency	$ 140k
Property tax	$ 80k
Total capital and O&M	$4,158k

* $52k is O&M for training

This project was approved in the 2019 Business Plan (BP) for $2,832k ($1,240k in 2019 and $1,592k in 2020). The total capital project cost including the sole source contract, internal labor, and contingency is $4,106k. The estimate for the 2019 BP was based on the last upgrade and escalated. That upgrade did not include the lease module, internal labor by non-dedicated resources from the business, or enhancements identified since that time. The additional project cost is being covered within IT which is monitored through the asks/giveback process in the Technology Portfolio Management Committee (TPMC) and approved by the Corporate Resource Allocation Committee.

We have an existing annual maintenance agreement which is expected to be 20% of the software purchase or roughly $350k O&M expense per year, escalated at 4% annually, subject to final agreement. A one-time O&M expense of $52k for training/job aids is anticipated for the project.

The job aids will facilitate the Company's ability to provide internal PowerPlan training to users on an on-going basis.

Risks

The primary risk of not completing the project is losing support June 30, 2019. Losing support could result in being unable to timely and accurately close the books for financial reporting purposes and could negatively impact financial planning. It is Company practice to use supported products.

Not implementing Phase 1 of the project in February will adversely impact Budgeting and Financial Planning's ability to provide required information to support the 2021 Business Plan cycle. The current mitigation of this risk is to perform those activities in spreadsheets and manual processes.

The technology is proven and there is no anticipated risk of moving to the current version. A 20% contingency was added to the contract and a 10% contingency was added to the labor and property tax. Past experience with testing cycles has identified issues that take additional time and resources to resolve, requiring additional funds based on a time and material contract.

Project Alternatives Considered

1. Recommendation: Complete the upgrade to version 2018, with enhancements.
   NPVRR: ($000s) $1,210
   See description of enhancements and benefits above. The enhancements will provide increased capabilities in mining O&M savings of approximately $500k and tax savings of approximately $250k each year from 2021 through 2025. Additionally, the upgrade with enhancements will provide operational efficiencies of 1,190 hours and will avoid costs related to identified risks.

2. Alternative #1: Do Nothing NPVRR: ($000s) $0
   If we do not complete the upgrade, we will lose support after June 30, 2019 and risk not being able to address system issues that may occur which could prevent the processing of critical accounting functions that directly impact the financial reporting and performance of the Company. Not upgrading could cause us to require contract services with PowerPlan to provide on-demand support. These project costs are unpredictable and could exceed existing maintenance and support costs since PowerPlan no longer will be providing a support model for the current version. It is Company practice to remain on supported versions of hardware and software to ensure security, functionality, and compatibility with other systems and software.

3. Alternative #2: Perform the upgrade, with no enhancements
   NPVRR: ($000s) $2,430
   The upgrade could be completed with no enhancements. This scenario would include only the cost of the basic upgrade. The total capital cost for this option is $2,263k. This option is not optimal as the enhancements requested provide improved accuracy and efficiencies, reduce customizations, and provide necessary reporting functionality for Budget.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the PowerPlan upgrade project for $4,106k to retain support for the product and approve the sole source contract with PowerPlan in the amount of $2,622k (including contingency).

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain approvals.

Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced:

The Capital project spending and contract authority requests included in this Investment Proposal have 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 the capital project and contract authority requests.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
PowerPlan v2018 Upgrade

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the PowerPlan v2018 Upgrade contract for $2,622k to PowerPlan, Inc. as part of the overall approval of $4,158k for this project.

Susan Lyons Sourcing Leader III Date:		Susan Neal Director, Accounting and Regulatory Reporting Date:	
Eboni Edwards Manager, Supplier Diversity Date:		Joan Ferch Director, IT Business Services Date:	
Antonio F. Moir Manager, IT Sourcing Date:		Chris Garrett Controller Date:	
David Cosby Director, Supply Chain Date:		Eric Slavinsky Chief Information Officer Date:	
Heather DiEnno Manager, Financial Systems & Processes Date:			

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Investment Proposal for Investment Committee Meeting on: 6/26/19

Project Name: DACS & SONET Replacement

Total Capital Expenditures: $4,169k (Including $200k of contingency and $1,600k of internal labor)

Total O&M: -

Project Number(s): IT1086B

Business Unit/Line of Business: IT Infrastructure & Operations

Prepared/Presented By: Jason Finn/Dan Reffett

Brief Description of Project

This is a four-year IT capital project to replace LKS's manufacture-discontinued Nokia 1665 DMX SONET (Synchronous Optical Network) transport and Infinera DNX-88 DACS (Digital Access Cross-connect) systems. End of life for these systems were announced by the manufacturers in 2016/2017 (Nokia – 12/31/23 and Infinera – 12/31/24), and subsequently a network redesign effort was undertaken to determine the best option for replacement for them, that supports current and future transport and circuit routing needs. The replacement system was selected to handle functionality of the DACS and SONET, all in one platform, provide network edge specialized circuit access, transport TDM and Ethernet traffic, mitigate vulnerabilities identified in 2017 EMS Single Point of Failure Analysis, and provide a useful life of at least 10-15 years beyond completion of replacement. The major benefits of this project include:

- Provide a supported platform for LKS's transport network and circuit access & routing systems – remove increasing risk of long-term circuit outages due to equipment failures and unavailability of replacements.

- Address risks identified in LKS's 2017 EMS Single Point of Failure analysis, including routing SCADA and relaying circuits from the substation edge, rather than more central DACS locations, to mitigate risk associated with a DACS site equipment failure or disaster knocking out many SCADA RTUs and line relay channels. Also included is SCADA cicuit bridging, rather than software-based manual circuit TCC (Transmission Control Center) switchover, for automatic and simultaneous presence of SCADA communication circuits at both TCCs.

- Improve circuit latency performance for many relay channels, with routing directly between substations rather than through a centralized DACS.

- Provide better circuit troubleshooting, problem resolution, and provisioning capabilities with remote visibility and control through the platform's NMS (Network Management System). It is anticipated that these capabilities will reduce circuit downtimes and technician truck rolls to fix them. Also included is increased capabilities of circuit outage logging and reporting.

Project key deliverables and target dates:

Project approved and opened	7/15/19
Louisville area transport equipment purchase & delivery	9/5/19
Louisville area equipment installation	12/9/19
Louisville area circuits cutover	4/20/20
Louisville – Lexington – Dix ring equipment purchase, system line-up and test, delivery	12/7/19
Louisville – Lexington – Dix ring equipment installation	4/6/20
Louisville – Lexington – Dix ring circuits cutover	8/4/20
Northern KY/Power Plants Microwave system equipment purchase, system line-up and test, delivery	4/6/20
Northern KY/Power Plants Microwave system equipment installation	7/20/20
Northern KY/Power Plants Microwave system circuits cutover	11/17/20
Lexington – Dix & Danville equipment purchase, system line-up and test, delivery	11/3/20
Lexington – Dix & Danville equipment installation	4/4/21
Lexington – Dix & Danville circuits cutover	8/3/21
Eastern KY & ODP rings equipment purchase, system line-up and test, delivery	4/4/21
Eastern KY & ODP rings equipment installation	8/19/21
Eastern KY & ODP rings circuits cutover	12/16/21
Western KY & Central MW linear equipment purchase, system line-up and test, delivery	4/4/22
Western KY & Central MW linear equipment installation	8/18/22
Western KY & Central MW linear circuits cutover	12/15/22
Balance of SONET & DACS removal	12/31/22

Why is the project needed? What if we do nothing?

This project is needed in order to maintain reliable mission critical communications for Transmission, Distribution and Gas SCADA, protective relaying, land mobile radio and other applications that rely on the Company's SONET backbone and DACS circuit routing system. With these platforms going end-of-life status, and the manufacturer discontinuance of the equipment for them, it is essential the Company moves to a next-generation system that provides these functions, while also providing a long life of supply and support into the future.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	1,143	1,142	1,142	742	4,169
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	1,143	1,142	1,142	742	4,169
4. Capital Investment 2019 BP	1,143	1,142	1,142	742	4,169
5. Cost of Removal 2019 BP					-
6. Total Capital and Removal 2019 BP (4+5)	1,143	1,142	1,142	742	4,169
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	-	-	-	(2,550)	(2,550)
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	2,550	2,550

Project includes a 5% contingency.

Risks

External project dependencies:

- Deployment of Trimble and Ghent microwave routes – Microwave radio system replacements will be done by the third quarter of 2020. If this project is delayed, it could impact SONET system replacements in these areas next year.

  - Deployment in Eastern Kentucky and Western Kentucky – OTN deployment in these areas is critical to SONET replacement in them, since we have only four fibers throughout the majority of those backbones. OTN affords the ability to deploy multiple networks on the same fibers.

Contention for internal engineering & technician resources due to high work volume over the next several years.

Major site improvements/modifications – site surveys have not yet been completed and the base assumption is existing facilities will have enough space and environmental provisions.

<u>Alternatives Considered</u>

LKS, in conjunction with Burns & McDonnell, conducted an network redesign effort in 2018, which looked at the leading viable technologies to replace the SONET & DACS systems. The Recommendation and Alternative #2 were identified as the top options for systems replacement.

1. Recommendation: SEL ICON NPVRR: ($000s) $3,086

The Recommendation is to deploy SEL ICON equipment as replacement for all Nokia DMX SONET and Infinera DACS systems. This solution has the added benefit of eliminating the use and need of channel banks at many locations. Other benefits include support of multiple transport formats and better performance for critical relay traffic. It also allows for an easier deployment, with more remote manageability and less O&M costs.

2. Alternative #1: Do Nothing NPVRR: ($000s) $0

Alternative 1 is not recommended since it will put reliable communications for EMS SCADA, protective relaying, and other critical Company communications at risk due to not being able to find replacements when equipment fails.

3. Alternative #2: Ciena Carrier Ethernet NPVRR: ($000s) $3,214

Alternative 2 is to deploy Ciena Carrier Ethernet equipment as replacement for all Nokia DMX SONET and Infinera DACS systems. It is not recommended because of higher O&M cost (manufacturer software and support) as compared to the Recommendation. This alternative is also more complex to deploy and support. It requires reliance on our aging channel bank equipment to provide the needed specialized substation circuits. Performance of transmission line high speed relaying circuits would also require more evaluation and possible mitigation measures due to additional latency added by packetization. There are also additional costs associated with external SCADA bridging that have not been quantified that will be needed to provide SCADA to both TCC's.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the DACS/SONET Replacement project for $4,169k to allow for provision of Company mission critical communications into the future.

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: June 26, 2019

Project Name: Next Generation Mobile Radio

Total Capital Expenditures: $9,556k
(includes $539k of contingency and $1,248k of internal labor)

Total O&M: $1,627k (thru 2030)

Project Number(s): IT0301CG

Business Unit/Line of Business: ITO – Transport Engineering

Prepared/Presented By: John Pulliam

Brief Description of Project

This is a three-year (2019-21) IT capital project, the goal of which is to replace the Company's aging land mobile radio (LMR) infrastructure. LGE/KU owns and operates a private land mobile radio network that is used to facilitate communications between dispatchers and field crews. This system is used heavily for service restoration following storms and daily for performing critical operations such as line switching. Some groups use LMR as backup communications in the event cellular services are unavailable. The LMR network consists of more than 60 transmitter sites spanning the LGE/KU operating territory with more than 1600 subscribers (mobiles, portables, fixed control stations). There are more than 70 dispatch consoles located at control centers and offices which allow dispatchers to access the network. LGE/KU undertook a project in 2016 to replace the dispatch console system with an IP based platform (AVTEC), however, much of the field infrastructure (repeaters, mobiles, portables) is more than 20 years old and is no longer supported by the manufacturer.

Most of these obsolete infrastructure components have been identified in the IT Capital Investment Plan as needing to be replaced within the next 5 years (at a budgeted cost of $7.8M). With this large investment in view, a Radio System Assessment was conducted by Black & Veatch in 2015 as a pre-cursor to the console system replacement, with the goal of providing a strategy for future radio system investments. Various deficiencies were identified with the current radio system (obsolescence, inadequate capacity, difficulty of use, etc,) with recommendations of migrating toward a system which included trunking features (automatic roaming). An RFP was issued in October of 2018 which sought proposals on an alternative technology, Digital Mobile Radio (DMR), thought to provide more features and capacity at a comparable cost to simply replacing the aged components in our current system.

The resulting recommendation from the RFP process is to replace the existing LMR system with a DMR Tier III system. The project, as proposed, would provide the following benefits:

- Lifecycle extension – existing obsolete equipment would be replaced with new equipment having an anticipated lifespan of at least 10 years.

- Automatic roaming (trunking) capability – users on the current system must be cognizant of area repeaters and manually switch radio channels as they traverse the territory. The proposed system will provide automatic subscriber registration and roaming between sites, removing that burden from the users. This will simplify communications for both the mobile user and the dispatcher.
- Group calling – the proposed system allows users to organize in functional work groups. This would alleviate users from hearing conversations not pertinent to their job function. Dispatchers could monitor their specific workgroup(s) instead of 60+ separate repeater sites as they do today. Situational groups could be pre-built (or even dynamically built) for storms or other emergency events.
- Increased capacity – the proposed system would accommodate multiple conversations per site (as opposed to one per site on the current system). The increased capacity, coupled with the trunking/group calling features, make for a highly efficient system. Calls for specific groups are only routed to sites that have registered users participating in that group.
- Improved maintainability – the proposed system features "Over the Air Programming" of subscriber units, allowing technicians to push programming changes and even firmware upgrades over the air to the radio. Such changes on the current system require a physical connection to the radio.
- Lower per unit cost for future purchases – the DMR radio components (repeaters, subscribers) are 40-50% less expensive than their current system counterparts.

This project is proposed to be completed during the budget years of 2019-21. This includes selected pilot installations to confirm design assumptions. Major milestones from the project plan are as follows:

- System detailed design completed by 10/17/2019
- Factory Acceptance Testing by 03/04/2020
- Pilot Implementations Complete by 08/12/2020
- All sites completed by 11/24/2020
- Cutover (by geographic region) completed by 08/30/2021
- Project completed by 10/11/2021

<u>Why is the project needed? What if we do nothing?</u>

- The timing of this project is primarily driven by the age and obsolescence of the current infrastructure. The repeater equipment used at tower sites has been out of production since 2011 and will totally be non-supported by the manufacturer in 2020 (no repairs, spare parts, etc.). Approximately 50% of the subscriber base (mobiles, portables) have been in service for over 20 years. These units went out of production in 2004 and went out of factory support in 2010. Out of our entire fleet of radios (over 1600), only about 150 are current production models that will remain manufacturer supported beyond the end of 2019.
- Not pursuing a replacement strategy increases the likelihood of system support issues moving forward. Laptop computers are used to access the craft port of the radio equipment for maintenance and troubleshooting. The last software versions for many of the out of production pieces of equipment are not certified to work on current operating systems. For example, the software used to program the ASTRO Spectra mobile radios was last updated in 2014 and is only certified to be compatible up to Windows 8. We have over 600 of these mobile radio units in service.
- While the need to replace obsolete equipment does not dictate the migration to another technology, the volume of equipment needing to be replaced does afford the company with the opportunity to evaluate our current system and make technology changes to

better support business needs. Completion of this project would provide significant operational benefits to the clients, especially dispatch operations. It was noted in the 2015 Radio System Assessment that the current conventional system can be very cumbersome for users to navigate, with dispatchers often being tasked with monitoring over 50 repeater channels simultaneously. Trunking would greatly simplify this task.

- The use of private radio systems by utilities inherently enhances safety of operations. Conversations are heard by all parties monitoring the channel or talk group (as opposed to telephone or cellular, which are typically private conversations). Radio systems have emergency features which can be used to alert dispatchers of incidents. Radio conversations are also recorded on the Company's voice recording systems for historical reference.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	2,582	3,112	3,862		9,556
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	2,582	3,112	3,862	-	9,556
4. Capital Investment 2019 BP	2,582	3,112	1,163	1,000	7,857
5. Cost of Removal 2019 BP					-
6. Total Capital and Removal 2019 BP (4+5)	2,582	3,112	1,163	1,000	7,857
7. Capital Investment variance to BP (4-1)	-	-	(2,699)	1,000	(1,699)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	-	(2,699)	1,000	(1,699)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	42	42	1,543	1,627
2. Project O&M 2019 BP	100	204	212	2,355	2,871
3. Total Project O&M variance to BP (2-1)	100	162	170	812	1,244

- O&M totals in the above comparison are projected thru 2030. It is noted that there is incremental O&M addition with the proposed project. The proposal includes a vendor support agreement that provides for regular software updates, help desk services and depot repair support. We have no such support agreements for the current system.
- IT currently has funding in the Capital Plan sufficient for the first two years of the project (2019-20), however a shortfall of $2,699k exists in 2021. The additional funding in 2021 has been included in the 2020 BP.
- This project includes 5% contingency on both the vendor and LKS costs.

Risks

- Completion of this project does require that additional channels be licensed through the FCC. There is some risk that delays in obtaining all of the needed channels may affect other project tasks. Also, there is no specified budget in this project should spectrum need to be purchased from any incumbent licensees.

- The completion of this project will require the addition of antennas at most locations. Some towers will require a structural analysis to confirm their loading capacity. Significant tower structural modifications are not included in this project.
- A risk associated with not completing the project would be the potential for increasing outages of the radio network. Individual subscriber radios can be replaced with current models as they fail, but there is the increasing risk that core components like repeaters or simulcast infrastructure could fail, which can affect large numbers of users and large geographic areas. LGE/KU does keep some spare hardware on hand, but once our spare inventories are depleted, repair parts will no longer be available.
- There is financial economy of scale to be realized by a large scale replacement project, as opposed to "ad hoc" replacement of individual pieces of equipment. The competitive bidding process yielded equipment discounts ranging from 25-35% plus system level discounts of roughly 15% of the project total (over $900k for this project). Not completing the project would forego these discounts.
- The underlying radio technology recommended is known as Digital Mobile Radio. DMR is an open digital radio standard defined in the European Telecommunications Standards Institute (ETSI), first published in 2005, that has gained acceptance in commercial applications around the world. Most major radio manufacturers now offer DMR systems as a part of their portfolio. The technology supports vendor interoperability and the inclusion of standard, off the shelf, network components, such as servers and data networking devices, making it more supportable for IT organizations. The introduction of Tier III operations (trunking) in 2012 has led to its adoption by a number of large organizations, such as utilities. Some North American utility references provided by the proposed vendor are:
    - Manitoba Hydro
    - Alliant Energy (Madison, WI)
    - Questar Gas (Salt Lake City, UT)
    - Talquin Electric Coop (Quincy, FL)
    - Grant County PUD (Ephrata WA)
    - Kansas City Power & Light (Kansas City, MO)

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $11,490

   The proposed project is to replace LGE/KU's existing conventional P25 radio system with a new DMR Tier III trunked system. All radio equipment (repeaters, subscribers) would be replaced with new. The vendor scope includes equipment, design, factory and field acceptance testing, installation services, console integration, management system, training and cutover activities. LKS activities associated with the project include the extension of the IP network to all radio repeater sites and site enhancements necessary to support the new system.

2. Alternative #1: NPVRR: ($000s) $13,801

   Alternative #1 would be to implement the refresh projects as currently defined in the IT Capital Plan. Those projects target replacement of the existing "out of support" components with a like-for-like replacement, as well as some site rebuild projects. It is noted that this alternative offers no substantial benefits over the current system other than a refresh of the equipment. The estimate for this alternative was created by Black & Veatch during the preliminary design process. These dollars have not been confirmed thru any formal RFP process.

3. Alternative #2: NPVRR: ($000s) N/A

   Alternative #2 is the "do nothing" option. Doing nothing would ultimately lead to a system that is unsupported/unrepairable. Many hardware components of the current system have been manufacturer discontinued and are no longer serviceable. Radio users would eventually have to migrate to public carrier networks to conduct business via cellular phones. This type of communication has inherent safety drawbacks as conversations are not overheard by the community of users as in a land mobile radio network. The radio system is particularly important during service restoration activities. Also, all radio communications is recorded (both mobile to mobile and dispatch to mobile).

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Next Generation Mobile Radio project for $9,556k to assure the long term viability of the Company's mobile radio system. Completion of this project would extend this network beyond the 10-year horizon while providing operational improvements to both users of the system and those that support the 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	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: June 26, 2019

Project Name: UIPlanner Upgrade

Total Capital Expenditures Requested: $2,311k (including $181k of total project contingency and $425k of internal labor)

Total O&M: $60k annual O&M for maintenance, which is an expected $6k incremental increase over current maintenance.

Project Number(s): NA
Business Unit/Line of Business: Finance/IT

Prepared/Presented By: Lesley Pienaar / Heidi Konynenbelt / Matt Smith

Brief Contract/Project Description

This project will upgrade UIPlanner Forecasting software to the current version. This software is used by the Financial Planning Departments at all PPL subsidiaries to develop the business plan for the Company subsidiaries as well as support rate case filings for the Utilities and various planning scenario analysis to facilitate decision making. LKE Financial Planning also provides uploads to PPL with Business Plan information and updated forecast information through this software. A four-day detailed assessment was completed with Utilities International, Inc. and the impacted business proponents to prepare for this upgrade. Based on that assessment, and a subsequent planning session with internal staff, the project cost and schedule was determined. This proposal requests the funds needed to complete the project.

The sole source contract with UIPlanner is to upgrade to the most current version, create or update required interfaces, and to configure the software to enable improved or new functionality. The contract will require UIPlanner to provide the following implementation services: Initiate, Design, Build, Test, Deploy, Sustain, and Project Management. The term of the contract is expected to be through June 2020 and will be $1,819k for professional services, travel, software licenses, and a 10% contingency. The project will incur a one-time license fee of $300k for the UIPlanner B2 Model and annual maintenance fee of $60k. No hardware costs are expected since the system will be hosted in a virtual environment.

The project will require internal labor to provide configuration, interfaces, testing, project support, and technical environment support. Internal labor is estimated at 4,248 hours, with 2,800 hours estimated for the business and 1,448 hours estimated for IT. Total estimated cost for internal labor is $424,800.

Why is the project needed? What if we do nothing?

UIPlanner Forecasting software is a vendor supported application that was implemented in 2011 and has been updated with several releases without additional costs incurred. The software was selected due to the integration into PPL's financial planning process since UIPlanner is used by all PPL subsidiaries. When it was implemented, the software was designed to do high level financial planning; therefore, the data is at a summarized level with details remaining in the source system. When LG&E and KU started to file rate cases using forward looking test year data in 2014, Financial Planning started to use the software to provide supporting data to the Rates Department to develop the revenue requirement and filing requirements. Due to the different utilization purpose from when the software was implemented, the process of providing data to the Rates Department for the rate case filing involves manual processes which are inefficient and has the potential for errors.

UIPlanner with B2 Model platform will have the ability to provide more detailed data and eliminate most of the manual processes for monthly forecasting, reconcile to detail support systems, scenario modelling and rate case filing support.

The current version is supported and end of life has not yet been defined by Utilities International Inc. However, the vendor is no longer investing in the legacy model and training and support are focused on the B2 Model. The Company expects to upgrade in the 2021-2022 timeframe to stay aligned with PPL if the upgrade does not occur in 2019. Doing the project in 2019 avoids the risks associated with anticipated labor turnover, including the loss of institutional knowledge and practices supporting financial planning. This project would codify that knowledge and ensure appropriate configuration intelligence is built into the upgraded system.

In addition, the new platform provides an application server and database environment to support end-users in place of the legacy “thick client” environment, enabling processing capability greater than the legacy version.

As part of the scoping effort the following objectives were identified:

- Automation of monthly forecast schedules, financial packet information, rate case filing schedules, and possibly other regulatory filings especially those that incorporate the use of forecasted data.
- Inclusion of additional detail to do line of business reporting and reduce the amount of time spent reconciling to source system.
- Knowledge transfer to automate rate case specific knowledge given upcoming retirements.
- Automation of integrations to source systems.
- Simplification and automation of the reporting process to reduce staff time required to generate and manipulate reports while improving data consistency and reducing the possibility for errors.
- Reduction of run times for current work activity. The model run-time is currently deemed excessive at five to ten minutes.

The following new capabilities and benefits can be gained through the project and the new UIPlanner Financial Model:

- Multi-dimensional ledger allows for planning in more dimensions, e.g., GAAP, FERC, Jurisdiction, etc.

- Drill into system-of-record data.
- Production quality interfaces allowing for automated integration. Therefore less manual intervention and allowing for easier and quicker access to data.
- Integrate tactical and strategic planning.
- Simplify all reporting to be automated within UI Planner.
- Integrate tax calculations.
- Faster run-time.
- Sensitivity analysis to measure results of assumptions.
- Rate case time savings in the Financial Planning department as well as in the Rates department by automating support files provided to the Rates department. Inputting information from the Rates department into UI Planner to create filing requirements therefore saving more time and increasing accuracy. Going forward potential automation of the Virginia rate case support documents and other regulatory filings can be explored to continue saving time and increasing accuracy.
- Increased capabilities for data mining allowing for a more thorough review of regulatory lag indicators and review for potential savings, optimization of rate case timing, regulatory leakage and mechanism opportunities.

The project will provide approximately 279 hours annually in operational efficiencies shared across three departments, in a rate case filing year an additional 330 hours will be saved across four departments. These efficiency gains will improve turn-around time and provide a higher level of accuracy, as well as allow for additional time to analyze the data.

Contract Bid Summary

The agreement is sole sourced because the code is developed and owned by Utilities International, Inc. The system product upgrade is performed by Utilities International, Inc. with LKE support for testing, technical environment support and integration support. The product comes to LKE similar to blank excel sheets (albeit with much more processing power) and the system logic is written together by Utilities International, Inc. and the Financial Planning Department. The Company has chosen not to bid out for other products for these services at this time due to the following reasons:

- The system must integrate with PPL Corporate.
- The software has been very inexpensive to maintain with great support.
- The software has an excellent reputation in the utility space.
- The employees from Utilities International, Inc. are very knowledgeable about utility best practices when assisting with logic writing.
- Timing associated with the project to get the software upgrade completed to support the Company’s next rate case.

Contract Financial Summary

Contract expenses ($k)	2019	2020	2021	2022	2023	Post 2023	Total
Amount requested based on contract award estimates	$990k	$691k					$1,680k
Contingency Amount Requested	$69k	$69k					$138k
Total contract authority requested	$1059k	$760k					$1,819k

A breakdown of contract costs is summarized below (in $000s):

System Upgrade	$1,381
Licenses	300
Contingency on Capital Spend	138
Grand Total	$1,819

Project Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	1,293	1,018			2,311
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	1,293	1,018	-	-	2,311
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)	(1,293)	(1,018)	-	-	(2,311)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(1,293)	(1,018)	-	-	(2,311)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	60	60	60	180
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	(60)	(60)	(60)	(180)

A breakdown of the total project cost by component follows:

Capital:

UIPlanner Contract with contingency	$1,819k
Internal Labor	$ 425k
Additional Project Contingency	$ 42k
CWIP (property tax)	$ 25k
Total capital	$2,311k

O&M:
There is $6k in annual incremental O&M for support and maintenance beginning in 2020. Total annual O&M will be $60k.

This project was not in the 2019 Business Plan (BP) since the company expected to be part of a potential PPL project to upgrade UIPlanner in the future. The project is in the 2020BP as year two of a two year project, assuming the 2019 request would be approved. The project for 2019 has been approved at the IT RAC and TPMC and is scheduled for the Investment Committee on June 26, 2019.

PPL Corporate and EU did participate in the initial discussions for the upgrade and they continue to stay engaged with Utilities International, Inc. to discuss upgrades at their locations based on their specific needs (i.e. Corporate had consolidation needs and EU wanted to be removed from the Corporate model similar to LKE). PPL Corporate and EU have decided to delay doing an upgrade temporarily; however, LKE can leverage the upgrade benefits immediately given the timing of the next rate case and the enhanced capabilities of PowerPlan from its upgrade project. The initial implementation occurred in 2011-2012 at a cost of $407k. That project did not include the licenses because they were already purchased by PPL, internal labor by Financial Planning, or an n-tier IT support structure which this project will include.

LKE is allocated $54k/year from PPL as part of the existing annual maintenance agreement with Utilities International, Inc. The new maintenance agreement is $60k/year, or roughly $6k more. Over the next five years, the company expects to achieve labor savings of 330 hours related to rate case filing support, 400 hours related to business planning support, and 920 hours related to monthly and quarterly reporting time savings . This results in annual labor efficiencies of $609k in 2020 and $279k annually thereafter.

Risks

The primary risk of not completing the project is losing the benefits of the system upgrade ahead of the next rate case, as well as the enhanced functionality and capabilities defined above that enable timely and financially optimal decision making.

The technology is proven and there is no anticipated risk of moving to the current version. A 10% contingency was added to the project cost.

<u>Project Alternatives Considered</u>

1. Recommendation: Complete the upgrade to the B2 Platform
NPVRR: ($000s) $2,924

2. Alternative #1: Complete the upgrade to the B2 Platform with UIPlanner Dash
NPVRR: ($000s) $3,310

   UIPlanner Dash is an optional additional feature that provides a web-based interface to give senior management the ability to do high level what-if scenarios for strategic decision making and support of forward-looking rate cases.

   It is difficult to identify benefits directly attributable to PlannerDash and the strategic benefits for scenario analysis and executive decision making that this additional feature could potentially offer. This alternative includes an annual $50k subscription fee for the Dash feature that is not able to be justified.

3. Alternative #2: Delayed upgrade to 2021
NPVRR: ($000s) $2,932
   Delaying the upgrade is not recommended because of the strategic and operational advantages of upgrading earlier, which primarily include ensuring institutional knowledge is maintained and codified in the upgraded system prior to anticipated retirements.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the UIPlanner Upgrade without UIPlanner Dash for $2,311k.

<u>Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced</u>:

The Capital project spending and contract authority requests included in this Investment Proposal have 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 the capital project and contract authority requests.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: July 31, 2019

Project Name: Mobile Dispatch Replacement

Total Capital Expenditures: $2,894k (Including $129k of contingency and $497k of internal labor)

Total O&M: $624k

Project Number(s): IT0594B

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

Prepared/Presented By: Chad Randall / Jason Jones

Brief Description of Project

IT and Electric Distribution Operations (EDO) are requesting $2,894k for the implementation of Oracle Utilities' Operations Mobile Application (OMA) for all EDO field crews. The project is part of a multi-year strategy to modernize EDO's mobile technology platform. The strategy includes multiple projects to migrate users from Panasonic Toughbook's running Windows-based applications to iPads running iOS applications. The scope of the project includes:

- Replacing Panasonic ToughBooks with iPads for approximately 700 users
- Replacing existing truck mounts with mounts designed for iPads
- Installing iPad charging stations at the operation centers
- Replacing ABB's Service Suite (Mobile Dispatch) application with OMA

Project Milestones:

- Start: August 15, 2019
- Final Oracle Delivery: December 13, 2019
- Testing Complete: January 29, 2020
- Go Live: April 30, 2020

Why is the project needed? What if we do nothing?

Customer outages are managed using Oracle Utilities' Network Management System (NMS). Distribution Control Center (DCC) operators and Public Safety Response Team (PSRT) dispatchers dispatch events from the NMS to field crews who use Panasonic ToughBooks running ABB's Service Suite and GE's FieldSmart View. The solution yielded positive results over the last 7 years, but newer technologies are now available that will maximize the use of tablet-based devices utilizing applications (apps) that are specific to the field worker's job function. Decoupling functionality into specific apps, similar to apps on a smartphone, will make upgrades easier and require much less coordination between disparate lines of businesses.

Staying with the existing enterprise platform (Toughbooks, Service Suite, and FieldSmart View) poses numerous challenges described below.

- The ToughBooks are nearly two inches thick and weigh just over 5 pounds. As the demand for additional mobile applications increases, utilizing these heavy computing devices outside the truck / vehicle will be an ongoing challenge. Case in point, EDO currently utilizes tablet-based apps for Downtown Network inspections. These devices are easy to carry into vaults / manholes as well as use to take photos of equipment for tracking purposes. Similarly, tablet-based apps for trouble response will allow the field user to carry with them to patrol lines, track damage assessment, take photos, and enter new trouble tickets.

- Service Suite's integrations with NMS and FieldSmart View are highly customized. The new iOS version of Service Suite does not offer integration with external mobile map applications. This functionality is necessary to seamlessly guide field workers to the exact location of the predicted trouble event.

- GE has discontinued FieldSmart View. They are not releasing additional functionality or new versions. There is not an iOS version.

- New, tech-savvy employees who are familiar with iOS technology require significant training to learn the aging technology. Tablet-based apps are the norm for smartphone users resulting in better use of current technology.

- The outdated technology prevents EDO from leveraging other technologies and applications which could be valuable to operations and improving the customer experience. For example, EDO continues to perform KPSC overhead inspections on paper. Once the iPads are deployed, EDO intends to implement a mobile application for the inspections.

- The existing FieldSmart View application displays the "normal state" of the electric distribution network. Due to limits in the technology, the map is updated nightly from the Smallworld Geographic Information System (GIS) and shows the network as normally mapped. The OMA application will pull map data from the NMS and display the "current state" of the electric distribution network. Data will be sent each time an event is dispatched from NMS and can be updated with the touch of a button by field users. Since the NMS data displays the network as currently switched, OMA will also see the current configuration of the network. As a result, field users will have realtime knowledge of device status, such as "switched abnormally".

The timeline below outlines the projects associated with EDO's mobile strategy. The strategy cannot be successfully executed if the iPads are not deployed and Service Suite is not replaced.

2018
- FieldSmart View Replacement RFP and Proof of Concept
- Began OMA Implementation for PSRT and Damage Assessment

2019
- OMA Go-live for PSRT and Damage Assessment (October)
- **Begin OMA Implementation for all EDO Field Crews**

2020
- **OMA Go-live for all EDO Field Crews**
- Replace FieldSmart View with MyWorld
- Implement Inspection Application for KYPSC Overhead Inspections

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	888	2,006	-	-	2,894
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	888	2,006	-	-	2,894
4. Capital Investment 2019 BP	990	140	140	280	1,550
5. Cost of Removal 2019 BP	-				-
6. Total Capital and Removal 2019 BP (4+5)	990	140	140	280	1,550
7. Capital Investment variance to BP (4-1)	102	(1,866)	140	280	(1,344)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	102	(1,866)	140	280	(1,344)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	156	156	312	624
2. Project O&M 2019 BP	-	30	30	60	120
3. Total Project O&M variance to BP (2-1)	-	(126)	(126)	(252)	(504)

- The incremental 2019 funding has been approved through the RAC. Proposed capital funding in 2020 is included in the proposed 2020 Business Plan (BP).
- Once OMA is implemented, the EDO Service Suite software maintenance will be cancelled for EDO, resulting in O&M savings of $30k annually.
- The Panasonic ToughBooks are significantly more expensive than iPads. IT has budgeted for the replacement of the ToughBooks. By implementing iPads, IT will be able to reduce the budgeted amount for hardware replacement by $700k ($140k per year).
- Contingency is calculated as 15% of internal labor and 10% of outside services.

Risks

- If OMA is not implemented, EDO field users will have to continue using the Panasonic ToughBooks in lieu of iPads preventing EDO from implementing its mobile strategy. A key component of the mobile strategy is replacement of GE's FieldSmart View (i.e. mobile GIS) with an iOS mapping application. GE has discontinued FieldSmart View so a new Windows-based solution would have to be identified and implemented.
- If iPads are not deployed, other projects in the Business Plan either cannot be completed or another solution must be identified. For example, EDO plans to implement a mobile application in 2020 for KPSC overhead inspections. This project would need to be re-evaluated.
- If the proposed project is not implemented, the capital reduction of $700k will not be realized.
- Implementing OMA will reduce the number of ABB Service Suite licenses resulting in reduced software maintenance. If the project is not implemented, the O&M reduction of $30k annually will not be realized.
- OMA is tightly integrated with the Network Management System (NMS). Therefore, when OMA is implemented a new version of the NMS will be required. The timing of the proposed OMA implementation coincides with the active NMS Upgrade Project. If OMA is delayed, an additional unplanned NMS upgrade will be required at a later date.

Alternatives Considered

1. Recommendation: NPVRR: $3,452k
   Mobile Dispatch Replacement

2. Alternative #1: NPVRR: N/A
   Do Nothing
   Do Nothing is not viable alternative. Mobile technologies are changing. The Panasonic ToughBooks continue to present usability and technical support challenges. In addition, GE has discontinued FieldSmart View. Integration between the mobile dispatch system and a map is required for the field users. Without the map, users will not be able to perform a number of tasks including damage assessment. The latest version of ABB's Service Suite does not offer a solution for integrating with other mobile map applications. Therefore, Service Suite is not a viable long-term solution.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Mobile Dispatch Replacement Project for $2, 894k to deploy iPads to field crews, implement OMA and support the EDO mobile strategy.

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 and Contract Proposal for Investment Committee Meeting on: September 25, 2019

Project Name: EMC TLA
Contract Name (Good/Service): EMC Transformative License Agreement

Selected Vendor(s): Prosys Information Systems, Inc.

Contract Authorization Requested: $4,396k

Contract Term: 4 years

Total Capital Expenditures Requested: $2,003k

Total O&M: $1,968k

Project Number(s): IT0687B
Business Unit/Line of Business: Information Technology

Prepared/Presented By: Tom Sager/Priya Mukundan

Brief Contract/Project Description

This Investment Committee investment and contract proposal is to request approval for the Sole Source Authorization of a contract to Prosys/EMC to provide a Transformative License Agreement (TLA) for a 4-year term to LKS consistent with a technical decision to implement EMC hardware/software in 2019. The TLA proposal enables LKS to establish perpetual software license rights and software maintenance for its enterprise storage and data backup systems for the term of the agreement. In evaluating the LKS Prosys/EMC proposal the LKS team determined that significant Capital and O&M savings will be achieved for software purchases and maintenance by entering into the agreement with the manufacturer.

The original EMC pricing model used for LKS purchases in 2012-2015 required the purchase of storage and backup as a single combined hardware and software appliance. Under the original pricing model, LKS would be required to purchase all software again when the systems are refreshed through our standard 5-year refresh policy. Subsequently, LKS moved to the TLA model and obtained the benefits of flexibility and financial savings. The agreement enables LKS to migrate software products within the scope of TLA to new and different EMC hardware platforms for an overall lower cost of ownership. LKS is scheduled to refresh Unity and Data Domain enterprise storage and backups systems during the proposed term of the agreement. The new agreement will enable LKS to transfer software licenses from hardware that will be retired to the new hardware appliances during system refresh versus having to buy the software again.

LKS continues to see growth in file storage and this purchase will increase the capacity of that storage to accommodate the observed growth rate. The cost per terabyte ("TB") of file storage under the TLA is lower than the current installation. This TLA proposal also keeps support costs at a significantly lower level than they would be without a TLA.

The value of the proposed contract is $4,396k for a period of 4 years beginning on contract execution in October 2019 and ending October 2023. The contract will be invoiced in 2019 for $3,996k.

This Investment Committee proposal is a request for a contract in the amount of $4,396k for spend with Prosys for a TLA as indicated above, and a request for authorization for capital spend of $2,003k. At the end of the 4-year agreement, LKS may choose to implement a new TLA, select a different pricing methodology, or adopt a new manufacturer standard.

The EMC proposal was thoroughly evaluated, and negotiations resulted in savings of approximately $2,267k over a 4-year term.

Prosys is a WBE company.

Why is the project needed? What if we do nothing?
This project is required for continued support and maintenance of existing storage and backup infrastructure and to enable needed capacity expansion for the file storage system. This is required to ensure that we continue to maintain a reliable storage and backup service.

The Isilon file storage system is nearing capacity and a separate project is proposed to refresh the hardware in 2019. This project includes the software licenses necessary to refresh the hardware.

Deferring the TLA renewal and Isilon refresh until 2020 was evaluated, but deemed to not be a viable alternative due to the risk of service disruption given the current capacity and growth rate of Isilon file share storage.

Contract Financial Summary
This is a Sole Source Authorization request. The TLA proposal project was not bid since this offer is available only from Prosys as reseller of EMC. Prosys/EMC proposed the TLA offering following discussion of LKS's 2020 objectives which included an emphasis on cost reduction.

Contract expenses ($k)	2019	2020	2021	2022	2023	Post 2023	Total
Amount requested based on contract award estimates	$1,966	$530	$530	$530	$440	0	$3,996
Contingency Amount Requested	$0	$0	$0	$200	$200	$0	$400
Total contract authority requested	$1,966	$530	$530	$730	$640	$0	$4,396

Project Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	2,003				2,003
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	2,003	-	-	-	2,003
4. Capital Investment 2019 BP	-	4,000			4,000
5. Cost of Removal 2019 BP					-
6. Total Capital and Removal 2019 BP (4+5)	-	4,000	-	-	4,000
7. Capital Investment variance to BP (4-1)	(2,003)	4,000	-	-	1,997
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(2,003)	4,000	-	-	1,997

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	28	440	530	970	1,968
2. Project O&M 2019 BP	28	500	500	900	1,928
3. Total Project O&M variance to BP (2-1)	-	60	(30)	(70)	(40)

The 2019 BP included $4,000k in 2020 to enable us to enter into a second TLA with EMC. This project proposes to pull forward $2,003k into 2019. The 2019 spend has been approved by the RAC.

Years 2019 and 2020 O&M reflect $150k that EMC would refund us for early termination of prior TLA.

Risks

- Legal advised that the correct entity to perform the credit review on is EMC Corporation since Prosys is, in this case, the reseller of software that is ultimately provided by EMC Corporation. The LKS Credit Department, after their review and analysis, provided the following: “We see no issues with making the above-noted contract award to Prosys as reseller of software from ultimate provider EMC Corporation based on EMC Corporation’s large scale and breadth.”

- The amounts for this TLA were included in the 2020 Business Plan with the planned assumption that the TLA agreement would be approved at these estimated levels. Without a TLA type agreement, the annual support costs would increase by $613k per year.

- The 2019 BP assumed that we would enter into a second TLA with EMC in order to enable us to continue the benefits that we received from our initial TLA. Not completing this project would increase our ongoing support costs and also lead to increased capital spend to keep up with our growing storage needs.

<u>Project Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) $3,849
Enter into a TLA with EMC in 2019 in conjunction with the hardware refresh for Isilon.

2. Alternative #1: Do Nothing NPVRR: ($000s) $5,730
If we do not enter into a TLA,then our O&M support costs will increase and our capital spend for capacity growth will be higher.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the sole source Prosys/EMC TLA contract for $4,396k to establish perpetual software license rights and flexibility to transfer software during hardware refresh. This contract will achieve a total of approximately $2,267k of capital and O&M savings during the 4-year term.

Additionally, it is recommended that the Investment Committee approve the EMC TLA capital project for $2,003k to enable us to continue the benefits that accrue from having TLA with EMC which include perpetual rights to software and reduced O&M support costs.

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

<u>Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced</u>:

The Capital project spending and contract authority requests included in this Investment Proposal have 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 the capital project and contract authority requests.

______________________________	______________________________
Kent W. Blake Date	Paul W. Thompson Date
Chief Financial Officer	Chairman, CEO and President

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
Prosys Information Systems Inc. as a Value Added Reseller for EMC Corporation

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the Transformational License Agreement contract for $4,396K to Prosys Information Systems.

Sourcing Leader Jacque English Date		Proponent/Team Leader Tom Sager Date	
Supplier Diversity Manager Eboni Edwards Date		Director – Supply Chain David Cosby Date	
Manager – Supply Chain Antonio F. Moir Date		Director – IT Infrastructure and Operations Priya Mukundan Date	
Chief Information Officer Eric Slavinsky Date			

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Investment and Contract Proposal for Investment Committee Meeting on: November 22, 2019

Project Name: Oracle Unlimited License Agreement (ULA) 2019

Selected Vendor(s): Oracle America, Inc.

Contract Authorization Requested: $6,037k

Contract Term: 2 year term with caps for 2 additional years of renewal

Total Capital Expenditures Requested: $1,067k
Total O&M: $5,037k

Project Number(s): IT 0304B
Business Unit/Line of Business: IT

Prepared/Presented By: Tom Sager/Priya Mukundan

Brief Contract/Project Description

The purpose of this contract/project is to enter into an Unlimited License Agreement (ULA) with Oracle America, Inc. to cover LG&E and KU Services Company (LKS) Oracle database license growth needs for next 2 years. This agreement also enables us to lock in the support costs for 2 years after the expiration of the contract.

Why is the project needed? What if we do nothing?

LKS Oracle database licenses are currently covered in a ULA owned by PPL Services Corp. (PPL). This current agreement began in November 2016. At the time the ULA was negotiated, LKS and PPL EU were combining IT management and strategies, thus a combined license agreement was an efficient way to share a single license pool that could be deployed by both companies. In 2017 the IT merger effort was discontinued. Since that time, PPL EU's strategy has diverged from LKS's. PPL EU has indicated that they plan to drop support for Oracle databases. Critical LKE operational systems like NMS, DA and OeBS use Oracle databases and it would not be prudent for us to drop support since that would mean we would no longer get patches for security vulnerabilities. So it is now advantageous to both companies to split the current license agreement into separate parts.

The proposed Oracle ULA for LKS accomplishes this license split. It also positions LKS for expected license growth over the next 2-years at a higher discount (76% off list price) than would otherwise be possible.

Not entering into a ULA would require LKS to purchase licenses for growth at a higher cost (due to a less favorable discount after the current agreement expires). In addition, our support cost would begin to escalate immediately. With the new ULA our support costs stay flat for 3 years, have only a 2% escalation on the 4th year . Without the new ULA, support costs begin escalation this year at 2% and 4% each year thereafter. The "Do Nothing" alternative was not considered viable since it would not cover the expected Oracle database license growth.

Contract Bid Summary

- **Sole Source**
  This is a sole-source contract with Oracle since it is their proprietary licensing.

Contract Financial Summary

Contract expenses ($k)	2019	2020	2021	2022	2023	Post 2023	Total
Amount requested based on contract award estimates	2,253	1,253	1,253	1,278			6,037
Contingency Amount Requested	0	0	0	0			
Total contract authority requested	2,253	1,253	1,253	1,278			6,037

Project Financial Summary

ULA capital cost is $1,067k:

- $1,000k Oracle ULA database licenses
- $60k 6% sales tax
- $7k 0.63% burden rate

ULA O&M cost (4-years):

- $220k Incremental support (50 additional licenses added to install base)
- $1,033k install base support (37.5% of $2,754k annual support of current combined agreement; 37.5% is LKS portion of current license deployment)
- Total: $1,253k/year, flat for 3 years, 2% escalation in year 4 ($1,278k),
- Budgeted amount: $1,056k, $1,098k, $1,142k, $1,182k for next 4 years
- Incremental add: $197k, $155k, $111k, $96k

Capital spend was not included in the 2019 BP; O&M was partially included in the 2019 and 2020 BP. The requested authorization is through 2022 and authorization for subsequent years will be requested in 2022.

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	1,067				1,067
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	1,067	-	-	-	1,067
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)	(1,067)	-	-	-	(1,067)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(1,067)	-	-	-	(1,067)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	1,253	1,253	1,253	1,278	5,037
2. Project O&M 2019 BP	1,056	1,098	1,142	1,182	4,478
3. Total Project O&M variance to BP (2-1)	(197)	(155)	(111)	(96)	(559)

Risks

Not completing this project would increase the likelihood that LKS's support costs would increase dramatically if/when PPL EU successfully exits Oracle support as part of their strategy. Without split agreements, the support costs for the original 680 ULA would fall to LKS in the event PPL EU drops Oracle support. Such an event would result in LKS annual support costs increasing by over $1,700k.

Project Alternatives Considered

1. Recommendation: NPVRR: ($000s) 7,761

2. Alternative #1: Transactional purchase of additional licenses in 2020 & 2021
   NPVRR: ($000s) 11,757

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Oracle ULA project for $1,067k as well as the Oracle ULA contract for $6,037k in order to:

- Acquire 50 additional Oracle database licenses for expected growth with most favorable discount
- Manage O&M support costs flat for three years, 2% escalation in year four
- Split the support agreement between PPL EU and LKS

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced:

The Capital project spending and contract authority requests included in this Investment Proposal have been approved by the members of the LKS Investment Committee. Pursuant to the LKS Authority Limit Matrix, the signatures below are also required for approval of the capital project and contract authority requests.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
Oracle Unlimited License Agreement (ULA) 2019

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the Oracle Unlimited License Agreement ULA contract for $5,870k to Oracle America, Inc.

Susan Lyons Senior Sourcing Lead Date:		Tom Sager Manager, Data Management Date:	
Eboni Edwards Manager, Supplier Diversity Date:		Priya Mukundan Director, IT Infrastructure and Ops Date:	
Antonio F. Moir Manager, IT Sourcing Date:		Eric Slavinsky CIO Date:	
David Cosby Director, Supply Chain Date:			

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Investment and Contract Proposal for Investment Committee Meeting on: December 19, 2019

Project Name: Enterprise GIS

Contract Name (Good/Service): System Integrator

Selected Vendor(s): [redacted]

Contract Authorization Requested: $11,600k (Including $1,421k of contingency)

Contract Term: October 11, 2018 through December 31, 2021

Total Capital Expenditures Requested: $14,361k (Including $1,814k of contingency and $5,085k of internal labor)

Total O&M: $5,332k (2020-2023)

Project Number(s): IT0101B, IT0569B, IT0927B

Business Unit/Line of Business: Information Technology (IT), Gas Distribution Operations (GDO)

Prepared/Presented By: Chris Tabler, Carla Fajardo, Joey Justice

Brief Contract/Project Description

A Geographic Information System (GIS) is used by multiple lines of business at LKE for the visualization and management of assets. In 2017, LKE evaluated the company-wide GIS needs and made the decision to implement a single enterprise GIS platform. Esri was selected as the vendor, and the direction was set to implement in a three phased approach. Phase I included purchasing Esri licenses, developing the GIS design for Gas Distribution Operations (GDO) and implementing Esri for Generation, IT Telecommunications and Electric Transmission. Phase II will include the GIS build and implementation for GDO. Due to lessons learned in Phase I, the GIS design for Electric Distribution Operations (EDO) will be moved to Phase III which will also include the EDO build and implementation. Phase I was approved for $11,468k in October 2018 with an estimated overall project cost of $39,000k which is consistent with the current overall estimate. [redacted] was selected as the system integrator for Phase I and will be contracted in Phase II for $6,500k. This Investment Proposal describes the Phase II Enterprise GIS project details and costs.

Through this Investment & Contract Proposal, GDO and IT seek capital funding authority of $14,361k for Phase II. An Amendment to the Phase I Award Recommendation of $6,500k plus 20% Contingency for Phase II is also being requested from the Investment Committee.

An Investment and Contract Proposal will be submitted for Phase III as business requirements and estimates are refined.

Why is the project needed? What if we do nothing?

The Enterprise GIS platform will provide broad access to geospatial data and will allow users to readily see company-wide assets layered together on a map. This will provide a much clearer view of potential interactions for routine operations and maintenance work as well as during storm restoration efforts. The Enterprise GIS will enable enhanced asset management and better decision making through information sharing. GDO utilizes the Enterprise GIS system for:

- Regulatory reporting and as the "system of record" for pipeline assets
- Locating gas assets in the field
- Input to gas regulatory compliance programs (public awareness, leak survey, line locating, valve and corrosion inspections)
- Input to the gas transmission and gas distribution risk software algorithms
- Input for gas system operational and reliability planning

Doing nothing is not a viable option because the existing GIS Smallworld application will not support all of the upcoming gas regulatory requirements. The current Black and Veatch (B&V) GIS data model has reached the product end-of-life and is no longer supported by the vendor. LKE is the last customer utilizing this data model. Security patching and updates will continue to become more challenging due to the outdated technology.

Contract Bid Summary

In 2018 LKE requested a bid for a System Integrator from three (3) bidders, [redacted]. A bid was received from [redacted] was the selected bidder because they provided a proposal that met all of the requirements. In addition, they participated in a presentation and project planning session. [redacted] was the unanimous recommendation for the role of SI (System Integrator) from a team including IT and representatives from each of the impacted lines of business. The decision was based on scoring criteria including favorable cost.

The evaluation team elected to have [redacted] based on their hourly rates being the lowest submitted in the bid process, provide a fixed price bid for Phase I. The contract was also negotiated to include Phase II hourly rates should LKE continue with [redacted] for Phase II. This proposal includes the request to continue with [redacted] as the SI for Phase II again with a fixed price quote. There was not a diverse supplier identified for this RFP.

Cost Summary Phase I

Cost Summary Phase I ($k)	[redacted]	[redacted]
SI Labor	2,534	3,214
SI Travel	369	559
Subtotal of SI Cost	[redacted]	[redacted]

Bid Evaluation Summary Phase I

Bid Criteria	Maximum Score	Schneider Electric	[redacted]	[redacted]	RAMTeCH
Compliant with Affordable Care Act		No Bid	Yes	Yes	No Bid
Price	30		23	30	
Completeness of Proposal	10		10	10	
Proposed Work Plan	25		25	25	
Key Resources	15		15	15	
References	10		0	10	
Company Leadership	10		10	10	
	100		**83**	**100**	

Contract Financial Summary

Contract expenses ($k)	2018	2019	2020	2021	Total
Phase I	717	2,532	430		3,679
Phase II-Amount requested based on contract award estimates			5,325	1,175	6,500
Contingency Amount Requested		121	1,070	230	1,421
Total contract authority requested	717	2,653	6,825	1,405	11,600

The project and contract are covered in the 2019 BP. Contract is fixed price and award recommendation includes contingency of 20% of Phase II costs for potential changes in scope and approved change orders.

Budget Comparison & Financial Summary

Overall capital project spend for years 2020-2023, which includes remainder of Phase I, Phase II and Phase III are shown below:

Capital cost ($000)	2020	2021	2022	2023	Total
Phase I	$ 900				$ 900
Phase II	$ 11,230	$ 3,131			$ 14,361
Phase III		$ 4,739	$ 7,000	$ 2,400	$ 14,139
Total	$ 12,130	$ 7,870	$ 7,000	$ 2,400	
2019 BP	$ 12,000	$ 8,000	$ 7,000	$ 2,400	$ 29,400
Variance to '19 BP	$ (130)	$ 130	$ -	$ -	$ -

Financial Details by Year are for Phase II only (2020-2023).

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed		11,230	3,131		14,361
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	-	11,230	3,131	-	14,361
4. Capital Investment 2019 BP		11,100	3,261		14,361
5. Cost of Removal 2019 BP					-
6. Total Capital and Removal 2019 BP (4+5)	-	11,100	3,261	-	14,361
7. Capital Investment variance to BP (4-1)	-	(130)	130	-	-
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	(130)	130	-	-

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed		2,351	2,401	580	5,332
2. Project O&M 2019 BP		2,351	2,401	580	5,332
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks to Phase II

- The technical complexity of the GIS project and changing business needs due to regulations or other conditions may cause needed modifications in applications interfacing with GIS and therefore delays in the project schedule. **Mitigation:** The project team will continue to work closely with GDO to identify needed changes as soon as possible. Integration resources have been added due to the number of critical integrations and lessons learned in Phase I.
- Esri Utility Network platform is an evolving technology and issues may cause delays in the project schedule. **Mitigation:** The Enterprise GIS system integrator, [redacted], is a Gold Partner with Esri and works closely with Esri and other customers to identify and correct issues early.
- Multiple overlapping and interdependent projects may put constraints on internal resources. **Mitigation:** Ensure regular communication with stake holders of known large initiatives to identify potential upcoming conflicts.
- Issues may arise in the conversion of the Smallworld data to the Esri platform. Data issues could negatively impact the risk algorithms for the Distribution Integrity Management Program (DIMP) and the Transmission Integrity Management Program (TIMP). **Mitigation:** Multiple data validation iterations leveraging internal and external resources have been dedicated to ensure the success of this effort.
- Potential Phase I implementation issues in early 2020 could require core team resources and delay the Phase II project work. **Mitigation:** Closely monitor Phase I implementation to identify and correct issues prior to go-live.
- [redacted] appears to be a growing technology company that has actively sought growth through acquisitions. The current credit risk is less than favorable. **Mitigation:** Should the need arise, LKS would be able to replace this vendor with another service provider. A contingency plan will be put in place and as always, there will be no prepayments for goods or services.

Alternatives Considered

All three phases of the Enterprise GIS project were included in the Capital Evaluation Model (CEM).

1. Recommendation: NPVRR: ($000s) [redacted]
   Implement Esri Enterprise GIS with [redacted] as the system integrator.

   The recommendation is to continue to move forward with the Esri Enterprise GIS project in the phased approach utilizing the expertise of [redacted] as the system integrator. This recommendation meets the business needs for an Enterprise GIS. The complete project and subsequent five years of O&M (2017-2028) were modeled in the CEM. The model includes separate in-service dates for the three phases as well as actuals and updated financial estimates for Phase I and Phase II.

2. Alternative #1: NPVRR: ($000s) $53,255
   Upgrade GE Smallworld GIS.

   This alternative is not optimal due to gaps in requirements and long-term dependency on the vendor for all enhancements. Significant customization would be required along with the conversion from the B&V ENOM data model to Smallworld v5 and the GE data model. In addition to Smallworld, an in-house Esri platform will need to be implemented and maintained for Generation and Electric Transmission as well as additional Esri interfaces to support GDO. Long term maintenance would be necessary to bridge the Smallworld and Esri platforms in order to simulate an Enterprise GIS. The complete Enterprise GIS project using Esri and Smallworld was modeled in the CEM with separate in-service dates for Phase I and the combination of Phase II and Phase III. Actual and updated financial estimates were utilized for Phase I. Phase II (GDO) and Phase III (EDO) are modeled together in the Alternative #1 because utilizing two different versions of Smallworld is not optimal.

3. Alternative #2: NPVRR: N/A
   Do Nothing

   This alternative puts LKE at risk due to lack of Smallworld functionality required to meet upcoming gas regulations and the need to move off a data model that is currently at the end of life. This option has not been modeled in the CEM due to the lack of long-term feasibility. The team does not recommend this option.

Conclusions and Recommendation

It is recommended that the Investment Committee approve Phase II of the Enterprise GIS project for $14,361k as well as the GIS System Integrator contract for $11,600k to [redacted] to complete the GIS implementation for GDO.

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced:

The Capital project spending and contract authority requests included in this Investment Proposal have 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 the capital project and contract authority requests.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

CONFIDENTIAL INFORMATION REDACTED

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
RFP 4025 System Integrator for Enterprise GIS

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the System Integrator for Enterprise GIS contract for $11,600 to [redacted]

Sourcing Leader Jacque English		Manager Chris Tabler	
Supplier Diversity Manager Eboni Edwards		Director Alpha Troutman	
Manager - Supply Chain Antonio F. Moir		Chief Information Officer Eric Slavinsky	
Director, Supply Chain David Cosby			

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Investment Proposal for Investment Committee Meeting on: December 19, 2019

Project Name: PC Tech Refresh

Total Capital Expenditures: $2,520k

Total O&M: N/A

Project Number(s): IT0671B

Business Unit/Line of Business: IT

Prepared/Presented By: Jason Adwell / Priya Mukundan

Brief Description of Project

This project is the continuation of current IT policy to provide upgrades to the workstation infrastructure. The project will provide the rotation of approximately 1,000 new desktops, laptops and Toughbooks into the environment in 2020, as well as 150 PCs for growth. The project maximizes operating efficiency for our knowledge workers and keeps IT support costs from increasing due to unplanned hardware maintenance.

Background

LGE and KU Energy (LKE) implemented a program in 2002 to replace desktops and laptops on a three-year cycle. The program was reevaluated in 2005, and it was determined then that the refresh cycle could be extended to four years for desktop computers. In 2017, the decision was made to begin refreshing laptop computers on the same four-year cycle due to advancements in technology, improved reliability and better warranties. The replacement cycle is consistent with industry norms as confirmed by Gartner, an American research and advisory firm that provides technology related insights to businesses.

The refresh process has continued to evolve over the years through various means. The 2020 Technology Refresh budget was reduced from its original budgeted amount of $2,994k by approximately $500k, with the savings attributed to thin client placement, reduction of the number of devices an individual may have, and placing the appropriate device into production. LKE continues to deploy thin client technology, which extends the rotation cycle to an estimated six years.

During the Tech Refresh process, devices are assessed for possible conversion with more than 500 thin clients currently deployed. Because we have hit some limits on the number of desktops that we can convert to thin clients, we are adopting a new strategy with the use of Chromebooks which run the Chrome OS. These can be viewed as mobile thin clients and will allow us to target further reductions in laptops (which is the largest segment of machines). This strategy is a reduction in both capital purchases as well as ongoing O&M. We’ve experienced unexpected challenges related to the Chromebooks, and as a result, our deployment numbers for 2019 were much lower than expected. Provided we can resolve the technical challenges, we will shift our deployment strategy to include more interaction and education of the Chromebook user base to improve the experience. Our target is to deploy an additional 100 Chromebooks in 2020, which will provide a cost savings of approximately $50k for this project.

In addition to the desktop and laptop refreshment, LKE also refreshes ruggedized Toughbooks on a four year rotation. These are devices placed into service in 2016, and earlier, for Electric and Gas Operations business. In 2020, some of these devices will be refreshed as part of the normal process while others will begin transitioning to the iPad or other lower cost devices.

Other alternatives, such as: doing nothing, deferring the project, running equipment to failure, or extending the refresh period to 5 years instead of 4 were not considered. These are not viable options because all of them increase the likelyhood of disruption to the business and are not quantifiable. Repair costs would increase O&M. There's potential for increased downtime due to failures and loss of data. As well, other alternatives would impair the company's ability to keep pace with advancing technology requirements. Providing an accurate number, or one that would even be close, for other alternatives would all be based on hypothetical situations and involve too many assumptions.

This project also accounts for PC purchases required for growth. Growth has continued to be higher than expected in recent years adding an average of an additional 130 PCs per year to our device count. The additional cost has been somewhat offset by the implementation of our virtualization strategy and lower cost alternatives for the user base.

Why is the project needed? What if we do nothing?

This project will evaluate and replace four year old desktops and laptops in 2020 before the computers experience hardware issues that cause out of warranty repair and unnecessary client down time. The project will be completed by 12/31/2020. All LKE desktops, laptops, and Toughbooks that were purchased in 2016 (and earlier) will be evaluated for replacement. Where possible, thin clients or Chromebooks will be used for replacements. The replacement schedule will be determined by site and will be reported monthly through departmental status reports. The project is budgeted and there are no incremental O&M expenditures or savings related to the project.

There are avoided costs associated with this project including improved reliability, reduced downtime for clients, and out of warranty repair costs, etc.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	-	2,520			2,520
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	-	2,520	-	-	2,520
4. Capital Investment 2020 BP		2,994			2,994
5. Cost of Removal 2020 BP					-
6. Total Capital and Removal 2020 BP (4+5)	-	2,994	-	-	2,994
7. Capital Investment variance to BP (4-1)	-	474	-	-	474
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	474	-	-	474

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

Risks

If the project is not approved, the main risk would include aging hardware that could fail that would create disruptions to individuals and processes. Hardware replacement after failure would be expected to be more costly than replacing prior to failure, along with the negative productivity impact to employees that experience unplanned hardware failure.

Alternatives Considered

Recommendation for 2020 Refresh Project NPVRR: $2,705k

- Positive impact on business operations for 2020
- Windows 10 will be deployed to all devices
- Keep pace with advancing technology
- Minimize risk to O&M budgets for repairs
- Ability to rollout new applications required by the lines of business

Conclusions and Recommendation

It is recommended that the Investment Committee approve the 2020 PC Tech Refresh project for $2,520k to ensure that our workstation environment meets the needs of the operational areas who are dependent upon the tools and technology to do their job.

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 and Contract Proposal for Investment Committee Meeting on: 2/27/2020

Project Name: Oracle Upgrade Project
Contract Name (Good/Service): [redacted]

Selected Vendor(s): [redacted]

Contract Authorization Requested: $15,775k (Including $1,299k of contingency)

Contract Term: August 2019 through May 2021

Total Capital Expenditures Requested: $20,130k (Including $1,655k of contingency and including $3,963k of internal labor)
Total O&M: $8,964k of project costs (including annual incremental support and maintenance of $144k/year)

Project Number(s): IT0076B
Business Unit/Line of Business: Accounting/Supply Chain/IT

Prepared/Presented By: Chris Garrett, Eric Slavinsky, David Cosby, Joe Clements

Brief Contract/Project Description

This proposal requests approval of the Oracle eBusiness Suite ("OeBS") Upgrade project which will move the Company from version 12.1.3 to version 12.2.9. This key Sarbanes Oxley (SOX) system will be unsupported as of December 2021. Due to the continuous innovation capability[1] of the 12.2 version of OeBS, the next major upgrade is not expected to be required through 2030 unless a major business change justifies a move to the cloud or some other version of the application. Oracle has committed to support the on-premise application through 2030, at a minimum, as they are still heavily investing in the on-premise version.

At the completion of the bid process [redacted] was engaged in August 2019 to perform an assessment of the current system and deliver recommendations for an upgrade plan. To remain on track for a 2021 implementation, the contract was amended to begin preliminary capital work on the technical upgrade portion (Phase 0). The award recommendation for the contract with [redacted] was approved for $1,530k in early November to provide detailed design for the upgrade of OeBS, in addition to the recently completed assessment. Approval to amend the Assessment and Phase 0 Award Recommendation to $15,775k including $1,299k in contingency for the OeBS Upgrade Project is being requested from the Investment Committee. This next phase of the project

[1] Oracle's Continuous Innovation means that Oracle E-Business Suite customers already running on 12.2. can continue to access new application's functionality and separately uptake later versions of underlying technology for years to come, without the time and expense of a major release upgrade. See Oracle press release: Continuous Innovation on Oracle E-Business Suite 12.2.

upgrade timeline will begin in March 2020 and Go-Live by April 19, 2021, with post Go-Live support through May 2021.

The capital project was originally opened in November for $750k primarily for [redacted] contract costs for detailed design work. In December, the project was increased $525k, which included additional internal labor and support from [redacted] relating to further detail design work.

This project is included in the 2020 Capital Business Plan (2020 BP) for $9,015k ($3,105k in 2020, $5,910k in 2021) based on the 2013 OeBS Upgrade project. This base-level budget was derived from the amount spent on the 2013 upgrade of $7,168k plus additional capital for possible increases in scope and company labor not eligible for capitalization in 2013. The 2013 project had a narrower scope, limited to a technical upgrade and enhancements for Accounting and Reporting, and did not include scope for Source-to-Pay. The project also includes projected O&M costs of $8,964 with incremental ongoing annual costs of $144k per year for support and maintenance.

This revised proposal in the amount of $20,130k in capital is for the full upgrade scope, schedule, and cost of the recommendations resulting from the project assessment including a 10% contingency on the [redacted] contract (O&M and capital and excluding one-time license costs). The increase in cost compared to the 2020BP is due largely to scope for system configuration and optimization for business process improvements in LKE's source-to-pay processes, security enhancements including NACHA compliance[2], accounting process improvements, and internal labor costs that were higher than initially assumed. This includes utilization of new and improved OeBS system functionality to address identified business needs and "pain points" and the deployment of capabilities for internal company users and external suppliers not previously available since the 10-year period of the last major upgrade.

Project Description

1) The Oracle Upgrade project encompasses the following components of work. Upgrade of OeBS instance from R12.1.3 to R12.2.9, including Single Sign-On.
    a. The purpose of this upgrade is to upgrade to a supported version of OeBS that provides all the functionality of the R12.2.9 release. Customizations will be removed where feasible to make the system more future-ready and streamline support.
    b. The benefits of the project include remaining on a supported version of technology that enables continuous deployment (the ability to upgrade the underlying infrastructure with limited disruption to the application and users) and streamlining user logins through Single Sign-On.
2) Implementation of Source-to-Pay improvements, which encompass the implementation of new modules and process and configuration changes to existing modules.
    a. The purpose of these improvements will be to standardize technology; increase security and control for vendor information management; automate and improve

[2] National Automated Clearing House Association (NACHA) Supplementing Data Security Requirements become effective June 20, 2020. Data protection requirements will be supplemented to explicitly require companies in scope to protect deposit account information by rendering it unreadable when it is stored electronically.

tasks related to review and approval of expenses; improve the accrual process; investigate Zycus system integration; and standardize and streamline buying channel and invoicing processes across the company.

b. Benefits of the improvements include compliance with NACHA regulations for ACH related data to safeguard confidential information; automation of expense reports; enhanced cost management through improved visibility and review capabilities for purchasing cards (P-Card), corporate cards, and iExpense reimbursements, including mobile review and approval capability and reduction in related manual corrections; efficiencies with remediation of Evaluated Receipt Settlements (ERS); vendor driven access to more early discounts for payables; digitization of invoices and resolution of problematic invoices; and vendor self-registration and access capabilities for updates. These benefits will also enable a more informed and effective user base of the system to support existing efforts to manage costs.

3) Implementation of Accounting improvements which encompass the implementation of a new module and process and configuration changes.
   a. The purpose of these changes is to standardize technology, automate processes such as journal entry approval, and enhance security and controls, including segregation of duties.
   b. Benefits of these improvements include improved system capability for sales tax by utilizing the E-Business Tax (“EB Tax”) module, eliminating the current custom program used; automation of cash reconciliations; automation of journal entry approval; digitization of miscellaneous invoices; and reduction of accounting corrections.
4) Implementation of Inventory improvements which encompass process and configuration changes.
   a. The purpose of these changes is to automate processes performed manually by employees experiencing workforce transition, improve data access, improve reporting capability, and maintain or reduce inventory on hand across areas.
   b. Benefits of implementing include consistency in item setup and maintenance; reduction in stockouts and percentage of erroneous item orders; and minimize new inventory additions through reduction in duplicate items and errors in inventory data.
5) Implementation of Supplier Information Management (SIM) improvements which encompass system integration between Zycus and OeBS systems, deployment of enhanced capabilities for both internal and external users.
   a. The purpose of these changes are to investigate the automation processes performed manually to sync , supplier/vendor information between Zycus and OeBS, redesign system workflows to establish traceable master data approval, develop a supplier launchpad to direct suppliers to appropriate OeBs and other 3rd party systems and to eliminate existing duplicate systems and processes that may be enabled within new or enhanced OeBS system modules.
   b. Benefits of implementing include increased control and safeguards for supplier information; avoidance of potential fraud risks and errors through further automation, integrations and workflow approvals; enhanced supplier experience

with company systems; and greater understanding of efficient processes across a wide population of employee proponents and external suppliers.

6) Upgrade EIS eXpress Reporting (financial reporting tool) with XL Connect and GL Connect (Microsoft Excel add-ins).
    a. The purpose of the reporting system upgrade is to move to a version that is compatible with OeBS 12.2.9.
    b. Benefits of this upgrade are to remain on a supported application and ensure timely and accurate reporting OeBS.

The project will require substantial change management and training, not only for internal employees but for external vendors and suppliers.

Contract Description

The contract with [redacted] is a time and materials contract and has the O&M and capital cost components noted below. The benefits of the work include designing the appropriate functionality to increase LKE's business value in using the OeBS. In 2019 a bid was conducted for the following components. The scope of the full upgrade was unknown, however rate cards were requested and negotiated. Based on the evaluation of such bid process Company is electing to continue the work with [redacted].

- **Assessment ($563k O&M) Contract** – [redacted] provided consulting services from August through October 2019 to conduct an assessment with LKE that prepared the company for the OeBS upgrade by evaluating and making recommendations in the following areas:
    - Oracle Technical Upgrade
    - Accounting Enhancements
    - Source to Pay Enhancements
    - Reporting
    - Inventory
    - Supplier Information Management
    - Procurement Services
- **Phase 0 ($924k Capital)** - [redacted] is providing system integrator services to lead detailed design for the technical upgrade to version 12.2.9, including detailed design for source-to-pay's buying channels taxonomy, and detailed process design for source-to-pay's payment channels. The term for this agreement is November 2019 through February 2020.
- **Oracle Upgrade Contract ($12,157k Capital, $832k O&M)** – This contract is for system integrator services for the OeBS upgrade and includes scope to support the project work including design, development, testing, training, deployment, and post Go-Live support. The term for this contract is March 2020 through May 2021. A 10% contingency of $1,299k is requested.

Why is the project needed? What if we do nothing?

- OeBS version 12.1.3 will be unsupported as of December 2021. In order to maintain a strong security posture, the Company is committed to maintaining support on OeBS, which is a SOX system. Doing nothing will put the Company at risk of losing its key financial system due to lack of support post 2021 resulting in the inability to produce required financial statements.

Contract Bid Summary

- The company solicited bids for the assessment from five bidders: [redacted] The bid finalists were [redacted].
- The bidders were identified based on whether they were an experienced system integrator (SI) capable of assessing the current OeBS environment and identifying the necessary steps to upgrade to a current version. They also had to be able to provide an assessment of Source to Contract and Procure-to-Pay alternatives (Source to Settle) as well as an evaluation of reporting alternatives. The bidder had to be experienced and capable of performing as the SI for a potential OeBS upgrade should LKE elect to upgrade and use their services.
- [redacted] provided a bid that included a combination of technology tools and workshops to assess LKE's environment and processes at the lowest price. [redacted] provided a comprehensive proposal for more than twice the cost of Accenture's for the Assessment Phase.
- Supplier Diversity did not identify any diverse suppliers for this opportunity.
- Below are the bid results for the assessment phase. The assessment contract included language providing the option to extend the contract for the full implementation at discounted labor rates.

Section/Questions	[redacted]	[redacted]
MBE/WBE designation	Large	Large
	Weighted Score	**Weighted Score**
Grand Total of Scores	**100**	**84**
Supplier Rank	**1**	**2**
Work Plan	33	33
Resumes	10	10
Timeline	24	24
Pricing	29	13
Clarifications	5	5
Grand Total of Scores	**100**	**84**
Supplier Rank	**1**	**2**
Total Cost	[redacted]	[redacted]

Contract Financial Summary

Contract expenses ($k)	2019	2020	2021	2022	2023	Post 2023	Total
Amount requested based on contract award estimates **-Assessment (O&M)** **-Phase 0 (Capital)** **-Implementation (O&M)** **-Implementation (Capital)** **Total**	 $563k $282k $ 0 $ 0 $845k	 $0 $642k $666k $10,187k $11,495k	 $0 $0 $167k $1,969k $2,136k				 $563k $924k $833k $12,156k $14,476k
Contingency Amount Requested	$0	$0	$1,299k				$1,299k
Total contract authority requested	$845k	$11,495k	$3,435k				$15,775k

Project Financial Summary

Financial Detail by Year - Capital ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed	298	14,883	4,950	-	20,130
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	298	14,883	4,950	-	20,130
4. Capital Investment 2020 BP		3,105	5,910		9,015
5. Cost of Removal 2020 BP					-
6. Total Capital and Removal 2020 BP (4+5)	-	3,105	5,910	-	9,015
7. Capital Investment variance to BP (4-1)	(298)	(11,778)	960	-	(11,115)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(298)	(11,778)	960	-	(11,115)

Financial Detail by Year - O&M ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Project O&M Proposed		2,638	2,105	4,221	8,964
2. Project O&M 2020 BP		1,655	1,617	3,734	7,006
3. Total Project O&M variance to BP (2-1)	-	(983)	(488)	(487)	(1,958)

Annual ongoing O&M for support and maintenance of OeBS is roughly $1,250k, including incremental ongoing O&M of approximately $144k for support beginning in 2020 and escalated at 4% per year. Of the incremental amount, $74k is for new modules and $70k is required by Oracle to "true-up" existing support for iSupplier. Remaining project O&M costs are for organizational change management and training activities during the project implementation. The incremental portion is $916k for [redacted] O&M and $262k for internal O&M labor that has been backfilled over the life of the project. The incremental O&M costs for 2020 will be funded by various groups under the CFO areas by capturing labor savings and other reductions included in monthly forecast updates.

Project O&M	2020	2021	2022-2024	Total
Business Plan O&M				
O&M in current BP (labor)	$548k	$467k	$0	$1,015k
Ongoing Support and Maintenance Fees in BP	$1,107k	$1,150k	$3,734k	$5,991k
Current O&M in Business Plan	***$1,655k***	***$1,617k***	***$3,734k***	***$7,006k***
Incremental O&M				
[redacted]	$666k	$250k	$0	$916k
Internal O&M (backfilled labor)	$173k	$89k	$0	$262k
New Support and Maintenance	$144k	$149k	$487k	$780k
Incremental O&M	***$983k***	***$488k***	***$487k***	***$1,958k***
Total Project O&M	**$2,638k**	**$2,105k**	**$4,221k**	**$8,964**

Capital and O&M savings/benefits are not included in the summary above but are reflected in the Capital Evaluation Model (CEM).

The project implementation and resulting benefits are expected to yield several forms of "soft" and "hard" savings to support existing and upcoming departmental plans for workforce utilization and cost control programs across the company. Potential hard savings after full implementation and optimization of system capabilities for internal and external users is estimated to be around $1.7M pre-tax per year from 2018 spend levels, split between O&M and Capital. These amounts are essentially included in the business planning process as supporting the changing spend levels from 2018 to the levels projected in 2022 and later years for Capital and O&M. The estimated annual savings amounts included as part of the budget planning assumptions from 2018 to 2022 are based on the following.

Category	**Calculation/Assumption**	**Capital**	**O&M**	**Total**
Accounting – iReceivables Module	Labor reductions and other efficiencies from digitization of printing and mailing bills.	$0	$100k	$100k
Accounting - EB Tax Module	Cash sales tax savings primarily from inventory tax accruals and identifying exempt items	$181k	$69k	$250k
iExpense and Corporate/Purchasing Card	Discretionary spend reduction through enhanced visibility and focused management control	$0	$400k	$400k
Purchasing – vendor payment discounts	Early payment discounts enabled for selected capital payments.	$750k	$0	$750k
Inventory – avoided stockouts	Reduction in errors and additional purchases due to stockouts.	$43k	$17k	$60k
Supplier Information Management	Reduction in existing system costs by transferring to Oracle.	$0	$25k	$25k
Supply Chain / Commercial Operations	Labor reductions for sourcing activities based on efficiencies achieved.	$0	$100k	$100k
Total		**$974k**	**$711k**	**$1,685k**

<u>Credit Review</u>

- A credit review was conducted on [redacted] the parent of [redacted] which identified no risks. [redacted] has signed a Parent Guaranty for [redacted]

<u>Project Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) $22,853k
   Technical upgrade with identified enhancements
   This recommendation addresses business requirements and "pain points" identified during the assessment phase of the project and includes configuration and process enablement for improved functionality across the company. For example, mobile capabilities and improved visibility for purchasing card and discretionary spend are designed to support cost control measures required to achieve financial objectives. The focused effort of enhanced deployment will also support more consistent and standardized system-driven processes that are not currently achievable due to increasing employee turnover and lack of current system enabled functionality. Employees across the company will benefit from streamlined processes that will allow them to devote time to other departmental efforts. The expanded capabilities for vendors using the new functionality provides more accuracy, controls, efficiencies, and a streamlined user experience for OeBS and other systems.

2. Alternative #1: NPVRR: ($000s) $23,400k
   Technical upgrade only
   This alternative includes an upgrade of OeBS, an upgrade of EIS Express Reporting, and system configurations and enhancements to comply with NACHA Regulations and mitigate increasing risk of vendor information fraud. This alternative was not considered as a viable option because it primarily focuses on upgrade of existing use of the system only. Enhanced capabilities would not be available under this option, which would forego roughly $1,700k of annual targeted cost control measures and other efficiency gains across the company derived from more automated and standardized business processes.

3. Alternative #2: NPVRR: ($000s) $24,817k
   Technical upgrade with full enhancements (per Assessment)
   This alternative included several components beyond the current recommendation.
   - Implementing an AP automation tool to replace our current OTAP system, which is end of life.
   - Implementing Product Data Hub
   - Implementing project billing
   - Implementing additional accounting enhancements
   - Implementing additional source-to-pay enhancements

   While these additional enhancements were expected to add value, they were assessed to not be cost justified and would add too much complexity to the project.

4. Alternative #3: NPVRR: ($000s) Not Applicable
   Stay on current version (do nothing)
   Do nothing was not considered a feasible alternative because the Company's position is to remain on supported technology for regulatory and security compliance.

- **Assumptions**
  - Licensing costs and any O&M support expenses will be included in the next business plan currently under development.
  - The software has a five-year depreciable life.
  - The depreciation rate for capital savings in the recommendation is 4% annually.
  - The incremental maintenance costs are $144k beginning in 2020 and escalated at 4% per year.
  - Change management project costs are incremental O&M only during the life of the project implementation.

- **Risks**
  - Implementation should be completed in advance of the loss of OeBS version 12.1.3 support in December 2021.
  - Changing the scope or timing of the project or not proceeding with the recommended plan may result in separate requests for change orders or enhancements that would be needed.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Oracle Upgrade Project for $20,130k and associated contract for $15,775k to [redacted] to remain supported and optimize system use.

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced:

The Capital project spending and contract authority requests included in this Investment Proposal have 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 the capital project and contract authority requests.

Kent W. Blake Date	Paul W. Thompson Date
Chief Financial Officer	Chairman, CEO and President

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
RFP 1310162114 2019 Oracle Assessment/Upgrade

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the Oracle Upgrade contract for the requested authority of $15,775k to [redacted]

Sourcing Leader Jacque English		Proponent/Manager Heidi Konynenbelt	
Supplier Diversity Manager Eboni Edwards		Director – Supply Chain David Cosby	
Manager - Supply Chain Antonio F. Moir		Chief Information Officer Eric Slavinsky	
Director Joan Ferch			

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Investment and Contract Proposal for Investment Committee Meeting on: June 30, 2020

Project Name: Meter Data Management System (MDMS)

Contract Name (Good/Service): MDM Siemens EnergyIP System Implementation (SSA)

Selected Vendor(s): Siemens, Accenture

Contract Authorization Requested: $2,500k (Including $ 200k of contingency)

Contract Term: 18 months

Total Capital Expenditures Requested: $7,562k (Including $ 768k of contingency and $2,904k of internal labor)

Total O&M: $1,163k

Project Number(s): IT0548B

Business Unit/Line of Business: IT Business Services

Prepared/Presented By: Mike Lowery and Jonathan Whitehouse / Joan Ferch and David Huff

Brief Contract/Project Description

This investment proposal (IP) is requesting approval for the following:

1. Siemens EnergyIP as the MDMS provider based upon evaluation of a competitive bid process.
2. Authorization to implement an MDMS with functionality to meet current operational requirements at a total cost of $8,725k ($7,562k CAPEX, $1,163k OPEX).
3. Sole source system integrator (SI) contract to Accenture for implementation of the proposed limited MDMS at a cost of $2,500k.

The results of a competitive bid process and evaluation concluded that Siemens EnergyIP MDMS is both best in-class system and lowest cost (compared to Do Nothing) due to its configurability and proven integration with SAP for both electric and gas at other utilities. It is recommended that Siemens EnergyIP MDMS be implemented with functionality described in this IP to address current operational needs.

Authorization to implement the MDMS is recommended to provide an industry standard system to store and process customer interval data. More specifically this system will:

- Provide a central repository that collects and stores data.
- Process interval data through validating, estimation, and editing.
- Process a limited number of high priority alarms or events such as high temperature.

- Provide register KWH and Demand KW billing for Residential Service (RS) and General Service (GS) customers.
- Automate data transfer for meter add/update/remove/exchanges through Command Center to MDMS, which will interface to SAP for customer data updates.
- Support both electric and gas.
- Provide core operational reporting using out-of-the-box Siemens EnergyIP functionality which shall include but are not limited to:
  - Non-reporting meters
  - Event Activity, e.g. outage, restoration, and voltage sag/swell
  - Meter resets
  - Theft/tamper flags
- Provide an industry standard system for future integration with the corporate data analytics strategy, when developed.

Access to Advanced Metering Infrastructure (AMI) interval data provides the Company the opportunity to do the following:

- Provides greater operational insight into voltage and customer usage patterns which can better inform load forecasting and Electric Distribution circuit models.
- Provides improved estimates on customer bills by using more data points within current billing month.
- Customer bill projections.
- Provides data that can be used in analyzing and developing potential new customer rate offerings.
- Provides data for unbilled revenue monthly calculations which could lead to future automated accruals using Robotic Processing Automation.
- Allows for collection, storage, and analysis of voltage and consumption data to understand transformer loading, EV adoptions, circuit performance, reliability issues, and private generation adoption.
- Identification of meter anomalies, failures, and meter bypass.

It is recommended to proceed now with the MDMS described in this IP to serve residential and commercial customers (RS and GS rate classes) by automating meter to cash processing for installed AMI meters. The Company requires increasing amounts of interval data for billing purposes to support Solar Share (SSP) and the Advanced Meter Program. Net billing and Green Tariff are programs that are on the horizon and which would benefit from the foundation a MDMS will provide to implement the requirements of these programs as they are developed.

SSP continues to grow through customer subscriptions and is expected to grow 10-fold (from about 1,000 meters today to about 10,000 meters as all eight arrays become subscribed). SSP requires an advanced meter to process the interval data required as per tariff. Processing the interval data to bill SSP participants currently requires a manual component to validate, estimate, and edit interval data for billing purposes. As the number of individual customers increase, so does the labor required to process the increased number of individual bills. The Company is committed to delivering the SSP at reasonable cost to customers through the shared services of an MDMS. The recommended solution provides for the needs of SSP while at the same time providing benefits to non-SSP advanced metering participants. Once in place, any current advanced meter customer as well as any expansion customer would benefit from the system already being in place.

All customers in rate classes RS and GS with an advanced meter will benefit from the MDMS described herein. Processes established will work regardless of the number of meters installed, thus should installed AMI meters grow, the system will continue to provide benefits although this benefit has not been included beyond the approved Solar Share Program.

Currently there are 21,500 AMI meters installed and a backlog of 5,100 customers.

At some point in the future, should the Company receive approval for additional AMI meter deployment, the recommended solution can be expanded to handle additional operational needs up to an estimated incremental $16 million to cover the operational requirements of a system-wide AMI deployment.

Detailed Contract/Project Description

On April 30, 2019 the Company requested approval for recovery of the monies required for the advanced meter program expansion granted as part of the DSM Case No. 2017-00441 and discussed the need for an MDMS with the Commission staff. Later, the Company issued a Request for Proposals (RFP) to fully evaluate the cost effectiveness of utilizing various vendor solutions and determined that Siemens offers a best-in-class solution, lowest vendor cost, and less risk as Siemens is a proven solution. This proposal recommends moving forward with Siemens Energy IP System MDMS to solve current issues (Detailed in the "Why is the Project Needed Now" section below) and provide an industry standard solution that can be built upon should the Companies receive a future approval for any additional AMI meter deployment.

Issues created from installation of the 21,500 AMI meters currently in the field, continued growth in Solar Share Program, and the processing of associated interval data for billing-specific programs drive the recommendation to invest in an industry standard system. Investing in an MDMS addresses the current issues detailed in the "Why is the Project Needed Now" section below, provides for expected AMI growth, and provides a foundation for Solar Share net billing needs.

Why is the project needed now? What if we do nothing?

Having no central system to manage interval data inhibits advancing operational benefits from the installed meters. The increasing number of AMI meters and the inability to store and process the data by utilizing a MDMS has created, and will continue to create, many operational challenges:

- The Companies have no central repository for the advanced meter data beyond 45 days.
- There is no validation, estimation, and editing of existing data, which means the Companies cannot use the data for internal processing or billing. Data is being provided to customers as "raw" data.
- No event/alarm processing. As the number of meters has increased, the risk of an adverse condition at a customer's meter likewise increases. Meters provide information

to the head-end system, which is not interfaced to SAP, and therefore does not provide timely insight into these events. The head-end is designed to interface to a MDMS application, which in turn interfaces into SAP, providing automated timely insight into these events. Events such as high temperature can be indicative of meter base or customer wiring problems.

- No register KWH and demand KW billing. Many customers assume that when they sign up for the program, the Companies will no longer need access to their premises. They are shocked that we manually read advanced meters, and this raises questions about the value of advanced meters. The ability to process register reads starts to provide benefits through reducing manual meter reading costs and meeting customer expectations.
- No automated meter add/update/remove/exchange process between the advanced meter head-end and SAP. Manual processes are administratively burdensome which increases cost.
- The current advanced meter deployment provides little to no support for gas. Providing the ability for gas further enhances the Companies' ability to eliminate manual meter reading.
- No core reporting to assure the system is operating as expected, identifies exceptions and responds to issues in a timely manner.
- The Companies are relying on custom temporary solutions that are not industry standard and therefore increases risk of application failure.
- Should the Company elect to offer new rates using interval data, in the future, development of a MDMS necessary to facilitate the billing is expected to require 12-18 months lead time. Establishes a firm foundation for more complex rates such as solar share, green tariff, and other alternate rates which our current systems are inadequate to handle at scale.

Expansion of advanced metering beyond the current Opt-In is occurring; via expanded Opt-In, limited new installations to address operational needs, solar share expansion or to address obsolete equipment challenges. More specifically:

- Increasing participation in Solar Share drives increased volumes of advanced meters.
- The Advanced Meter Program (AMP) has approximately 20,000 customers participating with an additional 5,100 customers on the waiting list for an advanced meter.
- Approximately, 4,000 Power Line Carrier (PLC) meters in Wilmore, KY have reached the end of their life and have become impractical to maintain with limited to no availability of spare parts. Currently these meters send a reading approximately every 27 hours. The Customer Care System (CCS) uses these readings to bill Wilmore customers. Once these PLC meters are retired due to end of life, the Company will need to install alternative metering. The options will be legacy electronic or AMI metering. In an AMI metering scenario, the MDMS is needed to validate, estimate and edit data required for billing and it would avoid the incremental costs associated with starting to manually read legacy meters.
- Power Service Secondary (PS) customers are becoming increasingly interested in having an advanced meter to allow them to analyze their energy consumption and demand patterns for more effective management, and substantiation, of their bills.
- Business solar continues to expand requiring additional meters to gather interval data

- In the event customers elect to be served under the Green Tariff Options, the MDMS would be used to provide data necessary to SAP for billing.

It is prudent for the Companies to address the issues above by implementing an MDMS.

Siemens' EnergyIP is SAP's recommended MDMS partner as well as the leading product as most recently reviewed by Gartner in 2018 (which is latest available data). By partnering with Siemens to implement a production-level instance of their EnergyIP MDMS, the Companies will be able to implement a base-level architecture and functionality that will address current issues, be utilized to mitigate the need and risk of custom developed applications for future capabilities that require interval data (e.g., Net Billing) through future enhancements, and interface to other applications where utilizing the meter head-end is inappropriate due to technical limitations.

This project is expected to cost $7,562k in CAPEX, and $1,163k in OPEX and will deliver the functionality and benefits discussed above.

Contract Bid Summary

The work described herein is being awarded to Siemens for the Energy IP MDMS following a competitive bid process.

An RFP was issued to fully evaluate the cost for an enterprise-level MDMS business case. Evaluation criteria included all customer rate classes. Siemens was selected to (1) address issues related to the current 21,500 advanced meters, (2) support interim AMI growth and the collection and processing of interval data, and (3) support any future additional AMI meter deployments.

The Siemens EnergyIP application is recommended for the following reasons:

- Siemens EnergyIP provides flexibility as a highly configurable system to meet the Company's requirements as they change, or the number of AMI meters grow.
- Siemens has the proven ability to interface with SAP electric and gas functionality
- Siemens technical architecture closely resembles SAP architecture and will facilitate a more efficient upgrade process.
- Siemens is the industry leader in the market segment according to Gartner Magic Quadrant[1]

The system integration contract described herein is being awarded to Accenture as a sole-source award for the following reasons:

- This SSA will be for the work described herein to implement an MDMS.
- Accenture has a proven history implementing projects of this scale and bring a wealth of experience specific to balancing the Companies' business processes within the Siemens' EnergyIP product.

[1] Gartner is a globally recognized research and advisory company. A Gartner Magic Quadrant reflects research in a specific market, providing wide-angle view of the relative positions of the market's competitors. By applying a graphical treatment and a uniform set of evaluation criteria, a Magic Quadrant helps quickly ascertain how well technology providers are executing their stated visions and how well they are performing against Gartner's market view.

- Siemens' implementation subsidiary, Omnetric, originated as a joint venture between Siemens and Accenture, leaving Accenture well positioned to support the Companies implementation efforts.
- The existing rate card for the SSA was competitively bid in 2016 and has only increased by inflation index.

Contract Financial Summary

Contract expenses ($k)	2020	2021	2022	2023	2024	Post 2024	Total
Amount requested based on contract award estimates	$700	$1,600					$2,300
Contingency Amount Requested	$0	$200					$200
Total contract authority requested	$700	$1,800					$2,500

Project Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	1,773	5,789			7,562
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	1,773	5,789	-	-	7,562
4. Capital Investment 2020 BP	3,988				3,988
5. Cost of Removal 2020 BP					-
6. Total Capital and Removal 2020 BP (4+5)	3,988	-	-	-	3,988
7. Capital Investment variance to BP (4-1)	2,215	(5,789)	-	-	(3,574)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	2,215	(5,789)	-	-	(3,574)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	343	631	61	128	1,163
2. Project O&M 2020 BP	169	540	108	216	1,033
3. Total Project O&M variance to BP (2-1)	(174)	(91)	47	88	(130)

This project is included in the IT 2020 BP at $3,988k. A contingency of 10% is included on internal labor, System Integrator fees and Vendor implementation costs.

NOTE: The Companies have internal labor of $683k in 2020 and $2,221k in 2021 reflected in the 2020 BP.

Risks

- The potential impacts to customers will be mitigated through thorough and structured testing.
- The product is a proven technology and is the market leader for the MDMS space.
- Both contracts are structured with appropriate protections against vendor failure to perform, including the ability to terminate the contract with 30 days' notice.
- The Siemens contract is based on a fixed fee. The SI contract is based on time and materials; however, contract language imposes a cap on the fees unless written authorization is provided by the Companies.
- Accenture will provide a Parent Guaranty for the contract. No concerns were noted, upon an internal credit review, for entering into the system integrator contract with Accenture.

Project Alternatives Considered

1. Recommendation: NPVRR: ($000s) $11,079

   Implement Siemens' Energy IP MDMS with associated development of interfaces and business processes, utilizing a two-phase approach to mitigate risk of application readiness and cost. This system was identified as the best in-class and least cost option at full scale functionality through a competitive bid evaluation and would remain useful in the event the Companies fully deploy AMI in the future. The NPVRR shown here reflects a 16-year time horizon (see note below) and all anticipated costs for maintenance and technical upgrades over that time period.

2. Do Nothing: NPVRR: ($000s) $11,994

   This option is unacceptable for several reasons. First, it limits the operational and customer experience benefits of the already deployed AMI meters as it requires the Companies to continue manually reading AMI meters indefinitely. Secondly, the Companies need the ability to adequately support Solar Share and Green Energy Tariffs as adoption continues to grow. While the Companies' currently plan to do this through a semi-automated process, the level of manual interaction is expected to increase as adoption continues due to higher volumes of customers in each array on the Solar Share program likely ranging from 700 – 2,000 per array. The resulting impact of the incremental manual effort is Company labor or contract labor associated with 1 – 2 full time equivalent (FTE) resources per new array. The NPVRR shown here reflects a ~1.5 FTE increase per array over the next 16 years. Thirdly, the Companies' lack a central repository and billing engine for AMI data. Implementing MDMS provides an opportunity to introduce foundational tools like these for customers with advanced meters and enable additional data analytics and reporting.

NOTE: Financial analysis on alternatives used a 16-year life on MDM system, based on average length of service of existing primary applications as of March 2020.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Energy IP capital project for $7,562k as well as the Accenture contract for $2,500k for the system integration of the MDMS application.

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced:

The Capital project spending and contract authority requests included in this Investment Proposal have 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 the capital project and contract authority requests.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
(RFQ number and/or name of job or contract)

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the proposed System Integrator contract with Accenture for $2,500k for 18 months.

Sourcing Leader Jessie Logsdon		Proponent/Team Leader David Huff	
Supplier Diversity Manager [If applicable]		Acting Manager – AMI Project Delivery Jonathan Whitehouse	
Manager - Supply Chain or Commercial Operations Tony Moir		Director – Supply Chain or Commercial Operations David Cosby	
Director – IT Business Services Joan Ferch		Manager – IT Development and Support Mike Lowery	
Vice President – Customer Services Eileen Saunders		Chief Information Officer Eric Slavinsky	

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Investment Proposal for Investment Committee Meeting on: December, 18, 2020

Project Name: PC Tech Refresh

Total Capital Expenditures: $2,559k

Total O&M: $ 0 k

Project Number(s): IT0873B

Business Unit/Line of Business: IT

Prepared/Presented By: Monica Green / Priya Mukundan / Eric Schrenger

Brief Description of Project

LGE and KU Energy (LKE) implemented a program in 2002 to replace desktops and laptops on a three-year cycle. The program was reevaluated in 2005, and it was determined then that the refresh cycle could be extended to four years for desktop computers. In 2017, the decision was made to begin refreshing laptop computers on the same four-year cycle due to advancements in technology, improved reliability and better warranties. The replacement cycle is consistent with industry norms as confirmed by Gartner, an American research and advisory firm that provides technology related insights to businesses.

The project will provide the rotation of approximately 1,400 new desktops, laptops and thin clients into the environment, in 2021, as well as 130 PCs for growth. This is an increase of 336 more units than last year. The project maximizes operating efficiency for our knowledge workers and keeps IT support costs from increasing due to unplanned hardware maintenance. The standard memory for laptop and desktop purchases, going forward, will be increased from 8GB to 16GB of RAM. This will allow us to keep pace with the memory required for the newer Windows 10 operating system and prevent performance issues . We have evaluated our PC environment and determined that a large portion of our currently deployed systems should have their memory increased to avoid a negative client experience as well. These costs are included in the project.

In addition to the desktop and laptop refreshment, LKE previously refreshed ruggedized laptops on a four-year rotation. These devices were placed into service in 2016, and earlier, for Electric and Gas Operations business. In 2021, these devices will not be refreshed, as we continue the transition to iPads or other lower-cost devices.

Other alternatives, such as: doing nothing, deferring the project, running equipment to failure, or extending the refresh period to 5 years instead of 4 were not considered. These are not viable options, because all of them increase the likelihood of disruption to the business and are not quantifiable. Repair costs would increase O&M. There’s potential for increased downtime due to failures and loss of data. Also, other alternatives would impair the company’s ability to keep pace with advancing technology requirements. Providing an accurate number, or one that would even be close, for other alternatives would all be based on hypothetical situations and involve too many assumptions.

This project also accounts for PC purchases required for growth. Growth continues to be higher than expected, in recent years, adding an average of an additional 130 PCs per year to our device count. The additional cost has been somewhat offset by the implementation of our virtualization strategy and lower cost alternatives, like thin clients. Although we have seen a consistent increase of systems over the past few years, we are attempting to reduce the overall device count for users, but there are some scenarios that we are unable to do that. Every new head count, whether it's an employee or contractor, will require a PC.

Why is the project needed? What if we do nothing?
This project will evaluate and replace four-year-old desktops and laptops in 2021 before the computers experience hardware issues that cause out of warranty repair and unnecessary client down time. The project will be completed by December 31, 2021. All LKE desktops and laptops, purchased in 2016 or earlier, will be evaluated for replacement. Where possible, thin clients or Chromebooks will be used for replacements. The replacement schedule will be determined by site and will be reported monthly through departmental status reports. The project is budgeted and there are no incremental O&M expenditures or savings related to the project.

There are avoided costs associated with this project including improved reliability, reduced downtime for clients, and out of warranty repair costs, etc.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2021	2022	2023	Post 2023	Total
1. Capital Investment Proposed	2,559				2,559
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	2,559	-	-	-	2,559
4. Capital Investment 2021 BP	2,995				2,995
5. Cost of Removal 2021 BP					-
6. Total Capital and Removal 2021 BP (4+5)	2,995	-	-	-	2,995
7. Capital Investment variance to BP (4-1)	436	-	-	-	436
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	436	-	-	-	436

Financial Detail by Year - O&M ($000s)	2021	2022	2023	Post 2023	Total
1. Project O&M Proposed					-
2. Project O&M 2021 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The request is less than the 2021 BP because the Rugged Laptops will not be replaced as part of this project. They will be replaced by the iPads for the OMA project. The iPads were not purchased until August and that was after the BP was finalized for 2021.

<u>Risks</u>
If the project is not approved, the main risk would be that aging hardware could fail, which would create disruptions to individuals and processes. Hardware replacement after failure would be expected to be more costly than replacing prior to failure, along with the negative productivity impact to employees that experience unplanned hardware failure.

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 2,746k
    a. Positive impact on business operations for 2021
    b. Keep pace with advancing technology
    c. Minimize risk to O&M budgets for repairs
    d. Ability to rollout new applications required by the lines of business

<u>Conclusions and Recommendation</u>
It is recommended that the Investment Committee approve the 2021 PC Tech Refresh project for $2,559k to ensure that our workstation environment meets the needs of the operational areas, who are dependent upon the tools and technology to do their job.

<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: February 27, 2020

Project Name: Ohio Falls Masonry and Trash Rack Upgrades

Total Capital Expenditures: $14,300k (Including $2,000k of contingency)

Project Number(s): 160416

Business Unit/Line of Business: Project Engineering

Prepared/Presented By: John S. Williams

Description of Project

This proposal seeks approval for masonry repairs and window replacement of the Ohio Falls Generating Station's (Station) multi-unit powerblock exterior as well as repairs to the Station's trash rack guides under the Ohio Falls Masonry and Trash Rack Upgrades project.

An effort began in 2004 to upgrade and refurbish the Station's eight hydroelectric units which had not seen a major overhaul since originally placed into service in the mid-1920s. That effort, in general terms, included major electrical/controls and mechanical upgrades which were completed in 2018 at an overall project spend of approximately $145M. That upgrade did not address the deterioration of the Station powerblock's exterior concrete façade masonry or windows, nor did it address the deteriorated trash rack guide system (which protects the hydroelectric units' intake(s) from river debris).

This proposal will fund three major contracts: (1) powerblock façade masonry; (2) window replacement; and (3) trash rack guide repairs. The contracts will be separate, due in large part to the specialty nature of façade work on the powerblock and the underwater repair work of the trash rack guides. The window replacement scope was added to this proposal subsequent to the powerblock façade masonry bidding period; there is potential the successful façade bidder may also win the window replacement.

Why is the project needed?

As captured in an annual FERC Dam Safety Inspection report, the exterior concrete of the powerblock is seeing cracking and experiencing spalling. Rebar is exposed in a multitude of locations across all four sides of the building. [redacted] was contracted to perform a survey of the entire building façade and engineer repairs to the deteriorated sections. Without repairs, the deteriorated sections will expand to damage adjacent, competent concrete, requiring a more extensive repair in the future. Also without repairs, the spalling will continue, allowing variously sized concrete sections to fall off the powerblock. The repairs generally consist of saw-cutting the deteriorated sections to an extent encountering competent concrete, cleaning or replacing rebar, and installing backfill concrete. In addition, the windows and window frames of the powerblock are deteriorating; periodically, windows free themselves of the failing frames and fall. Aside from the overhead debris hazard, this allows greater access for birds and insect infestation. The window replacement portion of this project was previously budgeted by the Station, but scheduled to occur in 2026. This window replacement work (and budget) has been accelerated to coincide with the concrete façade repair work, as significant concrete repairs are required at the window frame locations.

The upstream and northern side of the powerblock's façade repairs will occur in the 2020 construction season and the downstream and southern side repairs will occur in the 2021 construction season.

The trash rack guides, which protect the unit intakes from receiving river debris on all eight units, have become damaged by river debris impacts and freeze-thaw cycles over time. Visible rotation of the headworks' anchors exist, and as evidenced from a recent underwater dive inspection, the riverbed rock sockets are deteriorating. [redacted] was contracted to engineer repairs and improvements to the trash rack guides. Without the repairs/improvements, the trash rack guides will continue to deteriorate, ultimately allowing the racks to become free of the guide systems. The repairs generally consist of re-establishing a competent connection between the headworks' top-of-steel guides to existing concrete and the underwater installation of new steel beam supports, both of which are required across eight units.

The trash rack guide repairs will occur in the 2020 construction season.

Support contracts are required and captured in the proposal: (1) asbestos containing material is present in the window putty and frame caulk which must be abated to install the concrete repairs as well as the window replacement; (2) third party quality control and owner's engineer services are included in the project; and (3) there is potential river dredging required to access the trash rack guide repair locations.

The aforementioned support contracts and Project Engineering overheads will span the project duration (Q1 2020 through Q4 2021).

Budget Comparison & Financial Summary

Table 1 below details capital investment, by year:

Table 1

Capital ($000)	Pre-2020	2020	2021	Post 2021	Total
Subprojects					
Concrete Façade Repairs	$0	$2,600	$4,300	$0	$6,900
Trash Rack Repairs	$0	$1,500	$0	$0	$1,500
Façade Repairs Quality Control	$0	$180	$180	$0	$360
Trash Rack Owner's Engineer (Design)	$20	$50	$0	$0	$70
Dredging	$280	$0	$160	$0	$440
Trash Rack Quality Control	$0	$70	$0	$0	$70
Asbestos Abatement	$0	$100	$200	$0	$300
Window Replacement	$0	$0	$2,000	$0	$2,000
Subtotal	$300	$4,500	$6,840	$0	$11,640
Overheads & Contingency					
Overheads	$0	$300	$360	$0	$660
Project Contingency	$0	$0	$2,000	$0	$2,000
Subtotal	**$0**	**$300**	**$2,360**	**$0**	**$2,660**
Project Total	**$300**	**$4,800**	**$9,200**	**$0**	**$14,300**

This proposal incorporates actual bid data, vendor and Owner's Engineer estimates, and LG&E estimates based upon historical costs, as described below:

- The concrete façade repair value reflects recent bid data.
- The trash rack repair value reflects a vendor estimate.
- The window replacement value reflects a vendor estimate.
- The asbestos abatement value reflects an Owner's Engineer estimate.
- Quality Control values are based upon Owner's Engineer estimates.
- River dredging value is based upon historical costs.
- Project Engineering overheads are based upon historical values at Ohio Falls.

Table 2 below summarizes the project capital investment compared to the 2020 BP, by year:

Table 2

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	300	4,800	9,200	-	14,300
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	300	4,800	9,200	-	14,300
4. Capital Investment 2020 BP	2,500	7,500	-	-	10,000
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	2,500	7,500	-	-	10,000
7. Capital Investment variance to BP (4-1)	2,200	2,700	(9,200)	-	(4,300)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	2,200	2,700	(9,200)	-	(4,300)

(Funding for 2021 will be obtained during the 2021 BP process.)

Risks

If the project is not completed or not completed timely, the concrete facade and window frames will continue to deteriorate. This will result in potential safety issues concerning the spalled concrete and windows falling onto walkways as well as more extensive concrete repairs in the future. In addition, the trash rack guides' anchorage will continue to deteriorate, potentially in an accelerated manner, until the racks free themselves from the guides allowing river debris to enter the unit intakes.

Due to the age of the concrete at the Station and its exposure to the natural elements potentially increasing repair section(s) size, as well as the uncertainty of river conditions, approximately seventeen percent of project value is requested as contingency.

Alternatives Considered

1. Recommendation: NPVRR:$15,214k

2. No other feasible alternative exists for the recommended project. The Company operates the Station under a license from FERC allowing the Company to use water available from the operation of the McAlpine Dam. The license requires the Company to properly maintain the Station structures or return the McAlpine Dam to its condition before the license was issued approximately 100 years ago. Failure to restore the Station as described could subject the Company to the cost of returning the McAlpine Dam to its pre license condition (over $50,000k) and could also render useless the approximately $137,000k spent to date on the Station rehabilitation.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Ohio Falls Masonry and Trash Rack Upgrades project for $14,300k to ensure the façade and window frame deterioration is halted and the trash racks continue to protect generation at the Ohio Falls Generating Station.

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 and Contract Proposal for Investment Committee Meeting on: July 27, 2020

Project Name: Canal Coal Fired Assets Demolition
Contract Name (Good/Service): Canal Coal Fired Assets Demolition – Abatement and Demolition

Selected Vendor(s): [redacted]

Contract Authorization Requested: $ 8,600k (Including $1,400k of contingency)

Contract Term: Q4 2021

Total Capital Expenditures Requested: $ 11,800 k (Including $1,900k of contingency including

Total O&M: $0k

Project Number(s): 156485
Business Unit/Line of Business: Project Engineering

Prepared/Presented By: John S Williams

Brief Contract/Project Description

This Authorized Investment Proposal (AIP) seeks approval for the Canal Coal Fired Assets Demolition Project (Project). This approval will be for the full abatement, demolition, and restoration of the former Canal coal-fired generating station site.

This request also seeks Contract Proposal approval to enter into an Abatement and Demolition Agreement (Agreement) for the Canal Coal Fired Assets Demolition – Abatement and Demolition with [redacted] [redacted] [redacted].

The Project was previously approved at a partial sanction to initiate engineering surveys and the technical bidding package. A request is now presented to seek approval to increase the Project sanction to $11,800k to fund the complete abatement, demolition, and restoration of the Canal Generating Station's Coal Fired Facility (Facility), similar to that done on Paddy's Run, Cane Run, Green River, Pineville, and Tyrone stations. This request also seeks approval to award the Agreement to [redacted] in the amount of $8,600k, inclusive of twenty percent (20%) management contingency.

Canal consists of a former coal powerhouse complex, an active switch station along and on the south bank of the approach canal to the Ohio River lock and dam. This former powerhouse complex was developed in the 1880s and includes an approximately 400-foot by 400-foot building which houses four (4) coal-fired generating units, a screen house water intake structure, and sub-

[1] Contractor's Labor and Business Classification Information
Contract NAICS Code: [redacted]
Size Standard – [redacted]
Large or Small Business: [redacted]

surface river intake and discharge tunnels. The northeast wall of the powerhouse structure is integral to the Louisville Metro Flood Protection System. The powerhouse complex has been inactive since the 1970s and contains various hazardous substances, including asbestos and lead-based paints. The structural and mechanical systems are in a continual state of decline and the structures present numerous risks. The demolition of the Facility is being performed to eliminate on-going maintenance and capital costs associated with unmanned structures, potential security/public safety concerns, and other liabilities.

The Agreement will be a lump sum (net salvage) contract for performance of the work, inclusive of five (5) major phases: mobilization, abatement, demolition, restoration and demobilization. The Agreement will be paid out in accordance with a milestone payment schedule commensurate with actual work completed. Individual milestone payments will not exceed the value of the work performed and the maximum monthly cash flow will be limited by the aggregate of the monthly milestones.

Additional components of the contract include but are not limited to:

- Contractor compliance with Company health and safety requirements.
- Termination for convenience and cause.
- Limitation of liability of 125% of the contract price.
- Specific insurance requirements which Company is named as additional insured and contractor waives rights of subrogation. Insurance requirements also include Environmental Liability (pollution) and Public Liability Insurance.
- Indemnification by Contractor including third party claims, personal injury, property damage, claims by government authorities (arising from violation of law), and claims by government authorities for taxes and liens.
- Liquidated damages (LDs) - Guaranteed Substantial Completion Delay
- Three (3) letters of credit totaling $1,400k (20% of $7,200k).

Key Completion Dates:

Mobilization	August	2020
Asbestos Abatement Completion	March	2021
Power-Block Demolition Completion	September	2021
Substantial Completion	November	2021
Final Completion	December	2021

Approximately twenty percent (20%) contract management contingency is requested to address work resulting from exposure to any unknown conditions encountered, as outlined in the "Risk of Contract" section of this document.

<u>Why is the project needed? What if we do nothing?</u>

The powerhouse complex has been inactive since the 1970s and contains various hazardous substances, including asbestos and lead-based paints. The structural and mechanical systems are in a continual state of decline and the structures present numerous risks.

The “Do Nothing” alternative was not considered. The roof is partially collapsed and windows are broken, allowing contaminants (both hazardous and non-hazardous) to disperse and further deteriorate the interior of the building at a much faster rate than before. The existing liability of abating and demolishing the building is already heightened to the extent that few contractors are qualified to execute an abatement and demolition project of this magnitude. If the conditions are allowed to worsen, the costs of abatement will continue to rise. Theft and unauthorized building entrants create a safety liability. There is no certainty that the scrap market will maintain current levels or forecast that it will increase.

<u>Contract Bid Summary</u>

A Request for Quotation (RFQ) was issued to five (5) bidders on March 9, 2020: [redacted] and [redacted]. All bidders were vetted through a thorough pre-qualification process including a financial review by the Credit Department and a safety review. During the RFQ process, [redacted] notified PE of their intent to no-bid the Agreement.

Proposals were received on April 24, 2020 and initial bid presentation meetings were held with each bidder the week of May 4, 2020. The initial bid presentation meetings provided an opportunity for the bidders to present their proposed teams, technical offering, and to demonstrate their understanding of and adherence to scope, schedule and technical requirements. PE and its Owner’s Engineer, [redacted] participated in the initial bid presentations.

As part of the initial bid presentations, technical proposal clarification questions were developed and issued to three (3) short-list bidders.

A final bid evaluation was completed after receiving responses to a second round of clarification questions (See Attachment #1). After an extensive review of the proposals, responses to clarification questions, technical capabilities, commercial offering, bid review meetings, and the final proposal evaluation matrix, all three bidders were nearly even in scoring. [redacted] is recommended to execute the project based on its substantially lower price and the lack of commercial edits to the Agreement.

The bid summary is described in Table 1 below:

Table 1

Competing Bids ($ in Thousands)					
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MBE/WBE	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Initial Bid Response	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Normalized Bid Response	[redacted]	[redacted]	[redacted]		[redacted]
Total Cost	[redacted]		[redacted]		[redacted]

*Eliminated from consideration due to price.

Additional information on [redacted]:

- [redacted]

Contract Financial Summary
Table 2 below expresses contract spend by year:

Table 2

Contract expenses ($k)	2020	2021	2022	Post 2022	Total
Amount requested based on contract award estimates	$3,000	$4,200	$0	$0	$7,200
Contingency amount requested	$0	$1,400	$0	$0	$1,400
Total contract authority requested	$3,000	$5,600	$0	$0	$8,600

The Project is included in the 2020 Business Plan (BP) and is adjusted to reflect bid data in the 2021 BP. This adjustment results in an increase of $1,260k above the 2020 BP, which reflects additional PE & Owner Engineering oversight duration, zero-energy verification and air gapping, civil improvements, and future demolition of the Company owned portion of the floodwall integral to the powerblock (to occur once USACE/MSD has constructed its portion of the floodwall).

Project Financial Summary

Financial Detail by Year - Capital ($000s)	Pre 2020	2020	2021	2022	Total
1. Capital Investment Proposed	-	-	-	-	-
2. Cost of Removal Proposed	252	3,849	7,499	200	11,800
3. Total Capital and Removal Proposed (1+2)	252	3,849	7,499	200	11,800
4. Capital Investment 2020 BP	-	-	-	-	-
5. Cost of Removal 2020 BP	347	4,589	5,604	-	10,540
6. Total Capital and Removal 2020 BP (4+5)	347	4,589	5,604	-	10,540
7. Capital Investment variance to BP (4-1)	-	-	-	-	-
8. Cost of Removal variance to BP (5-2)	95	740	(1,895)	(200)	(1,260)
9. Total Capital and Removal variance to BP (6-3)	95	740	(1,895)	(200)	(1,260)

*Overage will be obtained through the 2021 BP process.

Risks

The key risks center around the work within the Agreement and are as follows:

- Weather/Schedule – Inclement weather is a moderate risk to the remediation portion of the work. Per the Agreement, this scope of work is to be substantially completed by September 2021. If the work under the Agreement was to experience extended wet weather, for which Force Majeure could be applied, additional contractor costs could be incurred.

- Hazardous Substances Adjustment – To minimize contractor risk pricing for specific hazardous substance conditions, an adjustment provision is incorporated into the Agreement for the following: Hazardous substance that is (i) held in storage containers inside any of the structures of the Facility, (ii) encountered by contractor or a subcontractor in the soil at the Facility, or (iii) any polychlorinated biphenyls that are located in a transformer.

- Flood Protection Levee – The powerhouse is integral to the Louisville Metro Flood Protection System. Thus, a levee modification permit must be approved by the Army Corps of Engineers (ACE). The engineered design of powerhouse demolition will, through selective mechanical and hand demolition methods, maintain the section of powerhouse at the proper elevation and extent to maintain its tie-in at the surrounding Flood Protection Levee. This segment will be demolished at a later date, once the ACE has constructed a new levee on-site. Should the contractor damage the powerhouse to an elevation below the design, it must re-establish the levee protection through approved means.

- Subsurface Bulkheads – The demolition design includes the installation of bulkheads in several areas. Most problematic to install are the screenhouse bulkheads, as the conditions within the intake tunnels (sediment loading and hydraulic connection to the river) are not fully understood. Methods to install the bulkheads may require change once the screenhouse is partially demolished, debris and internal structures removed, allowing divers to inspect the conditions.

Project Alternatives Considered

1. Recommendation:	NPVRR: ($000s) $11,698
2. Do Nothing:	NPVRR: ($000s) N/A

The "Do Nothing" alternative was not considered. The roof is partially collapsed and windows are broken, allowing contaminants (both hazardous and non-hazardous) to disperse and further deteriorate the interior of the building at a much faster rate than before. The existing liability of abating and demolishing the building is already heightened to the extent that few contractors are qualified to execute an abatement and demolition project of this magnitude. If the conditions are allowed to worsen, the costs of abatement will continue to rise. Theft and unauthorized building entrants create a safety liability. There is no certainty that the scrap market will maintain current levels or forecast that it will increase.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Canal Coal Fired Assets Demolition project for $11,800k as well as the Canal Coal Fired Assets Demolition - Abatement and Demolition Agreement for $8,600k to [redacted]

Please see the attached Award Recommendation Approvals page for additional proponent and Project Engineering approvals.

Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced:

The Capital project spending and contract authority requests included in this Investment Proposal have 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 the capital project and contract authority requests.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
Canal Coal Fired Assets Demolition – Abatement and Demolition Agreement

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL

The signatures below recommend that Management approve the Canal Coal Fired Assets Demolition - Abatement and Demolition Agreement for $8,600k to [redacted]

Engineer N/A		Manager – Major Capital Projects John S. Williams (up to $100,000)	
Manager – Contracts, Major Capital Projects Barry Elmore (up to $100,000)		Director – Project Engineering Douglas K. Schetzel ($100,001 up to $500,000)	
Vice President – Project Engineering R. Scott Straight ($500,001 up to $2,000,000)			

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

ATTACHMENT #1

CONFIDENTIAL INFORMATION REDACTED

Evaluation Factor	Evaluation Factor Weight	[redacted] Evaluator 1	2	3	4	5	Total	Weighted Score
SAFETY (Company Requirements)	**Pass/Fail**	Pass						
TECHNICAL								
· **Abatement Approach (including project specific safety and documentation)**	**10**	6	7	7	7	x	27	6.75
-- Self-perform or subcontracted?								
-- Water & power management								
-- Waste characterization								
-- Hazard assessment & mitigation								
· **Demolition Approach (including project specific safety)**	**15**	9	9	12	13	x	43	10.75
-- Powerhouse demo plan								
-- Coordination between demolition and abatement								
-- Protection of floodwall								
· **Site Management Plan & Restoration**	**10**	6	5	8	7	x	26	6.50
-- Waste water plan								
-- Scrap recovery process								
-- Cleaning procedure								
-- Backfill plan (basement/tunnels/screenhouse)								
· **Environmental Controls**	**5**	3	4	3	4	x	14	3.50
· **Experience of Proposed Project Team and Adequate Site Staffing**	**5**	2	4	5	5	x	16	4.00
· **Schedule**	**5**	2	2	5	5	x	14	3.50
Total Technical (50)								
COMMERCIAL								
· **Contract Pricing**	**45**	x	x	x	x	36		36.00
· **Clarifications/Exceptions to speciment contract T&C's and Technical Docs**	**5**	x	x	x	x	4		4.00
	100							**75.00**
Total Commercial (50)								

Evaluation Factor	[redacted] Evaluator 1	2	3	4	5	Total	Weighted Score
SAFETY (Company Requirements)	Pass						
Abatement Approach	8	9	8	8	x	33	8.25
Demolition Approach	11	11	14	14	x	50	12.50
Site Management Plan & Restoration	8	7	9	9	x	33	8.25
Environmental Controls	4	4	5	5	x	18	4.50
Experience of Proposed Project Team and Adequate Site Staffing	4	5	5	5	x	19	4.75
Schedule	4	4	5	5	x	18	4.50
Contract Pricing	x	x	x	x	19		19.00
Clarifications/Exceptions	x	x	x	x	3		3.00
Total							**64.75**

Evaluation Factor	[redacted] Evaluator 1	2	3	4	5	Total	Weighted Score
SAFETY (Company Requirements)	Pass						
Abatement Approach	9	9	9	9	x	36	9.00
Demolition Approach	14	13	14	14	x	55	13.75
Site Management Plan & Restoration	9	10	10	9	x	38	9.50
Environmental Controls	4	4	5	5	x	18	4.50
Experience of Proposed Project Team and Adequate Site Staffing	5	4	5	5	x	19	4.75
Schedule	4	4	4	5	x	17	4.25
Contract Pricing	x	x	x	x	26		26.00
Clarifications/Exceptions	x	x	x	x	4		4.00
Total							**75.75**

Evaluation Factor	[redacted] Evaluator 1	2	3	4	5	Total	Weighted Score
SAFETY (Company Requirements)	Pass						
Abatement Approach	5	5	3	3	x	16	4.00
Demolition Approach	7	7	7	8	x	29	7.25
Site Management Plan & Restoration	5	5	5	5	x	20	5.00
Environmental Controls	3	3	2	3	x	11	2.75
Experience of Proposed Project Team and Adequate Site Staffing	2	3	3	2	x	10	2.50
Schedule	3	2	2	3	x	10	2.50
Contract Pricing	x	x	x	x	45		45.00
Clarifications/Exceptions	x	x	x	x	5		5.00
Total							**74.00**

Investment Proposal for Investment Committee Meeting on: 7/27/2020

Program Name: Effluent Limitations Guidelines Program

Total Capital Expenditures: $405,226k (Including $52,860k of contingency)

Total O&M: $9,600k

Project Number(s): Ghent 152965, 162229, 162231 Mill Creek 162230, 152966 Trimble County 152967, 152968

Business Unit/Line of Business: Project Engineering

Prepared/Presented By: Joe Strickland / Douglas K. Schetzel

Brief Description of Program

This Authorized Investment Proposal (AIP) seeks approval for the Effluent Limitations Guidelines (ELG) Program.

The Clean Water Act (CWA) establishes the basic structure for regulating discharges of pollutants into the waters of the United States and regulating quality standards for surface waters. The CWA makes it unlawful to discharge any pollutant from a point source into navigable waters without a permit.

EPA's National Pollutant Discharge Elimination System permit program controls the discharge permitting process. By agreement between the EPA and the Commonwealth of Kentucky, permits are issued and enforced by Kentucky's Department for Environmental Protection and the Division of Water, under the Kentucky Pollutant Discharge Elimination System (KPDES). This means that, for the purposes of ELG, the KPDES permits already reflect the 2015 ELG Rule requirements for Ghent (GH), Trimble County (TC), and Mill Creek (MC) Generating Stations, but will be further impacted when the proposed revisions to the ELG Rule become final. The final ELG Rule's requirements for all pollutants will be imposed and enforced via revisions to the relevant KPDES permits.[1]

This program consists of six projects:

- GH ELG Treatment System, (Expected In-Service 2024)
- TC ELG Treatment System, (Expected In-Service 2023)
- MC ELG Treatment System, (Expected In-Service 2024)
- MC Diffuser, (Expected In-Service 2021)
- GH Diffuser, (Expected In-Service 2021) and

[1] For more information on the history of the ELG Rule, please refer to Gary Revlett's 2020 ECR Filing testimony.

- GH Bottom Ash Transport Water (BATW) Recirculation System. (Expected In-Service 2023)

This program is required to ensure compliance with industry/environmental regulations. This program is ECR recoverable and requires PSC approval. ECR filing was submitted in March 2020 and approval is expected in September 2020. The economic useful life of each project is expected to be 20 years or the end of station life.

Why is the program needed? What if we do nothing?
The program is necessary for each station to comply with the ELG Rule. Test results of the wastewaters regulated by the ELG Rule show that the stations will be out of compliance with the ELG Rule once the revised KPDES permit goes into effect. Without these projects, the stations will continue to be out of compliance resulting in closure of the stations. The generation would then need to be replaced and a Generation Planning analysis shows that the proposed ELG program is preferable to replacing the existing generation at GH, MC and TC.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	23,715	121,152	124,329	136,031	405,227
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	23,715	121,152	124,329	136,031	405,227
4. Capital Investment 2020 BP	22,697	170,347	244,022	61,643	498,709
5. Cost of Removal 2020 BP					-
6. Total Capital and Removal 2020 BP (4+5)	22,697	170,347	244,022	61,643	498,709
7. Capital Investment variance to BP (4-1)	(1,018)	49,195	119,693	(74,388)	93,482
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(1,018)	49,195	119,693	(74,388)	93,482

*The proposed Capital Investment of $23,715k in 2020 includes of $9,123K pre 2020 spend and $755k of 2020 spend on the non-ECR ELG project that will be moved to ECR when the ECR Order is granted.

Risks

- A risk associated with this program is the delayed receipt of the EPA revised rule. It is expected that the final revision will be forthcoming this fall, but in a presidential election year, it is entirely possible that this rule will not be published until sometime in the more distant future. The problem with pushing the rule off is that until the new rule is published, the existing rule requires compliance with the ELG requirements by the end of 2023. Additional time to comply is expected in the final rule.
- There is also the risk of the Engineering, Procurement, and Construction Agreements (EPC[s]) not meeting commercial operation in advance of the KPDES compliance date. The EPC(s) have provisions for a Contingency Deadline that requires the EPC contractor to have a temporary system in place, two months in advance, if they are not meeting the KPDES limits by the Contingency Deadline Date to reduce this risk.
- There is also the risk that since the preferred technology is a biological process, it is expected to take some time to learn and optimize the performance of the system. It is anticipated that

the KPDES permit will allow for six months of tuning between the ELG Commercial Operation Date and the KPDES compliance date to reduce this risk.

- The risk of an upset condition at the ultimate outfall to the river is expected to be mitigated by installing diffusers at MC and GH; TC already has a diffuser.
- Project Engineering has been working on the ELG Rule since 2014 and has engaged the Environmental Affairs department and the generating station management throughout the entire process.

Alternatives Considered

1. Recommendation:

Ghent NPVRR:	($000s)	$227,460
Mill Creek NPVRR:	($000s)	$120,008
Trimble NPVRR:	($000s)	$78,801

2. A do nothing option was not considered. Without these projects, the stations will continue to be out of compliance with the ELG Rule resulting in closure of the stations. The generation would then need to be replaced.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Effluent Limitations Guidelines program for $405,226k for compliance with the ELG Rule.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital program 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 program spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: **9/29/2020**

Project Name: **Environmental Protection Agency's (EPA's) Coal Combustion Residual (CCR) Rule Compliance Program**

Previous Authorized Expenditures: **$918,853k (net) (Approved on 10/26/2016)**

Total O&M: **$0.0k**

Amendment Value: **$101,147k (net)**

Total Revised Authorized Capital Expenditures including Amendment: **$1,020,000k (net)**

Project Number(s): **See Attachment #1**

Business Unit/Line of Business: **Project Engineering**

Prepared/Presented By: **Jeffrey B. Heun**

Description of Incremental Ask

This revised Authorized Investment Proposal (AIP) seeks to increase authorization related to the LG&E and KU's CCR Rule Compliance Program. All cost information is net of IMEA and IMPA.

An AIP for $8,500k was submitted on June 30, 2015 to allow engineering, preliminary studies, and compliance construction activities to start in support of the 2016 ECR filing. A revised AIP for $77,462k ($68,962k in additional funds) was approved on February 24, 2016 to provide funding through 2016, prior to approval of the 2016 ECR filing. A revised AIP for $918,853k ($841,391k in additional funds) was approved on October 26, 2016 for the total program which was based on the 2017 Business Plan (BP). This requested sanction of $1,020,000k ($101,147k in additional funds) is to complete the EPA's CCR Rule Compliance Program and is based on the proposed 2021 BP, inclusive of approximately $22,400k in program management contingency to address unknown and unexpected scope, as summarized below.

	Additional Authorization Approved/Requested	Revised Capital Expenditures Requested
Original Approved Capital Expenditures		$8,500k
1st Revision	$68,962k	$77,462k
2nd Revision	$841,391k	$918,853k
3rd Revision (Amendment Value Requested)	$101,147k	$1,020,000k
2016 ECR Filing[1]		$959,750K

[1] This request authorizes $941,900k compared to the 2016 ECR Filing of $959,750k, when excluding $78,100k for the Mill Creek (MC) Gypsum Dewatering project, which was not included in the 2016 ECR filing.

The EPA's CCR Rule Compliance Program encompassed three (3) major scopes of work outlined below. During execution of these three (3) major scopes of work, several issues were identified which impacted the scope and increased the cost:

1. Closure of wet CCR storage facilities and construction of new Process Water Ponds – approximately $10,000k (~2%) increase.
   - The cost impact for the Auxiliary CCR Pond at E.W. Brown was attributed to an inaccurate cost estimate for the closure, unforeseen delays in receiving the KPDES permit from the State of Kentucky, new incremental KPDES permit requirements to treat water from the impoundment dewatering process, as well as Excusable Events such as wet weather and unexpected scope. The total cost impact from these events was approximately $18,000k.
   - The cost of several sub-projects such as the Process Water System ended up being less than the requested sanction which offset some of the cost impacts above.

2. Construction of new Process Water Facilities (PWS) at the active coal-fired generating stations – approximately $64,000k (~16%) increase.
   - The cost impacts on the PWS projects was the net result of cost increases at Ghent and Mill Creek and cost decreases at Trimble County and E.W. Brown as described below.
   - On the Ghent project, the approximate $52,500k in cost increase was attributed to the initial award being higher than the estimate, moving the location of the PWS after project award, deeper foundations than estimated begin required, station requested changes to the power feeds, adding of redundant equipment, and balance of plant scope that was not included in the EPC contract.
   - On the Mill Creek projects, the approximate $62,000k in net cost increase was attributed to the initial award being higher than the estimate as well as moving forward with a dry pneumatic bottom ash system Coal Combustion Residual Transport (CCRT) scope. The original concept had the submerged flight conveyor (SFC) based system constructed on the ash pond. Moving the location of the SFC system was much more expensive and included schedule conflicts with pond closure that were eliminated by going to a dry system. The dry bottom ash conveying system, at a cost of approximately $90,000k, was the least cost option compared to the wet bottom ash SFC system, at a cost of approximately $107,000k while eliminating the risk for future capital expenditures related to future wet bottom ash water regulations.
   - On the Trimble County project, the approximate cost saving of $3,500k was attributed to the initial award being lower than the estimate.
   - On the E.W. Brown project, the decision to retire Unit 1 and 2 required the Company to re-evaluate the scope of the project. This re-evaluation resulted in an approximate cost savings of approximately $47,000k.

3. Construction of a new Gypsum Dewatering Facility at Mill Creek – approximately $4,800k (~6.5%) increase.
   - The cost increase impacts were attributed to the initial award being higher than the estimate and additional scope that was not included in the EPC contract.

See **Attachment 2** for additional detail on the individual project cost variances.

At the time of the initial sanction request, the EPA's CCR Rule and future Effluent Limitations Guideline (ELG Rule) set forth strict requirements which resulted in limiting options to comply with the rules. Considering the cost impacts outlined above, the chosen compliance alternative would still be the best option to meet current and future EPA regulations.

See **Attachment 3** for copies of all prior signed authorizations.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	Pre-2020	2020	2021	Post 2021	Total
1. Capital Investment Proposed	$ 593,361	$ 41,570	$ 19,553	$ -	$ 654,484
2. Cost of Removal Proposed	$ 152,984	$ 73,126	$ 46,977	$ 92,429	$ 365,516
3. Total Capital and Removal Proposed (1+2)	$ 746,346	$114,696	$ 66,530	$ 92,429	$1,020,000
4. Capital Investment 2020 BP	$ 594,858	$ 27,743	$ 11,104	$ 2,464	$ 636,170
5. Cost of Removal 2020 BP	$ 157,240	$ 63,849	$ 36,544	$ 45,102	$ 302,735
6. Total Capital and Removal 2020 BP (4+5)	$ 752,098	$ 91,592	$ 47,648	$ 47,566	$ 938,905
7. Capital Investment variance to BP (4-1)	$ 1,497	$ (13,827)	$ (8,449)	$ 2,464	$ (18,315)
8. Cost of Removal variance to BP (5-2)	$ 4,255	$ (9,277)	$(10,433)	$(47,327)	$ (62,781)
9. Total Capital and Removal variance to BP (6-3)	$ 5,753	$ (23,104)	$(18,881)	$(44,863)	$ (81,095)

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

Project Engineering is requesting approximately $22,400k in program management contingency to address unknown and unexpected scope on the active CCR Rule closure projects, bid uncertainty with the Trimble County Bottom Ash Pond (BAP) and Gypsum Storage Pond (GSP) project, as well as process improvements on the PWS Program (PWS, CCRT, and Gypsum Dewatering projects) that were identified once the projects achieved Commercial Operation and turned over to their respective Generating Stations. See the table below for additional detail on the contingency allocation.

Active CCR Rule closure projects (Approximately 10% of the outstanding work)	$10,000k
Trimble County BAP and GSP project bid uncertainty	$8,000k
Finalization of the PWS Program	$4,400k
Total	$22,400k

Upon approval of this revised investment proposal, Project Engineering will update the AIP’s for the projects identified in Attachment 1. The AIP’s will be updated to reflect the actual costs on projects that have been completed and sync up with the 2021 BP.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the EPA's CCR Rule Compliance Program project for $1,020,000k (net) to comply with the EPA's CCR Rule. This request authorizes $941,900k compared to the 2016 ECR Filing of $959,750k, when excluding $78,100k for the MC Gypsum Dewatering project, which was not included in the 2016 ECR filing.

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	

Attachment #1

Location	Project #	2021 BP (000's)	2016 ECR Filing (000's)
BR Aux Pond	148824	$30,524	$12,530
GH ATB #1	148827	$47,568	$67,712
GH ATB #2	148828	$87,379	$98,620
GR Main Ash Pond	148831	$13,008	$21,226
GR ATB #2	148832	$15,313	$22,894
MC Ash Pond	148833	$39,354	$46,837
MC Clearwell Pond	148834	$2,120	$2,898
MC Construction Pond	148836	$4,398	$4,504
MC Dead Stoarge Pond	148837	$2,757	$4,286
MC Emergency Pond	148838	$2,584	$8,548
PV Ash Pond	148839	$8,124	$6,974
TY Ash Pond	148840	$8,229	$9,577
TC BAP	148841	$47,879	$54,590
TC GSP	148843	$6,467	$16,147
GH Gypsum Stack	150045	$19,953	$38,257
GR SO2 Pond	150046	$7,093	$9,230
BR Capital	152898	$12,377	$760
GH Capital	152899	$52,725	$1,463
MC Capital (closed)	152901	$11,640	$13,289
MC Frost Land	154574	$1,254	$0
TC Capital (closed)	152902	$726	$721
TC Capital (open)	155513	$7,796	$0
MC Capital (open)	160433	$21,433	$0
BR Carey Land	161073	$351	$0
BR Process water	152377	$25,200	$72,233
GH Process water	152379	$167,104	$115,167
GH Froman Land	153616	$521	$0
MC Process water	152381	$196,900	$134,890
TC Process water	152384	$78,700	$82,197
Totals		**$919,477**	**$845,550**

Location	Project #	2021 BP (000's)	2016 ECR Filing (000's)
MC Gypsum Dewatering	152330	$75,125	$73,303
MC Gypsum PST Replacement	162240	$2,975	$0
Totals		**$78,100**	**$73,303**

Program Contingency	**$22,423**
Program Total Authorization	**$1,020,000**

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Attachment #2

CCR Rule Compliance Program - ECR & AIP Comparison
August 13, 2020

Station	Project	2016 ECR Filing	Original Project Sanction (2016)	2021 BP AIP Adjustment	Notes
Brown		**$101,307,000**	**$85,523,000**	**$68,452,000**	
Brown	Capital	$68,613,000	$760,000	$12,377,000	Based on Updated 2021BP (no contingency)
Brown	Aux Pond Capping	$32,694,000	$12,530,000	$30,875,000	Based on Updated 2021BP (no contingency)
Brown	Process Water System	$0	$72,233,000	$25,200,000	Based on Updated 2021BP
Ghent		**$364,177,000**	**$321,219,000**	**$375,250,000**	
Ghent	Capital	$114,290,000	$1,463,000	$52,725,000	Based on Updated 2021BP (no contingency)
Ghent	ATB #1 Capping & Secondary Pond Cleanout	$72,881,000	$67,712,000	$47,568,000	Based on Updated 2021BP (no contingency)
Ghent	ATB #2 Capping	$92,918,000	$98,620,000	$87,379,000	Based on Updated 2021BP (no contingency)
Ghent	Gypsum Stack Cooling Pond & Reclaim Pond Cleanout	$84,088,000	$38,257,000	$19,953,000	Based on Updated 2021BP (no contingency)
Ghent	Process Water System	$0	$115,167,000	$167,625,000	Based on Updated 2021BP (no contingency)
Green River		**$56,829,000**	**$53,350,000**	**$35,414,000**	
Green River	Main Ash Pond Capping	$20,204,000	$21,226,000	$13,008,000	Based on Updated 2021BP (project completed)
Green River	ATB #2 Capping	$21,436,000	$22,894,000	$15,313,000	Based on Updated 2021BP (project completed)
Green River	SO2 Pond Cleanout	$15,189,000	$9,230,000	$7,093,000	Based on Updated 2021BP (project completed)
Mill Creek		**$196,941,000**	**$215,252,000**	**$282,440,000**	
Mill Creek	Capital (Open)	$0	$0	$21,433,000	Based on Updated 2021BP (no contingency)
Mill Creek	Capital (Closed)	$121,361,000	$13,289,000	$12,894,000	Based on Updated 2021BP (project completed)
Mill Creek	Ash Pond Capping	$50,976,000	$46,837,000	$39,354,000	Based on Updated 2021BP (no contingency)
Mill Creek	Clearwell Pond Cleanout	$5,369,000	$2,898,000	$2,120,000	Based on Updated 2021BP (project completed)
Mill Creek	Construction Pond Cleanout	$7,283,000	$4,504,000	$4,398,000	Based on Updated 2021BP (project completed)
Mill Creek	Dead Storage Pond Cleanout	$6,433,000	$4,286,000	$2,757,000	Based on Updated 2021BP (project completed)
Mill Creek	Emergency Pond Cleanout	$5,519,000	$8,548,000	$2,584,000	Based on Updated 2021BP (project completed)
Mill Creek	Process Water System & CCRT	$0	$134,890,000	$196,900,000	Based on Updated 2021BP
Pineville		**$8,009,000**	**$6,974,000**	**$8,124,000**	
Pineville	Ash Pond Capping	$8,009,000	$6,974,000	$8,124,000	Based on Updated 2021BP (project completed)
Trimble Co. (Net)		**$219,384,000**	**$153,655,000**	**$141,568,000**	
Trimble Co.	Capital	$88,739,000	$721,000	$8,522,000	Based on Updated 2021BP (no contingency)
Trimble Co.	Ash Pond Capping	$101,747,000	$54,590,000	$47,879,000	Based on Updated 2021BP
Trimble Co.	Gypsum Pond Capping	$28,898,000	$16,147,000	$6,467,000	Based on Updated 2021BP
Trimble Co.	Process Water System	$0	$82,197,000	$78,700,000	Based on Updated 2021BP
Tyrone		**$13,103,000**	**$9,577,000**	**$8,229,000**	
Tyrone	Ash Pond Capping	$13,103,000	$9,577,000	$8,229,000	Based on Updated 2021BP (project completed)
	Projected ECR Total	**$959,750,000**	**N/A**	**$919,477,000**	
	Delta to ECR Filing	**$0**	**N/A**	**$40,273,000**	

Station	Project	2016 ECR Filing	Original Project Sanction (2016)	2021 AIP Adjustment	Notes
Mill Creek	Gypsum Dewatering (NOT INCLUDED IN ECR FILING)	$0	$73,303,000	$78,100,000	Based on Updated 2021BP
	Projected CCR Rule Program Total	**N/A**	**$918,853,000**	**$997,577,000**	
	Delta to Project Sanction	**N/A**	**$0**	**($78,724,000)**	

Revsied CCR Rule Program Sanction

Projected CCR Rule Program Total	[redacted]	[redacted]	[redacted]
Requsted Program Contingency			
Revised Sanction Request		[redacted]	[redacted]

CCR Rule
PWS and MC Gypsum

Revsied CCR Rule ECR Approval

Projected ECR Total	**$919,477,000**
Requsted Program Contingency	**$22,423,000**
Revised Projected ECR Total	**$941,900,000**
Delta to ECR Filing	[redacted]

Authorized Investment Proposal for Investment Meeting on: October 26, 2016

Project Name: Environmental Protection Agency's (EPA's) Coal Combustion Residual (CCR) Rule Compliance Program

CCR Rule Closure. CCR Rule Capital[1]. Process Water

E.W. Brown:	$85,523k
Ghent:	$321,219k
Green River:	$53,350k
Pineville:	$6,974k
Tyrone:	$9,577k
Mill Creek:	$215,252k
Trimble Co. (LGE) net/gross	$79,900k/$106,534k
Trimble Co. (KU) net/gross	$73,754k/$98,339k

CCR Rule Sanction Request: $845,550k (net)/$896,768k (gross)
Previous Approval: $77,462k (net)

Mill Creek Gypsum Dewatering: $73,303k

Total Sanction Request: $918,853k (net)/$970,071k (gross)
Project Numbers: See list of project numbers on page 5

Business Unit/Line of Business: Project Engineering

Prepared/Presented By: Scott Straight/Jeff Heun/Jeff Oeswein/Joe Strickland

Executive Summary

This revised Authorized Investment Proposal (AIP) is seeking full project authorization, under the 2016 ECR Filing, to continue compliance construction and closure activities associated with the project development, conceptual and final design, permitting, closure and construction activities to comply with the EPA's CCR Rule. The final CCR Rule was published on April 17, 2015 and became effective on October 19, 2015.

This document seeks to increase the approval of the CCR Rule Compliance Program spend to $845,550k (net)/$896,768k (gross) for the scope listed below. It is important to note that the requested authorization is based on CCR Beneficial Use and does not include a sensitivity of an additional $622,000k (per the 2016 Business Plan (BP)) if beneficial use is not utilized. This revised approval is required to meet critical deadlines outlined in the CCR Rule, which are tied to location restrictions, design criteria, operating criteria, groundwater monitoring, as well as conceptual and final design, permit development, and construction activities at all the generating

[1] CCR Rule Capital is for new construction activities, not including the Process Water systems that will remain in place and serve the Plants generation needs after compliance with the CCR Rule. An example is new process ponds.

stations. This document also seeks approval for the Mill Creek Gypsum Dewatering project spend for \$73,303k. The total amount seeking approval for the CCR Rule Compliance Program and the Mill Creek Gypsum Dewatering is \$918,853k (net).

An AIP for \$8,500k was submitted on June 30, 2015 to allow engineering, preliminary studies, and compliance construction activities to start in support of the 2016 ECR filing. A revised AIP for \$77,462k (net) was approved on February 24, 2016 to provide funding through 2016, prior to approval of the 2016 ECR filing. This requested \$918,853k sanction approval is for the total program included in the 2017 BP.

The overall scope of this project includes the design, permitting and final closures of all CCR impoundments at the stations listed above. The scope also includes the design and construction of new process water systems to manage the on-going operation at E.W. Brown, Ghent, Mill Creek and Trimhle County related to water usage, treatment and discharge within current permit conditions once the current impoundments are taken out of service and closure activities begin. This CCR Rule Compliance Program scope does not include treatment equipment associated with the EPA effluent limitations guidelines ("ELG") rule for any generating station. While Ghent, Brown and Trimble County stations have new landfill projects which include CCR Treatment (CCRT) scopes for the dewatering and dry handling of CCR, Mill Creek does not. This program also includes the CCRT scopes for Mill Creek consisting of a new gypsum dewatering facility, a new bottom ash dewatering system, and the dry fly ash transport systems that are similar to the CCRT programs at the other stations. Also included in this scope is the smaller compliance activities, including Trimble County's Bottom Ash Pond (BAP) berm stability project, Mill Creek's ash pond hydraulic and hydrological (H&H) and berm height increase projects, Mill Creek's gypsum stack-out pad reconstruction and the Ghent H&H construction on Ash Treatment Basin (ATB) #1 and #2.

Background

As a result of Tennessee Valley Authority's (TVA's) Kingston ash pond failure in 2008, the EPA issued a DRAFT CCR Rule in 2010 to address CCR impoundments. On April 17, 2015, the EPA published the final CCR Rule. The final CCR Rule is based on Subtitle "D" requirements and contained significant changes to the draft CCR Rule. The final CCR Rule requires all CCR storage facilities undergo structural stability, safety factor, and design flood assessments and corrective action hy October 17, 2016 to verify they meet minimum standards, as set forth in the rule. In addition, groundwater monitoring must be implemented, and a minimum of eight samples taken within 30 months of the rule being published.

The intent of the CCR Rule is to close all wet CCR Impoundments and move towards dry storage in landfills, which is in line with LG&E and KU's (the "Companies") current long term CCR Storage plans. It is anticipated that closure of Companies CCR storage facilities will be triggered by groundwater monitoring, and would require the facilities to stop receiving CCR 6-months after and to be closed within five years of a groundwater exceedance. It is assumed that closure must start by the first quarter of 2019, based on a groundwater exceedance.

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This request is seeking approval of $918,853k for project development, conceptual and final design, permitting, and compliance construction activities. Project development includes the structural stability, safety factor, and design flood assessments for each facility under the CCR Rule. The conceptual design will build on the work completed to date to identify the preferred plan to comply with the CCR Rule and develop a scope of work for final design. Final design will build upon the results of the conceptual design and will allow the Companies to submit the necessary state permits as well as develop construction drawings and specifications for closure activities.

Procurement & Schedule

The structural stability, safety factor and design flood assessment assessments for facilities with potential data gaps (Ghent, Mill Creek, and Trimble County) were completed in 2015, while the remainder of the assessments were completed in 2016. Issues identified during the assessments lead by Generation Engineering were handed off to Project Engineering to implement. The assessments and construction to address the issues must be in progress by October 17, 2016. During the 2015 assessments, two issues were identified: Trimble County BAP factor of safety and Mill Creek Ash Pond H&H. To address the Trimble County BAP factor of safety, a rock abutment was installed in late 2015. For the Mill Creek Ash Pond H&H issue, a new principal spillway is being installed and the height of the embankments is being raised. In 2016 it was determined that modifications to Ghent's ATB #1 and ATB #2 were needed to comply with CCR Rule H&H requirements. Work is in process to install a larger emergency spillway on ATB #1 and modify the existing emergency spillway on ATB #2.

Project Engineering has reviewed proposals for the conceptual design, final design, and owner's engineering service to comply with the CCR Rule. Upon completion of Project Engineering's bid review, the Ghent and Mill Creek conceptual design scopes were awarded to AECOM while Amec was awarded the E.W. Brown and Trimble County projects. The Green River project was awarded to [redacted] under a Sole Source Agreement. Project Engineering awarded the engineering work to three different engineering firms in an effort to apply lessons learned and best practices between the owner's engineers.

Project Cost

The overall cost to comply with the EPA's CCR Rule utilizing CCR Beneficial Use is $918,853k (net) per the 2017 BP (Table 2), which includes $441,063k (net) for CCR impoundment closure and new capital, and an additional $404,487k (net) for construction of process water systems and CCR handling facilities[2] and $73,303k for Mill Creek's gypsum dewatering facility. This revised approval seeks full authorization for project development, conceptual/final design, permitting, and construction activities. Requested authorization per station/project is shown in Table 1.

Other Alternatives Considered

For project development, no alternatives were considered. To meet the regulatory deadlines related to structural stability, safety factor, and design flood assessments, initial studies were

[2] New CCR handling facilities are primarily at Mill Creek.

completed by the second quarter of 2016 to allow adequate time to implement corrective action by October 17, 2016, or the facility will be forced to begin the closure process.

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

Below are the alternatives considered for the projects:

1. Recommendation: NPVRR: $978,018k
   CCR Rule Closure, CCR Rule Capital[3], Process Water
   - E.W. Brown: $102,056k
   - Ghent: $356,030k
   - Green River: $60,577k
   - Pineville: $7,772k
   - Tyrone: $10,909k
   - Mill Creek: $262,005k
   - Trimble Co. (LGE) (net): $92,873k
   - Trimble County (KU) (net): $85,798k
2. Do Nothing[4]: NPVRR: $0

Below are the alternatives considered for the Mill Creek Gypsum Dewatering projects:

1. Recommendation: Mill Creek Gypsum Dewatering NPVRR: $86,634k
2. Do Nothing: NPVRR: $0

Table 1 below shows a breakout of cost by station and project number for the current authorization request and does not reflect previous authorization request. Cost associated with the previous request will be reallocated to the corresponding new projects:

[3] CCR Rule Capital is for new construction activities, excluding process water systems, which will remain in place and serve the plants generation needs after compliance with the CCR Rule. An example is new process ponds.
[4] A Do Nothing alternative is not a viable option as this project is a regulatory requirement from the EPA.

Table 1[5]

Location	Project #	2017 BP (000's)	2016 ECR Filing (000's)
BR Aux Pond	148824	$12,530	$29,651
GH ATB #1	148827	$67,712	$48,630
GH ATB #2	148828	$98,620	$92,918
GH Gypsum Stack	150045	$38,257	$84,088
GR Main Ash Pond	148831	$21,226	$19,786
GR ATB #2	148832	$22,894	$21,436
GR SO2 Pond	150046	$9,230	$15,189
MC Ash Pond	148833	$46,837	$47,743
MC Clearwell Pond	148834	$2,898	$5,369
MC Construction Pond	148836	$4,504	$7,283
MC Dead Storage Pond	148837	$4,286	$6,433
MC Emergency Pond	148838	$8,548	$5,519
PV Ash Pond	148839	$6,974	$8,009
TC BAP	148841	$54,590	$94,739
TC GSP	148843	$16,147	$28,898
TY Ash Pond	148840	$9,577	$13,103
BR Capital	152898	$760	$68,613
GH Capital	152899	$1,463	$114,290
MC Capital	152901	$13,289	$121,361
TC Capital	152902	$721	$88,739
BR Process Waters	152377	$72,233	$0
GH Process Waters	152379	$115,167	$0
MC Process Waters	152381	$134,890	$0
TC Process Waters	152384	$82,197	$0
Totals		**$845,550**	**$921,797**

Location	Project #	2017 BP (000's)	2016 ECR Filing (000's)
MC Gypsum Dewatering	152330	$73,303	$0

Table 2 below shows the 2017 Business Plan and 2016 ECR filing costs broken out by year (net):

[5] Trimble County numbers are Net. The Capital and Process Water projects were combined in the ECR filing but were subsequently separated into standalone projects for tracking purposes.

Table 2[6]

$Millions	2016	2017	2018	2019	2020	2021	2022	2023	Totals
2017 BP	$43.6	$156.3	$299.1	$120.6	$56.8	$59.9	$69.8	$39.4	$845.6
2016 ECR	$39.5	$237.5	$283.6	$93.3	$95.6	$72.0	$68.1	$32.3	$921.8
Variance	($4.1)	$81.2	($15.5)	($27.3)	$38.7	$12.1	($1.7)	($7.2)	$76.2

The amounts incurred in Table 2 prior to approval of the 2016 ECR filing were recorded as non-mechanism, all future changes will be mechanism under the approved 2016 ECR filing. Table 3 below shows the 2017 Business Plan and 2016 ECR filing costs broken out by year for the Mill Creek Gypsum Dewatering:

Table 3

$Millions	2016	2017	2018	2019	2020	2021	2022	2023	Totals
2017 BP	$0.3	$28.6	$44.4	$0.0	$0.0	$0.0	$0.0	$0.0	$73.3
2016 ECR	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Variance	($0.3)	($28.6)	($44.4)	$0.0	$0.0	$0.0	$0.0	$0.0	($73.3)

Economic Analysis and Risks

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000's)	Pre-2016	2016	2017	2018	Post 2018	Total
Capital Investment Proposed	-	17,203	152,416	278,207	44,037	491,863
Cost of Removal Proposed	-	26,724	32,476	65,321	302,469	426,990
Total Capital and Removal Proposed	-	43,927	184,892	343,528	346,506	918,853
Capital Investment 2017 BP	-	17,203	152,416	278,207	44,037	491,863
Cost of Removal 2017 BP	-	26,724	32,476	65,321	302,469	426,990
Total Capital and Removal 2017 BP	-	43,927	184,892	343,528	346,506	918,853
Capital Investment variance to BP	-	-	-	-	-	-
Cost of Removal variance to BP	-	-	-	-	-	-
Total Capital and Removal variance to BP	-	-	-	-	-	-

[6] Numbers are based on Trimble County Net costs.

Financial Summary ($000's):

Below is the financial analysis for the project:

Financial Analysis -Project Summary ($000)	Project CCR Rule, PWS, New Construction	2016	2017	2018	2019	2020	Life 2016-2059
Project Net Income	Brown	$79	$1,332	$3,603	$4,231	$5,118	$78,717
	Ghent	$363	$2,788	$7,326	$9,043	$10,755	$318,435
	Green River	$112	$305	$1,431	$3,192	$2,639	$45,185
	Mill Creek	$1,425	$4,096	$8,783	$10,094	$10,562	$199,506
	Tyrone	$16	$39	$299	$573	$474	$8,133
	Pineville	$14	$32	$112	$417	$345	$5,823
	TC LGE	$156	$1,042	$2,546	$2,999	$3,274	$74,779
	TC KU	$144	$962	$2,350	$2,768	$3,022	$72,559
Project ROE							
	Brown	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
	Ghent	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
	Green River	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
	Mill Creek	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
	Tyrone	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
	Pineville	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
	TC LGE	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
	TC KU	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%

Summary ($000)	Project	2016	2017	2018	2019	2020	2016-2059
Project Net Income	MC Gypsum Dewatering	$0	$1,484	$3,518	$3,312	$3,449	$56,298
Project ROE							
	MC Gypsum Dewatering	0.0%	9.6%	9.4%	9.2%	9.6%	9.9%

Environmental Risks:

There are no environmental risks related to New Source Review associated with this project.

Conclusions and Recommendation

It is recommended that this revised Authorized Investment Proposal be approved to provide full funding, per the 2017 BP and in concert with the 2016 ECR Filing, in the amount of $918,853k (net) as outlined in the 2017 BP. Work under this authorization includes, Project Development, Conceptual and final design, permitting and construction activities for the EPA's CCR Rule compliance program impoundment closure activities, new CCR Rule related process water systems, and Mill Creek's gypsum dewatering, bottom ash and dry fly ash handling systems.

Kent W. Blake Chief Financial Officer	Victor A. Staffieri Chairman, CEO and President

Authorized Investment Proposal for Investment Meeting on: February 24, 2016

Project Name: Environmental Protection Agency's (EPA's) Coal Combustion Residual (CCR) Rule Compliance Program

LG&E:	$250k[1]
KU:	$250k[2]
E.W. Brown:	$1,025k
Ghent:	$35,595k
Green River:	$4,148k
Mill Creek:	$31,835k
Pineville:	$323k
Trimble County:	$3,616k (net)
Tyrone:	$920k
Total Sanction Request:	**$77,462k (net)[3]**
Previous Approval:	$8,500k

Project Numbers: 147098, 147099, 147965, 147966, 147967, 147968. 147969, 147971, 147972, 147973

Business Unit/Line of Business: Project Engineering

Prepared/Presented By: Scott Straight/Jeff Heun/Jeff Oeswein

Executive Summary

This revised Authorized Investment Proposal (AIP) is being submitted for the continuation of compliance activities associated with the Project Development, Conceptual Design, Permitting and Construction to comply with the EPA's CCR Rule. The final CCR Rule was published on April 17, 2015 and became effective on October 19, 2015.

This document seeks to increase the approval of the CCR Rule Compliance Program spend to $77,462k (net) for the scope listed below. This revised sanction request is only to cover spend through 2016, in agreement with the 2016 ECR Filing Plan (Table 2). This request seeks approval for an incremental portion of the overall CCR Rule Compliance Program which is $959,749k (net), assuming the ability of CCR Beneficial Use in constructing the closure plans at each pond. It is important to note that the 2016BP amounts do not include a sensitivity of an additional $622,000k

[1] This project was initially opened to allow early CCR Rule compliance development activities to begin. The amounts shown have been included in the Mill Creek Project. This project will be closed upon approval of ECR filing and expenditures reallocated to the Mill Creek Project.
[2] This project was initially opened to allow early CCR Rule compliance development activities to begin. The amounts shown have been included in the Ghent Project. This project will be closed upon approval of ECR filing and expenditures reallocated to the Ghent Project.
[3] Total Sanction Request is based on spend though 2016, per the 2016 ECR Filing Plan, and does not take into account previous sanction requests. This request seeks to reallocate previous authorizations to match up with the current CCR Rule plan. Costs for the Cane Run Project are no longer included in this AIP request.

if beneficial use is not approved. This revised approval is required to meet critical deadlines outlined in the CCR Rule, which are tied to Location Restrictions, Design Criteria, Operating Criteria, Groundwater Monitoring, as well as Conceptual and Final Design, Permit Development, and Construction Activities at Ghent and Mill Creek. An AIP for $8,500k was submitted on June 30, 2015 to allow engineering, preliminary studies, and compliance construction activities to start prior to this Investment Committee authorization request. The requested $77,462k sanction approval was included in the 2016 Business Plan. Upon approval of the 2016 ECR filing, Project Engineering (PE) will submit a revised AIP requesting the full authorization of the CCR Rule and move the project to mechanism capital (Environmental Cost Recoverable).

The overall scope of this project includes the design, permitting and final closures of all CCR ponds at the stations listed above. The scope also includes the design and construction of new process water systems to manage the on-going operation at Brown, Ghent, Mill Creek and Trimble County related to water usage, treatment and discharge with current permit conditions. This CCR Rule Compliance Program scope does not include treatment equipment associated with the EPA effluent limitations guidelines ("ELG") rule. While Ghent, Brown and Trimble County stations have new landfill projects which include CCRT scopes for the dewatering and dry handling of CCR, Mill Creek does not. This Program also includes a new bottom ash dewatering facility that is similar to the CCRT programs at the other stations. Also included in this scope is the smaller compliance activities at Trimble County (BAP berm stability project), Mill Creek's ash pond berm height increase, Mill Creek's gypsum stackout pad reconstruction and the Mill Creek ash pond discharge structure and piping.

Background

As a result of Tennessee Valley Authority's (TVA's) Kingston ash pond failure in 2008, the EPA issued a DRAFT CCR Rule in 2010 to address CCR Impoundments. On April 17, 2015, the EPA published the final CCR Rule. The final CCR Rule is based on Subtitle "D" requirements and contained significant changes to the DRAFT CCR Rule. The final CCR Rule requires all CCR storage facilities undergo structural stability, safety factor, and design flood assessments and corrective action by October 17, 2016 to verify they meet minimum standards, as set forth in the rule. In addition, groundwater monitoring must be implemented, and a minimum of 8 samples taken within 30 months of the rule being published.

The intent of the CCR Rule is to close all CCR Impoundments and move towards dry storage in landfills, which is in line with LG&E and KU's (the "Company") current long term CCR Storage plan. It is anticipated that closure of LG&E and KU's CCR storage facilities will be triggered by groundwater monitoring, and would require the facilities to stop receiving CCR 6-months after and to be closed within 5 years of a groundwater exceedance.

This request is seeking approval of $77,462k for Project Development, Conceptual Design, Final Design, Permitting, and Compliance Construction activities. Project Development includes the structural stability, safety factor, and design flood assessments for each facility under the CCR Rule. The Conceptual Design will build on the work completed to date to identify the preferred plan to comply with the CCR Rule and develop a scope of work for Final Design. Final Design will build upon the results of the Conceptual Design and will allow the Company to submit the necessary state permits as well as develop construction drawings and specifications for closure activities. Initial construction activities include, but are not limited to: Trimble County Buttress (completed), Mill Creek Stackout Pad (ongoing), Mill Creek Hydraulic & Hydrological (H&H) modifications, Ghent ATB #1 reactivation, Ghent Gypsum Stack reclamation and hauling to ATB #2, and preliminary closure activities at the Mill Creek Clearwell and Dead Storage ponds. A Certificate of Public Convenience and Necessity (CPCN) and Environmental Cost Recovery (ECR) filing was submitted to the Kentucky Public Service Commission (KPSC) on January 29, 2016 for approval of the overall project.

Procurement & Schedule

Generation Engineering is currently working with existing engineering firms to address the structural stability, safety factors, and design flood assessments. The assessments for facilities with potential data gaps (Ghent, Mill Creek, and Trimble County) were completed in 2015, while the remainder of the assessments will be completed by early 2016. If issues are identified during the assessments, construction plans will be developed and handed off to Project Engineering to implement. The assessments and construction to address the issues must be completed by October 17, 2016. During the 2015 assessments, two issues were identified: Trimble County Bottom Ash Pond factor of safety and Mill Creek Ash Pond H&H. To address the Trimble County BAP factor of safety, a rock abutment was installed in late 2015. For the Mill Creek Ash Pond H&H issue, engineering is ongoing and construction will commence in late first quarter or early second quarter of 2016 to meet the October 17, 2016 deadline.

Project Engineering has reviewed proposals for the conceptual design, final design, and owner's engineering service to comply with the CCR Rule. Upon completion of Project Engineering bid review, the Ghent and Mill Creek projects were awarded to AECOM while Amec was awarded the E.W. Brown and Trimble County projects. The Ghent and Mill Creek projects are critical due to the size of the work and logistics required to implement the closure plan. Project Engineering awarded the engineering work to two different contractors in an effort to apply lessons learned and best practices between the engineering firms.

Project Cost

The overall cost to comply with the EPA's CCR Rule utilizing CCR Beneficial Use is $959,749k (net) per the 2016 ECR Filing Plan (Table 2), which includes $566,746k (net) for CCR impoundment closure, and an additional $393,003k (net) for new construction of process water systems and CCR handling facilities, primarily at Mill Creek. This revised approval seeks $77,462k (net) for Project Development, Conceptual/Final Design, Permitting, and Construction activities. Requested authorization per station/project is shown in Table 1.

Other Alternatives Considered

For Project Development, no alternatives were considered. To meet the regulatory deadlines related to structural stability, safety factor, and design flood assessments, initial studies were completed in the 4th Quarter of 2015 to allow adequate time to address inadequacies by October 17, 2016, or the facility will be forced to begin the closure process.

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

Below are the alternatives considered for the projects:

1. Recommendation: NPVRR: ($000s)
   - Project 147965: Brown CCR Ruling – Non Mech. $1,397
   - Project 147966: Ghent CCR Ruling – Non Mech. $47,503
   - Project 147967: Green River CCR Ruling – Non Mech. $5,336
   - Project 147968: Pineville CCR Ruling – Non Mech. $417
   - Project 147969: Tyrone CCR Ruling – Non Mech. $1,184
   - Project 147971: Mill Creek CCR Ruling – Non Mech. $41,248
   - Project 147972: Trimble Co. (LGE) CCR Ruling – Non Mech. $2,614
   - Project 147973: Trimble Co. (KU) CCR Ruling – Non Mech. $2,615
   - Project 147098: CCR Ruling Engineering - LGE $316
   - Project 147099: CCR Ruling Engineering - KU $315
2. Do Nothing: NPVRR: ($000s) $0
3. Next Best Alternative(s): NPVRR: ($000s) $0

Table 1 below shows a breakout of cost by station and project number for the current authorization request:

Table 1

Location	**Project #**	**Previous AIP ($000's)**	**2016 BP ($000's)**	**2016 ECR Filing ($000's)**
LG&E	147098	$250	-	-
KU	147099	$250	-	-
E.W. Brown	147965	$750	$10,588	$1,025
Ghent	147966	$750	$35,528	$35,595
Green River	147967	$3,250	$4,148	$4,148
Pineville	147968	$625	-	$323
Tyrone	147969	$625	-	$920
Cane Run	147970	$500	-	-
Mill Creek	147971	$750	$26,453	$31,835
Trimble Co. (LGE) (net)	147972	$390	$2,011	$1,880
Trimble Co. (KU) (net)	147973	$360	$1,856	$1,736
Totals		**$8,500**	**$80,584**	**$77,462**

Table 2 below shows the 2016 Business Plan and 2016 ECR filing costs broken out by year (net):

Table 2

	2015	**2016**	**2017**	**2018**	**2019**	**2020**	2021	2022	2023	**Totals**
2016 BP	$4,824	$75,760	$235,572	$277,695	$83,054	$90,814	$79,972	$73,126	$32,183	**$953,000**
2016 ECR	$5,561	$71,901	$237,492	$283,604	$93,267	$95,554	$71,976	$68,108	$32,286	**$959,749**

The amounts incurred prior to approval of the 2016 ECR filing will be recorded as non-mechanism and moved to mechanism when the project receives ECR approval, currently anticipated for the third quarter of 2016.

Economic Analysis and Risks

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	Pre-2015	2015	2016	2017	Post 2017	Total
1. Capital Investment Proposed	-	751	36,586			37,337
2. Cost of Removal Proposed	-	2,155	37,970			40,125
3. Total Capital and Removal Proposed (1+2)	-	2,906	74,556	-	-	77,462
4. Capital Investment 2016 BP		-	46,149	159,177	187,677	393,003
5. Cost of Removal 2016 BP	-	4,824	29,611	76,395	449,168	559,996
6. Total Capital and Removal 2016 BP (4+5)	-	4,824	75,760	235,572	636,845	953,000
7. Capital Investment variance to BP (4-1)	-	(751)	9,563	159,177	187,677	355,666
8. Cost of Removal variance to BP (5-2)	-	2,669	(8,359)	76,395	449,168	519,872
9. Total Capital and Removal variance to BP (6-3)	-	1,917	1,204	235,572	636,845	875,538

Financial Summary ($000's):

Below is the financial analysis for the project:

Financial Analysis - Project Summary ($000)	Project	2015	2016	2017	2018	2019	Life 2015-2055
Project Net Income							
	LG&E	$6	$15	$12	$12	$11	$197
	KU	$5	$12	$11	$12	$11	$204
	E.W. Brown	$11	$22	$38	$54	$54	$1,175
	Ghent	$232	$464	$1,169	$1,873	$1,873	$38,069
	Green River	$26	$52	$136	$220	$248	$3,802
	Pineville	$9	$17	$17	$17	$19	$323
	Tyrone	$12	$23	$36	$49	$55	$867
	Mill Creek	$212	$424	$1,049	$1,674	$1,674	$29,177
	Trimble-LGE	$46	$93	$96	$100	$100	$2,171
	Trimble-KU	$43	$87	$89	$92	$92	$2,006
Project ROE							
	LG&E	19.8%	15.2%	9.6%	9.8%	9.8%	10.1%
	KU	19.7%	13.2%	8.6%	9.8%	9.8%	9.9%
	E.W. Brown	83.6%	7.6%	7.0%	10.0%	10.0%	9.7%
	Ghent	96.7%	4.8%	6.2%	10.0%	10.0%	9.6%
	Green River	252.7%	4.7%	6.2%	10.0%	11.4%	9.5%
	Pineville	309.4%	19.4%	10.0%	10.0%	11.4%	10.3%
	Tyrone	416.5%	9.4%	7.4%	10.0%	11.4%	9.8%
	Mill Creek	161.5%	5.0%	6.3%	10.0%	10.0%	9.5%
	Trimble-LGE	29.1%	14.1%	9.7%	10.0%	10.0%	10.1%
	Trimble-KU	28.6%	14.2%	9.7%	10.0%	10.0%	10.1%

Environmental Risks:

There are no environmental risks related to New Source Review associated with this project.

Conclusions and Recommendation

It is recommended that this revised Authorized Investment Proposal be approved to cover the estimated spend through the end of 2016 in the amount of $77,462k to perform Project Development, Conceptual and Final design, Permitting and Construction activities for the EPA's CCR Rule Compliance Program. Sanction request for the remaining project spend will be requested upon approval of the 2016 KPSC ECR filing.

Kent W. Blake
Chief Financial Officer

Victor A. Staffieri
Chairman, CEO and President

Authorized Investment Proposal for Investment Meeting on: June 30, 2015

Project Name: Environmental Protection Agency's (EPA's) Coal Combustion Residual (CCR) Rule – Impoundment Closure

CCR Rule Conceptual Design: $5,000k
Green River Construction Inactive Status: $2,500k
Cane Run Closure Activities: $500k
Previous Approval: $500k
Total Sanction Request: $8,500k

Project Numbers: 147098, 147099, 147965, 147966, 147967, 147968. 147969, 147970, 147971, 147972, 147973

Business Unit/Line of Business: Project Engineering

Prepared/Presented By: Scott Straight/Jeff Heun/Gary Revlett

Executive Summary

This Authorized Investment Proposal (AIP) is being submitted for Project Development, Conceptual Design, and Initial Construction related to the EPA's CCR Rule. The final CCR Rule was published on April 17, 2015 and will become effective on October 17, 2015.

This document seeks approval of the CCR Rule – Impoundment Closure project spend of $8,000k for the conceptual scope listed below. This request seeks approval for an incremental portion of the overall Impoundment Closure which is $557,418k gross ($522,898k net), per the 2015 Business Plan (Table 3), $5,000k for project development/conceptual design and $3,000k for early closure of various ponds listed herein. This initial approval is required to meet critical deadlines outlined in the CCR Rule, which are tied to Location Restrictions, Design Criteria, Operating Criteria, and Groundwater Monitoring, as well as construction activities to move active CCR storage facilities into an inactive status. An AIP for $500k ($250k for LG&E and $250k for KU) was submitted on April 2, 2015 to allow engineering activities to start prior to this Investment Committee authorization request. This request is seeking an additional $8,000k approval on top of the previously approved $500k. The 2015 amount is $500k higher than the budget but has been fully funded by the RAC as non-mechanism capital.

Background

As a result of Tennessee Valley Authority's (TVA's) Kingston ash pond failure in 2008, the EPA issued a DRAFT CCR Rule in 2010 to address CCR impoundments. On April 17, 2015, the EPA published the final CCR Rule. The final CCR Rule is based on Subtitle "D" requirements and contained significant changes to the DRAFT CCR Rule. The final CCR Rule requires all CCR storage facilities undergo structural stability, safety factor, and design flood assessments and corrective action by October 17, 2016 to verify they meet minimum standards, as set forth in the rule. In addition, groundwater monitoring must be implemented, and a minimum of 8 samples taken within 30 months of the rule being published.

The intent of the CCR Rule is to close all CCR Impoundment and move towards dry storage in landfills, which is in line with LG&E and KU's (the "Company") current long term CCR Storage plan. It is anticipated that closure of LG&E and KU's CCR storage facilities will be triggered by groundwater monitoring, and would require the facilities to stop receiving CCR 6 months after and to be closed within 5 years of a groundwater exceedance.

This request is seeking approval of $5,500k for Project Development and Conceptual Design. Project Development includes the structural stability, safety factor, and design flood assessments as well as development of the groundwater monitoring plan for each facility. The Conceptual Design will build on the work completed to date to identify the preferred plan to comply with the CCR Rule and develop a scope of work for Final Design. A Certificate of Public Convenience and Necessity (CPCN) and Environmental Cost Recovery (ECR) filing will be made to the Kentucky Public Service Commission (KPSC) for approval of the overall project in late 2015. In conjunction with the KPSC filing, Project Engineering will seek Investment Committee approval for the overall CCR Rule – Impoundment Closure project.

This request is seeking approval of $3,000k for engineering and initial construction activities that would allow Green River ATB #2, and Green River SO_2 ponds to attain "Inactive" status and final closure of Cane Run's impoundments as part of the ongoing Ash Pond and Landfill closure project. If a CCR storage facility is "Inactive", as defined in the CCR Rule, the company is not required to perform: structural stability, safety factor, design flood assessments, location restriction, or groundwater monitoring, but must close the facility by April 17, 2018. In addition, LG&E and KU are not required to perform 30-years of groundwater monitoring and publication of test results on the Company's website per the CCR Rule's requirements. However, the facilities will be closed under State requirements which will require a minimum of 5-years of groundwater monitoring and submittal of test results to the State. To attain "Inactive" status, the CCR storage facility must stop receiving CCR material by October 14, 2015 and be closed by April 17, 2018.

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

Below are the alternatives considered for project:

1. Recommendation:

	NPVRR: ($000s)
Project 147965	$1,011
Project 147966	$1,011
Project 147967	$4,452
Project 147968	$835
Project 147969	$847
Project 147970	$608
Project 147971	$1,010
Project 147972	$527
Project 147973	$488
Project 147098	$330
Project 147099	$331

2. Do Nothing: NPVRR: ($000s) $0
3. Next Best Alternative(s): NPVRR: ($000s) $0

Procurement & Schedule

Generation Engineering is currently working with existing contractors to address the structural stability, safety factors, and design flood assessments. Generation Engineering is working within existing contracts or will be issuing new contracts against master service agreements. The assessments for facilities with potential data gaps (Ghent, Mill Creek, and Trimble County) are scheduled to be completed by the end of 2015 with the remainder of the assessments completed by early 2016. If issues are identified during the assessments, construction plans will be developed and handed off to Project Engineering to implement. The assessments and construction to address the issues must be completed by October 17, 2016.

Currently, Project Engineering is developing the scope of work and Request for Quotation (RFQ) package for the conceptual design, final design, and owner's engineering service to comply with the CCR Rule. The current plan is to issue the RFQ package by the end of the 3rd quarter of 2015 and award the engineering work no later than December 2015. The RFQ package will be structured to award the engineering and owner's engineering service to one contractor for the entire fleet or to choose multiple contractors and award the work plant specific.

Project Cost

The overall gross cost of the EPA's CCR Rule is $557,418k ($522,898k net) per the 2015 Business Plan (Table 3), which includes $554,319k gross cost ($520,282k net) for CCR impoundment closure, and an additional $3,099k gross cost ($2,616k net) for construction of new process ponds once the CCR impoundments are taken out of service. This initial approval seeks $5,500k for Project Development/Conceptual Design, $2,500k for construction activities to attain "Inactive" status, and $500k for closure of the Cane Run CCR impoundment as part of the ongoing landfill and ash pond closure project. Requested authorization per location is shown in Table 1 while estimated cash flows are shown in Table 2.

Other Alternatives Considered

For Project Development, no alternatives were considered. To meet the regulatory deadlines related to structural stability, safety factor, and design flood assessments, initial studies must be completed in the 3rd Quarter of 2015 to allow adequate time to address inadequacies by October 17, 2016, or the facility will be forced to begin the closure process.

For Initial Construction activities to attain Inactive Status, a "do nothing" alternative was considered. A "do nothing" alternative would require the closure of the Green River ATB #2 under the full CCR Rule. A "do nothing" alternative would not affect the closure of the Cane Run Impoundments due to ongoing work or the Green River SO_2 Pond, as it's currently inactive. Closure of the facilities listed above under the full CCR Rule would require studies for Location Restrictions, Design Criteria, Operating Criteria, and Groundwater Monitoring. Based on discussions with engineering companies, it is anticipated that Location Restrictions, Design

Criteria, and Operating Criteria studies would cost between $100k and $250k per facility. Groundwater Monitoring for the Green River is estimated at $250k to $350k for the design and construction of the groundwater monitoring system that meets the CCR Rule's requirements. In addition to the studies listed above, the facility would have to undergo 30 years of post-closure care. Results of the studies listed above and the 30 years of post-closure care must be posted to a publically accessible website. If the facilities were to attain inactive status, they would be closed under State requirements; Groundwater Monitoring would be approximately ¼ to 1/3 the cost, the post-closure care is 5 years, and all information is submitted to the State. The main unknown is citizen lawsuits. Since the CCR Rule establishes minimum standards that must be followed, compliance with those standards are based on citizen suits. Since all information pertaining to a CCR facility must be posted to a publically accessible website, the information is readily available to the general public. Based on internal discussions, a citizen suit could cost between $2,000k to $5,000k per suit to defend and settle. If the CCR facility is closed under State requirements, a permit is issued for closure and enforcement is by the State.

Table 1 below shows a breakout of cost by location and project number for the current authorization request:

Table 1

Location	Project #	Conceptual Design ($000's)	Initial Construction ($000's)	Closure Construction ($000's)	Total ($000's)
LG&E	147098	$250			**$250**
KU	147099	$250			**$250**
E.W. Brown	147965	$750	-	-	**$750**
Ghent	147966	$750		-	**$750**
Green River	147967	$750	$2,500	-	**$3,250**
Pineville	147968	$625	-	-	**$625**
Tyrone	147969	$625	-	-	**$625**
Cane Run	147970	-	-	$500	**$500**
Mill Creek	147971	$750	-	-	**$750**
Trimble Co. (LGE)	147972	$390	-	-	**$390**
Trimble Co. (KU)	147973	$360	-	-	**$360**
Totals		**$5,500**	**$2,500**	**$500**	**$8,500**

Table 2 below shows estimated cash flows for the current authorization request:

Table 2

Estimated Cash Flows ($000's)			
Task	**2015**	**2016**	**Total**
Engineering	$500		**$500**
Development & Conceptual Design	$1,342	$3,658	**$5,000**
Inactive Construction Activities	$2,500	-	**$2,500**
Cane Run Final Closure	-	$500	**$500**
Totals	**$4,342**	**$4,158**	**$8,500**

Table 3 below shows the 2015 Business Plan closure costs broken out by year (net):

Table 3

2015 Business Plan ($000's)								
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Totals**
CCR Ruling	$403	$3,565	$105,508	$76,836	$86,040	$120,222	$129,629	**$522,898**
Totals	**$403**	**$3,565**	**$105,508**	**$76,836**	**$86,040**	**$120,222**	**$129,629**	**522,898**

The amounts incurred through the first quarter of 2016 will be recorded as non-mechanism and moved to mechanism when the project receives ECR approval, currently anticipated for the second quarter of 2016.

Economic Analysis and Risks

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	Pre-2015	2015	2016	Post 2016	Total
1. Capital Investment Proposed	-	-	-	-	-
2. Cost of Removal Proposed	-	4,342	4,158	-	8,500
3. Total Capital and Removal Proposed (1+2)	-	4,342	4,158	-	8,500
4. Capital Investment 2015 BP	-	-	-	2,616	2,616
5. Cost of Removal 2015 BP	403	3,565	105,508	410,806	520,282
6. Total Capital and Removal 2015 BP (4+5)	403	3,565	105,508	413,422	522,898
7. Capital Investment variance to BP (4-1)	-	-	-	2,616	2,616
8. Cost of Removal variance to BP (5-2)	403	(777)	101,350	410,806	511,782
9. Total Capital and Removal variance to BP (6-3)	403	(777)	101,350	413,422	514,398

Financial Summary ($000s):

Below is the financial analysis for the project:

Financial Analysis - Project Summary ($000)	Project	2015	2016	2017	2018	2019	Life of Project
Project Net Income							
	147098	$ (3)	$ (5)	$ 10	$ 14	$ 12	$ 198
	147099	$ (3)	$ (5)	$ 10	$ 14	$ 12	$ 213
	147965	$ (3)	$ (9)	$ 32	$ 41	$ 41	$ 808
	147966	$ (3)	$ (9)	$ 32	$ 41	$ 41	$ 808
	147967	$ (23)	$ (38)	$ 141	$ 177	$ 177	$ 3,491
	147968	$ (3)	$ (7)	$ 27	$ 34	$ 29	$ 622
	147969	$ (3)	$ (7)	$ 27	$ 34	$ 34	$ 672
	147970	$ -	$ (10)	$ 20	$ 27	$ 25	$ 402
	147971	$ (3)	$ (9)	$ 32	$ 41	$ 41	$ 762
	147972	$ (2)	$ (5)	$ 17	$ 21	$ 21	$ 396
	147973	$ (2)	$ (4)	$ 16	$ 20	$ 20	$ 387
Project ROE							
	147098	-4.4%	-3.8%	7.9%	11.2%	10.8%	9.8%
	147099	-4.4%	-3.7%	7.9%	11.2%	10.8%	9.9%
	147965	-4.4%	-3.1%	8.2%	10.3%	10.3%	10.4%
	147966	-4.4%	-3.1%	8.2%	10.3%	10.3%	10.4%
	147967	-4.4%	-2.7%	8.2%	10.3%	10.3%	10.2%
	147968	-4.4%	-3.0%	8.2%	10.3%	8.9%	10.1%
	147969	-4.4%	-3.0%	8.2%	10.3%	10.3%	10.3%
	147970	0.0%	-7.8%	7.9%	11.2%	10.8%	10.6%
	147971	-4.4%	-3.1%	8.2%	10.3%	10.3%	10.3%
	147972	-4.4%	-3.1%	8.2%	10.3%	10.3%	10.3%
	147973	-4.4%	-3.0%	8.2%	10.3%	10.3%	10.3%

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	N
#2	Does the project involve equipment that is part of a regulated air emission unit? a. Is change a like-kind or functionally equivalent replacement?	N
#3	Does the project increase through-put with any of the material handling systems?	N
#4	Will the project affect the dispatch order or utilization of the unit?	N
#5	Does the project increase the emissions unit's maximum hourly heat input?	N
#6	Does the project increase the emissions unit's electrical output (gross MW)?	N
#7	Has the equipment or component in question been repaired or replaced in the past at this unit? a. Provide frequency or when equipment or component in question was last repaired or replaced.	N
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	N

Conclusions and Recommendation

It is recommended that this Authorized Investment Proposal be approved in the amount of $8,500k to perform overall Project Development/Conceptual Engineering, and Initial Construction at Cane Run, and Green River for the EPA's CCR Rule – Impoundment Closure projects. Sanction request for the remaining project spend may be made in late 2015 in conjunction with the KPSC ECR filing.

Kent W. Blake
Chief Financial Officer

Victor A. Staffieri
Chairman, CEO and President

Investment Proposal for Investment Committee Meeting on: September 29, 2020

Project Name: Ghent Dry Sorbent Injection (DSI) Balancing and Cobra Lances

Total Capital Expenditures: $7,886k (Including $675k of contingency)

Total O&M: $0

Project Number(s): 157591

Business Unit/Line of Business: Project Engineering (PE)

Prepared/Presented By: Jeffrey B. Heun

Brief Description of Project

During the March 30, 2016 Investment Committee (IC) meeting, the IC approved the Ghent Dry Sorbent Injection (DSI) System Improvements for $4,000k (*Attachment #1*). The scope of work was to modify the Units 1, 3, and 4 DSI system to address flow distribution issue between each unit's two (2) flue gas ducts. The initial concept was to utilize a design similar to the Unit 2 system which had a blower for each injection point which allowed for proper balancing of the DSI flows between the flue gas ducts. The work was approved in the 2011 ECR Plan and included in the 2016 BP.

Upon completion of the Pulse Jet Fabric Filter (PJFF) projects, DSI consumption was evaluated on Units 1, 3, and 4 and a determination was made that the consumption was higher than expected when compared to similar sized generation units equipped with similar pollution control equipment due to the imbalance from one duct to another on each unit, as well as injection lance designs. As a result of this evaluation, the Company (Plant and PE) reviewed multiple options that addressed the flow distribution and ultimately determined that modifying the Unit 1, 3, and 4 DSI system to have one blower for each injection location was the best option.

Why is the project needed? What if we do nothing?

Modification to the Units 1, 3, and 4 DSI systems will significantly reduce DSI consumption as well as the daily maintenance activities associated with having to unplug the existing injection lances. The current configuration of the DSI system is not balanced between each unit's two (2) flue gas ducts. As a result of the unbalanced configuration, DSI is over injected into the flue gas stream to ensure both ducts achieve the required SO_3 reduction. In addition to flue gas flow imbalance, the current configuration of the conveying system biases the DSI flow to the ducts based on least path of resistance caused by injection lance pluggage. To ensure that both ducts receive an adequate flow of DSI to meet SO_3 limits, the overall DSI flow has to be increased.

In an effort to address pluggage of the injection lances and address the flow bias between the two ducts, the injection lances are cleaned at least once per shift. This maintenance activity helps but does not eliminate the lances from plugging. At the same time, the flow biases result in increased DSI flow though the lances above their normal operation which increases the rate of lance plugging.

If no action is taken to address the unbalanced flows and plugging of the injection lances, DSI consumption will remain higher than optimized and additional ongoing maintenance will be required resulting in higher O&M costs.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	Pre 2020	2020	2021	Post 2021	Total
1. Capital Investment Proposed	12	2,250	5,625	-	7,886
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	12	2,250	5,625	-	7,886
4. Capital Investment 2020 BP	3,078	2,838	-	-	5,916
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	3,078	2,838	-	-	5,916
7. Capital Investment variance to BP (4-1)	3,067	588	(5,625)	-	(1,970)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	3,067	588	(5,625)	-	(1,970)

PE is requesting $675k in program management contingency which is ten percent (10%) of the construction contract. As a result of the project, an O&M savings of $1,100k per year compared to the 2020 BP should be realized, which is based on a reduction of two (2) resident contractors and 15% reduction in DSI consumption. As a result of the improved DSI distribution in the DSI delivery system and reduced pluggage, the Plant has determined that a reduction of two (2) resident maintenance contractors is appropriate. Based on current and ongoing flow modeling by United Conveyor Corporation (UCC), UCC has indicated the Plant will see at least a 15% reduction in DSI consumption. This request is based on achieving the minimum predicted savings.

Risks

- If no action is taken to address the unbalanced flows and injection lances, the Plants DSI consumption will be higher and additional ongoing maintenance will be required resulting in higher O&M costs.
- Unit outages will be required to perform the flowing balancing work as well as the installation of the cobra lances. The Plant and PE will work together with the contractor to ensure adequate time and access is available to perform the work during the upcoming 2021 outages at Ghent.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $7,716
   - Reduction of two (2) resident maintenance contractors
   - A 15% reduction in DSI consumption
   - CEM depreciation life – 2037
2. Alternative #1 – Do Nothing: NPVRR: ($000s) $8,519

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Ghent Dry Sorbent Injection Balancing and Cobra Lances project for $7,886k to reduce DSI consumption and Plant O&M costs.

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	

Attachment #1

Revised Project and Contract Proposal for Investment Committee Meeting on: March 30, 2016

Contract:

Contract Name: Ghent Environmental Air Compliance – Engineering, Procurement, and Construction Agreement – [redacted]

Revised Contract Authorization: $577,100k (including 1.8% forward contingency)

September 2015 Contract Authorization: $573,100k

Original Contract Authorization: $501,400k

Project:

Project Name: Ghent Environmental Air Compliance

Revised Ghent Environmental Air Compliance Project Total Seeking IC Approval: $667,750k

May 2015 Ghent Environmental Air Compliance Project Total Project Sanction: $656,750k

Business Unit/Line of Business: Project Engineering

Prepared/Presented by: Doug Schetzel and Scott Straight

Executive Summary

This proposal seeks a revised Ghent Environmental Air Compliance (GEAC) Project authorization of $672,750k, an increase of $16,000k from the May 2015 authorization. The sanction increase is necessary to complete demolition of the Ghent (GH) Unit 2 Electrostatic Precipitators (ESP), to design and install improvements to the GH Unit 1, 3 & 4 Dry Sorbent Injection Systems (DSI), and either to stabilize the partially demolished Unit 1 ESP or demolish similar to Unit 2. The 2016 BP contains $4,000k for the GH Unit 1 and Unit 2 ESP Demolition project and $4,000k for the DSI System Improvement projects. Please see Table 1 below which reflects the breakdown of the requested authorization increase from the May 2015 authorization:

Table 1

GEAC Project Authorization Request ($000s)	Requested Sanction	2016 BP Amount	Variance to 2016 BP
GH 2 ESP Demolition	$6,500	$2,000	$4,500
GH 1 ESP Stabilization (Option 1)	$500	$0	$500
GH 1 ESP Demolition (Option 2)	$5,500	$2,000	$3,500
GH DSI Improvements	$4,000	$4,000	$0

This proposal also seeks to increase the September 2015 authorization of the GEAC Engineering, Procurement and Construction (EPC) contract with [redacted] by $9,000k. The increased authorization will allow for some or all of the non-EPC demolition cost on the Unit 1 and Unit 2's ESP be moved into [redacted] scope of work. The requested amount for the [redacted] contract is $5,000k greater than the 2016 BP amount to allow some or all the ESP demolition scope to be performed by [redacted] under the EPC Agreement. The new sanction is $38,250k less than the 2011 Environmental Cost Recoverable (ECR) filing amount.

Background

- **Ghent DSI System Improvements**

The design of the DSI systems at Ghent has evolved during the course of the project. The last system installed on GH Unit 2 has dedicated piping and a blower for each injection point. This allows proper balancing of the DSI flows to assure proper SO_3 control, as well as significant improvement in DSI utilization which reduces cost with a very short payback on this investment. The concentration of SO_3 must be less than 5 parts per million (ppm) for optimum mercury (Hg) in the Pulse Jet Fabric Filter (PJFF) and to limit downstream gas path corrosion. The DSI systems on GH Units 1, 3 & 4 will be modified to a design similar to GH Unit 2. This modification is being considered for the Mill Creek Units 3&4 and Trimble County Unit 1 baghouses that also have an A and B baghouses serving individual units. The requested authorization to spend $4,000k on GH DSI improvements is contained in the 2016 BP.

- **Ghent ESP Demolition Background**

When the GH Unit 1 & 2 Pulse Jet Fabric Filters (PJFF) were placed in service, the GH Unit 1 & 2 ESPs were abandoned in place. The footprint around GH Unit 1 & 2 is very constrained and the demolition of the GH Unit 1 & 2 ESPs is necessary to improve access to the units. The GH Unit 2 PJFF is located in what was the GH 1& 2 courtyard. Demolition of the GH Unit 2 ESP will restore some of the open space around the units necessary for maintenance and outage laydown areas. The last project sanction included $3,000k for general demolition of GH Unit 1 & 2. Those funds were used to remove GH Unit 1 ESP duct to allow for the placement of a crane to construct the Unit 2 PJFF and to begin demolition of the GH Unit 2 ESP. The decision to use a majority of the budgeted demolition funds to allow crane access for Unit 2's PJFF was attributed to the significant savings of the Unit 2 PJFF and the shorter tie-in outage duration. These significant benefits resulted in greater savings and execution risk to the project than the incremental cost of demolition. An additional savings was realized by starting the GH Unit 2 ESP demolition when the Unit 2 PJFF was finished by utilizing the large outage crane used to construct the GH Unit 2 PJFF to be utilized to begin demolition of the Unit 2 ESP, saving approximately $500k in crane mobilization and demobilization costs. The attached sketch shows the area around the GH Unit 1 and 2 ESPs. Demolition of the GH Unit 2 ESP provides most of increase in useable footprint (Attachment 1 & 2).

- **Ghent Unit 2 ESP Demolition**

The estimated remaining cost to demolish the GH Unit 2 ESP is approximately $6,500k. The 2016 BP has $4,000k for Ghent ESP Demolition, representing a $2,500k increase over the 2016 BP.

- **Ghent Unit 1 – Option 1 (ESP Stabilization)**

Since the ducting to the GH Unit 1 ESP was removed to allow more efficient construction of the GH Unit 2 PJFF, the GH Unit 1 ESP can be stabilized by removing as much ash as possible and closing the duct openings and other penetrations to the ESP and the GH Unit 1 structure. The estimated cost to stabilize the GH Unit 1 ESP is $500k. The requested authorization of $500k to stabilize the GH Unit 1 ESP is incremental to the 2016 BP. It should be noted that this spend does not avoid the eventual need to demolish the ESP, but merely defers the expense. As with any flue gas related equipment, "mothballing" the ESP will eventually result in it corroding away and becoming a safety hazard over the next 5-15 years. It will then require demolition.

- **Ghent Unit 1 – Option 2 (ESP Demolition)**

The estimated cost to demolish the GH Unit 1 ESP is approximately $5,500k. The GH Unit 1 ESP footprint is mostly under the Selective Catalytic Reduction (SCR), thus minimal usable foot print is achieved. As stated in Option 1, demolition of the GH Unit 1 ESP will still be needed within 5-15 years, since any ash residue exposed to ambient moisture will corrode the ESP structure. If this option is chosen, the requested authorization of $5,500k would be $5,500k over the 2016 BP amount but this authorization would be in place of the authorization of the GH Unit 1 ESP stabilization.

Economic Analysis and Risks

- **Financial Summary**

Table 2 reflects the history of all Ghent Air Compliance project scopes that were part of the 2011 ECR filing.

Table 2:

($000)	ECR Filing	AIP	2012 MTP	2013 BP	2014 BP	2015 BP	2016 BP	Current Forecast
Ghent EAC	$711,000	$519,340	$692,000	$532,000	$599,000	$650,700	$664,750	$672,750

Table 3 gives a summary of total project spend and shows actual spend through January 2016 and projected costs through the completion of the project.

Table 3:

Summary of Total Project Spend ($000)	
Actual Costs:	
SAM Mitigation	$ 12,700
PJFF pre-2016	$ 630,116
PJFF January 2016	$ 1,704
Actual Costs through January 2016	$ 644,520
Projected Costs:	
February - Completion 2016	$ 25,409
Contingency 2016	$ 2,821
Projected Costs to completion	$ 28,230
Total Project Spend	**$ 672,750**

Table 4 lists the budget breakout that supports the current forecast using the Ghent Unit 1 – Option 2 (ESP Demolition) above vs the 2016 Business Plan (BP). The overage for 2016 was a carryover of funds from 2015 as well as any additional overages, will be funded through the RAC process by other Project Engineering projects.

Table 4:

Financial Detail by Year - Capital ($000s) (includes Ghent SAM projects)	**Pre 2016**	**2016**	**Total**
1. Capital Investment Proposed	634,736	14,652	649,388
2. Cost of Removal Proposed	7,820	15,541	23,361
3. Total Capital and Removal Proposed (1+2)	642,556	30,194	672,750
4. Capital Investment 2016 BP	640,993	10,669	651,662
5. Cost of Removal 2016 BP	8,088	5,000	13,088
6. Total Capital and Removal 2016 BP (4+5)	649,081	15,669	664,750
7. Capital Investment variance to BP (4-1)	6,257	(3,983)	2,274
8. Cost of Removal variance to BP (5-2)	268	(10,541)	(10,273)
9. Total Capital and Removal variance to BP (6-3)	6,525	(14,525)	(8,000)

Alternative Option: Delayed Demolition of GH1 ESP

Alternatively, if it is not desired to demolish the Ghent Unit 1 Electrostatic Precipitator for $5,500k, authorization for the Ghent Environmental Air Compliance Project could be increased by $11,000k to $667,750k and the authorization for the Ghent Environmental Air Compliance Engineering, Procurement, and Construction Agreement with [redacted] could be increased $4,000k to $577,100k. This authorization allows the Ghent Dry Sorbent Injection System Improvements for $4,000k, the demolition of the Ghent Unit 2 Electrostatic Precipitator for $6,500k and the stabilization of the Ghent Unit 1 Electrostatic Precipitator for $500k. The Ghent Unit 1 Electrostatic Precipitator will still need to be demolished at a later date.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the $11,000k increase of the Ghent Environmental Air Compliance Project total authorization to $667,750k and the $4,000k increase of the Ghent Environmental Air Compliance Engineering, Procurement, and Construction Agreement with [redacted] to $577,100k. This authorization allows the Ghent Dry Sorbent Injection System Improvements for $4,000k, the Stabilization of the Ghent Unit 1 Electrostatic Precipitator for $500k and Demolition of the Ghent Unit 2 Electrostatic Precipitator for $6,500k.

The Investment Committee approved the Alternative Option: Delayed Demolition of GH1 ESP. Further analysis will be completed regarding the optimal timeframe for the demolition of the Ghent Unit 1 Electrostatic Precipitator. Results of this analysis will be distributed for discussion.

Douglas Schetzel 4/4/2016
Douglas K. Schetzel
Dir. Business Development/Mgr. Major Capital Projects

Anthony L. Ruckriegel 4/5/2016
Anthony L. Ruckriegel
Mgr. Contracts/Major Capital Project

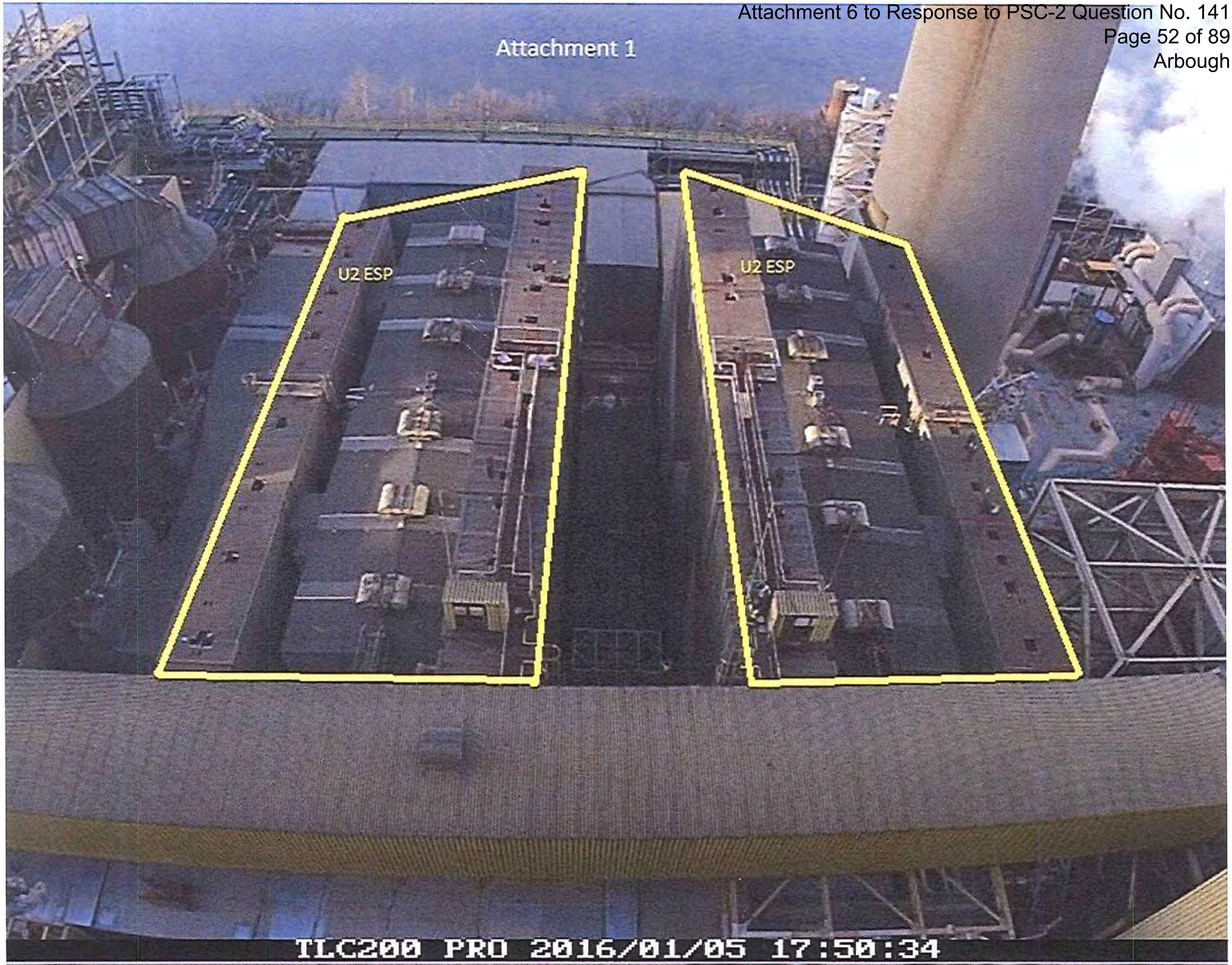
4/5/16
R. Scott Straight
Dir. Project Engineering

DUA for J. Voyles 4/5/16
John N. Voyles
VP Transmission & Generation Services

4/5/16
Paul W. Thompson
Chief Operating Officer

KtWBlake 4/6/16
Kent W. Blake
Chief Financial Officer

4/7/16
Victor A. Staffieri
Chief Executive Officer


Attachment 1
U2 ESP
U2 ESP
TLC200 PRO 2016/01/05 17:50:34


Attachment 2
U1 ESP

Jacobs, John

From: Allgeier, Lana
Sent: Friday, April 08, 2016 9:10 AM
To: Jacobs, John
Subject: FW: Delegation Of Authority Notification For JOHN VOYLES to SCOTT STRAIGHT

From: LG&E ERS Website
Sent: Friday, April 01, 2016 3:20 PM
To: Delegation of Authority <doa@lge-ku.com>; Saunders, Eileen <Eileen.Saunders@lge-ku.com>; Mattingly, Jennifer <Jennifer.Mattingly@lge-ku.com>; Voyles, John <John.Voyles@lge-ku.com>; Thompson, Paul <Paul.Thompson@lge-ku.com>; Straight, Scott <Scott.Straight@lge-ku.com>; Jessee, Tom <Tom.Jessee@lge-ku.com>; Oracle Security <oracle@lge-ku.com>; Cash Management <Cash@lge-ku.com>; Hance, Chuck <Chuck.Hance@lge-ku.com>; Singery, Debbie <Debbie.Singery@lge-ku.com>; Lipp, Joan <Joan.Lipp@lge-ku.com>; Disney, Judy <Judy.Disney@lge-ku.com>; Ruckriegel, Tony <Tony.Ruckriegel@lge-ku.com>; Burns, Kyle <Kyle.Burns@lge-ku.com>; Mooney, Lisa <Lisa.Mooney@lge-ku.com>; Heun, Jeff <Jeff.Heun@lge-ku.com>; Imber, Philip <Philip.Imber@lge-ku.com>; Allgeier, Lana <Lana.Allgeier@lge-ku.com>; Wilson, Dan <Dan.Wilson@lge-ku.com>; Schetzel, Doug <Doug.Schetzel@lge-ku.com>; Ware, Dianne <DIANNE.WARE@lge-ku.com>
Subject: Delegation Of Authority Notification For JOHN VOYLES to SCOTT STRAIGHT

This delegation of authority is effective with the start of the work day 4/4/2016 through the end of the work day 4/8/2016.
The Reason for this delegation of authority is Vacation.

Delegation of Authority for		Authority being delegated to	
Name	JOHN VOYLES	**Name**	SCOTT STRAIGHT
Location	LG&E Center 14th floor	**Location**	Broadway Office Complex-3
Department	VP-Transmission/Generation Svc	**Department**	Project Engineering
Company	LG&E and KU Services Company	**Company**	LG&E and KU Services Company
Phone	502/627-4762	**Phone**	502/627-2701
E-Mail	JOHN.VOYLES@LGE-KU.COM	**E-Mail**	SCOTT.STRAIGHT@LGE-KU.COM
Cell Phone	N/A	**Cell Phone**	N/A
Pager	N/A	**Pager**	N/A

Comments :

Investment Proposal for Investment Committee Meeting: November 20, 2020

Project Name: Trimble County CCR Project (Landfill) - Additional Buffer Property Acquisition 2020

Total Capital Expenditures: $1,600k (gross), $1,200k (net)[1]

Project Number(s): TC Landfill will provide funding (151119 / 151123) via projects: 163984 / 163985 (LGE/KU)

Business Unit/Line of Business: Project Engineering

Prepared/Presented By: Joan S. Lipp / R. Scott Straight

Description of Project

Authority is being requested to purchase two adjacent properties to the Trimble County Coal Combustion Residual (CCR) Landfill from the Leach families for a total of $1,600k (gross) or $1,200k (net). No contingency is being sought. These properties have been included in a past IC authorization request and are being purchased to:

- provide additional property buffers between local residents and the landfill area, and
- allow local residents to relocate away from the landfill area.

Previous adjacent property purchase IC Papers:

- **August 2012** Trimble County CCR Project, Additional Property Acquisition: 17 named parcels (see Attachment #1). The two parcels included in this paper were part of the original listing.
- **March 2016** Trimble County Landfill Phase 1A Project: Updated funding amount for remaining parcels not purchased per the August 2012 IC Paper (see Attachment #2 Appendix D).

This authorization request includes: a) the purchase of two parcels totaling 153 acres (closing is planned to be completed by December 2020) from the Leach families, and b) removal of residential buildings and structures in the Spring of 2021. As stated above, the land will be used as a buffer between the landfill and adjacent landowners. Funding was approved per August 2012 and March 2016 IC papers and is in accordance with LG&E and KU's ("Companies") Quarterly KPSC ECR project reports that have continuously stated that the Companies continue to acquire properties adjacent to the landfill to allow buffer from the remaining neighbors and allow an opportunity for those adjacent to relocate. The property purchase prices are 152% of appraisal which is in the range of prices paid for other surrounding properties.

Budget Comparison & Financial Summary

[1] Co-Owners of the Trimble County plant: Illinois Municipal Electric Agency (IMEA) and Indiana Municipal Power Agency (IMPA) are responsible for 25%. IMEA owns 12.12% and IMPA owns 12.88%.

Financial Detail by Year - Capital ($000s) (Net)	2020	2021	2022	Total
1. Capital Investment Proposed (Net)	1,050	150	-	1,200
2. Cost of Removal Proposed (Net)	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	1,050	150	-	1,200
4. Capital Investment 2021 BP (Net)	1,050	150	-	1,200
5. Cost of Removal 2021 BP (Net)	-	-	-	-
6. Total Capital and Removal Proposed (Net) (4+5)	1,050	150	-	1,200
7. Capital Investment variance to BP (4-1)	-	-	-	-

Risks

No additional risks were identified if the properties are not purchased beyond the current risk of having adjacent land owners to the landfill daily operation.

Alternatives Considered

1. Recommendation: Purchase of property — NPVRR: (000s) $1,874 (net)
   Purchase of the property is consistent with other purchases of adjacent property.

2. Alternative #1: Do Nothing — NPVRR: (000s)

Conclusions and Recommendation

It is recommended that the Investment Committee approve the purchase of two adjacent properties for the Trimble County Coal Combustion Residual (CCR) Landfill for $1,600k (gross) or $1,200k (net) to provide additional buffer around the landfill.

Approval Confirmation for Land Purchase Greater Than $500,000:

The Capital property purchase 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 property purchase spending request.

Kent W. Blake
Chief Financial Officer

Paul W. Thompson
President and Chief Operating Officer

Contract Proposal for Investment Committee Meeting on: **E-Mail Vote**

Contract Name: **Trimble County CCR Project, Additional Property Acquisition**

Contract Total Seeking IC Approval **$ 5,190 k (gross) and $ 3,893 k (net)**
Total Contract Expenditures: **$ 5,190 k (gross) and $ 3,893 k (net)**

Business Unit/Line of Business: **Generation Services/Project Engineering**
Prepared/Presented By: **Robert C. Waterman, Ronald D. Gregory**

Executive Summary

Authority is being requested to procure adjacent properties for the Trimble County Coal Combustion Residual (CCR) Landfill Project for $5.190 million (gross) or $3.893 million (net). No contingency is being sought. These properties are necessary to:

- provide additional soil borrow areas and reduce stream and wetland impacts to the Ravine B watershed
- provide additional property buffers between local residents and the landfill
- optimize the landfill and view shed designs
- provide additional landfill cover for use during operation
- eliminate the potential for Reverse Condemnation Litigation
- reduce complaints during construction and operation of the landfill

This request is being made due to the original sanction of the landfill not including the purchase of land. Permitting activities to date have resulted in the United States Army Corps of Engineers (USACE), Kentucky Division of Water (DOW), and the United States Environmental Protection Agency (EPA) commenting on the amount of streams planned to be “taken” in the development of the new landfill, including the affected land used for borrow material. This addition of scope to purchase land provides the benefits listed above and reduces the amount of stream taking for the development and maintenance of the new landfill.

Background

In 2005, Louisville Gas & Electric (LG&E) and Kentucky Utilities (KU) began a fleet-wide study of all coal combustion residual (CCR) storage facilities. CCR materials are the byproducts of burning coal and include the follow materials: bottom ash, pyrites, fly ash, and gypsum. The Trimble County Generating Station was identified as one of the stations requiring additional CCR storage.

Engineering on the new CCR storage plan for Trimble County began in 2005 and continues to the present. The CCR plan was divided into two stages:

- Stage I: Bottom Ash Pond Dike Extension and Gypsum Storage Pond Liner Project (TC BAP/GSP Project)

- Stage II: Landfill Project

Stage I---TC BAP/GSP Project

This scope provided for incremental storage for CCR materials while the Stage II CCR Project (Landfill) is being designed, permitted, and constructed. Construction of the TC BAP/GSP Project began in June, 2009, and was completed in December, 2011. Both BAP and GSP are now in service.

Stage II---Landfill Project

During the construction of Unit 1, LG&E purchased properties northeast of the power block and contiguous to properties containing the power block. This new property included three ravines, designated as A, B, and C, and was approximately 1,000 acres. The property is located on the east side of Kentucky State Road 1838. LG&E purchased this property for the development of future CCR storage. However, the land was never utilized until now.

Simultaneous to the design and construction of the BAP/GSP Project, design and permitting began on the CCR landfill. The Detailed Design for the Landfill is substantially completed and includes the development of approximately 220 acres for the new landfill in Ravine B only. Ravine B is bounded on the north by Wentworth Road and on the south by Ogden Ridge Road. Ravines A or C will not be utilized for CCR storage.

Various permits are necessary for the landfill. Below is a description as well as a status on each of the permit:

- DOW 401 Permit. This permit was filed in December, 2010. The permit application is pending, except as noted. The DOW Permit has the following components:
  - Flood Plain Permit. This portion of the permit was received in July, 2012.
  - Water Quality Permit (stream and wetland impacts)
  - Dam Safety Permit (embankments for Sediment Pond and Leachate Collection Pond). The permit application will be submitted in August.

- Kentucky Division of Waste Management (DWM). The DWM Permit was filed in May, 2011. DWM has issued Notice of Deficiencies (NOD) #1 and #2. A response for NOD #1 has been completed. The response to NOD #2 is currently being developed and will be submitted in August. Additional NODs are anticipated based upon experience on similar landfill projects. This permit is also pending.

- USACE 404 Permit. The permit was filed in December, 2010 and is pending. USACE has requested the following additional items:

  - A supplement to the previously submitted Alternative Analysis, which is currently being developed, including a review of the location of borrow areas.
  - A review of the karst feature known as "Lime Cave" or "Wentworth Cave" relative to the Civil War Underground Railroad. A consultant from Berea College recommended by the USACE has been retained to perform this consultation.
  - A review of the View Shed issues relative to a local structure deemed as eligible for listing on the National Register of Historic Places. (Section 106).

Originally, property acquisition for the Trimble County CCR Landfill was not required, since the properties had already been obtained. However, due to permitting changes and other issues, property acquisition should now be considered for the following reasons:

1. **<u>Borrow Areas and Associated 401 and 404 Permitting Issues</u>**. The development of the Trimble County Landfill may now require additional borrow materials, including top soil, clay, and blasted rock to provide for the following:

- Clay subbase for the lined landfill
- Structural fill

- Aesthetic berms for shielding the view of the landfill from adjacent neighbors
- Other future soil borrow needs

As part of the USACE 404 Permit, a meeting was held at the Trimble County site in December, 2011, to review the pending permit. Representatives from the EPA and DOW personnel were also present.

At this meeting, these regulatory agencies indicated that the stream and wetland impacts being proposed by LG&E were excessive. As a result of this meeting, LG&E reduced the impacts by removing all of the proposed borrow areas from the upper terraces of Ravine A. (The Landfill is being built within Ravine B, which is located immediately to the south of Ravine A).

LG&E was also requested to revise the Alternative Analysis contained in the 404 Permit. In this revised analysis, the USACE has requested an additional analysis of alternative borrow sites, since 24% of the stream and wetland impacts in the permits are due to stream and wetland impacts in the borrow sites.

By purchasing these proposed properties, additional borrow sites will become available, outside of the existing permit boundaries. LG&E will be able to demonstrate to the USACE and EPA that the streams and wetland impacts in Ravine B have been further minimized. This would reduce one of the USACE and EPA objections to the pending 404 Permit.

2. **Borrow Areas and Associated DWM Permitting Issues**. In addition, when the DWM issues the landfill permit, various permit conditions will be included. Many of these conditions exist to protect adjacent property owners. If LG&E obtains additional properties, some of the permit conditions may be mitigated or eliminated.

3. **Optimization of Borrow Areas for Landfill Construction**. The additional properties will also allow the Trimble County Landfill Design Engineer to optimize the borrow areas, which may result in project cost reductions.

4. **Future Landfill Cover for Operations**. In addition to the borrow areas required to meet the requirements of the construction of the landfill, borrow materials are also required for landfill cover during operation of the landfill. As CCR materials are placed in the landfill during operation, the exposed or "open" faces must be periodically covered with a suitable soil cover. This cover prevents fugitive dust from the CCR materials (bottom ash, pyrites, fly ash and gypsum). Also, the cover reduces water from penetrating into the core of the landfill.

   The landfill cover materials will require soil borrow areas, which have the same issues as with the USACE's permitting as indicated above.

   Without this landfill cover material being available near the landfill, it will be necessary to truck the landfill cover from off-site at a considerable operating expense, similar to what has been experienced at other LG&E landfills.

5. **Additional Buffer beyond Statutory Requirements**. The current landfill design includes provisions for buffer as required by Kentucky statutes for special waste landfills within the properties owned by LG&E. These newly procured properties will provide additional buffer, over and above what is required by statute. This additional buffer is deemed a prudent mechanism to reduce or eliminate future neighbor complaints due to noise, dust, and other issues during the operation of the landfill.

6. **Reduces Potential of Reverse Condemnation Litigation and Community Goodwill**. Adjacent property owners to the proposed landfill may litigate for reduced property value due to the construction and operation of the adjacent landfill, a process known as "Reverse Condemnation."

   In these cases, where the landowner prevails, LG&E would be forced to pay the difference between the land value before landfill development/operation and the land value after landfill development. In these cases where judgment is granted against LG&E, costs would be expended for which LG&E receives no value.

If the properties are purchased before Reverse Condemnation, then this issue is eliminated and LG&E has additional properties to show for the costs.

In most cases, where properties are being considered for purchase, the property owner approached LG&E with a desire to sell. By buying these properties, it gives the property owner an opportunity to relocate to another location, thereby eliminating their objections to the landfill.

7. **Optimize View Shed Design**. A requirement of the landfill design is the construction of aesthetic berms and other means to "hide" the view of the landfill from the public. This is commonly known as "view shed." By obtaining these adjacent properties, the view shed design can be optimized, and in some cases, may be reduced or eliminated altogether.

   One property in particular, the Stansbury property, has been evaluated and may be eligible for listing on the National Register of Historic Places. Special view shed considerations will need to be included in the design due to this potential designation.

8. **Optimize Surface Drainage Design**. Directing rain water around the perimeter of the landfill is a significant part of the Detailed Design of the landfill. By obtaining these adjacent properties, the rain fall diversion ditch design will be optimized. This optimization may create more space available for CCR storage.

Project Description

Authority is being sought to procure additional properties contiguous to the proposed Trimble County Generating Station landfill. All of these properties are either on Ogden Ridge Road or Wentworth Road. The potential purchase includes up to seventeen (17) parcels for a total of approximately 480 acres.

All the properties are either on the east or south sides of the landfill. Ravine A is located on the north side of the landfill and LG&E owns all the property on the west side. See Appendix I (project drawing TC0-C02418 Revision A) which shows the proposed properties relative to the landfill. The proposed properties are REDACTED.

The property acquisition will be part of the Trimble County CCR Landfill Project. This project's initial phase was approved for $79,720k (net) or $ 106,293 (gross) at the Investment Meeting on October 15, 2009 (Project Numbers 127135 and 127134). See Appendix II for the Original Investment Proposal. This original proposal included the following:

- Engineering for the landfill development and CCR Treatment/Transportation
- Permitting, and
- Construction of Phase I of the Landfill

The Trimble County CCR Landfill Project has received Environmental Cost Recovery (ECR) approval in June 2009 as well as approval from the Kentucky Public Service Commission.

Economic Analysis and Risks

Authority is being requested for $5.190 million (gross) or $3.893 million (net) for the purpose of procuring adjacent properties to the proposed Trimble County Generating Station CCR Landfill. This Property Acquisition has been included in the proposed 2013 Business Plan. The Property Acquisition Cash Flows by year are estimated as follows:

2012	$ 1.223 million (gross)	$ 0.918 million (net)
2013	$ 1.271 million (gross)	$ 0.953 million (net)
2014	$ 1.322 million (gross)	$ 0.992 million (net)
2015	$ 1.374 million (gross)	$ 1.030 million (net)
	$ 5.190 million (gross)	$ 3.893 million (net)

Attached Appendix III shows the details for the property acquisition estimate.

No contingency has been included.

The above amount for property acquisition can be absorbed in the existing authority. However, at a later date, additional authority will be sought for the latter phases of the project due the following:

- Increased Landfill construction cost due to changes from the Final Conceptual to the Detailed Design,
- Increased CCR Treatment and Transportation infrastructure estimate due to changes from the Initial Conceptual Design to the Final Conceptual Design

- ### Risk of Project

  The risks associated with this project are only associated with a "do-nothing" approach, which has the following risks:

  - Reduces stream and wetland impacts to the Ravine B water shed
  - Provides additional property buffers between local residents and the landfill
  - Optimizes the landfill and view shed designs
  - Provides additional landfill cover for use during operation
  - Eliminates the potential for Reverse Condemnation Litigation
  - Reduces complaints during construction and operation of the landfill

- ### Other Alternatives Considered

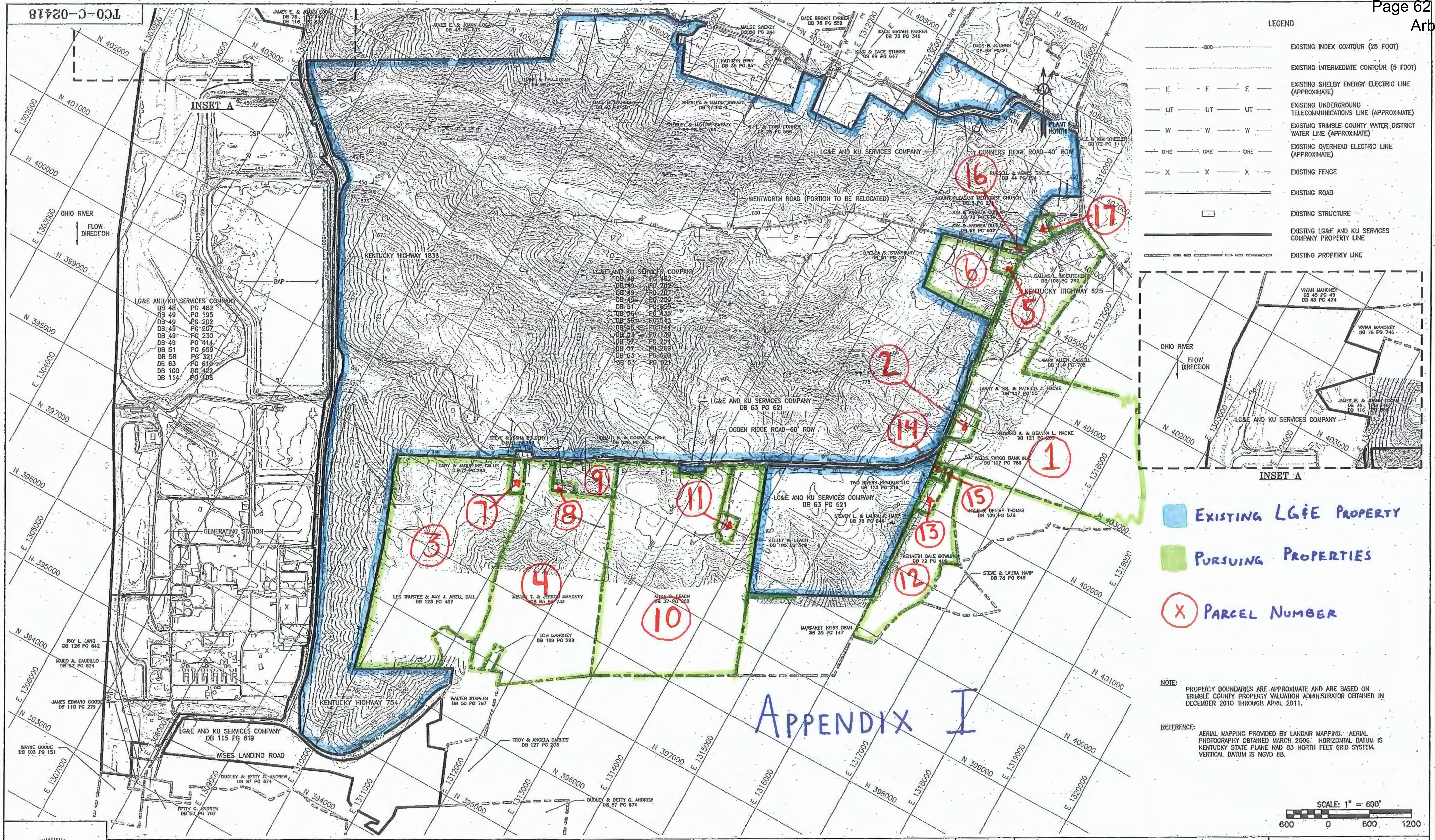
  The only Alternative is the "do-nothing" approach. The risks associated with this Alternative are discussed above.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the **Trimble County CCR Project, Additional Landfill Property Acquisition** project for **$ 5,190 k (gross) and $ 3,893 k (net)**.

Attachments

Appendix I:	Property Drawing TC0-C-02418 Revision A
Appendix II:	Original Investment Proposal dated October 15, 2009
Appendix III:	Cost Estimate



DRAWING RELEASE RECORD

REV.	DATE	PREPARED	APPROVED	PURPOSE
A	4/18/11	TPM/RPH	KCC	KY-DWM SPECIAL WASTE PERMIT APPLICATION

This drawing was produced with computer aided drafting technology and is supported by electronic drawing files. Do not revise this drawing via manual drafting methods.

gai consultants

DRAWN: IP APPROVED: KCC
CHECKED: RPH DATE: 4/18/11
DRAWING NUMBER: C100784-00-003-00-E-E001
SHT. NO. 1 OF 1

PITTSBURGH OFFICE • 385 EAST WATERFRONT DRIVE, HOMESTEAD, PA 15120-5005

SCALE 1" = 600'

Title
TRIMBLE COUNTY GENERATING STATION LANDFILL
SPECIAL WASTE PERMIT APPLICATION
ATTACHMENT 1/3 - 1
PROPERTY MAP

Location and Unit:
TRIMBLE COUNTY GENERATING STATION

LG&E

Drawing No: TCO-C-02418
Rev.: A

DMS Version 2.0

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Investment and Contract Proposal for Investment Committee Meeting on: March 30, 2016	
Project Name:	Trimble County Coal Combustion Residuals Project – Phase I
Contract Name:	Trimble County Coal Combustion Residuals Treatment Project - Engineer, Procure, and Construct
Initial Project Total Approved: Phase I Sanction $106.0m (Gross); $79.0m (Net)[1]	
Revised Project Total Seeking IC Approval: Phase I Sanction $369.0m (Gross); $276.0m (Net)[1]	
Total Initial Contract Authorization: $256.0m (≈ 5% contingency) Gross	
Total Initial Contract Authorization: $192.0m (≈ 5% contingency) Net[1]	
Business Unit/Line of Business: Project Engineering	
Prepared/Presented By: Joan Lipp and Scott Straight	

Executive Summary

The Trimble County Coal Combustion Residuals (CCR) Project was originally approved by the Investment Committee on October 15, 2009 at a partial sanction for Phase I of $79.7m (Net) and a total Project cost of $228.0m (Net), which can be found in Appendix A. This authorization request seeks approval to increase the sanction to $369.0m[2] (Gross), $276.3m (net) to cover all major components of Phase I, *less the cost of constructing the landfill proper*. This request also seeks approval to award the Trimble County Coal Combustion Residual Treatment & Transport (CCRT) Engineering, Procurement, and Construction (EPC) contract to [redacted] for an initial award amount of $225.0m (Gross), with a total contract authorization of $256.0m[3] (Gross), $192.0m (net) inclusive of a 5% contract management contingency. The 2016 BP for the scopes included in this sanction is $338.0m (Gross), $253.5m (net) compared to the request of $368.7m (Gross), $276.5m (net). This variance of $23.0m (net) is an increase of 9.1 percent above the amounts included in the approved 2016 BP for these scopes. Funding for construction of the Phase 1 landfill proper is not included in this sanction request, but will be requested at a later date in concert with the receipt of permits and initial bids of Landfill Phase I construction.

Phase I scope included in this request is comprised of the following components:

- EPC contract award to [redacted] for the CCRT system, including the bottom ash and gypsum dewatering systems, conversion of station fly ash transport from wet to dry conveyance, fly ash storage silos, pipe conveyor from the CCRT area to the landfill location;

[1] Co-Owners of the Trimble County plant: Illinois Municipal Electric Agency (IMEA) and Indiana Municipal Power Agency (IMPA) are responsible for 25%. IMEA owns 12.12% and IMPA owns 12.88%.
[2] This amount is $31.0m (Gross) greater than 2016 BP process. Total does not include Bottom Ash Pond/Gypsum Storage Pond (BAP/GSP) or Holcim project costs.
[3] This amount is $21.0m (Gross) greater than 2016 BP. The contingency is calculated based on a total CCRT EPC contract price of $244.0m (Appendix D), which includes option pricing for various equipment, installation and engineering.

- Landfill engineering, permitting and construction
  - Landfill permitting engineering, studies and activities
  - Payment of landfill stream and wetland mitigation fees
  - Payment of Indiana Bat mitigation fees
  - Property Acquisition (properties to date and future purchases)
  - 345kV transmission line relocation in the future landfill area
  - Construction of the bridge, road and pipe conveyor to the future landfill area (this is managed under the CCRT EPC as a separate release)
  - Fencing and utility relocation in the future landfill area

While the bridge, road and pipe conveyor from the station up to the landfill area is included in this sanction, the project schedule and termination costs related only to transporting of CCRs (Transport Subproject[4]) to the landfill is estimated based on receipt of permit approvals by October 1, 2016. The EPC contract has provisions for addressing any duration delay or termination. If permit approval is received after October 1, 2016, the cost impacts would be agreed upon per terms of the contract based on date certain of permit issuance. The delay would result in transporting CCRs to the landfill via truck rather than the pipe conveyor. All other work would not be affected.

The EPC authorization request seeks approval to enter into a fixed price, lump sum contract (the "Contract") with [redacted] for the Trimble County CCRT EPC Contract Proposal. [redacted] was the EPC firm for the successful E.W. Brown Unit 3 baghouse project, the Trimble County Unit 1 baghouse project and is currently constructing the E.W. Brown 10 MW Solar facility. The EPC scope includes the engineering, procurement, and installation of one (1) 100% under-boiler submerged flight conveyor for dewatering Unit 1 bottom ash, two (2) 100% gypsum dewatering belts, vacuum/pressure fly ash transport system for Unit 1 and Unit 2, two (2) concrete fly ash silos, modifications to the plant's existing CCR handling systems, an overland pipe conveyor, ancillary balance of plant systems/components, and a bridge and road to the planned landfill area. This scope also includes demolition necessary to construct the scope listed above. This Contract is expected to begin in early April 2016 and be utilized through completion of the CCRT project in 2018.

With regards to our partners at Trimble County (i.e. IMPA and IMEA), they have reviewed the contract and sanction recommendation. There have been reviews held with both partners in joint meetings. Both partners are in favor of the EPC award and moving the requested sanction forward. Both partners expect to have their internal and board approvals by April 2, 2016 and be in a position to sign the EPC the first week of April, 2016.

Background

The purpose of the TC CCR Project is to provide dry permanent storage (a special waste landfill) for all CCR generated from the Station with an estimated 37 years or more of storage capacity. Based on projections of remaining life of the existing CCR disposal facilities (Bottom Ash Pond

[4] The Transport Subproject costs are $59.0m (Gross). Termination costs due to Contractor prior to October 1, 2016 of $1.3m are owed for engineering and locking-in pipe conveyor delivery.

and Gypsum Storage Pond) at the Station, the landfill and CCRT construction should begin in 2016 in order to avoid more costly transport and disposal of CCR materials at an off-site location.

The landfill will be located in Ravine B, which is located east of the Station on property owned by LG&E. The footprint of the proposed landfill will occupy an estimated 189 acres. The major ancillary components of the landfill include a leachate pond, sediment pond, storm water collection and diversion ditches, soil borrow areas, a bridge and road across State Road 1838 to the landfill area, and a CCRT system including an overland pipe conveyor.

The project was approved by the Kentucky Public Service Commission (KPSC) in 2009 and reaffirmed for Phase I in late 2015. Permitting activities have been on-going continuously since 2009 and the landfill permit is expected to be issued by the KYDWM in the fall of 2016. The progression of the relevant and subsequent planning and regulatory coordination actions to date is summarized in Appendix B.

Project Description

The Trimble County CCR project includes the engineering, permitting, procurement, construction and commissioning of new CCRT facilities, as well as a new CCR landfill and associated infrastructure for the storage and management of CCR generated at the Trimble County Station. The CCRT facilities will collect, condition, dewater, store, and transport CCR materials (fly ash, bottom ash, gypsum) to the new landfill for storage. An overland pipe conveyor will be used for primary transport of the CCR materials to the landfill. The new landfill will be located on LG&E property in Ravine B which is located northeast of the power block on the east side of State Road 1838. A road and bridge over State Road 1838 will be constructed to provide access to the landfill area from the power block area.

The CCRT facilities will include a new Unit 1 and Unit 2 fly ash system consisting of pneumatic conveying equipment, fly ash silos, and conditioning equipment used for transport, temporary storage, and conditioning of economizer ash, air heater ash, and fly ash collected in existing electrostatic precipitators (ESP) and pulse-jet fabric filters (PJFF). A new Unit 1 bottom ash system will be constructed for dewatering and temporary storage of Unit 1 bottom ash. This scope includes a new reclaim system for Unit 1 bottom ash, Unit 2 bottom ash and pyrites, and Unit 1 pyrites. A new Unit 1 and Unit 2 gypsum dewatering facility will be constructed for dewatering and temporary storage of each unit's dewatered gypsum. This scope includes horizontal vacuum filters for gypsum dewatering and a portal reclaimer to recover stored gypsum. A series of new belt conveyors and an overland pipe conveyor will be constructed to transport the conditioned/dewatered CCR materials to the landfill.

The landfill will be designed and constructed to store CCR over an approximately 37 year period. The landfill will be developed in four construction phases with each fully integrated as an extension of the adjacent landfill phase or cell. Each phase will have an estimated lifespan (placement of CCR) of between 6 to 12 years. The landfill will be constructed with an engineered composite liner system consisting of a prepared subgrade, a synthetic liner, leachate collection system layer (including piping), and a protective clay soil cover. This system of engineered layers will be constructed in order to contain the CCR and collect leachate that may accumulate, while protecting groundwater. Additional infrastructure for the landfill facility will include paved haul roads, access roads, a drainage system to separate CCR contact water from non-contact surface water, a sediment basin and erosion control features for storm water management, a lined leachate pond, and groundwater wells for monitoring groundwater quality.

Contract Description

The CCRT EPC contract is a fixed price, lump sum contract negotiated by PE and Legal. The duration of the contract is approximately three (3) years with a two (2) year warranty period that ends on the second anniversary of Commercial Operation of the CCRT system. The Contract has been divided into four (4) Subprojects: Bottom Ash, Fly Ash, Gypsum and Transport. Each Subproject has its own independent Guaranteed Commercial Operation Date. The contract will be paid out in accordance with a milestone payment schedule commensurate with completion of the work. Individual milestone payments will not exceed work performed and the maximum monthly cash flow will be limited by the aggregate of the monthly milestones.

Additional components of the contract are listed below:

- Contractor is required to comply with all Health & Safety Requirements.
- No "First of a Kind" technology is acceptable without LGE-KU's written consent.
- Termination - convenience and cause, with the aggregate payment amount outlined on a percentage basis for each month of the contract through commercial operation.
- Delay Schedule for Transport Subproject – due to uncertainty associated with the timing of landfill permit approvals (required for construction of the Transport Subproject), a payment schedule is included with payment amounts for each month the Work associated with the Transport Subproject is delayed.
- Any legal action will be in the Federal District in Louisville, Kentucky, with no jury.
- The overall limit of liability is 100% of the Contract price.
- Liquidated Damages (LDs) – LD's shall apply to unit derate and outage hours, auxiliary power consumption limits as defined in Exhibit G, and availability.
- Performance Guarantees – Described in detail in Exhibit G of the Contract. Specific Performance Guarantees include: bottom ash dewatering system, fly ash conveying system, gypsum dewatering system, pipe conveyor system, sound emissions, dust emissions, reliability, and auxiliary power consumption.
- Warranty – Twenty-four (24) months after Commercial Operation for each Subproject. Any extended warranties from equipment manufacturers under this Contract flow to LGE-KU after the two (2) year warranty provided by [redacted].
- Insurance – Company named as additional insured and Contractor waives rights of subrogation and general liability limits as set forth and agreeable to our consultant, Risk Management Services Company. [redacted] will hold the overall builder's risk policy with policy limit to the value of the Contract.
- Intellectual Property – Contractor grants an irrevocable, permanent, transferable, sub-licensable, non-exclusive, fully assignable, royalty-free, paid-up license to copy, perform, display, and otherwise use the information and intellectual property to allow owner to operate, maintain, repair, train personnel, modify, improve, and alter the work.

- Indemnity – Indemnification by [redacted] includes third party claims, personal injury, property damage, claims by government authorities (arising from violation of law), and claims by government authorities for taxes and liens.
- Risk of Loss – Care, custody and control will pass to LGE-KU upon achievement of Commercial Operation.
- Performance Securities – The contract includes a parent guarantee from AMEC Foster Wheeler PLC and three (3) Letters of Credit totaling $45.0m (20% of $225.0m Contract value).
- Key Dates:

Table 1

Schedule Milestone		Date
Mobilization		2Q 2016
Fly Ash Subproject	**Guaranteed Commercial Operation**	July 31, 2018
	Guaranteed Final Completion	August 30, 2018
Bottom Ash Subproject	**Guaranteed Commercial Operation**	February 24, 2018
	Guaranteed Final Completion	March 30, 2018
Gypsum Subproject	**Guaranteed Commercial Operation**	July 31, 2018
	Guaranteed Final Completion	August 30, 2018
Transport Subproject	**Guaranteed Commercial Operation**	July 31, 2018
	Guaranteed Final Completion	August 30, 2018

Economic Analysis and Risks

- **Bid Summary**

After specification and conceptual development in concert with the Trimble County engineering and management team, a RFQ was sent to the following five (5) bidders on July 2, 2015: [redacted] and [redacted]. A pre-bid meeting was held at the Trimble County Station on July 21 and 22, 2015.

Bids were received on October 8, 2015, from four (4) bidders as [redacted] declined to bid. PE provided un-priced copies of the bids to the Trimble County Station staff, [redacted] and [redacted] for their use to complete a technical evaluation of the submittals. PE conducted an initial bid evaluation encompassing price (See Table 2 "Initial Proposal"), commercial terms and adherence to the technical specifications in preparation for bid review meetings (bidder presentations). As part of the initial bid evaluation process, technical bid clarification questions were developed and issued to all bidders.

Each of the bidders was required to present their proposed project teams, technical offering, and to demonstrate their understanding of the required scope, project execution, schedule and technical requirements. The bidder presentations took place during the week of November 2, 2015, with participants from PE, Trimble County Station staff, [redacted] and [redacted] Multiple rounds of bid clarifications were issued to all bidders after the bid review meetings and were based on a review of schedule, cost, man-hours, unit quantities, and terms and conditions. These clarifications were intended to normalize bidders' responses for comparison to the required scope of work.

After reviewing the multiple rounds of clarifications, each bidder was evaluated on the following components of their proposal: safety, pricing, risk assessment, project plan, construction, schedule, technical plans and expertise, experience, project management and contract clarifications and exceptions. The combined rankings by the Station staff, [redacted] and PE are as follows: [redacted] 73.92, [redacted] 64.27, [redacted] 60.65, and [redacted] 45.16, with 100 being the maximum score. Complete rankings for all four (4) bidders are located in Appendix C – TC CCRT EPC Bid Evaluation Matrix. Zachry was eliminated from further consideration based on the Bid Evaluation Matrix results and a large disparity in price.

After these clarifications, several LGE-KU internal technical bid review meetings were conducted with PE, Trimble County Station Staff and [redacted]. These technical meetings primarily focused on issues associated with the proposals such as building layouts, maintenance access, equipment redundancy, plant operations, and proposed equipment suppliers. The proposals were reviewed in detail to verify compliance with the scope of work, identify opportunities for operation and maintenance improvements, incorporate clarifications to the specifications for a more complete adherence to the Trimble County Station standards, and agreement to the specifications. These additional technical reviews did not change the EPC Bid Evaluation Matrix results but aided in the consistency of Best and Final Offer (BAFO) from the remaining Short List bidders. On January 28, 2016, PE issued a list of technical clarifications to all three (3) remaining bidders, and requested that each bidder provide a BAFO.

After receipt and review of the BAFO from the remaining bidders, it was determined that [redacted] was the best evaluated bidder and had the lowest price among the bidders (see Table 2, BAFO).

To support further consideration of [redacted] proposal, PE visited a gypsum dewatering facility at a plant in Georgia which had previously been designed and constructed by [redacted] was responsible for engineering and construction; purchasing of major equipment was provided by the owner. PE's overall evaluation of [redacted] work was favorable, as their work product was equivalent to our current contractors. Discussions with the owner indicated they had no major issues with [redacted], and wouldn't hesitate to award the project to [redacted] again. In addition, LGE-KU has a significant amount of experience working on large EPC contracts with [redacted] (e.g. – Trimble County Unit 1 PJFF, E.W. Brown PJFF and Solar Projects.)

The PE commercial team and Legal met with [redacted] on several occasions starting January 11, 2016, to review technical and commercial matters. Performance guarantees, warranties, LDs, performance securities and insurance requirements were discussed among other key project topics. During this process, there were no serious obstacles to overcome in an effort to reach agreed upon contractual terms with [redacted] Certain schedule, equipment, and commercial offerings resulted in the agreed Initial Lump Sum Contract Award as shown in Table 2 below.

Table 2 (CONFIDENTIAL DUE TO BID DATA)

Competing Bids ($ in Millions Gross)				
	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BAFO	[redacted]	[redacted]	[redacted]	[redacted]
Initial Lump Sum Contract Award	$[redacted]			

- **Financial Summary**

Table 3 below highlights the budgeted amounts as reflected in the approved 2016 Business Plan (BP) against [redacted] BAFO cash flows, inclusive of 5% contract management contingency.

Table 3

Contract Expenditures ($ in Millions Gross)	Prior to 2016	2016	2017	2018	Total [2]
2016 BP [1]	$0	$88	$87	$60	$235
Total Contract Authorization Seeking Approval[3]	$0	$87	$79	$90	$256
Variance to 2016 BP[2]	$0	($1)	($8)	$30	$21

1 – Costs shown are for the portions of Phase I which pertain to the scope of the CCRT Contract.

2 – The 2017 BP will be updated based on the cash flows developed during final negotiations with AMEC along with the appropriate project contingencies.

3 – Total contract authorization is greater than initial lump sum bid for additional expenditures, due to studies, options, and plant requested items (See Appendix D – Project Cost Summary).

Table 4 lists the budget breakout that supports the current project forecast as compared to the 2016 BP. Any project overage will be addressed during the 2017 Business Plan process.

Table 4

Financial Detail by Year - Capital ($000s) (all amounts are Gross)	Pre 2016	2016	2017	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	36,435	128,114	134,579	146,323	15,694	16,772	-	477,917
2. Cost of Removal Proposed	-	-	-	-	-	-	11,742	11,742
3. Total Capital and Removal Proposed (1+2)	36,435	128,114	134,579	146,323	15,694	16,772	11,742	489,659
4. Capital Investment 2016 BP	43,362	141,097	124,391	109,481	12,094	16,772	-	447,197
5. Cost of Removal 2016 BP	-	-	-	-	-	-	11,742	11,742
6. Total Capital and Removal 2016 BP (4+5)	43,362	141,097	124,391	109,481	12,094	16,772	11,742	458,938
7. Capital Investment variance to BP (4-1)	6,928	12,982	(10,188)	(36,842)	(3,600)	-	-	(30,721)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	6,928	12,982	(10,188)	(36,842)	(3,600)	-	-	(30,721)

Note: Amount requested of $489.0m (Gross) is $31.0m (Gross) greater than 2016 BP; however, the project overage will be adjusted during the 2017 BP process. The $31.0m (Gross) overage is comprised of $21.0m (Gross) greater costs than the 2016 BP amount for the EPC, and $10.0m (Gross) greater than the 2016 BP amount for costs other than the EPC. Totals do not include BAP/GSP or Holcim project costs.

- **Risk of Contract**
  The risks of the Contract are as follows:

  - **Price Risk:** The EPC Contract is to be a fixed price, lump sum contract.

  - **Schedule Risk:** The project has a very aggressive timeframe that [redacted] believes they can meet. The Transport Subproject schedule is estimated based on receipt of permit approvals by October 1, 2016. Any change in permit issuance from the state/federal agencies will result in Guaranteed Commercial Operation Date and Final Completion Date adjustments only to the Transport portion of the CCRT EPC. The Bottom Ash Subproject will be installed during the fall 2017 eight (8) week outage on Unit 1. The work associated with this outage is scheduled to be completed in six (6) weeks to allow time at the end of the outage timeframe for cold-commissioning. The major risk of not proceeding is the remaining life of the BAP due to water volume and the pH operational issues associated with the existing CCR transport water systems. Delaying the CCR treatment portion of the overall Trimble County CCR Project is not recommended. This significant risk of delay was clearly communicated in the KPSC review held in late 2015.

  - **Financial Risk:** A financial analysis of [redacted] was conducted by the Company Credit Department before prequalification and after BAFO. The review of the financial statements yielded an adequate rating. [redacted] is providing Letters of Credit (which would represent 20% of the Contract value), and [redacted] is providing a parent guarantee.

  - **Risk Mitigation Factors:** Components of the Contract that are designed to mitigate the risks of the Contract are described in the Contract Description section of this paper.

- **Other Alternatives Considered**

  - A "do nothing" alternative was not considered due to the requirements for the new CCRT system described previously.
  - A rigorous bid process was held where four (4) bidders were considered and the recommended contractor meets the technical and commercial requirements to complete the project. Award to an alternate acceptable bidder at a minimum $6,000k higher cost.
  - Due to potential permit delay related to the Transport Subproject, this work would be deferred until the landfill permit was obtained. This delay affects placement of the CCRs in the landfill. The balance of scope associated with Fly Ash handling, TC1

Bottom Ash conversion from wet-to-dry, and Gypsum dewatering would be completed by the EPC per the agreed schedule. Various options have been documented to management and governmental agencies that specifically list numerous options for CCR placement that include on-site, sending CCRs off-site related to beneficial use arrangements, or transport to another permitted location off the Trimble County site.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the revised Trimble County Coal Combustion Residuals Project – Phase I sanction for a total authorization of $369.0m (Gross) which releases all scopes on the project except for the construction of the landfill proper.

It is recommended that the Investment Committee approve the award of the Trimble County Coal Combustion Residual Treatment & Transport EPC contract to [redacted] for an initial award amount of $225.0m (Gross) and a total contract authorization of $256.0m (Gross), which is inclusive of a 5% contract management contingency.

Joan S. Lipp
Joan S. Lipp
Mgr. Major Capital Projects

Anthony L. Ruckriegel 4/5/2016
Anthony L. Ruckriegel
Mgr. Contracts/Major Capital Projects

4/5/16
R. Scott Straight
Dir. Project Engineering

4/5/16
DOA for J. Voyles
John N. Voyles
VP Transmission & Generation Services

Ralph Bowling 4/6/16
D. Ralph Bowling
VP Power Production

4/6/16
Paul W. Thompson
Chief Operating Officer

KW Blake 4/7/16
Kent W. Blake
Chief Financial Officer

4/11/16
Victor A. Staffieri
Chief Executive Officer

Investment Proposal for Investment Meeting on: **October 15, 2009**

Project Name: **Trimble County CCP Project**

Total Expenditures: **Phase I – $79,720k (net) & Total Project – $227,973k (net)**

Project Number: **127135 and 127134**

Business Unit/Line of Business: **Generation Services/Project Engineering**

Prepared/Presented By: **R. Waterman/J. Heun/S. Straight/T. Crutcher**

Executive Summary

The Coal Combustion Products (CCP) from the Trimble County Generating Station are treated and stored at on-site facility called the Bottom Ash Pond (BAP). The CCP materials include gypsum, bottom ash, fly ash, and pyrites. In addition, the pond is used to treat and store waste materials from various operating sumps. The BAP is located at the far north end of the Generating Station and was constructed with Unit 1. Recent bathymetric (volume) surveys indicate that the BAP will be at capacity in early 2011, several months after Unit 2 is scheduled begin commercial operations.

The Trimble County CCP Project has been under development for over four years. The Project has been divided into two stages. The first stage is the extension of the BAP Dikes and lining of the Gypsum Storage Pond (GSP). This first stage has been previously approved by the Investment Committee and work is currently in progress. This first stage will provide incremental storage until the second stage can be placed into service. The second stage of the CCP project includes the development, permitting and construction of a landfill at the head of Ravine B. Approval for the second stage of CCP project is sought in this Investment Paper.

MACTEC was contracted in 2005 to provide an Initial Siting Study (Conceptual Engineering) and subsequently retained to perform additional studies related to the project. Additional studies performed by MACTEC include Final Conceptual Study for Impoundments, Initial Siting Study for Landfills, and Final Conceptual Study for Landfills. Detailed descriptions of the studies performed are provided in the Project Description section of this paper.

Based on the numerous studies performed by [redacted], NPV cost analysis, environmental concerns, and permitting issues (KPDES and KDWM) it was determined that Case 21 was the best alternative for long term CCP storage. Case 21 is a single combined landfill in upper Ravine B with a pipe conveyor for CCP transport from the plant to the storage facility, a design life of 40 years, and a final crest elevation of 910 feet above sea level. Further NPVRR analysis supports this selection of Case 21 and the results of the analysis are proved in the Financial Summary section.

Total capital cost for the overall project is projected at $303,964k (gross) and is based on Level I Engineering. Capital cost for Phase I only is $106,293k (gross) and will provide 12-years of the 40-year design life. All phases of the Trimble County CCP Project are eligible for ECR recovery and a request to recover Phase I expenses was included in the June 2009 ECR filing. Phase II and Phase III activities will be presented to the Investment Committee for approval and seek ECR recovery at a later date.

Project Description

- **Project Scope and Timeline**

Initial Siting Study
During the Initial Siting Study performed by [redacted] approximately twelve (12) on-site and off-site storage options were considered in addition to the evaluation of various material handling alternatives. Ultimately, a decision was made to pursue the storage of CCP materials in Ravines A and B.

The ravines were purchased and permitted by LG&E during the construction of Unit 1 for the purpose of landfilling the CCP materials. However the landfills were never constructed. The ravines are located northeast of the power block and are contiguous with the remainder of the Trimble County Generating Station properties.

Final Conceptual Study for Impoundments
Based upon the Initial Siting Study results, [redacted] was retained to perform the Final Conceptual Design. As part of this study, a decision was made in December, 2006 to pursue the incremental storage of CCP materials in the existing Bottom Ash Pond and Gypsum Storage Pond (GSP) due to their lower cost per ton of storage. This also provided storage contingency during the development, permitting, and construction of CCP storage in the ravines.

Simultaneous to the engineering design of the BAP and GSP, [redacted] continued to evaluate storage options in the Ravines. Twelve (12) sets of design parameters were considered for three (3) scenarios which included fly ash in Ravine A, gypsum in Ravine B, and both materials in Ravine B along with various numbers of dike alternatives. Both landfills and impoundments were considered along with various CCP transport methods.

Ultimately, the E.ON U.S. project team selected a 40-year storage plan which consisted of an ash pond in Ravine A (Scenario 6) and a gypsum pond in Ravine B (Scenario 10). [redacted] then began developing a phased construction approach for the storage facilities.

The Final Conceptual Study was completed in late 2008. In December 2008, prior to start of the Detailed Engineering Design for impoundments, E.ON U.S. received word that the US EPA Region IV would reject the Trimble County KPDES permit modification application. This rejection was due to the use of fly ash water for use in the FGD processes at Trimble County and the plan to discharge gypsum sluicing water to the Ohio River. As a result of this decision the use of impoundments to treat CCP materials was reviewed and it was determined that due to a significant water balance issue for the station once TC2 became operational, impoundments were no longer feasible and the CCP materials would need to be placed in a landfill.

Initial Conceptual Study for Landfill Development
[redacted] in early January 2009 was commissioned to develop an Initial Conceptual Design for a landfill in Ravines A and/or B utilizing various material transport options included sluicing, trucking, pipe conveyor and dense slurry systems. This resulted in a total of nineteen (19) initial cases being evaluated during the Initial Conceptual Design.

During an April 8, 2009 review meeting, the majority of the storage scenarios were eliminated from further consideration due to cost, permitting, or other significant reasons. Ravine A options were eliminated since all CCP material could be stored in Ravine B and trucking of CCP materials to the ravine area was eliminated due to fugitive dust issues. Other cases were added as "hybrids" by combining some of the above cases.

[redacted] and E.ON U.S. met with the Kentucky Division of Waste Management (KYDWM) on April 17, 2009 to review the remaining conceptual storage scenarios. During this meeting, the agency expressed a preference to locate storage facilities in one ravine and to avoid storage facilities in both ravines confirming our decision during the April 8, 2009 review meeting. The use of only one ravine would be better received by the surrounding public and potentially less opposition would occur during the permit review process. The KYDWM also acknowledged that E.ON U.S. has an existing permit for development of a landfill in both Ravines A and B and indicated that the "new" permit application would be considered a "major permit modification."As a result of this meeting, no further consideration was given to landfill storage in Ravine A.

After several additional cases were eliminated, revised cash flow projections were developed and an initial draft report was issued on April 30, 2009. Based on the updated cost estimates, NPVRR analysis, and environmental issues, the Initial Siting Study recommended 3 cases for further development (Case 16, 21, & 23).

Final Conceptual Study for Landfill Development

The three remaining cases were further evaluated during the Final Conceptual Design. At this stage, all storage options were normalized to a 40-year storage life based on tonnage projections provided by E.ON U.S. Generation Services. Case 16 is two separate landfills, one for gypsum and one for fly ash. Cases 21 and 23 are combined landfills with slightly different configurations. A major difference between the alternatives it the peak elevation of the landfill above sea level as noted below.

Case	Peak Elevation
16	980 feet
21	910 feet
23	1000 feet

Cases 16 and 23 both have the disadvantage of the high peak elevation. The surrounding ridges are at elevation 800 feet approximately. Cases 16 and 23 would both be nearly 200 feet above the existing peaks, nearly the same elevation as the top of the stack at Trimble County. Fugitive dust emissions are a critical issue to the Trimble County Title V permit. The emissions are a function of the height of the landfill, so Case 21 is the favored case. Further, the permitting difficulty is also a function of the landfill height. The greater height will result in greater public opposition due to view shed issues. Taking into account the elevations and permitting issues of the three (3) cases along with the NPV and subsequent NPVRR analysis, Case 21 is the landfill design selected and the design this request is based upon.

Permit Studies for Landfill Development

Many of the permit studies for the previous impoundments have been completed and are also applicable to the landfill and will not be required to be repeated. However, additional studies will be required for the Indiana Bat and possibly additional studies for the historical structures as a minimum.

- **Project Cost**
  The total project cost of Case 21 (Phases I, II & III) including engineering, permitting, and construction is $303,964k (gross), including Phase I at $106,293k (gross).

APPENDIX A

Authority is requested now for $106,293k (gross) to fund the following:

- On-going engineering for landfill development, including the engineering for the CCP transportation systems, access roadways, and utilities. (Previous authority has been granted for developmental engineering.)
- Permitting of the landfill.
- Construction of Phase I of the landfill consistent with Case 21

It should be noted that budget estimates are based on Level I Engineering, the 2008 [redacted] estimated and other sources. A line-by-line contingency was added to each line item. This amount varied between 10% and 40% with a weighted average of 25% along with a 5% contingency applied to the overall estimate, 3.5% for E.ON U.S. overheads, and 6% annual escalation consistent with the 2010 MTP. Requested contingency is in line with the level of engineering and based on results from Phase I of the Brown ATB Project currently under construction. The construction contracts will be competitively bid and will likely include firm priced unit rates for units of work that cannot be defined via detailed engineering, as well as a lump sum component for fully engineered and predictable activities.

Economic Analysis and Risks

- **Assumptions**
The design life of the first phase of landfill development is assumed to be approximately 12-years (2013 to 2024). The total life is projected at 40-years for the storage of bottom ash, fly ash, gypsum, and pyrites.

- **Financial Summary**
Per E.ON U.S., an inflation rate of 6% and a discount rate of 5.4% were used for the time-value-of-money calculations. E.ON U.S. overheads were added at 3.5%. Allowances were made for mitigation of the Indiana bat, which have been found in the project area in the summer of 2009. The total capital and operational costs for storage of ash and gypsum were calculated in 2009 dollars and inflated, then discounted using the present worth method. All phases were projected to be capped in the same years. The cash flow spreadsheet results for the final round of preliminary conceptual design are summarized in the table below:

Case	NPV ($1,000)	NPVRR ($1,000)	Storage Capacity (yd^3)	Cost per Cubic Yard (2009)
16	$345,414	$357,800	36,900,000	$ 9.70
21	$300,631	$268,500	36,900,000	$ 7.28
23	$309,940	$276,400	37,200,000	$ 7.43

The NPV and NPVRR analysis, shown above, indicates that Case 21 is the best case for long term CCP storage for Trimble County.

APPENDIX A

A comparison between the 2009 and 2010 MTP/LTP plan and requested capital expenditure for Phase I is given below.

GAAP	Pre 2009	2009	2010	2011	2012	2013	Total
Case 21 (Net)	$1,500	$500	$500	$37,486	$39,734	$000	$79,720
2009 MTP/LTP	$000	$1,500	$6,900	$27,100	$45,500	$20,400	$101,400
Variance w/2009	**($1,500)**	**$1,000**	**$6,400**	**($10,386)**	**$5,766**	**$20,400**	**$21,680**
2010 MTP/LTP	$1,500	$500	$500	$34,000	$36,100	$000	$72,600
Variance w/2010	**$000**	**$000**	**$000**	**($3,486)**	**($3,634)**	**$000**	**($7,120)**

The capital cost for this investment proposal is $106,293k gross ($13.14 per cubic yard for on-site storage), or $79,720k net.

Financial Summary ($000s):	
Discount Rate CEM Model:	6.30%
Discount Rate NPVRR Model:	7.76%
Escalation	6.0%
Estimated Capital Breakdown:	
Labor & Equipment*:	$47,457
Materials*:	$15,819
Contingency (25%):	$16,444
Net Capital Expenditure:	$79,720k
NPV:	($2,887)
IRR**:	5.6%

* Assumes a 75/25 split between Labor/Equipment and Materials.
** The IRR is lower by approximately 2% points due to the less than 100% retail recovery percentage (taking into account OSS, FERC, and municipal portions).

Financial Detail by Year ($000s)	**Pre 2009**	**2009**	**2010**	**2011**	**2012**	**Phase I Total**
Project Costs (Capital proposed)(Net)	$1,500	$500	$500	$37,486	$39,734	$79,720
Project Costs (Cap. interest, if applicable)	-	-	-	-	-	-
Total project costs proposed (Net)	$1,500	$500	$500	$37,486	$39,734	$79,720
Project Costs (Capital, 2010 MTP)(Net)	$1,500	$500	$500	$34,000	$36,100	$72,600
Project Costs (Cap. interest 2010 MTP)	-	-	-	-	-	-
Total project costs 2010 MTP (Net)	$1,500	$500	$500	$34,000	$36,100	$72,600
Variance to 2010 MTP	$000	$000	$000	($3,486)	($3,634)	($7,120)
Project Costs (Cost of removal)	-	-	-	-	-	-
Project Costs (Cost of removal 2010 MTP)	-	-	-	-	-	-
Variance to 2010 MTP	-	-	-	-	-	-
Project Costs (O&M, proposed)(Net)	-	$000	$000	$000	$000	$000
Project Costs (O&M, 2010 MTP)	-	-	-	-	-	-
Variance to 2010 MTP	-	$000	$000	$000	$000	$000
EBIT	$59	$164	$213	$1,987	$5,348	$111,897
ROCE	4.0%	9.4%	9.5%	9.4%	9.0%	11.2%

APPENDIX A

- **Sensitivities**

Sensitivities	Change in EBIT					Change in NPV Total
	Pre-2009	2009	2010	2011	2012	
Project Costs (Capital +/-10%)	$6	$16	$21	$199	$535	($265)
Project Costs (O&M +/-10%)	$0	$0	$0	$0	$0	($24)

- **Environmental**
Permits for Trimble County CCP Storage Project, include, but not limited to:
  - KDWM Landfill Permit – 1 to 2 years
  - Corp of Engineers Individual 404 Permit –1 to 1 ½ years
  - KYDOW 401 Permit – 1 to 1 ½ years
  - KYDOW Dam Safety Permit (if required) – 90 days

New Source Review Evaluation, questions 1-6 (as applicable) must be completed on all investment proposals.		
1	Does the project include any new equipment or component with emissions, result in emissions not previously emitted or cause the unit to exceed any emission limit? If yes, Environmental Affairs is required to review this project. If no, go to Question #2.	**YES[1]**
2	Question 2: Is the change a like-kind or functionally equivalent replacement under $500K? If yes, the project is not subject to NSR and no further evaluation is required. If no, go to Question #3.	**NO**
3	Question 3: Does the equipment change increase the emissions unit's maximum hourly heat input? If yes, Environmental Affairs is required to review this project. If no, go to Question #4.	**NO**
4	Question 4: Does the equipment change increase the emissions unit's electrical output? If yes, Environmental Affairs is required to review this project. If no, go to Question #5.	**NO**
5	Question 5: Has the equipment being repaired/replaced been repaired or replaced in the past at this unit or other units in the fleet? If no, Environmental Affairs is required to review this project. If yes, list any known projects and go to Question #6.	**NO**
6	Question 6: Have there been forced outages or unit de-rates in the past 5 years due to this component? If no, the project is not subject to NSR and no further evaluation is required; if the answer is yes, Environmental Affairs needs to review this project.	**NO**

[1] The CCP transportation system will be an emission source. The Environmental Affairs Department was included in the development of the Trimble County CCP Landfill and agrees with the chosen path forward.

- **Risks**
  Schedule – If the Trimble County Landfill is canceled or delayed, the existing BAP and GSP will reach capacity by 2014. To keep the station operating beyond this date, CCP materials would have to be transported to an offsite storage facility at an estimated 2009 cost of $25-$30 per ton. This is several times more expensive than the capital and O&M costs of the landfill in the ravine.

  Beneficial Reuse – Remaining life of the BAP, GSP, and the Landfill can be extended if beneficial reuse opportunities materialize.

  Weather – Weather will play a major role as earthwork construction is difficult during wet and freezing conditions. If the project experiences extreme wet or cold conditions this could delay the completion of the project. The schedule developed accounts for average weather risk.

  Oil Prices – The cost of oil is another risk as oil has a direct affect on material placement unit rates as well as petroleum based products such as flexible membrane liners and filter fabrics. The 6% annual escalation is a composite rate that includes the projected cost of oil per Generation Planning.

  Permits – Denial or litigation of any of the permits could result in a substantial delay. Of particular concern would be the KYDOW 401 and Corp of Engineers 404 permits as well as the KDWM Special Waste landfill permit.

  Endangered Species - During a previous environment study, a juvenile female Indiana Bat was discovered. The Indiana Bat is classified as a Threatened and Endangered Species and as such, is protected by Commonwealth of Kentucky and Federal Law. Certain fees will be applicable for the destruction of the trees in the area of the new landfill. These fees will be negotiated between E.ON U.S., US Fish & Wildlife and Kentucky Fish & Wildlife. The applicable fee could be as high as $9,000/acre. With a landfill footprint up to 270 acres, the fees could approach $2.5 million. This amount is covered in the sanction request.

- **Other Alternatives Considered**
  Numerous combinations of landfills/ponds, materials stored, transportation methods, and locations were considered. In addition, several off-site alternatives were investigated. A "Do Nothing" alternative was not considered as this approach would require CCP disposal at a third party facility which is a very costly short term solution and doesn't meet the plants long term disposal needs.

Conclusions and Recommendation
Due to the rapidly decreasing storage capacity of the existing BAP, along with Case 21 having the lowest NPVRR cost, the least view shed issues, and the lowest peak elevation, it is recommended that the Investment Committee approve the overall Trimble County Landfill Project for $227,973k (net) and sanction Phase I for $79,720k (net) to meet the long-term CCP storage needs of the station.

APPENDIX B – TC CCR Project Key Dates

- 1979: LG&E performed a hydrogeologic investigation of Ravines A and B to assess the land's suitability for storage of CCR materials.
- 1984: LG&E proceeded with the design of disposal facilities and obtained a permit to construct a special waste landfill for CCR storage in Ravine A and B from the KY Department of Environmental Protection.
- 2005: LG&E performed a fleet-wide study of CCR storage facilities at all coal-fired generating stations. The study identified that the existing Trimble County Generating Station BAP did not sufficient disposal capacity for the long-term operation of the station. An *Initial Conceptual Design Study* considered various off-site and on-site storage alternatives and the Two-Part (short-term and long-term) Storage Plan was developed.
- 2006: The long-term part of the storage plan was developed in more detail in the *Final Conceptual Design Phase* report by [redacted] LG&E initiated correspondence with the KY Division of Water (KDOW) and the US Army Corps of Engineers (USACE) concerning the long-term disposal of CCR material and an initial meeting was held in early 2007 which was followed by several exchanges of information and requests.
- 2008: The conceptual design identified a wet disposal option (e.g., impoundment) in Ravine A and B as the recommended alternative.
- 2009-2010: With the addition of Unit 2 CCR production (in 2010), LG&E commissioned a *Final Conceptual Design Report* (2009), prepared by [redacted] which resulted in a landfill site in the upper reach of Ravine B (originally identified as Case 21) being the recommended site alternative. The US Environmental Protection Agency's (USEPA) 2010 release of a proposal to regulate CCR handling further reinforced this decision to initiate the design of a dry storage facility, or landfill.
- 2009: LG&E received ECR/CCN approval from KPSC to construct Phase I (based on landfill Case 21).
- 2010: LG&E submitted a 401/404 application to KDOW and USACE.
- 2011: LG&E submitted a special waste landfill permit application for the revised landfill design referred to as Plan II-3D to the KY Division of Waste Management (KDWM.
- 2012: In response to USEPA's request, LG&E and GAI performed a comprehensive review of the original site alternatives that were documented in the Alternatives Analysis report, in addition to evaluating and comparing additional site alternatives. The purpose was to more definitively demonstrate that the selected alternative is the least environmentally damaging practicable alternative.
- 2013: The KDWM denied the special waste landfill permit application for the selected alternative plan (Plan II-3D) based on its impact to a small karst feature known as the "Lime Cave" or "Wentworth Cave."

- 2013: LG&E and GAI reviewed several landfill alternative designs to avoid the "Lime Cave" and other small karst features; the Alternative Plan IIC-4B was selected as the least environmentally damaging practicable alternative using the Alternatives Analysis process.

- 2014: LG&E submitted a new special waste landfill application for the revised landfill design referred to as Plan IIC-4B to KDWM in January.
- 2014: LG&E submitted a permit application to construct a bridge over State Road 1838 to KY Transportation Cabinet (KTC) Department of Highways in January.
- 2014: LG&E submitted a new 401/404 application for the revised landfill design referred to as Plan IIC-4B to KDOW and USACE in April.
- 2014-2015: In January, 2014, GAI prepared an Alternatives Analysis Report which determined that the Ravine B project is the Least Environmentally Damaging Practicable Alternative (LEDPA) for LG&E's CCR facility. Region 4 of the U.S. Environmental Protection Agency wrote letters to USACE dated July 11, 2014 and August 7, 2014. These letters asserted that the Ravine B project is not environmentally acceptable, and that LG&E's alternatives analysis had not adequately justified its conclusion regarding the LEDPA. EPA recommended denial of the 404 permit application for the project as it was currently proposed. LG&E worked with Baker Botts LLP, Lee Wilson & Associates, LLC, and GAI to develop a Supplement to the Alternatives Analysis report which was intended to be a response to the two EPA letters referenced above. The Supplement was submitted to USACE in December, 2014.
- 2015: A privately held company, Sterling Ventures, filed a complaint with the KPSC, claiming that LG&E-KU should use Sterling Ventures' underground limestone mine for off-site storage of CCR, and that the KPSC should revoke all or portions of its previous orders. After several rounds of data requests from both parties, the KPSC granted LG&E-KU's request to affirm the Companies' existing CPCN and ECR authority for the Trimble County Landfill and related facilities, including the CCRT, for Phase I of the landfill and denied Sterling Ventures' request to revoke LG&E/KU's CPCN to construct the Trimble County Landfill.
- 2015: LG&E received approval of the KTC permit for bridge construction in November.

TC CCRT
BID EVALUATION MATRIX

Evaluation No.	Evaluation Category	Evaluation Factor	Category Value Points	Max Points Per Item
	Commercial		35	
1	Safety (Reviewed by Chuck Hance - see Prequalification Folder)			
		Meets Standards - Yes/No		
		LTIRC		
		RIR		
		EMR		
2	Pricing (see All Bidders Summary - BAFO 2-3-16 worksheet)			
		Base Scope		17.0
		Options		6.0
		Exhibit R Rates - Labor and Equipment (see Individual Exh R in bi		2.0
3	Risk Assessment (see Bid Risk Assessment 1-19-16 worksheet)			10.0
		Total Commercial Score -		
	Technical		65	
4	Project Plan			
		Engineering Plan/Narrative (Design/Technical)		6.0
		Construction Plan/Narrative		6.0
		Safety Plan/Narrative		3.0
5	Construction			
		Bottom Ash Subproject (Option 1)		5.0
		Gypsum Subproject		5.0
		Fly Ash Subproject		5.0
		Transport Subproject (Option 2)		5.0
		Reclaim Water Tanks - Option 1		2.0
		Construction Manhours		4.0
		In-house Work vs Subcontracted Work		2.0
6	EPC Technical Bid Compliance			6.0
7	Planned Schedule			6.0
8	Technical Expertise			3.0
9	CCRT Experience			3.0
10	Major Subcontractors/Suppliers (Exhibit E Compliance)			2.0
11	Alternate Technical Offerings			2.0
		Total Technical Score -		
		TOTALS	100	100

[redacted]

Scoring System (1-5 on each item)

Evaluation Factor	Plant (Note 1)	PE	Comm Team	BMcD Team	GAI Team	AVG Score	Overall Points
LTIRC	Y	Y	Y	N/A	N/A		
RIR	Y	Y	Y	N/A	N/A		
EMR	Y	Y	Y	N/A	N/A		
Base Scope	N/A	N/A	5	N/A	N/A	5.00	17.00
Options	N/A	N/A	1	N/A	N/A	1.00	1.20
Exhibit R Rates	N/A	N/A	3	N/A	N/A	3.00	1.20
Risk Assessment	N/A	N/A	4	N/A	N/A	4.00	8.00
Total Commercial Score							27.40
Engineering Plan/Narrative	4	4.25	N/A	4	N/A	4.08	4.90
Construction Plan/Narrative	4	4.25	N/A	5	N/A	4.42	5.30
Safety Plan/Narrative	4	4	N/A	N/A	N/A	4.00	2.40
Bottom Ash Subproject	4	4	N/A	4	N/A	4.00	4.00
Gypsum Subproject	4	4	N/A	4	N/A	4.00	4.00
Fly Ash Subproject	4	4	N/A	4	N/A	4.00	4.00
Transport Subproject	4	4	N/A	4	3	3.75	3.75
Reclaim Water Tanks	4	4	N/A	4	N/A	4.00	1.60
Construction Manhours	4	3.5	N/A	3	N/A	3.50	2.80
In-house Work vs Subcontracted Work	4	4	N/A	3	N/A	3.67	1.47
EPC Technical Bid Compliance	4	4.75	N/A	4	N/A	4.25	5.10
Planned Schedule	4	4	N/A	4	N/A	4.00	4.80
Technical Expertise	4	4	N/A	4	N/A	4.00	2.40
CCRT Experience	4	4.5	N/A	4	N/A	4.17	2.50
Major Subcontractors/Suppliers	4	4.75	N/A	4	4	4.19	1.68
Alternate Technical Offerings	4	3	N/A	3	N/A	3.33	1.33
Total Technical Score							46.52
TOTAL POINTS							73.92

[redacted]

Scoring System (1-5 on each item)

Evaluation Factor	Plant (Note 1)	PE	Comm Team	BMcD Team	GAI Team	AVG Score	Overall Points
LTIRC	Y	Y	Y	N/A	N/A		
RIR	Y	Y	Y	N/A	N/A		
EMR	Y	Y	Y	N/A	N/A		
Base Scope	N/A	N/A	4	N/A	N/A	4.00	13.60
Options	N/A	N/A	5	N/A	N/A	5.00	6.00
Exhibit R Rates	N/A	N/A	2	N/A	N/A	2.00	0.80
Risk Assessment	N/A	N/A	1	N/A	N/A	1.00	2.00
Total Commercial Score							22.40
Engineering Plan/Narrative	3	3.75	N/A	4	N/A	3.58	4.30
Construction Plan/Narrative	3	3.75	N/A	4	N/A	3.58	4.30
Safety Plan/Narrative	4	4	N/A	N/A	N/A	4.00	2.40
Bottom Ash Subproject	3	3.5	N/A	4	N/A	3.50	3.50
Gypsum Subproject	4	3.5	N/A	4	N/A	3.83	3.83
Fly Ash Subproject	4	3.5	N/A	4	N/A	3.83	3.83
Transport Subproject	4	3	N/A	4	3	3.50	3.50
Reclaim Water Tanks	4	3.5	N/A	4	N/A	3.83	1.53
Construction Manhours	3	3.5	N/A	4	N/A	3.50	2.80
In-house Work vs Subcontracted Work	4	3	N/A	4	N/A	3.67	1.47
EPC Technical Bid Compliance	3	3	N/A	4	N/A	3.33	4.00
Planned Schedule	2	4	N/A	4	N/A	3.33	4.00
Technical Expertise	3	4	N/A	5	N/A	4.00	2.40
CCRT Experience	3	4.25	N/A	5	N/A	4.08	2.45
Major Subcontractors/Suppliers	2	3	N/A	3	3	2.75	1.10
Alternate Technical Offerings	3	3.5	N/A	3	N/A	3.17	1.27
Total Technical Score							41.87
TOTAL POINTS							64.27

[redacted]

Scoring System (1-5 on each item)

Evaluation Factor	Plant (Note 1)	PE	Comm Team	BMcD Team	GAI Team	AVG Score	Overall Points
LTIRC	Y	Y	Y	N/A	N/A		
RIR	Y	Y	Y	N/A	N/A		
EMR	Y	Y	Y	N/A	N/A		
Base Scope	N/A	N/A	4.5	N/A	N/A	4.50	15.30
Options	N/A	N/A	4.5	N/A	N/A	4.50	5.40
Exhibit R Rates	N/A	N/A	3	N/A	N/A	3.00	1.20
Risk Assessment	N/A	N/A	2	N/A	N/A	2.00	4.00
Total Commercial Score							25.90
Engineering Plan/Narrative	2	2.75	N/A	3	N/A	2.58	3.10
Construction Plan/Narrative	2	2.75	N/A	3	N/A	2.58	3.10
Safety Plan/Narrative	3	4	N/A	N/A	N/A	3.50	2.10
Bottom Ash Subproject	2	3	N/A	4	N/A	3.00	3.00
Gypsum Subproject	3	3	N/A	4	N/A	3.33	3.33
Fly Ash Subproject	3	3	N/A	2	N/A	2.67	2.67
Transport Subproject	3	3	N/A	4	3	3.25	3.25
Reclaim Water Tanks	3	3.5	N/A	4	N/A	3.50	1.40
Construction Manhours	3	3	N/A	4	N/A	3.33	2.67
In-house Work vs Subcontracted Work	3	3	N/A	4	N/A	3.33	1.33
EPC Technical Bid Compliance	2	3.5	N/A	2	N/A	2.50	3.00
Planned Schedule	2	4	N/A	4	N/A	3.33	4.00
Technical Expertise	3	3	N/A	3	N/A	3.00	1.80
CCRT Experience	3	2.5	N/A	3	N/A	2.83	1.70
Major Subcontractors/Suppliers	2	2	N/A	3	2	2.25	0.90
Alternate Technical Offerings	2	3	N/A	3	N/A	2.67	1.07
Total Technical Score							34.75
TOTAL POINTS							60.65

[redacted] INC.

Scoring System (1-5 on each item)

Evaluation Factor	Plant (Note 1)	PE	Comm Team	BMcD Team	GAI Team	AVG Score	Overall Points
LTIRC	Y	Y	Y	N/A	N/A		
RIR	Y	Y	Y	N/A	N/A		
EMR	Y	Y	Y	N/A	N/A		
Base Scope	N/A	N/A	1	N/A	N/A	1.00	3.40
Options	N/A	N/A	1	N/A	N/A	1.00	1.20
Exhibit R Rates	N/A	N/A	3	N/A	N/A	3.00	1.20
Risk Assessment	N/A	N/A	3	N/A	N/A	3.00	6.00
Total Commercial Score							11.80
Engineering Plan/Narrative	2	3	N/A	3	N/A	2.67	3.20
Construction Plan/Narrative	2	2.5	N/A	3	N/A	2.50	3.00
Safety Plan/Narrative	3	4	N/A	N/A	N/A	3.50	2.10
Bottom Ash Subproject	2	3	N/A	4	N/A	3.00	3.00
Gypsum Subproject	2	3	N/A	4	N/A	3.00	3.00
Fly Ash Subproject	2	3	N/A	2	N/A	2.33	2.33
Transport Subproject	2	2.5	N/A	4	4	3.13	3.13
Reclaim Water Tanks	2	3.5	N/A	4	N/A	3.17	1.27
Construction Manhours	2	3	N/A	3	N/A	2.67	2.13
In-house Work vs Subcontracted Work	2	3.5	N/A	2	N/A	2.50	1.00
EPC Technical Bid Compliance	2	2.5	N/A	3	N/A	2.83	3.40
Planned Schedule	2	4	N/A	4	N/A	3.33	4.00
Technical Expertise	2	4	N/A	3	N/A	3.00	1.80
CCRT Experience	2	4	N/A	3	N/A	3.00	1.80
Major Subcontractors/Suppliers	2	2.5	N/A	3	4	2.88	1.15
Alternate Technical Offerings	1	3	N/A	3	N/A	2.33	0.93
Total Technical Score							33.36
TOTAL POINTS							45.16

Scoring System
0 (unacceptable) through 5 (exceptional)

Notes:
1. TC Plant staff: a) reviewed the SOW/technical specification/schedule b) were provided hardcopy and electronic copies of all bids (unpriced); c) participated in the Technical Presentation Meetings, and d) provided input for certain C&Es.

CONFIDENTIAL INFORMATION REDACTED

APPENDIX D - Project Cost Summary

[redacted]

CCRT EPC		
EPC Initial Award	$	[redacted]
Tank Sizing / Equipment	$	2,000,000
Geotechnical / Engineering Investigation Adjustments	$	4,000,000
Service Water / Other Equipment	$	500,000
Bottom Ash Demo / Service Building	$	1,000,000
WFGD Bleed VFD and Piping	$	2,000,000
CCR Material Characteristics	$	500,000
Outage Change	$	200,000
Transport Subproject Permit Delay (6 months)	[redacted]	
Stormwater/Sanitary Sewer Survey / Piping Upgrades	$	1,000,000
Fire Protection Study / Upgrades	$	500,000
Fly Ash Study Results / Engineering Changes	$	4,000,000
Air Compressor Study Upgrades	$	500,000
Auxiliary Power, Cathodic Protection, Grounding Studies Results / Changes	$	1,000,000
CCRT EPC Subtotal	$	[redacted]
5% contingency	$	[redacted]
CCRT EPC Total	[redacted]	Gross Net

2016 BP		Variance to 2016 BP[2]	
$ 235,000,000	$	21,000,000	Gross

Other and Non TC CCRT EPC		
[redacted]		
Spare Parts	$	2,500,000
Gate, Security, Parking	$	2,000,000
14kv Power Cable and Install (existing manholes)	$	2,500,000
Property Acquisition	$	4,400,000
345kV Line Relocation	$	6,200,000
Owner Cost - Rolling Stock	$	2,200,000
Expenses Prior to January 2016 (per 2016BP)	$	36,400,000
Owner General Costs EPC Total x 3.5%	$	9,000,000
Stream/Wetland/IN Bat Mitigation Fees	$	33,500,000
Other and Non CCRT Subtotal	$	[redacted]
5% contingency	$	[redacted]
[redacted]		

2016 BP		Variance to 2016 BP[2]	
$ 103,000,000	$	9,700,000	Gross

Project Total = EPC + Other and Non CCRT EPC (A)	[redacted]0	Gross Net	$ 338,000,000	$ 30,700,000	Gross

Phase I Items Excluded from Project Sanction Request		
Phase I - Landfill Proper Construction[1] (B)	$ 121,000,000	
Subtotal - Excluded Items	$ 121,000,000	Gross
	$ 90,750,000	Net

			Variance to 2016 BP[2]
Phase I Total (A+B)	$ 489,700,000	Gross	
Phase I Total Estimate (per 2016 BP)[2]	$ 459,000,000	Gross	
Variance to 2016 BP[3]	$ 30,700,000	Gross	$ 30,700,000 Gross
	$ 23,025,000	Net	

Notes:

1. Includes costs for Phase 1 cover system. Haul Road and Bridge included in CCRT EPC.
2. The 2016 Business Plan for all Phases of the CCR Project is $709M.
   Phases 2, 3 and 4 costs that extend thru 2044.
   Total does not include BAP/GSP or Holcim.
3. The 2017 BP will be updated to include any variances.

Investment Proposal for Investment Committee Meeting on: 12/18/2020

Project Name: Mill Creek Primary Gypsum Slurry Tank Rehabilitation

Total Capital Expenditures: $2,645k (Including $345k of contingency)

Total O&M: N/A

Project Number(s): 162240

Business Unit/Line of Business: Project Engineering

Prepared/Presented By: Timothy Coomer

Brief Description of Project

This Authorization for Investment Proposal (AIP) seeks approval for the design and construction of the Mill Creek Station (the "Station") Primary Gypsum Slurry Tank Rehabilitation project and associated supporting scopes (the "Project").

In 2018, in order to optimize the gypsum dewatering system and reduce the risks associated with system or single component failures, the new Gypsum Dewatering Processing Plant (GPP) was installed with a complete one hundred percent (100%) redundant secondary tank system to the primary tank system this paper seeks authorization to rehabilitate.

As part of this GPP system upgrade, it was identified that the existing primary gypsum slurry tank has experienced aging issues. The existing tank coating, which was placed in service in November 2000, is currently experiencing coating failures. The failed coating has led to metal tank deterioration, structural steel integrity loss, and an expected shorter service life of tank components and infrastructure directly exposed to the slurry operational process.

As a result of the above issues to the primary gypsum slurry tank, this AIP seeks approval for the rehabilitation of the tank including the fabrication, procurement, and construction for all civil, mechanical, and electrical components, comprising the Project. The Project will be subdivided into the following 2 subprojects (the subprojects will comprise two [2] separate contracts):

- Subproject #1:
    - Relocation of underflow lines and mechanically/electrically air gapping existing secondary tank.
- Subproject #2:
    - Rehabilitation of the existing primary tank and all required process and service infrastructure.

The Project, shown as subprojects above, includes the major activities required to restore the tank to nearly original condition as follows:

- Removal and replacement of primary tank platform
- Installation of a new underflow valve platform (not located above the tank)
- Installation of new agitator (matching the Secondary Gypsum Tank)
- Remove and replace tank interior coating
- Rehabilitation of tank shell and exterior recoating
- Replacement of functionally obsolete and degrading primary tank stairwell.
- Replacement of Primary Tank Enclosure (constructed as temporary) into a permanent enclosure
- Demolition of existing agitators
- Electrical work to support new infrastructure and equipment

The Project timeline with these major milestones:

Item:	Completion Date:
Subproject #1 - Underflow Relocations and air gapping	March 31, 2021
Subproject #2 – Rehabilitation of the primary tank, coating and infrastructure installation	July 30, 2021

This rehabilitation project will increase the overall life of the primary tank to remain in line with the remaining life of the Mill Creek Station. This Project is part of the 2021 Business Plan. As part of the GPP project, this rehabilitation project is not included in an ECR filing.

Why is the project needed? What if we do nothing?

The degradation of the existing primary slurry tank could cause system failure within the next few years based upon the current condition of equipment and tank coating, as well as chemical attacks that will and have occurred due to failing coating systems. An independent third party inspection, conducted in August 2020, found that the tank has experienced structural steel integrity loss, substantive interior coating failures, and the exterior coating is quickly approaching the end of its usable lifecycle.

The inspection report recommends rehabilitation of the tank coatings and steel, in lieu of replacement of the tank as the tank steel and foundation are suitable to be rehabilitated to meet the service life needs of the Mill Creek Station; however, the tank will not remain viable for the life of the Station without substantial rehabilitation and updating in the very near future. The inspection identified considerable number of deficiencies of which some are notated in the Risks section below.

The Project is necessary for continued long-term operation of the recently commissioned GPP which allows for beneficial use of the gypsum byproducts. The gypsum byproduct sales for beneficial use has increased dramatically from 2015 to 2019. The tonnage beneficially used increased from 26% (171 ktons) to 87% (515 ktons) . With improved byproduct contracts in place, leading to increased revenues that are passed on to the customers, the necessity to perform the scope of work is even more justified. The beneficial use of the gypsum byproducts also extends the life of the onsite landfill and can limit the future expansion (the Phase 2 or 3 expansions) and those associated costs.

The Project will also improve agitator operation and reliability, as the current agitators are an outdated design, which results in sixty percent (60%) of the maintenance work orders. A new agitator, common to the secondary and rehabilitated primary tank, will be installed as part of the Project. The Station will reap lower overhead and maintenance costs plus increased system reliability.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2021	2022	2023	Post 2023	Total
1. Capital Investment Proposed	$ 2,345				$ 2,345
2. Cost of Removal Proposed	$ 300				$ 300
3. Total Capital and Removal Proposed (1+2)	$ 2,645	$ -	$ -	$ -	$ 2,645
4. Capital Investment 2021 BP	$ 2,975				$ 2,975
5. Cost of Removal 2021 BP					$ -
6. Total Capital and Removal 2021 BP (4+5)	$ 2,975	$ -	$ -	$ -	$ 2,975
7. Capital Investment variance to BP (4-1)	$ 630	$ -	$ -	$ -	$ 630
8. Cost of Removal variance to BP (5-2)	$ (300)	$ -	$ -	$ -	$ (300)
9. Total Capital and Removal variance to BP (6-3)	$ 330	$ -	$ -	$ -	$ 330

Financial Detail by Year - O&M ($000s)	2021	2022	2023	Post 2023	Total
1. Project O&M Proposed					$ -
2. Project O&M 2021 BP					$ -
3. Total Project O&M variance to BP (2-1)	$ -	$ -	$ -	$ -	$ -

Risks

Project and relevant risks include the following:

- If this Project is not undertaken, then the tank and supporting mechanical/electrical equipment will become less reliable and experience increased downtime in order to patch coating, install steel patch plates, perform piecemeal replacements/repairs of steel, platforms and exterior coating, replace tank valves (located above top of primary tank), and perform maintenance on outdated agitators and electrical power/control equipment.
- By taking the new primary tank out service, only the secondary tank is available for service. The major failure point for this tank is the agitator gearbox/motor. A capital spare has been purchased and its onsite storage is a prerequisite for rehabilitation of the primary tank.
- By not completing the Project, the reliability of the existing primary tank and its infrastructure continues to deteriorate to an unacceptable level, eventually creating an emergency condition for resolution of tank failure. Tank replacement or repairs at a future date, conducted on a compressed schedule, will increase the costs and create the risk of process/engineering errors due to the compressed schedule to conduct corrective actions.

- Potential risks to beneficial use customers would be averted by the rehabilitation for the life of the Station and ensuring the market would remain viable and profitable. Since the existing primary tank has not yet failed, the immediate risks are currently mitigated but are imminent without corrective actions. The agitator reliability presents ongoing challenges and higher maintenance costs.
- The Project is not subject to the New Source Review criteria per the Environmental Affairs Department.
- The nature of the Project has several schedule and scope risks which are included in the Project pricing as follows:
    a. The tank exterior repair scope is 'high risk' as not all metal repairs are currently exposed and the depth of the metal degradation is indeterminate.
    b. The tank exterior coating overlay (adding a new coat of exterior paint) has uneven amounts of remaining coating. This leads to a higher risk of coating removal in isolated areas which can affect cost and schedule.
    c. Major steel work, replacing primary tank platform and functionally obsolete stairwell, are subject to market risk due to the limited availability of steel galvanizers which has gotten worse with the Corona virus.
    d. The compact work area and operational secondary gypsum tank introduces more risk of delays with elevated work, containment concerns and adjacent road traffic. The area has considerable flux which can cause delays.
    e. In these current times, the risks associated with the Corona virus are challenging to identify and control. This alone can, and has on other recent projects, delay schedules and impact costs.

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) $3,076

   Rehabilitation which includes relocating all three unit underflow lines, constructing new access platforms, electrical and heat tracing, improved infrastructure, removal of the existing primary tank interior coating, inspection/repair of existing primary tank, new primary system pump enclosure and exterior recoating with upgraded coating systems and would also include installing a state-of-the-art agitator.

   The Rehabilitation of Primary Slurry Tank with the addition of a new agitator, agitator structural steel, additional infrastructure, and substantive amount of demolition work. This recommendation provides the following benefits:

   - Spare parts reduction due to common agitator with the primary tank.
   - Supports life of the Station operational needs with lower capital cost than the tank replacement alternative
   - Supports the beneficial use sales of gypsum byproducts through the Station's expected operating life.
   - Avoids crisis management situation by implementing a disciplined and sufficiently robust scope to maintain the 2x100% operational configuration of the original system design by rehabilitation of tank. This scope also produces less downtime than a tank replacement project.

2. Alternative #1: NPVRR: ($000s) $0
   'Do nothing' would include any routine and preventive maintenance plus the costs of indeterminate repairs for the life of the existing primary tank. Although the existing primary tank could be patched, the nature of coating requires a smooth surface to properly adhere to the tank steel wall. Patching the coating is a short-term fix and doesn't positively affect the steel wall already under corrosive attack. A 'patch strategy' is not considered a viable operational strategy.

3. Alternative #2: NPVRR: ($000s) $3,460
   Total demolition and replacement of the primary tank including new agitator, new gearbox/motor and new infrastructure. This also includes relocation of all three unit underflow lines, constructing new access platforms, electrical, and heat tracing, and improved infrastructure.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Mill Creek Primary Slurry Tank Rehabilitation project for $2,645k, inclusive of a 15% contingency, to ensure the continuation of long term operation of the Gypsum Processing Plant at the Mill Creek Generating Station.

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 Project 156694 Hillside-Green River Plant Pole Replacement

Investment Proposal for Investment Committee Meeting on: January 30, 2019

Project Name: Hillside-Green River Pole Replacement

Total Expenditures: $2,635k
Total Contingency: $239k (10%)

Project Number(s): 156694

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Ronnie Bradford/Adam Smith

Executive Summary

The proposed project is to replace fifty-three (53) wood structures on the Hillside-Green River Plant 69kV line with new steel structures that were identified through inspection in 2017. Due to the difficulty in obtaining an extended outage, approximately 50% of the structures will be energized when they are replaced. If the opportunity to complete the entire project de-energized would occur, this option would be pursued and would reduce the cost by $140k.

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. 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.

This project was included in the 2019 Business Plan (BP) for $1,482k. Subsequent to the 2019 BP planning, an additional eleven (11) structures were identified to be in need of replacement. In addition, a decision was made to complete 50% of the structures energized. Funding in the amount of $466k was included for structure access and matting. The incremental funding of $1,153k was approved by the RAC in the 0+12 forecast. See table below for a detailed breakdown of the cost changes.

Incremental Cost Detail	
11 Additional Structures	$547k
Energized Adder	$140k
Matting	$184k
Structure Access	$282k
Total	$1,153k

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 Indian Hill-Green River Plant 69kV line was completed in 2017, fifty-three (53) 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.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) 3,283
     Due to the difficulty in obtaining an extended outage, 50% of the fifty-three (53) wood structures will be energized when they are replaced with steel structures. If the opportunity to complete the entire project de-energized would occur, this option would be pursued and would reduce the cost by $140k and the NPVRR by $175k
  2. Alternative #1: Do Nothing NPVRR: ($000s) 4,722
     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 network reliability.
  3. Alternative #2: Replace with Wood NPVRR: ($000s) 3,672
     The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (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 fourteen (14) standard steel H-frame structures, thirty-four (34) tangent steel davit arm structures, one (1) steel single pole running corner, four (4) steel single pole dead end structures, and associated hardware and material, and the removal of fifty-three (53) wood structures, and associated hardware and material. Construction is scheduled to begin in February of 2019 and be completed in June of 2019.

Construction Milestones	
July 2018	Engineering and Design
August 2018	Space reserved for steel pole production with manufacturer
November 2018	Steel Poles Ordered
February 2019	Steel Poles Received
February 2019	Line Construction Begins
June 2019	Line Construction Completed

A facility map of the Hillside-Green River Plant 69kV line is shown below:
Total line length: 10.01 miles Total structures in line: 147

[redacted]

- **Project Cost**
  The current total project cost is $2,635k. 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 $826k. This project will utilize standard steel structures. The steel structures will be purchased through the Company's steel pole alliance partner. The line construction will be based on continuing contracts from the Company's line contractors.

Transmission Lines Material Cost Breakdown	
Material	**Cost**
Steel Poles	$737k
Hardware	$89k
Total	$826k

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed	2,374	-	-	-	2,374
2. Cost of Removal Proposed	262	-	-	-	262
3. Total Capital and Removal Proposed (1+2)	2,635	-	-	-	2,635
4. Capital Investment 2019 BP	1,482	-	-	-	1,482
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	1,482	-	-	-	1,482
7. Capital Investment variance to BP (4-1)	(892)	-	-	-	(892)
8. Cost of Removal variance to BP (5-2)	(262)	-	-	-	(262)
9. Total Capital and Removal variance to BP (6-3)	(1,154)	-	-	-	(1,154)

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)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$72
Contract Labor:	$1,106
Materials:	$826
Local Engineering:	$181
Burdens:	$211
Contingency:	$239
Reimbursements:	($0)
Net Capital Expenditure:	$2,635

- **Assumptions**

  Recommendation – The cost of this alternative assumes that the line outage will not be available for the duration of the project, and approximately 50% of the fifty-three (53) structures will need to be completed with the 69kV line energized.

  Alternative #1 – 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.

  Alternative #2 – The cost of this alternative assumes the cost of the wood poles is 37% the cost of the steel poles, and that the wood poles would be replaced again in 30 years. The estimated life of the steel poles is 90 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 Hillside-Green River Plant 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.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Hillside-Green River Plant pole replacement project for $2,635k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

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: January 30, 2019

Project Name: TEP-MOT-Morganfield-Wheatcroft

Total Expenditures: $2,859k
Total Contingency: $260k (10%)

Project Number(s): LI-000092

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Jonathan Meacham

Executive Summary

The Morganfield – Wheatcroft Tap 69 kV line overloads during planning studies and was identified through the 2018 Transmission Expansion Plan (TEP). This project will provide a facility rating increase for the Morganfield – Wheatcroft Tap 69 kV line and eliminate the overloads currently identified. The 2018 TEP identified a need date of 5/30/2019.

The maximum operating temperature (MOT) on the Morganfield – Wheatcroft Tap 69 kV line needs to be increased from 125°F to 135°F in order to alleviate the existing overload condition. To achieve this higher operating temperature, thirty-two (32) spans need corrective action. This work will involve the replacement of thirty-four (34) existing steel towers with thirty-four (34) new steel poles. These structures will raise the height of the line enabling it to meet the National Electric Safety Code (NESC) required clearance when the line is operated at 135°F.

This project was included in the 2019 Business Plan for $2,163k to replace twenty-six (26) structures, with estimated spend of $25k in 2018 and $2,138k in 2019. As scope, timing, and certainty of work has evolved, the estimates have been further refined. The current total project cost is $2,859k, and was approved by the RAC in the 0+12 forecast.

Background

The overload of the Morganfield – Wheatcroft Tap 69 kV line was identified in the TEP and approved by TranServ, the Company's Independent Transmission Organization (ITO).

The Morganfield – Wheatcroft Tap 69 kV line currently consists of 397.5 ACSR (aluminum conductor steel reinforced) with an MOT of 125°F. To eliminate the overload, the MOT on this line section will be increased to 135°F.

During the 90/10 summer peak conditions, an outage of the Morganfield – Sunoco Tap section of the Morganfield – Wheatcroft 69 kV line results in an overload of 104% in the 2019 summer. This overload exists throughout the planning horizon.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) 3,562
     The recommendation is to install thirty-four (34) new steel poles, and remove thirty-four (34) steel towers during a scheduled outage.
  2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
     This alternative puts the customer load at risk and violates the company's Planning Guidelines.
  3. Alternative #2: Replace with Towers NPVRR: ($000s) 4,236
     The next best alternative would be to replace the thirty-four (34) existing steel towers with new steel towers. Towers typically have less deflection (movement) than steel poles, which make them a better application for terminal structures. At the time when these were installed (late 1920s), the use of tubular steel poles in the utility industry had not yet occurred.

Project Description

- **Project Scope and Timeline**
  The scope of work will involve the installation of thirty-four (34) new steel poles, and associated hardware and material, and the removal of thirty-four (34) steel towers, and associated hardware and material. The line construction will be based on continuing contracts from the Company's line contractors. Construction is scheduled to begin in June of 2019 and be completed in September of 2019.

Construction Milestones	
August 2018	Engineering and Design
November 2018	Space Reserved with Steel Pole Manufacturer
February 2019	Steel Poles Ordered
May 2019	Steel Poles Received
June 2019	Line Construction Begins
September 2019	Line Construction Completed

CONFIDENTIAL INFORMATION REDACTED

A one-line diagram showing the overloaded line (Morganfield – Wheatcroft Tap 69 kV) and contingency (Morganfield – Sunoco Tap 69 kV) is included below:

[redacted]

A geographical map of the Morganfield-Wheatcroft 69kV line is included below:
Total line length: 30.07 miles Total structures in line: 170

[redacted]

- **Project Cost**
  The total project cost is $2,859k. 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 the engineering analysis, Transmission Lines has estimated the material packages for construction of this project to be $615k. This project will utilize standard steel structures. The steel structures will be purchased through the Company's steel pole alliance partner. The line construction will be based on continuing contracts from the Company's line contractors.

Transmission Lines Material Cost Breakdown	
Material	**Cost**
Steel Poles	$550k
Hardware	$65k
Total	$615k

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	**2018**	**2019**	**2020**	**Post 2020**	**Total**
1. Capital Investment Proposed	-	2,367	-	-	2,367
2. Cost of Removal Proposed		492	-	-	492
3. Total Capital and Removal Proposed (1+2)	-	2,859	-	-	2,859
4. Capital Investment 2019 BP	25	2,138	-	-	2,163
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	25	2,138	-	-	2,163
7. Capital Investment variance to BP (4-1)	25	(229)	-	-	(204)
8. Cost of Removal variance to BP (5-2)	-	(492)	-	-	(492)
9. Total Capital and Removal variance to BP (6-3)	25	(721)	-	-	(696)

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)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$96
Contract Labor:	$1,489
Materials:	$615
Local Engineering:	$198
Burdens:	$201
Contingency:	$260
Reimbursements:	($0)
Net Capital Expenditure:	$2,859

- **Assumptions**

Recommendation - This assumes that thirty-four (34) existing steel towers will be replaced with thirty-four (34) new steel poles. An outage must be obtained to complete the project and is scheduled for 2019.

Alternative #1 – Do Nothing - This alternative puts the customer load at risk and violates the Company's Transmission Planning Guidelines.

Alternative #2 – Replace with Steel Towers – This alternative assumes that thirty-four (34) existing steel towers would be replaced with thirty-four (34) new steel towers during a scheduled outage.

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

- **Risks**
  Without the proposed replacement of the designated structures in the Morganfield – Wheatcroft Tap 69 kV line, there is risk of losing load in the Morganfield area. Inclement weather which affects site access and working conditions would 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 TEP-MOT-Morganfield-Wheatcroft project for $2,859k to maintain proper operating temperature of 135°F.

<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 for Investment Committee Meeting on: February 27, 2019

Project Name: Loudon-Rockwell-Winchester Pole Replacement

Total Capital Expenditures: $3,604k
Total Contingency: $328k (10%)
Total Internal Labor: $85k

Total O&M: $0k

Project Number(s): 156698

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Andrew Bailey/Adam Smith

Brief Description of Project

The proposed project is to replace one hundred eighteen (118) wood structures, on the Loudon-Rockwell-Winchester 69kV line with new steel structures during a scheduled outage. The scope of work includes the replacement of eighty-eight (88) structures identified through inspection in 2017. The replacement of thirty (30) additional adjacent structures is required to accommodate the increased height of the new structures.

Project Milestones	
September 2018	Engineering and Design
October 2018	Space reserved for steel pole production with manufacturer
February 2019	Steel Poles Ordered
April 2019	Steel Poles Received
April 2019	Line Construction Begins
October 2019	Line Construction Completed

This project was included in the 2019 Business Plan (BP) for $2,694k to replace one hundred (100) structures. Twelve (12) structures will be replaced as a part of project LI-000083 (TEP-CR-Loudon Avenue-Hume Road) due to the location of the structures. Subsequent to the 2019 BP planning, thirty (30) structures were added to the project scope. In addition, funding in the amount of $241k was included for structure access. The incremental funding of $910k was approved by the RAC in the 0+12 forecast.

Incremental Cost Detail	
18 Additional Structures	$505k
Structures Access	$241k
Reclamation/Damages/Traffic Control	$164k
Total	$910k

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. Two inspections were completed on the Loudon-Rockwell-Winchester 69kV line. A routine climbing was completed in 2016, and a Comprehensive Visual Inspection (CVI) was completed in 2017. From these inspections, eighty-eight (88) 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. Thirty (30) additional adjacent structure will also be replaced in order to accommodate the increased height of the new structures

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost 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. 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.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	3,042	-	-	-	3,042
2. Cost of Removal Proposed	562	-	-	-	562
3. Total Capital and Removal Proposed (1+2)	3,604	-	-	-	3,604
4. Capital Investment 2019 BP	2,694	-	-	-	2,694
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	2,694	-	-	-	2,694
7. Capital Investment variance to BP (4-1)	(348)	-	-	-	(348)
8. Cost of Removal variance to BP (5-2)	(562)	-	-	-	(562)
9. Total Capital and Removal variance to BP (6-3)	(910)	-	-	-	(910)

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)	-	-	-	-	-

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.

Risks

Without the proposed replacement of the priority poles on the Loudon-Rockwell-Winchester 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.

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

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 4,489
   The recommendation is to replace all one hundred eighteen (118) wood structures with new steel structures during a scheduled outage.
2. Alternative #1: Do Nothing NPVRR: ($000s) 6,458
   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 network reliability.
3. Alternative #2: NPVRR: ($000s) 4,848
   The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Loudon-Rockwell-Winchester pole replacement project for $3,604k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<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 LI-000036 Pineville-Rocky Branch Pole Replacement

Investment Proposal for Investment Committee Meeting on: February 27, 2019

Project Name: Pineville-Rocky Branch Pole Replacement

Total Capital Expenditures: $4,509k
Total Contingency: $410k (10%)
Total Internal Labor: $92k

Total O&M: $0k

Project Number(s): LI-000036

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Adam Smith/John Doll

Brief Description of Project

The proposed project is to replace forty-five (45) wood structures, on Pineville-Rocky Branch 69kV line with new steel structures during a scheduled outage. The scope of work includes the replacement of forty-five (45) structures identified through inspection in 2017.

Project Milestones	
June 2018	Engineering and Design
October 2018	Space reserved for steel pole production with manufacturer
December 2018	Steel Poles Ordered to Inventory
February 2019	Steel Poles Received to Inventory
February/March 2019	Steel Poles Charged from Inventory
March 2019	Line Construction Begins
July 2019	Line Construction Completed

This project was included in the 2019 Business Plan (BP) for $4,629k to replace fifty-six (56) structures. As timing and certainty of work has developed, the estimates have been further refined. The current total project cost is $4,509k.

Why is the project needed? What if we do nothing?

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 was performed on the Pineville-Rocky Branch 69kV circuit. The Gardner Tap inspection was completed in 2015, and the inspection of the main line between Pineville and Rocky Branch line was completed in 2017. A total of fifty-six (56) structures were identified to be in need of replacement in order to ensure the integrity and reliability of this circuit. Forty-five (45) of these structures will be replaced on this project. Six (6) structures were previously completed on the Gardner Tap pole replacement project (LI-158326) in 2018, a tap off the main Pineville to Rocky Branch circuit. The remaining five (5) structures were identified as Line to Ground (LTG) structures and will be replaced in 2019 on project LI-158816.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost 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. 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.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	3,652	-	-	-	3,652
2. Cost of Removal Proposed	857	-	-	-	857
3. Total Capital and Removal Proposed (1+2)	4,509	-	-	-	4,509
4. Capital Investment 2019 BP	4,629	-	-	-	4,629
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	4,629	-	-	-	4,629
7. Capital Investment variance to BP (4-1)	978	-	-	-	978
8. Cost of Removal variance to BP (5-2)	(857)	-	-	-	(857)
9. Total Capital and Removal variance to BP (6-3)	120	-	-	-	120

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)	-	-	-	-	-

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.

Risks

Without the proposed replacement of the priority poles on the Pineville-Rocky Branch 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.

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

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $5,617
   The recommendation is to replace all one forty-five (45) wood structures with new steel structures during a scheduled outage.
2. Alternative #1: Do Nothing NPVRR: ($000s) $8,079
   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 network reliability.
3. Alternative #2: NPVRR: ($000s) $5,992
   The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Pineville-Rocky Branch pole replacement project for $4,509k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

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	

Combined Project and Contract Investment Proposal

Investment and Contract Proposal for Investment Committee Meeting on: April 24, 2019

Project Name: [redacted] Generator Interconnection Agreement and Project

Contract Authorization Requested: $5,479k (Including $501k of contingency)

Total Capital Expenditures Requested: $5,479k (gross) (Including $501k of contingency and $199k of internal labor); $4,758k net
Total O&M: $0k

Project Number(s): 158933 Interconnection Subs, 158936 Network Subs, and 158937 Network Lines
Business Unit/Line of Business: Transmission

Prepared/Presented By: Chris Balmer

Brief Contract/Project Description

Louisville Gas & Electric and Kentucky Utilities (LG&E/KU) are required to provide open access generation interconnection service as detailed in the FERC approved Open Access Transmission Tariff (OATT) and administered by the Independent Transmission Organization (ITO), TranServ.

On April 27, 2017 [redacted] (customer) proposed the interconnection of a new 35MW solar generating facility in [redacted] and LG&E/KU have performed all necessary studies related to this request and [redacted] has granted interconnection service to the customer, subject to the terms and conditions of the Large Generator Interconnection Agreement (LGIA). The LGIA describes, among other things, the required Transmission Interconnection Facilities and Network Upgrades that the Company is obligated to construct to accommodate the interconnection of the solar facility. In addition, the LGIA includes cost estimates and the allocation of costs between the Customer and LG&E/KU.

The total cost of construction that LG&E/KU are obligated to perform is estimated to not exceed $5,479k. The Customer is obligated to pay for actual costs of LG&E/KU's construction of the Transmission Interconnection Facilities which collectively make up an estimated $721k of the total. This estimate also includes an allocation of common costs, such as the substation fence, grounding, and associated labor. The cost of Network Facilities are paid for by LG&E/KU and are estimated to be $4,758k. The OATT includes a provision to protect LG&E/KU from constructing unnecessary network facilities. The customer must provide LG&E/KU with acceptable security to ensure LG&E/KU is reimbursed for unnecessary network upgrade costs if the generation interconnection is not completed.

In order to provide the required generation interconnection service granted to customer by the ITO, this request is for Investment Committee approval of the LGIA and project approval of up

to $5,479k, which includes a 10% contingency. This contingency matches the level of analysis performed to develop the cost estimate and covers increases in actual costs beyond the estimate. This work was not budgeted in the 2019 Business Plan (BP), as it was unknown if the customer desired to move forward with the LGIA; however, it will be included in the 2020 BP if the LGIA is executed.

Why is the project needed? What if we do nothing?

LG&E/KU is obligated to provide generator interconnection service as required by FERC, detailed in the LG&E/KU OATT, and administered by [redacted] as the ITO. The customer has met the applicable requirements to-date and has been granted generator interconnection status by [redacted]. The next required step is to execute the LGIA. Doing nothing would likely result in a FERC complaint filed by the customer stating LG&E/KU did not follow the OATT and allow the generator to interconnect. The customer would certainly prevail in such a proceeding; therefore, doing nothing is not a viable option.

The new facility will be located in [redacted] and interconnect with LG&E/KU's Cynthiana EK Tap to Millersburg 69kV line. This project will have minimal impact on reliability and/or the customer experience.

[redacted]

[redacted]

[redacted]

<u>Contract Bid Summary</u>

Once Customer agrees to the terms in the LGIA, this project will be bid as required. LG&E/KU plan to execute the Large Generator Interconnection Agreeement with the Customer in early May 2019. The Customer has indicated that they are likely to suspend the agreement, effectively “pausing” the project, and provide LG&E/KU notice to proceed at some later date (not to exceed 36 months from date agreement is executed). Once the project is started, it will take approximately twenty-four months until construction is complete and the unit achieves commercial operation status.

<u>Contract Financial Summary</u>

Contract expenses ($k)	2019	2020	2021	2022	2023	Post 2023	Total
Amount requested based on contract estimates	-	-	3,858	1,120	-	-	4,978
Contingency Amount Requested	-	-	389	112	-	-	501
Gross contract authority requested	-	-	4,247	1,232	-	-	5,479

Interconnection Reimbursement	-	-	(541)	(180)	-	-	(721)
Net contract	-	-	3,706	1,052	-	-	4,758
Network Upgrade Security Payment	-	-	(4,758)	4,758	-	-	-

Project Financial Summary

Financial Detail by Year - Capital ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed	-	-	4,142	1,232	5,374
2. Cost of Removal Proposed	-	-	105	-	105
3. Total Capital and Removal Proposed (1+2)	-	-	4,247	1,232	5,479
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)	-	-	(4,142)	(1,232)	(5,374)
8. Cost of Removal variance to BP (5-2)	-	-	(105)	-	(105)
9. Total Capital and Removal variance to BP (6-3)	-	-	(4,247)	(1,232)	(5,479)

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)	-	-	-	-	-

($000s)	**158933 [redacted] Interconnection Subs**	**158936 [redacted] Network Upg Subs**	**158937 [redacted] Network Upg Lines**	**Total**
Company Labor	30	$159	$10	$199
Contract Labor	$306	$1,653	$254	$2,213
Materials	$212	$1,378	$158	$1,748
Contingency	$66	$385	$50	$501
Burdens	$107	$634	$77	$818
Gross Capital Expenditure	$721	$4,209	$549	$5,479
Reimbursement	($721)	$0	$0	($721)
Net Capital Expenditure	$0	$4,209	$549	$4,758
Contingency %	10%	10%	10%	10%

Risks

- Facilities are not built in time by LG&E/KU. LG&E/KU may be responsible for liquidated damages in accordance with Section 5.3 of the LGIA if the work required by LG&E/KU is not completed by the mutually acceptable dates determined by LG&E/KU and the Customer.
- Actual costs could deviate from the estimate. A conceptual design has been developed, however there is not sufficient information available at this conceptual stage to develop a detailed scope and project execution plan. This uncertainty necessitated the need to make several assumptions that influenced the estimated cost; however, it is not feasible at this stage to reduce these assumptions and the associated financial risk. The customer is required to pay the actual cost of the Transmission Interconnection Facilities and will be required to provide security for the Network Facilities.
- Customer does not proceed with the generation interconnection and does not achieve commercial operations of the solar facility. This is primarily a financial risk and is minimized since the Customer is providing security for the Transmission Interconnection Facilities and Network Upgrades. If the commercial operations date is not achieved, LG&E/KU are allowed to recover any funds spent via the security provided by the Customer.

Project Alternatives Considered

1. Recommendation: NPVRR: ($000s) $6,339
   Pursue execution of the LGIA with [redacted], as required under the OATT. If LGIA is executed by [redacted], proceed with construction of transmission interconnection facilities and network upgrades, as granted by the ITO, [redacted]
2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   LG&E/KU is obligated to offer generator interconnection service as it is a requirement in the FERC approved OATT and the ITO, [redacted] has granted service. Doing nothing is not a viable alternative as it is not in compliance with the FERC approved OATT.
3. Alternative #2: Not Applicable NPVRR: ($000s) N/A
   To provide non-discriminatory generation interconnection service, the recommendation is designed and proposed similarly to the previously approved project and executed LGIA with [redacted]. Deviating from the [redacted] project is not recommended.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the [redacted] LGIA and project for $5,479k to satisfy its Open Access Transmission Tariff obligations.

Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced:

The Capital project spending and contract authority requests included in this Investment Proposal have 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 the capital project and contract authority requests.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
[redacted] Large Generator Interconnection Agreement

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the [redacted] Large Generator Interconnection Agreement contract for $5,479k with [redacted].

Sourcing Leader		Proponent/Team Leader	
Supplier Diversity Manager		Manager Ashley Vinson	
Manager - Supply Chain or Commercial Operations		Director – Supply Chain or Commercial Operations	
Director Chris Balmer		Vice President Tom Jessee	

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Combined Project and Contract Investment Proposal

Investment and Contract Proposal for Investment Committee Meeting on: April 24, 2019

Project Name: [redacted] to KU West Shelby Interconnection
Contract Name: [redacted] Interconnection Agreement (IA) and Contribution In Aid of Construction Agreement (CIAC)

Contract Authorization Requested: $5,708k (Including $463k of contingency)

Total Capital Expenditures Requested: $5,097k (Including $463k of contingency and $132k of internal labor), net $0k
Total O&M: $0k

Project Number(s): 159001 & 159597 (Subs) and 158961 (Lines)
Business Unit/Line of Business: Transmission

Prepared/Presented By: Chris Balmer

<u>Brief Contract/Project Description</u>

This proposal requests contract and project approval for a new transmission interconnection between LG&E/KU and [redacted]. [redacted] requested the new interconnection and has agreed to pay the actual construction costs which have been grossed up for taxes as agreed upon in the CIAC. Upon execution, the CIAC will be filed with FERC.

The project consists of a 69kV three-breaker ring bus switching station, to be constructed by LG&E/KU, at a point approximately 600 feet north of the Simpsonville-Shelbyville 69kV line on the north side of US 60 in Shelby County. The construction timeline is estimated to commence in September 2019 and be completed around June 2020. [redacted] will construct the necessary 69kV line from their Bekaert station to the new interconnection point.

LG&E/KU have performed all necessary studies and estimated construction costs of $5,097k, which includes $463k of contingency. This work was not budgeted in the 2019 Business Plan (BP), as it was unknown if [redacted] desired to move forward with the interconnection; however, it will be included in the 2020 BP assuming internal approvals are obtained and applicable agreements are executed with [redacted].

In order to provide the requested interconnection and properly document the cost allocation responsibility, this request is for Investment Committee approval of the IA, CIAC and project approval of up to $5,097k, which includes a 10% contingency of $463k. The CIAC includes tax gross up of $611k in addition to the project cost.

Why is the project needed? What if we do nothing?

[redacted] has requested the construction of the new interconnection to enhance the reliability of several distribution loads that are currently served from and relying solely on a radial [redacted] 69kV transmission line. The distribution loads that are currently served from the [redacted] 69kV line *do not* require the new interconnection; rather, the interconnection is being requested to improve what is currently sufficient service from [redacted]s own transmission system and facilities. FERC's general policies contemplates transmission interconnections to be accommodated, with the interconnection parties agreeing on the cost and compensation related to the interconnection, as is the case here. Since the new requested interconnection does not result in adverse impacts to the LG&E/KU transmission system and [redacted] has agreed to pay appropriate cost, LG&E/KU does not have a reasonable basis to deny the request.

· **Project Scope and Timeline**	
Description	**Date**
Engineering Start(Subs) –	5/22/2019
Engineering Complete (Sub) –	12/17/2019
Engineering Start (Lines)	11/15/2019
Engineering Complete (Lines)	12/4/2019
Civil Construction complete (Subs)	9/10/2019
Below Grade Construction Complete (Subs)	4/20/2020
Above Grade Construction Complete (Subs)	5/4/2020
Protection and Control Complete (Subs)	6/17/2020
Line Construction Complete	2/24/2020
In Service date	6/17/2020

Contract Bid Summary

- Once [redacted] agrees to the terms in the IA and CIAC agreement, this project will be bid as required.

Contract Financial Summary

Contract expenses ($k)	2019	2020	2021	2022	2023	Post 2023	Total
Amount requested based on contract estimates	4,311	323	-	-	-	-	4,634
Contingency amount requested	430	33	-	-	-	-	463
Gross Capital	4,741	356	-	-	-	-	5,097
Tax Gross Up	611	-	-	-	-	-	611
Gross contract authority requested	5,352	356	-	-	-	-	5,708
Reimbursement	(5,352)	(356)	-	-	-	-	(5,708)
Net contract	-	-	-	-	-	-	-

Project Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	4,741	339	-	-	5,080
2. Cost of Removal Proposed	-	17	-	-	17
3. Total Capital and Removal Proposed (1+2)	4,741	356	-	-	5,097
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)	(4,741)	(339)	-	-	(5,080)
8. Cost of Removal variance to BP (5-2)	-	(17)	-	-	(17)
9. Total Capital and Removal variance to BP (6-3)	(4,741)	(356)	-	-	(5,097)

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)	-	-	-	-	-

($000s)	159001 Network Upg Subs	158961 Network Upg Lines	159597 Land Acquisition	Total
Company Labor	$120	$12	$0	$132
Contract Labor	$1,603	$182	$0	$1,785
Materials	$1,612	$87	$0	$1,699
Land	$0	$0	$250	$250
Contingency	$402	$33	$28	$463
Burdens	$689	$51	$28	$768
Gross Capital Expenditure	$4,426	$365	$306	$5,097
Reimbursement	($4,426)	($365)	($306)	($5,097)
Net Capital Expenditure	$0	$0	$0	$0
Contingency %	10%	10%	10%	10%
Tax Gross Up	$565	$46	$0	$611

The Tax Gross Up will be recorded as revenue on the Income Statement.

Risks

There are minimal financial risks to LG&E/KU associated with this project. While the customer has been provided with a good faith estimate, the amount LG&E/KU will be reimbursed will be based on the actual cost of construction.

[redacted] has requested an in service date of June 1st, 2020. Delays in acquiring the property and obtaining the necessary permits could impact meeting this date. In the absence of a geotechnical report, assumptions were made regarding the subsurface conditions of the site. Should the geotechnical report reveal that the site conditions are unfavorable for the construction of a substation, then the project schedule will be compromised and the overall cost of the project will increase, which [redacted] would be contractually required to pay.

Project Alternatives Considered

1. Recommendation: NPVRR: ($000s) N/A
   Pursue execution of the Interconnection Agreement and Contribution In Aid of Construction Agreement. If executed, construct the project as outlined above. [redacted] will reimburse LG&E/KU's cost; therefore, there is not a revenue requirement for LG&E/KU customers.
2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   Since there are no adverse impacts to the LG&E/KU transmission system as a result of the interconnection and [redacted] will pay for actual costs incurred by LG&E/KU for the project, doing nothing is not considerd a viable alternative. Under these circumstances, if [redacted] files a FERC complaint against LG&E/KU, it is believed [redacted] will prevail.

3. Alternative #2: Not applicable NPVRR: ($000s) N/A
   No other alternative was seriously evaluated since [redacted] agreed to pay for the costs associated with the interconnection design suggested by LG&E/KU.

<u>Conclusions and Recommendation</u>
It is recommended that the Investment Committee approve the Interconnection Agreement, Contribution In Aid of Construction Agreement amounts of $5,708k, and the project for $5,097k.

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

<u>Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced</u>:

The Capital project spending and contract authority requests included in this Investment Proposal have 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 the capital project and contract authority requests.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
[redacted] to KU West Shelby Interconnection Agreement and CIAC Agreement

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the [redacted] to KU West Shelby Interconnection Agreement contract and CIAC Agreement for $5,708k with [redacted]

Sourcing Leader		Proponent/Team Leader	
Supplier Diversity Manager		Manager Ashley Vinson	
Manager - Supply Chain or Commercial Operations		Director – Supply Chain or Commercial Operations	
Director Chris Balmer		Vice President Tom Jessee	

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Investment Proposal Project LI-159181 KU Park-Greasy Creek-Bimble Pole Replacement

Investment Proposal for Investment Committee Meeting on: April 24, 2019

Project Name: KU Park-Greasy Creek-Bimble Pole Replacement

Total Capital Expenditures: $2,282k
Total Contingency: $207k (10%)
Total Internal Labor: $66k

Total O&M: $0k

Project Number(s): LI-159181

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Joe Dionisio/Adam Smith

Brief Description of Project

The proposed project is to replace seventeen (17) wood structures, on the KU Park-Greasy Creek-Bimble 69kV line with new steel structures during a scheduled outage. The scope of work includes the replacement of sixteen (16) structures identified through inspection in 2018. The replacement of one (1) additional adjacent structure is required to accommodate the increased height of the new structures.

Project Milestones	
December 2018	Engineering and Design
January 2019	Space reserved for steel pole production with manufacturer
May 2019	Steel Poles Ordered
July 2019	Steel Poles Received
August 2019	Line Construction Begins
October 2019	Line Construction Completed

This project was not included in the 2019 Business Plan (BP). A climbing inspection was completed in August of 2018, subsequent to the 2019 BP planning. The total project cost of $2,282k was approved by the RAC in the 2+10 forecast.

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. A routine climbing inspection was completed in 2018, and sixteen (16) 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. One (1) additional adjacent structure will also be replaced in order to accommodate the increased height of the new structures.

The scope of work consists of installing eleven (11) steel H-Frame structures, four (4) steel three-pole running corners, and two (2) three-pole dead end structures. The four (4) running corner structures and two (2) dead end structures are drivers for the higher than typical per structure replacement cost on this project. In addition, funding for road building and vegetation clearing to gain access to the structures is contributing to the higher than typical per structure replacement cost.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost 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. 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.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed	1,967	-	-	-	1,967
2. Cost of Removal Proposed	316	-	-	-	316
3. Total Capital and Removal Proposed (1+2)	2,282	-	-	-	2,282
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)	(1,967)	-	-	-	(1,967)
8. Cost of Removal variance to BP (5-2)	(316)	-	-	-	(316)
9. Total Capital and Removal variance to BP (6-3)	(2,282)	-	-	-	(2,282)

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)	-	-	-	-	-

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.

Risks

Without the proposed replacement of the priority poles on the KU Park-Greasy Creek-Bimble 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.

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

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 2,843
   The recommendation is to replace all seventeen (17) wood structures with new steel structures during a scheduled outage.
2. Alternative #1: Do Nothing NPVRR: ($000s) 3,997
   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 network reliability.
3. Alternative #2: NPVRR: ($000s) 3,760
   The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the KU Park-Greasy Creek-Bimble pole replacement project for $2,282k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

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 LI-159178 Nebo-Wheatcroft Crt Pole Replacement

Investment Proposal for Investment Committee Meeting on: April 24, 2019

Project Name: Nebo-Wheatcroft Crt Pole Replacement

Total Capital Expenditures: $2,970k
Total Contingency: $270k
Total Internal Labor: $96k

Total O&M: $0k

Project Number(s): LI-159178

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Anthony Mount/Adam Smith

Brief Description of Project

The proposed project is to replace thirty-four (34) structures on the Nebo-Wheatcroft 69kV line during a scheduled outage. Thirty-one (31) structures were identified through inspection in 2018. Three (3) additional adjacent structures will be replaced to support the project design.

The scope of work includes replacement of thirty-three (33) existing wood structures with new steel structures, and the replacement of one (1) existing wood structure with a new wood structure. In addition, one (1) existing platform switch will be replaced with two (2) new one-way switches at the Providence East tap point.

To ensure service is maintained at the Providence East and Barnhill substations throughout project construction, replacement of twenty-three (23) defective poles and three (3) existing poles will be accomplished by constructing 1.6 miles of 69kV line within existing easements and parallel to the existing line. A portable substation will be required to maintain service at the Providence East and Barnhill substations during construction. In addition, eight (8) defective poles are being replaced in other sections of this line.

Project Milestones	
January 2019	Engineering and Design
January 2019	Space reserved for steel pole production with manufacturer
April 2019	Standard Steel Structures Ordered to Inventory
May 2019	Standard Steel Structures Received to Inventory
June 2019	Custom Steel Structures Ordered

July 2019	Custom Steel Structures Received
August 2019	Standard Steel Structures Charged from Inventory
September 2019	Line Construction Begins
December 2019	Line Construction Completed

This project was included in the 2019 Business Plan (BP) under the K9-2019 pole replacement blanket to replace twelve (12) structures. Subsequent to the 2019 BP planning, twenty-two (22) structures were added to the project scope. The total project cost of $2,970k was approved by the RAC in the 2+10 forecast.

<u>Why is the project needed? What if we do nothing?</u>

The Nebo-Wheatcroft 69kV line contains three hundred eighteen (318) structures along the 20.9 mile line. A PSC inspection was completed on this line in 2017, and a Comprehensive Visual Inspection (CVI) was completed on this line in 2018. From these inspections, twelve (12) structures were identified as priority defective replacements, and 155 additional structures were identified as defective:

- Two (2) priority defective poles and thirteen (13) defective poles were identified on the 1.1 mile radial tap off the Nebo-Wheatcroft line out of the 17 poles that feeds the Providence East Substation.
- Two (2) priority defective poles and six (6) defective poles were identified on the 0.5 mile section of the Nebo-Wheatcroft line serving the Barnhill substation.
- Eight (8) priority defective poles were identified in other sections of the Nebo-Wheatcroft line.

[redacted]

To ensure service is maintained at the Providence East and Barnhill substations throughout project construction, replacement of twenty-three (23) defective poles and three (3) existing poles will be accomplished by constructing 1.6 miles of 69kV line within existing easements and parallel to the existing line. This parallel line will replace the 1.6 mile section of the existing line and the twenty-three (23) defective poles. A portable substation will be required to maintain service at the Providence East and Barnhill substations during construction. The map below details the 1.6 mile section that is being replaced.

[redacted]

A second pole replacement project will be completed in 2020 (PR Nebo-Wheatcroft 157635) to replace the remaining one hundred eighteen (118) rejected structures.

Following the pole replacement project, a conductor replacement project will also be completed in 2020 (CR Nebo-Providence East LI-158946) on this circuit. This project will replace 3.70 miles of 2/0 ACSR conductor and the remaining eighteen (18) rejected structures. The one (1) pole being replaced now with a wood pole will be replaced with steel as part of the reconductor project.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost 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. 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.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	2,559	-	-	-	2,559
2. Cost of Removal Proposed	411	-	-	-	411
3. Total Capital and Removal Proposed (1+2)	2,970	-	-	-	2,970
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)	(2,559)	-	-	-	(2,559)
8. Cost of Removal variance to BP (5-2)	(411)	-	-	-	(411)
9. Total Capital and Removal variance to BP (6-3)	(2,970)	-	-	-	(2,970)

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)	-	-	-	-	-

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. The total project cost of $2,970k was approved by the RAC in the 2+10 forecast.

Risks

Without the proposed replacement of the priority poles on the Nebo-Wheatcroft 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.

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

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 3,701
   The recommendation is to replace all thirty-four (34) wood structures during a scheduled outage.
2. Alternative #1: Do Nothing NPVRR: ($000s) 4,853
   The alternative of do nothing would result in replacing the thirty-one (31) rejected 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. Alternative #2: NPVRR: ($000s) 4,606
   The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a

recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

4. Alternative #3: Total Line Rebuild NPVRR: ($000s) 31,141
   A total rebuild of the line has an estimated NPVRR of $31,141k, compared to the three projects identified for this line which have an estimated NPVRR of $13,994k. Based on the current estimated value of the projects, completing the three projects as planned is the least cost alternative when compared to cost of a total line rebuild.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Nebo-Wheatcroft Crt pole replacement project for $2,970k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

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	

Capital Investment Proposal

Investment Proposal for Investment Committee Meeting on: May 29, 2019

Project Name: Dorchester Control House Replacement

Total Capital Expenditures: $4,580k (Including $420k of contingency including $160k of internal labor)

Total O&M: $0k

Project Number(s): SU-000324

Business Unit/Line of Business: Transmission

Prepared/Presented By: Brent Birchell

Brief Description of Project

The scope of work for this project includes multiple system integrity programs that are represented in the Transmission System Improvement Plan (TSIP). The Dorchester substation has Transmission facililities operating at 161 kV, and 69 kV. This substation was originally placed in service in 1940. The earliest 69 KV asset was installed circa 1965 and the earliest 161 kV was installed in 1976. This substation is part of the Bulk Electric System (BES) backbone in the Virginia service territory. The programs and project specific information are shown below:

- Improve Protection and Control Systems – The control building will be replaced along with the related protection and control system components (relay panels, batteries, etc)
- Replace Substation Insulators – Eleven sets of cap and pin insulators will be replaced.
- Replace Substation Line Arresters – Two sets of 161kV and four sets of 69kV arresters will be replaced.
- Replace Coupling Capacitors – Two 161kV coupling capacitors will be replaced as well as associated power line carrier equipment at the three remote termninals of the 161 KV lines.

For the above mentioned TSIP replacements identified, see Appendix; Exhibits A through E for a switching diagram and a substation overview.

Major equipment at this location include a 161/69 kV, 93 MVA transformer; 161 and 69 kV breakers, and two control houses.

Why is the project needed? What if we do nothing?

The TSIP outlines the benefits of proactively replacing problematic equipment. The following excerpt was taken from the TSIP:

"System integrity and modernization projects and programs are designed to replace a comprehensive slate of poor performing, obsolete, and end-of-life assets. These programs will reduce the aggregate age of the inventory and ensure that critical assets remain serviceable to support the system. Programs are designed to remove and replace problem assets prior to failure through systematic replacement. Detailed inspections will serve as the central driver for logical and timely asset replacements. Replacement priorities will be determined through assessment of a number of conditional factors in addition to age and, when possible, replacement priorities will be determined by testing and inspections."

Budget Comparison & Financial Summary

The control house replacement is being accelerated from the timing in the 2019 BP. The 69kV Lancaster Control House (project # SU-000405) was planned for replacement in 2019-2020 in the 2019 BP, but that project was replaced with the Dorchester Control House in an effort to meet NERC issued guidelines for a target rate of mis-operations on the BES. The Lancaster Control House replacement was moved to 2021-2022. Additonally, work at the Dorchester substation was aggregated to reduce the cost associated with mobilizing and demobilizing crews. As shown below in the alternative project, savings to the customer are realized by bundling work at a station and minimizing the number of times crews are mobilizedfor specific asset replacements over time. The projects that were included in the 2019 BP for work at Dorchester are SU-000104 ($126k-2018), SU-000396 (249k 2019-2020) and SU-000324 (1,810K 2021-2022). Also, there was additional scope included in the project during the site visit and preliminary work for the project.

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	454	4,097	-	-	4,551
2. Cost of Removal Proposed	-	29	-	-	29
3. Total Capital and Removal Proposed (1+2)	454	4,125	-	-	4,580
4. Capital Investment 2019 BP	-	-	725	885	1,610
5. Cost of Removal 2019 BP	-	-	90	110	200
6. Total Capital and Removal 2019 BP (4+5)	-	-	815	995	1,810
7. Capital Investment variance to BP (4-1)	(454)	(4,097)	725	885	(2,941)
8. Cost of Removal variance to BP (5-2)	-	(29)	90	110	172
9. Total Capital and Removal variance to BP (6-3)	(454)	(4,125)	815	995	(2,770)

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)	-	-	-	-	-

Risks

- Increased Customer Outages: Aged-protection equipment that has failed in place can result in remote clearing of the fault by other equipment on the system and thus result in larger impacts to customer reliability by producing larger outage areas on the system. Failure of breakers, insulators, and other equipement targeted in this project can also require remote clearing of the fault.
- Misoperations: Failure of the protection systems associated with this substation can result in misoperations of the system. NERC has targeted a 7.5% misoperation rate for the BES.

- Expensive Repairs: Failure of this aging equipment can result in incremental damage to transfomers on the system and other equipement. Proactive replacement of this equipment will minimize the potential of this incremental damage.
- Environmental Impacts: As represented in the TSIP, failed equipement, such as transformers, can result in large financial impacts to the company due to environmental cleanup costs associated with oil-filled equipment failing violently. There is also a risk due to asbestos potentially in the control cable and other material in the control house. It is not anticipated that the control houses being replaced by this project will be demolished as part of this project. Those control houses will be abandoned in place and retired on a separate project after this work is complete.

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 4,994

2. Alternative #1: No Control house/Multiple Year work NPVRR: ($000s) 6,484
   Do not install a new control house. Complete the other work detailed in the IP over a period of several years. Performing all the work at once is preferred because it reduces engineering and construction labor costs due to efficiencies gained in performing some functions once instead of two or more times. Also, delaying the work leaves LKE open to failure of the equipment which could result in unnecessary outages, additional damage/stress on transmission equipment, and decreased system reliability. Finally, a new control house is much preferred over updating the equipment in the existing control house and replacing the equipment over in the existing structure. The structure is deteriorating and will require additional maintenance. The new relays will have a life span of 20+ years and the existing structure has already reached the end of its expected life. The new relays should be installed in a modern building with a life expectancy greater than the new relays to be installed.

3. Alternative #2: Do Nothing NPVRR: ($000s) N/A
   Do nothing. This is not a viable alternative based on the risks to the system listed above

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Dorchester Control House project for $4,580k to enhance the reliability of the 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	

Appendix

Exhibit A: Dorchester Switching Diagram

[redacted]

Exhibit B: D[redacted]ugh

CONFIDENTIAL INFORMATION REDACTED

Exhibit C: Arnold Switching Diagram

[redacted]

Exhibit D: Imboden Switching Diagram

[redacted]

CONFIDENTIAL INFORMATION REDACTED

Exhibit E: Pocket [redacted] **gh**

Capital Investment Proposal

Investment Proposal for Investment Committee Meeting on: May 29, 2019 Project Name: Winchester Control House, Relay, Breaker, & Arrester Replacements Total Capital Expenditures: $2,570k (Including $113k of contingency and $236k of internal labor) Total O&M: $0k Project Number(s): SU-000055 Business Unit/Line of Business: Transmission Prepared/Presented By: Brent Birchell

<u>Brief Description of Project</u>

The scope of work for this project includes multiple system integrity programs that are represented in the Transmission System Improvement Plan (TSIP). The Winchester substation has Transmission facililities operating at 69 kV. This substation was originally placed in service in 1959. This substation is part of the network backbone in the Winchester area and serves multiple distribution substations serving many industrial customers. The programs and project specific information are shown below:

- Improve Protection and Control Systems – The control building will be replaced along with the related protection and control system components (relay panels, batteries, etc)
- Replace Substation Breakers: Three 69 kV oil-filled circuit breakers removed and SF6 insulated breakers will be installed.
- Replace Substation Line Arresters – 15 sets of 69kV arresters will be replaced.

[redacted]

<u>Why is the project needed? What if we do nothing?</u>

The TSIP outlines the benefits of proactively replacing problematic equipment. The following excerpt was taken from the TSIP:

“System integrity and modernization projects and programs are designed to replace a comprehensive slate of poor performing, obsolete, and end-of-life assets. These programs will reduce the aggregate age of the inventory and ensure that critical assets remain serviceable to support the system. Programs are designed to remove and replace problem assets prior to failure through systematic replacement. Detailed inspections will serve as the central driver for logical and timely asset replacements. Replacement priorities will be determined through assessment of a number of conditional factors in addition to age and, when possible, replacement priorities will be determined by testing and inspections.”

Budget Comparison & Financial Summary

There is an increase in capital spending in 2020 due to additional scope (15 sets of arresters) added during the site visit and preliminary work for the project. As shown below in the alternative project, savings to the customer are realized by bundling work at a station rather than mobilizing and demobilizing crews for specific asset replacements over time.

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	205	2,290	-	-	2,495
2. Cost of Removal Proposed	-	75	-	-	75
3. Total Capital and Removal Proposed (1+2)	205	2,365	-	-	2,570
4. Capital Investment 2019 BP	187	1,638	-	-	1,824
5. Cost of Removal 2019 BP	19	214	-	-	233
6. Total Capital and Removal 2019 BP (4+5)	205	1,852	-	-	2,057
7. Capital Investment variance to BP (4-1)	(19)	(652)	-	-	(671)
8. Cost of Removal variance to BP (5-2)	19	139	-	-	158
9. Total Capital and Removal variance to BP (6-3)	0	(513)	-	-	(513)

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)	-	-	-	-	-

Risks

- Completing the project involves risk related to high voltage substation construction work.
- Not completing the project decreases the reliability of the lines and substations discussed in this document.
- Delaying this project exposes the system to the continuing risk of impacts from other potential transmission failures.
- Environmental: There is also a risk due to asbestos potentially in the control cable and other material in the control house. It is not anticipated that the control houses being replaced by this project will be demolished as part of this project. This control house will be abandoned in place and retired on a separate project after this work is complete.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 2,798

2. Alternative #1: Complete over multiple years NPVRR: ($000s) 4,699
   Performing all the work at once is preferred because it reduces engineering and construction labor costs due to efficiencies gained in performing some functions once instead of two or three times. Also, delaying the work leaves LKE open to failure of

the equipment which could result in unnecessary outages, additional damage/stress on transmission equipment, and decreased system reliability.

3. Alternative #2: Do Nothing NPVRR: ($000s) N/A
This is not a viable alternative. The system is experiencing occasional, unpredictable failures of the breakers, line relaying and remote terminal unit (RTU) types installed at this station. Similar failures will eventually happen here if the equipment is not replaced.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Winchester Control House, Relay, Breaker and Arrester Replacement project for $2,570k to improve system reliability.

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

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Appendix:

Exhibit A: Winchester Switching Diagram

[redacted]

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Exhibit B: Winchester Substation Overview

[redacted]

Investment and Contract Proposal for Investment Committee Meeting on: June 26, 2019

Project Name: [redacted] Solar Generator Interconnection Project
Contract Name (Good/Service): [redacted] Solar Generator Interconnection Agreement

Contract Authorization Requested: $2,466k (Including $603k of contingency)

Total Capital Expenditures Requested: $2,466k (Including $603k of contingency and $122k of internal labor)
Total O&M: $0k

Project Number(s): 159803
Business Unit/Line of Business: Transmission

Prepared/Presented By: Ashley Vinson

Brief Contract/Project Description

Louisville Gas & Electric and Kentucky Utilities (LG&E/KU) are required to provide open access generation interconnection service as detailed in the FERC approved Open Access Transmission Tariff (OATT) and administered by the Independent Transmission Organization (ITO), [redacted]

On August 8, 2017 [redacted] (Customer) proposed the interconnection of a new 100MW solar generating facility in [redacted] and LG&E/KU have performed all necessary studies related to this request and [redacted] has granted interconnection service to the customer, subject to the terms and conditions of the Large Generator Interconnection Agreement (LGIA). The LGIA describes, among other things, the required Transmission Interconnection Facilities and Network Upgrades that the Company is obligated to construct to accommodate the interconnection of the solar facility. In addition, the LGIA includes cost estimates and the allocation of costs between the Customer and LG&E/KU.

The total cost of construction that LG&E/KU are obligated to perform is estimated to not exceed $2,466k. The Customer is obligated to pay for actual costs of LG&E/KU's construction of the Transmission Interconnection Facilities which make up the entirety of the $2,466k total. This interconnection does not require any Network Facilities.

In order to provide the required generation interconnection service granted to customer by the ITO, this request is for Investment Committee approval of the LGIA and project approval of up to $2,466k, which includes a 32% contingency. This contingency matches the level of analysis performed to develop the cost estimate and covers increases in actual costs beyond the estimate. This work was not budgeted in the 2019 Business Plan (BP), as it was unknown if the Customer desired to move forward with the LGIA; however, it will be included in the proposed 2020 BP with the assumption that the LGIA will be executed.

<u>Why is the project needed? What if we do nothing?</u>

LG&E/KU is obligated to provide generator interconnection service as required by FERC, detailed in the LG&E/KU OATT, and administered by [redacted] as the ITO. The customer has met the applicable requirements to-date and has been granted generator interconnection status by [redacted]. The next required step is to execute the LGIA. Doing nothing would likely result in a FERC complaint filed by the customer stating LG&E/KU did not follow the OATT and allow the generator to interconnect. The Customer would certainly prevail in such a proceeding; therefore, doing nothing is not a viable option.

The new facility will be located in [redacted] and interconnect with LG&E/KU's existing 138kV Green River substation. As required by the established and approved generation interconnection criteria, the Customer will interconnect as designed in Figure 1 and will construct and own the approximately 1.7 mile long 138kV lead line from the generating plant to the Green River substation. This project will have minimal impact on reliability and/or the customer experience.

[redacted]

[redacted]ough

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[redacted]

Contract Bid Summary

Once Customer agrees to the terms in the LGIA, this project will be bid as required. LG&E/KU plan to execute the Large Generator Interconnection Agreeement with the Customer in early July 2019. The Customer has indicated that they are likely to suspend the agreement, effectively “pausing” the project, and provide LG&E/KU notice to proceed at some later date (not to exceed 36 months from date agreement is executed). Once the project is started, it will take approximately twenty-four months until construction is complete and the unit achieves commercial operation status. LG&E/KU will be reimbursed for actual construction costs upon completion of the project.

Contract Financial Summary

Contract expenses ($k)	2019	2020	2021	2022	2023	Post 2023	Total
Amount requested based on contract estimates (including contingency embedded in contract)	-	-	-	130	1,916	3	2,049
Contingency amount requested (in addition to contingency in contract)	-	-	-	-	-	417	417
Gross contract authority requested	-	-	-	130	1,916	420	2,466
Interconnection Reimbursement	-	-	-	-	-	(2,466)	(2,466)
Network Upgrade Prepayment	-	-	-	-	-	-	-
Network Upgrade Refund	-	-	-	-	-	-	-
Net contract	-	-	-	130	1,916	(2,046)	-

Project Financial Summary

Financial Detail by Year - Capital ($000s)	2022	2023	2024	Post 2024	Total
1. Capital Investment Proposed	130	1,916	420	-	2,466
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	130	1,916	420	-	2,466
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)	(130)	(1,916)	(420)	-	(2,466)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(130)	(1,916)	(420)	-	(2,466)

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)	-	-	-	-	-

Risks

- Facilities are not built in time by LG&E/KU. LG&E/KU may be responsible for liquidated damages in accordance with Section 5.3 of the LGIA if the work required by LG&E/KU is not completed by the mutually acceptable dates determined by LG&E/KU and the Customer.
- Actual costs could deviate from the estimate. A conceptual design has been developed, however there is not sufficient information available at this conceptual stage to develop a detailed scope and project execution plan. This uncertainty necessitated the need to make several assumptions that influenced the contingency amount of the estimated cost; however, it is not feasible at this stage to reduce these assumptions and the associated financial risk. The Customer is required to pay the actual cost of the Transmission Interconnection Facilities.
- Customer does not proceed with the generation interconnection and does not achieve commercial operations of the solar facility. This is primarily a financial risk and is minimized since the Customer is providing security for the Transmission Interconnection Facilities. If the commercial operations date is not achieved, LG&E/KU are allowed to recover any funds spent via the security provided by the Customer.

Project Alternatives Considered

1. Recommendation: NPVRR: ($000s) $2,681
   Pursue execution of the LGIA with Customer as required under the OATT. If LGIA is executed by Customer, proceed with construction of transmission interconnection facilities, as granted by the ITO, [redacted]. The NPVRR above is for the Gross capital requested, the NPVRR is $0 on a net project basis.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   LG&E/KU is obligated to offer generator interconnection service as it is a requirement in the FERC approved OATT and the ITO, [redacted] has granted service. Doing nothing is not a viable alternative as it is not in compliance with the FERC approved OATT.

3. Alternative #2: Not Applicable NPVRR: ($000s) N/A
   To provide non-discriminatory generation interconnection service, the recommendation is designed to meet the approved generator interconnection criteria and is proposed similarly to the previously approved projects and executed LGIAs with [redacted] and [redacted]. Deviating from the approved criteria and the [redacted] and [redacted] projects is not recommended.

<u>Conclusions and Recommendation</u>
It is recommended that the Investment Committee approve the Interconnection Agreement and the project for $2,466k.

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

<u>Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced</u>:

The Capital project spending and contract authority requests included in this Investment Proposal have 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 the capital project and contract authority requests.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
[redacted]

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the [redacted] r Interconnection Agreement contract for $2,466k with [redacted]

Sourcing Leader [If applicable; the approvers for this table can be modified as needed]		Proponent/Team Leader	
Supplier Diversity Manager [If applicable]		Manager Ashley Vinson	
Manager - Supply Chain or Commercial Operations		Director – Supply Chain David Cosby	
Director Chris Balmer		Vice President Tom Jessee	

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Investment Proposal for Investment Committee Meeting on: June 26, 2019

Project Name: Proactive Control House - Middlesboro

Total Capital Expenditures: $2,309k (Including $210k of contingency including $111k of internal labor)

Total O&M: $0k

Project Number(s): SU-000002

Business Unit/Line of Business: Transmission

Prepared/Presented By: Brent Birchell

Brief Description of Project

The scope of work for this project includes multiple system integrity programs that are represented in the Transmission System Improvement Plan (TSIP). The Middlesboro 1 substation has Transmission facilities operating at 69 KV. This substation was originally placed in service in 1958. The earliest 69 KV asset was installed circa 1960. This substation is part of the network backbone in the Pineville area and serves multiple distribution substations.

The programs and project specific information are shown below:

- Improve Protection and Control Systems – The control building will be replaced along with the related protection and control system components (relay panels, batteries, etc.)
- Install Station Service Transformer – One 69kV station service voltage transformer will be installed.

[redacted]

Major equipment at this location include 69 KV breakers (which were replaced in 2016), a 69 KV capacitor bank, and 1 control house.

Description	Date
Preliminary Funding for Project Approved	December 2018
Full Funding for Project Approved	June 2019
Major Materials Ordered	June 2019
Major Materials Received	January 2020
Project Complete	Dec 2020

Why is the project needed? What if we do nothing?

The TSIP outlines the benefits of proactively replacing problematic equipment. The following excerpt was taken from the TSIP:

"System integrity and modernization projects and programs are designed to replace a comprehensive slate of poor performing, obsolete, and end-of-life assets. These programs will reduce the aggregate age of the inventory and ensure that critical assets remain serviceable to support the system. Programs are designed to remove and replace problem assets prior to failure through systematic replacement. Detailed inspections will serve as the central driver for logical and timely asset replacements. Replacement priorities will be determined through assessment of a number of conditional factors in addition to age and, when possible, replacement priorities will be determined by testing and inspections."

Budget Comparison & Financial Summary

This project was originally opened for $279k during December 2018 for preliminary engineering and is being revised for full funding based on the results of preliminary engineering. There is an increase in capital spending in 2020 that accounts for additional scope added to the project during the site visit and preliminary work for the project. As shown below in the alternative project, savings to the company are realized by doing more work at a station rather than mobilizing and demobilizing crews for specific asset replacements over time. This project was approved by the RAC in the 4+8 forecast.

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	480	1,797	-	-	2,276
2. Cost of Removal Proposed	-	33	-	-	33
3. Total Capital and Removal Proposed (1+2)	480	1,829	-	-	2,309
4. Capital Investment 2019 BP	642	700	-	-	1,342
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	642	700	-	-	1,342
7. Capital Investment variance to BP (4-1)	162	(1,097)	-	-	(934)
8. Cost of Removal variance to BP (5-2)	-	(33)	-	-	(33)
9. Total Capital and Removal variance to BP (6-3)	162	(1,129)	-	-	(967)

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)	-	-	-	-	-

Risks

Increased Customer Outages: Aged-protection equipment that has failed in place can result in remote clearing of the fault by other equipment on the system and thus result in larger impacts to customer reliability by producing larger outage areas on the system. Failure of breakers, insulators, and other equipment targeted in this project can also require remote clearing of the fault.

Misoperations: Failure of the protection systems associated with this substation can result in misoperations of the system. NERC has targeted a 7.5% misoperation rate for the Bulk Electric System (BES).

Expensive Repairs: Failure of this aging equipment can result in incremental damage to transformers on the system and other equipment. Proactive replacement of this equipment will minimize the potential of this incremental damage.

Environmental Impacts: There is a risk of asbestos that has been identified with control cables and certain parts of pre-1980 control houses. Existing control cables and the control house will be abandoned in place. These assets will be removed on another project after the work at a later date.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $2,540

2. Alternative #1: Stagger replacements NPVRR: ($000s) $3,089
   2019 - Install new transclosure to contain DFR and RTU. Install SSVT, trench, battery equipment, new distribution panels, and various communication upgrades. Remove arresters and insulators. Upgrade ground grid.
   2020 - Replace bus differential relays and capacitor bank relays, add slip over CTs.
   2021 - Replace remaining equipment including five remaining line relay panels.

   Performing all the work at once is preferred because it reduces engineering and construction labor costs due to efficiencies gained in performing some functions once instead of two or three times. In addition, delaying the work leaves LKE open to failure of the equipment, which could result in unnecessary outages, additional damage/stress on transmission equipment, and decreased system reliability.

3. Alternative #2: Do nothing NPVRR: ($000s) N/A
   This is not a viable alternative. The system is experiencing occasional, unpredictable failures of the line relaying and RTU types installed at this station. Similar failures will eventually happen here if the equipment is not replaced.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Proactive Control House Middlesboro project for $2,309k to enhance the reliability of the 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	

Appendix
Exhibit A: Middlesboro Switching Diagram

[redacted]

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Exhibit B: Middlesboro Substation Overview

[redacted]

Investment Proposal for Investment Committee Meeting on: July 31, 2019

Project Name: Proactive Control House Replacement - Canal

Total Capital Expenditures: $9,636k (Including $851k of contingency and $400k of internal labor)

Total O&M: $0k

Project Number(s): SU-000370

Business Unit/Line of Business: Transmission Substations

Prepared/Presented By: Brent Birchell

Brief Description of Project

Consistent with the scope of the Transmission System Improvement Plan (TSIP) this project is an aggregation of several system integrity programs to address assets in need of replacement at one of LG&E's oldest electrical substations. The Canal substation has Transmission facilities operating at 138 kV and 69 kV. This substation was originally placed in service in 1939. The earliest 69 KV asset was installed circa 1959 and the earliest 138 kV was installed in 1957. This substation serves as part of the backbone that both directly feeds the downtown Louisville network and is interconnected with other stations that are sources to this area. The programs and project specific information are as follows:

- Improve Protection and Control Systems – A new control building will be installed for the Transmission assets, along with the related protection and control system components (relay panels, batteries, etc.). One remote relaying panel will be replaced at the Madison and Paddys West Substations, and two remote relaying panels will be replaced at the Ohio Falls Substation. The existing elecromechanical type control and protective relay systems will be replaced with modern, microprocessor based systems that will ensure reliable operation as well as provide added data for analysis of system events.
- Replace Substation Breakers - Eight (8) 69kV and two (2) 138KV oil-filled circuit breakers will be removed and replaced with modern SF6 insulated breakers. The modern breakers are reliable and require less maintenance over time than the legacy oil type circuit breakers. Elimination of the oil circuit breakers reduces the risk of oil contamination due to failure or accidental release. The Canal Substation is adjacent to the Ohio River.
- Replace Substation Disconnect Switches – Fourteen (14) 69kV and six (6) 138kV high voltage disconnect switches will be replaced. The switches targeted for replacement are at an age where failure is common, often times during operation.
- Replace Substation Insulators – Ninety-one (91) 69KV underhung and cantilever cap & pin type insulators will be replaced with station post type insulators. The cap and pin type insulators have a known history of failure due to radial cracks in the porcelain.

- Install Substation Line Arresters – twenty-one (21) single phase surge arresters will be installed. Surge arrestors are being installed to provide open breaker protection due to lightning strikes. The exsting substation uses an outdated spark gap protection system mounted on the disconnect switches that are being removed.

[redacted]

Why is the project needed? What if we do nothing?
The project is needed to modernize this substation and ensure reliable operation far into the future. The existing equipment and systems are 50-60+ years old, are outdated and have reached their end of life. As described in the TSIP: "System integrity and modernization projects and programs are designed to replace a comprehensive slate of poor performing, obsolete, and end-of-life assets. These programs will reduce the aggregate age of the inventory and ensure that critical assets remain serviceable to support the system. Programs are designed to remove and replace problem assets prior to failure through systematic replacement. Detailed inspections will serve as the central driver for logical and timely asset replacements. Replacement priorities will be determined through assessment of a number of conditional factors in addition to age and, when possible, replacement priorities will be determined by testing and inspections."

Budget Comparison & Financial Summary
There is an increase in the cost compared to the original budget estimate due to additional scope required to accomplish the objectives of the program that was determined during the preliminary engineering work for the project as well as a more accurate estimate based on bids. Multiple asset replacements will be aggregated on this project to reduce the cost associated with mobilizing and demobilizing crews. As shown below in the alternative project, savings to are realized by bundling work at a station and minimizing the number of times crews are mobilized for specific asset replacements over time. This project was approved by the RAC in 2019 6+6 Forecast.

Financial Detail by Year - Capital ($000s)	2018	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	258	1,275	7,569	42	-	9,144
2. Cost of Removal Proposed	-	-	492	-	-	492
3. Total Capital and Removal Proposed (1+2)	258	1,275	8,061	42	-	9,636
4. Capital Investment 2019 BP	258	372	1,600	-	-	2,230
5. Cost of Removal 2019 BP	-	46	229	-	-	275
6. Total Capital and Removal 2019 BP (4+5)	258	418	1,829	-	-	2,505
7. Capital Investment variance to BP (4-1)	0	(903)	(5,969)	(42)	-	(6,914)
8. Cost of Removal variance to BP (5-2)	-	46	(263)	-	-	(217)
9. Total Capital and Removal variance to BP (6-3)	0	(857)	(6,232)	(42)	-	(7,131)

Financial Detail by Year - O&M ($000s)	2018	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)	-	-	-	-	-	-

Risks

- Contracting Strategy – An EPC contract strategy has been used for this project and the costs are reflected above.
- Increased Customer Outages: Aged-protection equipment that has failed in place can result in remote clearing of the fault by other equipment on the system and thus result in larger impacts to customer reliability by producing larger outage areas on the system. Failure of breakers, insulators, and other equipment targeted in this project can also require remote clearing of the fault.
- Misoperations: Failure of the protection systems associated with this substation can result in misoperations of the system. NERC has targeted a 7.5% misoperation rate for the Bulk Electric System (BES).
- Expensive Repairs: Failure of this aging equipment can result in incremental damage to transformers on the system and other equipment. Proactive replacement of this equipment will minimize the potential of this incremental damage.
- Environmental Impacts: As represented in the TSIP, failed equipment, such as transformers, can result in large financial impacts due to environmental cleanup costs associated with oil-filled equipment failing violently. There is also a risk due to asbestos potentially in the control cable and other material in the control house. Materials suspected to contain asbestos will be managed by qualified personnel.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 10,072

2. Alternative #1: NPVRR: ($000s) 10,724
   The alternative consists of performing the recommended scope of work over a period of five years. Performing all the work at once is preferred because it reduces engineering and construction labor costs due to efficiencies gained in performing some functions once instead multiple times. Additionally, delaying the work leaves LKE open to failure of the equipment which could result in unnecessary outages, additional damage/stress on transmission equipment, and decreased system reliability.

3. Alternative #2: Do Nothing NPVRR: ($000s) N/A
   This is not a viable alternative. Oil circuit breakers and other equipment of this vintage will eventually fail with a high likelihood of that happening in the near future. The system is experiencing occasional, unpredictable failures of the pilot wire line relaying and C&P insulators of the types proposed to be replaced and the same will eventually happen here if the equipment is not replaced.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Proactive Control House Canal project for $9,636k to enhance the reliability of the 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	

CONFIDENTIAL INFORMATION REDACTED

Appendix:

Exhibit A: Canal Switching Diagram

[redacted]

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Exhibit B: Canal Substation Overview

[redacted]

Investment Proposal for Investment Committee Meeting on: August 29, 2019

Project Name: Bimble-London Pole Replacement

Total Capital Expenditures: $2,909k (Including $262k of contingency and $48k of internal labor)

Total O&M: $0k

Project Number(s): 157641

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Joe Mina/Adam Smith

Brief Description of Project

The proposed project is to replace twenty-seven (27) structures identified through inspection in 2018 on the Bimble-London 69kV line during a scheduled outage. The scope of work includes replacement of twenty-seven (27) existing wood structures with new steel structures.

Project Milestones	
April 2019	Engineering and Design
July 2019	Space reserved for steel pole production with manufacturer
September 2019	Steel Poles Ordered
November 2019/January 2020	Steel Poles Received
January 2019	Line Construction Begins
March 2020	Line Construction Completed

This project was included in the 2019 Business Plan (BP).

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. A PSC inspection was completed in 2018, and 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.

The scope of work consists of installing twenty-five (25) steel H-Frame structures, one (1) steel three-pole running corner, and one (1) three-pole dead end structure.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost 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. 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.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	94	2,438	-	-	2,533
2. Cost of Removal Proposed	-	377	-	-	377
3. Total Capital and Removal Proposed (1+2)	94	2,815	-	-	2,909
4. Capital Investment 2019 BP	390	2,799	-	-	3,189
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	390	2,799	-	-	3,189
7. Capital Investment variance to BP (4-1)	296	361	-	-	657
8. Cost of Removal variance to BP (5-2)	-	(377)	-	-	(377)
9. Total Capital and Removal variance to BP (6-3)	296	(16)	-	-	280

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)	-	-	-	-	-

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.

Risks

Without the proposed replacement of the priority poles on the Bimble-London 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.

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

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 3,409
   The recommendation is to replace all twenty-seven (27) wood structures with new steel structures during a scheduled outage.

2. Alternative #1: NPVRR: ($000s) 5,212
   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 network reliability.

3. Alternative #2: NPVRR: ($000s) 4,100
   The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Bimble-London pole replacement project for $2,909k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

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: August 29, 2019

Project Name: Farmers-Spencer Road Conductor Replacement

Total Capital Expenditures: $15,896k (Including $1,444 of contingency and $436k of internal labor)

Total O&M: $0k

Project Number(s): Transmission Lines - 152706
Distribution Operations – 20XMUB366

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: David Todd/Adam Smith

Brief Description of Project

The proposed project is to replace 13.5 miles of overhead transmission line with conductor that is over 80 years old and beyond its expected useful life. Performance of this line has diminished, with the most recent event occurring in 2019. Kentucky Utilities Salt Lick Tap serves over 900 customers with 5.1 MVA of load. In addition, the [redacted] interconnection at the Cave Run Tap serves 2.2 MVA of load. This project will improve reliability, maintain system integrity, and reduce the risk of failures and unplanned transmission interruptions to the Morehead and Mt. Sterling 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 lives was included as part of the Transmission System Improvement Plan to replace aging infrastructure.

Transmission Lines plans to replace the 13.5 mile section of 2/0 aluminum conductor steel reinforced (ACSR) conductor from structure 264 to structure 482 in the Salt Lick-Spencer Road section of the Farmers-Spencer Road 69kV line with 397 26/7 ACSR, and new optical ground wire (OPGW) will be installed. In addition, two hundred twenty-three (223) wood structures will be replaced with one hundred thirty-two (132) new steel structures. The proposed project utilizes a new design which optimizes the structure placement, removing ninety-one (91) structures. Distribution Operations will provide the layout work and transferring of underbuilt distribution conductors where needed.

Project Milestones – Transmission Lines	
July 2018-July 2019	Engineering and Design
July 2019	Space reserved for steel pole production with manufacturer
September 2019	Steel Poles Ordered
January 2020	Steel Poles Received
January 2020	Line Construction Begins
March 2021	Line Construction Completed

Project Milestones – Distribution Operations	
October 2019	Engineering and Design
November 2019	Materials Ordered
January 2020	Materials Delivered
January 2020	Construction Start
April 2020	Construction Completed

The total project cost is $15,896k ($15,881k Transmission Lines, $15k Distribution Operations). This project was included in the 2019 Business Plan (BP) for $11,993k, including an estimated spend of $33k in 2018, $200k in 2019, $5,046k in 2020, $5,748k in 2021, and $966k in 2022. As the scope, timing and certainty of work has evolved, the estimates have been further refined, with current estimates of $29k in 2018, $722k in 2019, $6,202k in 2020 and $8,943k in 2021. 2019 spend was approved by the Corporate Resource Allocation Committee. 2020 spend is included in the proposed 2020 BP. Spend in 2021 is included in the proposed 2020 BP for $7,674k. Project 147248 (TEP-MOT-Waitsboro-Union UW) was reduced $1,269k to fund difference in 2021.

	Transmission Lines	Distribution Operations	Total
Total 2018	$29.1k	$0k	$29.1k
Total 2019	$722.3k	$0k	$722.3k
Total 2020	$6,186.2k	$15.4k	$6201.6k
Total 2021	$8,943.4k	$0k	$8,943.4k
Project Total	$15,881k	$15k	$15,896k
Contingency	10%	0%	

<u>Why is the project needed? What if we do nothing?</u>

The existing 13.5 mile section of 69kV line between the Farmers and Spencer Road substations contains the original 2/0 ACSR conductor installed in 1930. Non-destructive testing was performed on the conductor in 2017 and revealed that it was in poor condition and showed that the conductor had less than 85% of its original rated breaking strength remaining. In addition, a routine inspection was performed on this line in 2015 that identified twelve (12) poles for replacement. A portion of this line was built using non-traditional transmission framing consisting of short wood poles with vertical post insulators mounted on cross arms, similar to distribution framing. The line is also absent an overhead ground wire (OHGW) which makes it vulnerable to lighting strikes that can cause momentary or sustained interruptions. The line has experienced a total of thirty-seven (37) interruptions since 2012. The initiating events of these interruptions consist of lightning strikes, vegetation, pole and insulator failures. The most recent event occurred in April 2019 and was caused by a tree making contact with the line and breaking a crossarm.

In July 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 development of the construction plan. Geotechnical services have begun in order to provide geotechnical reports to support drilled shaft foundation design. In addition, easement information has been provided for the entire corridor. No new easement acquisition is required for the project. The transmission line design was provided to all departments involved for comment and review.

Approximately half of the conductor rebuild is within rolling hills and wooded terrain, while the remaining portion runs along rural and relatively sparse residential properties. Structures lie on both private and public land. Company owned easement and KYTC owned road right of way will be used to access the structures.

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 communities and businesses along the route.

The structure design consists of fifty-two (52) steel single pole structures, sixty-nine (69) standard and custom steel H-frame structures, and eleven (11) custom steel self-supporting single pole dead end structures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	29	721	5,874	7,280	13,904
2. Cost of Removal Proposed	-	1	328	1,664	1,993
3. Total Capital and Removal Proposed (1+2)	29	722	6,202	8,943	15,896
4. Capital Investment 2019 BP	33	200	5,046	6,713	11,992
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	33	200	5,046	6,713	11,992
7. Capital Investment variance to BP (4-1)	4	(521)	(828)	(566)	(1,912)
8. Cost of Removal variance to BP (5-2)	-	(1)	(328)	(1,664)	(1,993)
9. Total Capital and Removal variance to BP (6-3)	4	(522)	(1,156)	(2,230)	(3,904)

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)	-	-	-	-	-

Funding for Distribution Operations is included in the proposed 2020 BP under project 155309.

Risks

- Without the proposed replacement of the existing conductor in the Farmers-Spencer Road 69kV line, the company risks increased exposure to line outages. The conductor along the 13.5 mile section has deteriorated over time and is beyond its expected useful life. There have been notable failures in the conductor's 80+ year service life. Unplanned outages are often time-consuming and costly when it comes to repairs.
- A single overhead transmission failure would impact over 900 customers, reducing their reliability until the repairs are complete.
- 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.
- There are no known environmental risks regarding air, water, lead, asbestos, etc., associated with this project.
- Risks associated with project timeline:
  - Winter and early spring weather impacts could pose significant delays, including issues with structure access and rough terrain.
  - As the construction footprint continues to expand, this remains a risk for construction delays in 2020 and beyond.
  - Loss of existing crews providing mutual assistance during major storm events outside of the LKE footprint.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 17,010
   The recommendation is to replace 13.5 miles containing 2/0 conductor with new 397 ACSR 26/7 conductor and install new OPGW. In addition, two hundred twenty-three (223) wood structures will be replaced with one hundred thirty-two (132) 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: NPVRR: ($000s) 24,089
   The Next Best Alternative would be to construct a new 14.85 mile transmission line which would parallel 4.65 miles of existing line. Constructing a new route would require the purchase of 8.8 miles of new right of way and 4.7 miles of expanded 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.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Farmers-Spencer Road conductor replacement project for $15,896k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<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 for Investment Committee Meeting on: 08/29/2019

Project Name: TEP-CR-Clay Village Tap-Shelbyville East

Total Capital Expenditures: $5,054k (Inlcuding $453k of contingency and $184k of internal labor)

Total O&M: $0k

Project Number(s): Transmission Lines - 145803
Distribution Operations - 159705

Business Unit/Line of Business: Transmission

Prepared/Presented By: Delyn Kilpack

Brief Description of Project

Conductor replacement of Clay Village Tap to Shelbyville East section of the Shelbyville to West Frankfort 69kV. The line overloads during planning studies in the TEP process. This project is approved by the Company's Independent Transmission Organization (ITO).

During the TEP process, the Clay Village Tap to Selbyville East line overloads during the outage of East Frankfort – West Frankfort 138 kV line in the near term summer model.

This project will provide a facility rating increase for a 3.25 mile section of the Clay Village Tap to Shelbyville East section of the Shelbyville to West Frankfort 69kV line. The existing summer normal and emergency rating is 41 MVA and a winter normal and emergency rating of 62 MVA. To eliminate the overload, the upgraded line will increase the rating to a summer rating of 83/105 MVA for the normal and emergency rating. The winter rating will be 128/141 MVA respectively.

Transmission plans to replace a 3.25 mile section of 2/0 7ST CU conductor between structure 177 and structure 240 on the Shelbyville to West Frankfort 69kV line with 556.5 ACSR 26/7, and the existing static wire between structure 177 and the East Shelbyville substation face of steel will be replaced with new optical ground wire (OPGW). In addition to the conductor and static being replaced, fifty-three (53) existing wood structures will be replaced with new steel structures. In addition, this estimate assumes that eleven (11) existing steel structures installed during the 2017 priority pole replacement project will be reused. Electric Distribution Operations (EDO) will provide the layout work and transferring of distribution underbuild where needed.

Project Milestones – Transmission Lines	
May 2019	Engineering and Design
July 2019	Space reserved for steel pole production with manufacturer
November 2019	Steel Poles Ordered
January 2020	Steel Poles Received
January 2020	Line Construction Begins
July 2020	Line Construction Completed

Project Milestones – Distribution Operations	
June-August 2019	Engineering and Design
August 2019	Materials Ordered
October 2019	Materials Delivered
January 2020	Construction Start
July 2020	Construction Completed

This project was included in the 2019 Business Plan for $4,319k, with estimated spend of $100k in 2019 and $4,219k in 2020. As scope, timing, and certainty of work has evolved, the estimates have been further refined to include funding for vegetation clearing, structure access, and traffic control. The current total project cost is $5,054k. 2019 spend was approved by the Corporate RAC. The 2020 spend is included in the proposed 2020 BP.

	Transmission Lines	Distribution Operations	Total
Total 2019	$134k	$0k	$134k
Total 2020	$4,351k	$569k	$4,920k
Project Total	$4,485k	$569k	$5,054k
Contingency	10%	10%	

<u>Why is the project needed? What if we do nothing?</u>

The overload of the Clay Village Tap to Shelbyville East section of the Shelbyville to West Frankfort 69kV line was identified in the TEP process and has also been reviewed and approved by [redacted] the Company's ITO.

The 3.25 mile section of 69kV line from Clay Village Tap to Shelbyville East will be reconductored. To eliminate the overload, the ratings will increase to a summer rating of 83/105 MVA for the normal and emergency rating. The winter rating will be 128/141 MVA respectively.

During the 50/50 summer peak season, a line outage of the East Frankfort to West Frankfort 138kV line results in an overload of 108.5% in the 2019 summer 50/50. This overload exists throughout the planning horizon. [redacted]

[redacted]

Structure replacement will consist of three (3) steel dead end structures, forty-three (43) tangent steel structures, seven (7) steel angle structures, and associated hardware and material.

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.

<u>Budget Comparison & Financial Summary</u>

Financial Detail by Year - Capital ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed	134	4,146	-	-	4,280
2. Cost of Removal Proposed		775	-	-	775
3. Total Capital and Removal Proposed (1+2)	134	4,920	-	-	5,054
4. Capital Investment 2019 BP	100	4,219	-	-	4,319
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	100	4,219	-	-	4,319
7. Capital Investment variance to BP (4-1)	(34)	73	-	-	39
8. Cost of Removal variance to BP (5-2)	-	(775)	-	-	(775)
9. Total Capital and Removal variance to BP (6-3)	(34)	(702)	-	-	(736)

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)	-	-	-	-	-

Distribution funding was included in the 2019 BP under project 155309 for $569k and is included in the table above.

<u>Risks</u>

Without the recommended re-conductor of the Clay Village Tap-Shelbyville East section of the Shelbyville-West Frankfort 69kV line, there is risk of losing load in the Shelbyville area.

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

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 5,920
   The recommendation is to replace 3.32 miles containing 336.4 ACSR 26/7 conductor with new 556.5 ACSR 26/7 conductor, existing static with OPGW, and fifty-three (53) wood structures will be replaced with new steel structures.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   This alternative puts customer load at risk and violates the Company's Planning Guidelines.

3. Alternative #2: Create Redundant Line NPVRR: ($000s) 8,857
   Create a redundant line in the Clay Village Tap to Shelbyville East section of the Shelbyville to West Frankfort 69kV line.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the TEP-CR-Clay Village Tap-Shelbyville East project for $5,054k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<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 for Investment Committee Meeting on: September 25, 2019

Project Name: Bond-Virginia City Pole Replacement

Total Capital Expenditures: $2,132k (Including $194k of contingency and $67k of internal labor)

Total O&M: $0k

Project Number(s): LI-158885

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Andrew Bailey/Adam Smith

Brief Description of Project

The proposed project is to replace sixteen (16) existing wood structures on the Bond-Virginia City 69kV line with steel. The scope of work includes the replacement of twelve (12) structures on the Bond-Virginia City 69kV line, and two (2) structures on the Toms Creek 69kV Tap identified through a 2018 inspection. The replacement of two (2) adjacent structures is required to accommodate the height of the new structures. This project will also support the installation of one (1) new two-way switch at the Toms Creek 69kV Tap Point. Due to the difficulty in obtaining an extended outage on the Toms Creek 69kV Tap, two (2) of the sixteen (16) structures will need to be replaced energized. The switch installation will be completed following the replacement of the energized structures. This will allow for the remaining fourteen (14) structures to be replaced de-energized.

Project Milestones	
July 2019	Engineering and Design
August 2019	Space reserved for steel pole production with manufacturer
October 2019	Steel Poles Ordered
October 2019	Steel Poles Received
January 2019	Line Construction Begins
May 2020	Line Construction Completed

This project was not included in the 2019 BP. This project is included in the proposed 2020 Business Plan (BP) for spend of $1,797k in 2020, using an average per structure cost prior to the completion of detailed engineering analysis to replace sixteen structures de-energized. Subsequent to the 2020 BP planning, a decision was made to include the switch installation to allow most of the poles to be replaced under a planned outage. In addition, incremental funding was required to support the energized work on the Toms Creek 69kV tap. The current total project cost is $2,132k, with spend of $116.5k in 2019 and $2,015.5k in 2020. 2019 spend was approved by the RAC. Incremental spend in 2020 will be funded through reallocation from other Transmission projects.

<u>Why is the project needed? What if we do nothing?</u>

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. A PSC inspection was completed in 2018, and fourteen (14) 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.

The scope of work consists of installing eleven (11) steel H-Frame structures, two (2) steel three-pole running corners, two (2) steel single pole structures, one (1) steel two-way switch structure, and one (1) two-way switch.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost 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. 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.

<u>Budget Comparison & Financial Summary</u>

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	117	1,734	-	-	1,851
2. Cost of Removal Proposed	-	281	-	-	281
3. Total Capital and Removal Proposed (1+2)	117	2,016	-	-	2,132
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)	(117)	(1,734)	-	-	(1,851)
8. Cost of Removal variance to BP (5-2)	-	(281)	-	-	(281)
9. Total Capital and Removal variance to BP (6-3)	(117)	(2,016)	-	-	(2,132)

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)	-	-	-	-	-

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.

<u>Risks</u>

Without the proposed replacement of the priority poles on the Bond-Virginia City 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.

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

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 2,588
   The recommendation is to replace fourteen (14) wood structures with new steel structures during a scheduled outage. The remaining two structures will need to be replaced energized.

2. Alternative #1: NPVRR: ($000s) 3,700
   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 network reliability.

3. Alternative #2: NPVRR: ($000s) 3,031
   The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Bond-Virginia City pole replacement project for $2,132k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

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: November 1, 2019

Project Name: Corydon-Rumsey Pole Replacement

Total Capital Expenditures: $8,030k (Including $730k of contingency and $208k of internal labor)

Total O&M: $0k

Project Number(s): LI-158880

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: John Doll/Adam Smith

Brief Description of Project

The proposed project is to replace two hundred (200) existing wood structures on the Corydon-Rumsey 69kV line with steel during a scheduled outage. The scope of work includes the replacement of one hundred ninety-six (196) structures identified through a 2018 inspection. The replacement of four (4) adjacent structures is required to accommodate the height of the new structures.

Eighty-one (81) structures will be replaced between the Rumsey Station and the Ashby Electric Tap. One hundred nineteen (119) structures will be replaced between the Ashby Electric Tap and the Corydon Station.

Project Milestones	
April 2019	Engineering and Design
June 2019	Space reserved for steel pole production with manufacturer
September 2019	Steel Poles Ordered to Inventory
January 2020	Steel Poles Charged from Inventory
January 2020	Line Construction Begins
April 2021	Line Construction Completed

This project was not included in the 2019 Business Plan (BP). Subsequent to the 2019 BP planning, a PSC required pole inspection was completed. The current total project cost is $8,030k, with estimated spend of $251k in 2019, $4,912k in 2020, and $2,867k in 2021. 2019 spend was approved by the Resource Allocations Committee. Spend in 2020 and 2021 is included in the proposed 2020 BP.

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. A routine pole inspection and Comprehensive Visual Inspection were completed in 2018, and one hundred ninety-six (196) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line. In addition, four (4) adjacent structures will be replaced in order to accommodate the height of the new structures.

The scope of work consists of installing one hundred eighty-seven (187) steel single pole structures, one (1) steel H-Frame structure, ten (10) single steel pole running corners, and two (2) steel three pole dead end structures.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost 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. As such, this proposal is to proactively replace them over the course of the next two years, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	245	4,273	2,464	-	6,982
2. Cost of Removal Proposed	6	639	403	-	1,048
3. Total Capital and Removal Proposed (1+2)	251	4,912	2,867	-	8,030
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)	(245)	(4,273)	(2,464)	-	(6,982)
8. Cost of Removal variance to BP (5-2)	(6)	(639)	(403)	-	(1,048)
9. Total Capital and Removal variance to BP (6-3)	(251)	(4,912)	(2,867)	-	(8,030)

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)	-	-	-	-	-

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.

<u>Risks</u>

Without the proposed replacement of the priority poles on the Corydon-Rumsey 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.

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

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 9,613
   The recommendation is to replace two hundred (200) wood structures with new steel structures during a scheduled outage.

2. Alternative #1: Do Nothing NPVRR: ($000s) 14,911
   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 network reliability.

3. Alternative #2: Replace with Wood NPVRR: ($000s) $13,457
   The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Corydon-Rumsey Pole Replacement project for $8,030k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

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: November 1, 2019

Project Name: Kentucky Dam-South Paducah Conductor Replacement

Total Capital Expenditures: $13,677k (Including $1,243k of contingency and $250k of internal labor)

Total O&M: $0k

Project Number(s): Transmission Lines: Phase I - LI-160438 & Phase II – LI-160439
Transmission Substations: 159504

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: John Doll/Adam Smith

Brief Description of Project

The proposed project is to replace two existing circuits in an 18.21 mile section of the South Paducah-Kentucky Dam 69kV line with a single circuit. This project will replace the existing overhead transmission line conductors that are over 90 years old and beyond their expected useful life. Performance of these circuits have diminished, with the most recent conductor failure occurring in 2018. Since 2012, these circuits rank as two of the worst performing transmission circuits for outage events. In addition, the existing 69kV (624) oil circuit breaker (OCB) at South Paducah will be retired and removed. Transmission Planning has completed a study of this circuit in coordination with [redacted] and confirmed that only one circuit is required between South Paducah and Kentucky Dam. A conversion to a single circuit eliminates the replacement for a significant number of the existing lattice towers. This project will improve reliability, maintain system integrity, and reduce the risk of failures and unplanned transmission interruptions to Ashland Oil, and the Princeton and Paducah areas.

Due to these modifications, [redacted] will be required to retire an existing 69kV interconnection tie line, along with the associated relays, protection, and communication path. In July of 2019, a payment was made to [redacted] in the amount of $50k to perform a facilities study to develop the scope, estimate, and schedule to complete these modifications.

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 was included as part of the Transmission System Improvement Plan to replace aging infrastructure.

Transmission Lines plans to replace the existing double circuit 18.21 mile section of 3/0 aluminum conductor steel reinforced (ACSR) conductor in the South Paducah-Kentucky Dam section of the South Paducah-Kentucky Dam TVA-Kuttawa 69kV line in two phases. Phase one will consist of completing 76% of the proposed construction, and phase two will complete the remaining 24% of the proposed construction. The existing double circuit will be replaced with a single circuit of 397 ACSR 26/7, and a new optical ground wire (OPGW) will be installed. In addition, seventeen (17) of the one-hundred eighteen (118) existing lattice steel towers will be replaced with new steel structures. Static peaks will be added to the remaining one-hundred one (101) lattice steel towers to accommodate the installation of new OPGW. Three (3) existing platform switch structures will be completely removed.

Project Milestones – Transmission Lines	
January 2019-September 2019	Engineering and Design
July 2019	Space reserved for steel pole production with manufacturer
November 2019	Steel Poles Ordered
January 2020-February 2020	Steel Poles Received
January 2020	Line Construction Begins
December 2021	Line Construction Completed

Transmission Substation will retire and remove the 69kV (624) OCB which will no longer be needed once the conductor is replaced and one of the circuits coming into the South Paducah Substation is eliminated.

Project Milestones – Transmission Substations	
January 2020-February 2020	Engineering and Design
November 2020	Construction Start
December 2020	Construction Completed

This project was included in the 2019 Business Plan (BP) under project 127111 for $7,991k. As the scope, timing and certainty of work has evolved, the estimates have been further refined. This project is included in the proposed 2020 Business Plan (BP) for $12,536k, including an estimated spend of $473k in 2019, $7,232.7k in 2020, $4,830.7k in 2021. Subsequent to the 2020 BP planning, an environmental study was completed, and it was determined that approximately 50% of the proposed construction would require matting to gain access to structures and limit property damages to these areas.

The current total project cost is $13,677k ($13,624k Transmission Lines, $53k Transmission Substations), with current estimates of $778k in 2019, $6,983k in 2020, and $5,916k in 2021. 2019 spend was approved by the Corporate Resource Allocation Committee. 2020 spend is included in the proposed 2020 BP. Incremental spend in 2021 will be addressed in the 2021 BP.

	Transmission Lines	Transmission Substations	Total
Total 2019	$778k	$0k	$778k
Total 2020	$6,930k	$53	$6,983k
Total 2021	$5,916k	$0k	$5,916k
Project Total	$13,624k	$53k	$13,677k
Contingency	10%	10%	

<u>Why is the project needed? What if we do nothing?</u>
The existing 18.21 mile double circuit section of 69kV line between the Kentucky Dam and South Paducah substations contains the original 3/0 ACSR conductor installed in the 1920s. Non-destructive testing was performed on the conductor in 2017 and revealed that it was in poor condition and showed that the conductor had less than 90% of its original rated breaking strength remaining. The circuits experienced a total of one hundred twenty-one (121) interruptions since 2012, ranking as two of the worst performing transmission circuits for outage events. The initiating events of these interruptions consist of lightning strikes, conductor failures, insulator failures, and several unknown events. The most recent event occurred in September of 2019 and no initiating cause was found. A PSC mandated ground patrol inspection was performed in 2017 and noted a significant number of flashed or broken insulators.

In August 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 development of the construction plan. In addition, easement information has been provided for the entire corridor. No new easement acquisition is required for the project. The transmission line design was provided to all departments involved for comment and review.

The structure design consists of ten (10) steel H-frame structures, five (5) standard Z-Frame structures, one (1) steel three pole dead end structure, and one (1) steel single pole dead end structure. Of the seventeen structures being replaced, one structure (283A) is being replaced in order to separate the structure from the existing [redacted] tie line.

The Ashland Oil switch will be replaced as part of the Ashland Oil-City of Paducah existing switch replacement (ESR) project (157708). The ESR project will be completed in coordination with the proposed 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 communities and businesses along the route.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	778	5,870	5,013	-	11,661
2. Cost of Removal Proposed	-	1,113	903	-	2,016
3. Total Capital and Removal Proposed (1+2)	778	6,983	5,916	-	13,677
4. Capital Investment 2019 BP	300	1,999	4,772	-	7,070
5. Cost of Removal 2019 BP	-	-	920	-	920
6. Total Capital and Removal 2019 BP (4+5)	300	1,999	5,692	-	7,991
7. Capital Investment variance to BP (4-1)	(478)	(3,871)	(241)	-	(4,591)
8. Cost of Removal variance to BP (5-2)	-	(1,113)	17	-	(1,096)
9. Total Capital and Removal variance to BP (6-3)	(478)	(4,984)	(224)	-	(5,686)

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)	-	-	-	-	-

This project was included in the 2019 BP under project 127111.

Risks

- Without the proposed replacement of the existing conductor in the Kentucky Dam-South Paducah 69kV line, the company risks increased exposure to line outages. The conductor along the 18.21 mile section has deteriorated 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 customers, reducing their reliability until the repairs are complete.
- 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.
- There are no known environmental risks regarding air, water, lead, asbestos, etc., associated with this project.
- Risks associated with project timeline:
  - Winter and early spring weather impacts could pose significant delays, including issues with structure access and rough terrain.
  - As the construction footprint continues to expand, a risk remains for construction delays in 2020 and beyond.

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 16,310
   Transmission Lines will replace 18.21 miles containing 3/0 conductor with new 397 ACSR 26/7 conductor and install new OPGW. In addition, seventeen (17) existing lattice steel towers will be replaced with new steel structures, and static peaks added to the remaining one-hundred one (101) lattice steel towers. In addition, Transmission Substations will retire and remove the existing 69kV (624) OCB at South Paducah.

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. These objectives include reducing the risk of failure, avoiding an extended sustained outage, and costly emergency repairs.

3. Alternative #2: Rebuild the Line NPVRR: ($000s) 22,517
   The Next Best Alternative would be to rebuild the 18.21 mile transmission line between the Kentucky Dam and South Paducah substations. Rebuilding the line would add significant cost. Locating areas outside of the existing easement to stage the additional structures would be challenging. In addition, constructing a new line would create additional disturbance in an already difficult work location.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Kentucky Dam-South Paducah Conductor Replacement project for $13,677k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<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 for Investment Committee Meeting on: November 1, 2019

Project Name: Nebo-Wheatcroft Pole Replacement

Total Capital Expenditures: $4,415k (Including $401k of contingency and $132k of internal labor)

Total O&M: $0k

Project Number(s): 157635

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Andrew Bailey/Adam Smith

Brief Description of Project

The proposed project is to replace one hundred (100) existing wood structures on the Nebo-Wheatcroft 69kV line with steel during a scheduled outage. The scope of work includes the replacement of ninety-seven (97) structures identified through a 2018 inspection. The replacement of three (3) adjacent structures is required to accommodate the height of the new structures.

Project Milestones	
July 2019	Engineering and Design
September 2019	Space reserved for steel pole production with manufacturer
November 2019	Steel Poles Ordered
December 2019-January 2020	Steel Poles Received
March 2019	Line Construction Begins
June 2020	Line Construction Completed

This project was included in the 2019 Business Plan.

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. A routine inspection was completed in 2018, and ninety-seven (97) 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.

The scope of work consists of installing seventy-two (72) steel single pole structures, sixteen (16) steel H-Frame structures, eleven (11) single steel pole running corners, and one (1) single steel pole dead-end structure.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost 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. 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.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	353	3,827	-	-	4,180
2. Cost of Removal Proposed	-	235	-	-	235
3. Total Capital and Removal Proposed (1+2)	353	4,063	-	-	4,415
4. Capital Investment 2019 BP	798	4,175	-	-	4,972
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	798	4,175	-	-	4,972
7. Capital Investment variance to BP (4-1)	445	348	-	-	793
8. Cost of Removal variance to BP (5-2)	-	(235)	-	-	(235)
9. Total Capital and Removal variance to BP (6-3)	445	112	-	-	557

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)	-	-	-	-	-

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.

Risks

Without the proposed replacement of the priority poles on the Nebo-Wheatcroft 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.

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

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 5,372
   The recommendation is to replace one hundred (100) wood structures with new steel structures during a scheduled outage.

2. Alternative #1: Do Nothing NPVRR: ($000s) 7,664
   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 network reliability.

3. Alternative #2: Replace with Wood NPVRR: ($000s) 5,663
   The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Nebo-Wheatcroft Pole Replacement project for $4,415k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<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 and Contract Proposal for Investment Committee Meeting on: November 1, 2019

Project Name: [redacted] Interconnection Green River-Green River Steel
Contract Name (Good/Service): Amended and Restated Interconnection Agreement between [redacted] and Louisville Gas and Electric Company and Kentucky Utilities Company

[redacted]

Contract Authorization Requested: $2,750k (Including $217k of contingency)

Contract Term: N/A

Total Capital Expenditures Requested: $2,750k (Including $217k of contingency and $152k of internal labor)
Total O&M: $0k

Project Number(s): 158817 (Substations), 158818 (Lines) and 160252 (Easement)
Business Unit/Line of Business: Transmission

Prepared/Presented By: Adam Smith

Brief Contract/Project Description

An Interconnect Agreement (IA) with [redacted] has been approved for [redacted] to connect a new 138kV line to the Green River to Green River Steel line, which will become a three terminal line between KU's Green River and Green River Steel substations and [redacted] substation.

This project was approved for a total of $552k during May 2019 which included full authorization of $334k for transmission substation project (158817) and $218k for preliminary engineering on transmission lines project (158818). Separately, easement acquisition was approved for $120k on project 160252 during May 2019. In addition, a revision was submitted for intermediate approval of spending through mid November of 2019 in Octobor of 2019 in the amount of $1,335k, ($224k Subs, $991k Lines construction, and $120k Lines easement acquisition). This intermediate approval was needed to ensure the project could remain on schedule to meet [redacted] desired in-service date of May 2020 without exceeding the authorized spending level.

Per Facility Study Schedule 4 in the IA, the original estimated cost of this work was $1,593k. Once detailed engineering analysis was completed and contractor pricing obtained, the estimates were further refined. The current total project estimate is $2,750k ($224k Transmission Substations, $2,406k Transmission Lines Construction, $120k Transmission Lines Easement acquisition). This project was not included in the 2019 Business Plan. This project is included in the proposed 2020 BP for $2,234k. [redacted] will reimburse LG&E/KU for 100% of the costs to complete construction of this project per the agreement dated November 13, 2018. [redacted] has been informed of the increased anticipated project costs and [redacted] has confirmed in writing acknowledgement and acceptance of the updated costs.

	Transmission Substation	Transmission Lines Construction	Transmission Lines Easement Acquisition	Total
Total 2019	$174k	$1,537k	$120k	$1,831k
Total 2020	$50k	$869k	$0k	$919k
Project Total	$224k	$2,406k	$120k	$2,570k
Contingency	0%	10%	0%	

Transmission Substations will install (1) 009-794 Retrofit Line Relay Panel and (1) 100-714 Retrofit Line Relay Panel (both w/ SEL-411L and SEL-421 relay packages) and will remove electromechanical relays on both the 009-794 and 100-714.

Project Milestones – Transmission Substations	
August 2019	Engineering and Design
August 2019	Materials Ordered
October 2019	Materials Received
October 2019	Construction Start
January 2020	Construction Completed

Transmission Lines will install 0.97 miles of new 954 ACSR 45/7 conductor beginning at the tap point on the Green River-Green River Steel 138kv line and extending to the [redacted] 138kV Substation. Also included in the scope of this project is the installation of eight (8) new steel structures and the removal of four (4) existing structures. A 3-way switch will be installed at the new [redacted] tap-point. Approximately one acre of new right of way easement has been acquired at the tap point.

Project Milestones – Transmission Lines	
January 2019-September 2019	Engineering and Design
May 2019	Space reserved for steel pole production with manufacturer
July 2019	Steel Poles Ordered
September 2019	Steel Poles Received
October 2019	Line Construction Begins
May 2020	Line Construction Completed

In addition to the work described above, [redacted] will install new fiber optic cable between the KU Green River Steel station and the [redacted] station. LG&E/KU will assume ownership of the fiber as part of the LG&E/KU Green River Steel to [redacted] 138 and 69 kV Line Differential Protection Scheme.

Why is the project needed? What if we do nothing?

[redacted] is retiring both generating units at the Elmer Smith station. Unit 1 was retired in June of 2019. Unit 2 will be retired in June of 2020. [redacted] will replace this generation by importing power from [redacted] This interconnection is required to maintain reliability to the transmission system.

LG&E/KU is obligated to provide transmission and generator interconnection service as required by FERC, detailed in the LG&E/KU OATT, and administered by [redacted] as the ITO. This project will have minimal impact of reliability and/or the customer experience.

Contract Financial Summary

Contract expenses ($k)	2019	2020	2021	2022	2023	Post 2023	Total
OMU Payments	$521k	$2,012k	$0k	$0k	$0k	$0k	$2,533k
Contingency	$0k	$217k	$0k	$0k	$0k	$0k	$217k
Total Payments	$521k	$2,229k	$0k	$0k	$0k	$0k	$2,750k

This project was not included in the 2019 Business Plan. This project is included in the proposed 2020 BP for $2,234k, including $890k in 2019 and $1,344k in 2020, less reimbursements for a net $6k.

The current total project cost of $2,750 exceeds the amount included in the 2020 BP on a gross basis, however [redacted] will reimburse LG&E/KU for 100% of the costs of construction to complete this project per the agreement dated November 13, 2018. [redacted] has been informed of the increased anticipated project costs and [redacted] has confirmed in writing acknowledgement and acceptance of the updated costs.

The Transmission Lines 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. Contingency is calculated at 10% of the total project cost after burdens are applied.

The contract does not include built in escalators.

Project Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	1,823	694	-	-	2,517
2. Cost of Removal Proposed	8	225	-	-	233
3. Total Capital and Removal Proposed (1+2)	1,831	919	-	-	2,750
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)	(1,823)	(694)	-	-	(2,517)
8. Cost of Removal variance to BP (5-2)	(8)	(225)	-	-	(233)
9. Total Capital and Removal variance to BP (6-3)	(1,831)	(919)	-	-	(2,750)

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)	-	-	-	-	-

Risks

- Failure to perform risk and mitigation measures.
- Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

Project Alternatives Considered

1. Recommendation: NPVRR: ($000s) 3,512

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
LG&E/KU is obligated to offer generator interconnection service as it is a requirement in the FERC approved OATT and the ITO, [redacted], has granted service. Doing nothing is not a viable alternative as it is not in compliance with the FERC approved OATT.

3. Alternative #2: Construct a Ring Bus NPVRR: ($000s) 7,644
Construct a 138kV three breaker ring bus at the proposed transmission tap point in the Green River – Green River Steel 138 KV line and install 1.04 miles of new 954 ACSR 45/7 conductor beginning at the tap point on the Green River-Green River Steel 138kv line and extending to the [redacted] 138kV Substation. Included in the scope of this project is the installation of eight (8) new steel structures and the removal of four (4) existing structures.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the [redacted] Interconnection Green River-Green River Steel project for $2,750k to satisfy its Open Access Transmission Tariff obligations, and to maintain system integrity and reliability.

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced:

The Capital project spending and contract authority requests included in this Investment Proposal have 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 the capital project and contract authority requests.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
Amended and Restated Interconnection Agreement between [redacted] and Louisville Gas and Electric Company and Kentucky Utilities Company

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the Amended and Restated Interconnection Agreement between [redacted] and Louisville Gas and Electric Company and Kentucky Utilities Company contract for $2,750k with [redacted].

Sourcing Leader		Proponent/Team Leader	
Supplier Diversity Manager		Manager	
Manager - Supply Chain or Commercial Operations		Director – Supply Chain or Commercial Operations David Cosby	
Director		Vice President Tom Jessee	

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Investment Proposal for Investment Committee Meeting on: November 1, 2019

Project Name: TEP Rogers Gap Distribution Station

Total Capital Expenditures: $7,174k (Including $648k of contingency and $514k of internal labor)

Project Number(s): Transmission Lines – LI-159700
Distribution Substations – 160207
Distribution Operations - 160773

Business Unit/Line of Business: Transmission and Distribution

Prepared/Presented By: Dan Hawk/Delyn Kilpack

Brief Description of Project

This Investment Proposal (IP) requests funding authority for distribution substation, distribution circuit, and transmission line improvements in and around the KU Rogers Gap Substation near Georgetown, KY. The goal of this project is to reduce the loading on the 69kV transmission system in the area in order to mitigate a contingency related conductor overload risk. The Adams – Delaplain 69kV tap overloads during planning studies and was identified through the Transmission Expansion Plan (TEP) process.

This project was originally identified under the TEP-CR-Adams-Delaplain Tap conductor replacement project (144065). After preliminary engineering was underway, it was determined that moving the load at Rogers Gap from 69kV to 138kV is a lower cost alternative.

In the 90/10 winter peak conditions and during an outage of Scott County to Rogers Gap causes the Adams – Delaplain 69 kV to load to 101.9% in 2019. In the 50/50 winter peak, the overload is 101.5% in 2025.

The Adams-Delaplain conductor replacement project was approved by [redacted] the Company's Independent Transmission Organization (ITO). [redacted] has been supplied documentation showing that the Rogers Gap Distribution Substation project is the lower cost alternative of both projects and is expected to support the alternative solution.

A Network Integration Transmission Service (NITS) request will be submitted to [redacted] in October of 2019 to get approval for modifications to the transmission system.

Project Scope and Milestones

Transmission Lines will install four (4) steel self-supporting dead-end structures, one (1) steel self-supporting tangent structure, and associated hardware and material as needed to terminate and connect the 138kV transmission line to the new 138kV substation.

Project Milestones – Transmission Lines	
April 2019-September 2019	Engineering and Design
September 2019	Space reserved for steel pole production with manufacturer
November 2019	Steel Poles Ordered
April 2020	Steel Poles Received
August 2021	Line Construction Begins
October 2021	Line Construction Completed

Distribution Substation will provide the installation of a new 15/28 MVA 138-12 kV transformer, steel transmission/distribution bay, one (1) 138kV transformer breaker, two (2) 138kV motor operated switches, one (1) 12kV switchgear, control house, underground cable, conduit, manholes, SPCC, and other associated equipment in the Rogers Gap substation.

Project Milestones – Distribution Substations	
November 2019-April 2020	Engineering and Design
December 2019	Materials Ordered
December 2020	Materials Delivered
February 2021	Construction Start
October 2021	Construction Completed

Distribution Operations will provide the installation of manholes, underground cable, poles, overhead conductor, and switches as needed to connect the new 12kV substation switchgear to the existing distribution circuits. In addition, Distribution Operations will relocate one distribution pole currently in the Transmission right of way in order to maintain proper mid-span clearances and transfer existing distribution conductor to the new transmission structures as needed. An air break switch will be installed between the existing distribution circuits to help facilitate construction.

Project Milestones – Distribution Operations	
September 2020-October 2020	Engineering and Design
November 2020	Materials Ordered
February 2021	Materials Delivered
March 2021	Construction Start
September 2021	Construction Completed

Although it will not serve any normal service load, it is proposed that the existing 22.4 MVA, 69-12 kV transformer, steel, breakers, and other associated equipment remain in the Rogers Gap Substation in order to support the Company's Distribution Substation Transformer Contingency Program (N1DT).

This project was included in the 2019 BP for $3,762k under project 144065 (Adams-Delaplain Conductor Replacement) with estimated spend of $156k in 2018, and $3,606k in 2019. Once detailed engineering was completed, the estimates for this project were further refined, and the estimate was revised to include incremental funding of $3,671k, bringing the total project cost to $7,433k. Upon further analysis, it was determined that moving the load at Rogers Gap is the lower cost and preferable alternative to minimize customer risk. The TEP Rogers Gap

Distribution Station project is included in the proposed 2020 BP for $7,688k with estimated spend of $1,047k in 2020, $6,641k in 2021. The current total project cost is $7,174k with estimated spend of $3,264k in 2020 and $3,910k in 2021. Incremental spend in 2020 will be funded through reallocation from other Transmission projects.

	Transmission Lines	Distribution Substation	Distribution Operations	Total
Total 2020	$297k	$2,830k	$137k	$3,264k
Total 2021	$1,801k	$1,971k	$138k	$3,910k
Project Total	$2,098k	$4,801k	$275k	$7,174k
Contingency	10%	10%	10%	

Why is the project needed? What if we do nothing?

Transmission Planning has identified a transmission system need in the Georgetown area and has a project included in the Transmission Expansion Plan (TEP) for transmission conductor upgrades to mitigate conductor overloads during contingency conditions. Under the original project (Adams-Delaplain Conductor Replacement) it was proposed to replace 2.86 miles of 266 ACSR with 795 ACSR conductor in the Adams-Delaplain Tap section of the Adams-Oxford 69kV transmission line. However, Transmission Planning, in conjunction with Distribution System Planning, has now identified an alternate project (Rogers Gap Distribution Station) that transfers the Rogers Gap substation load from the 69kV to the 138kV transmission system and accomplishes the same goals as the original project.

The Do Nothing option is not considered to be an acceptable option because it is not compliant with transmission planning guidelines.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	**2018**	**2019**	**2020**	**Post 2020**	**Total**
1. Capital Investment Proposed	-	-	3,256	3,611	6,868
2. Cost of Removal Proposed	-	-	8	299	306
3. Total Capital and Removal Proposed (1+2)	-	-	3,264	3,910	7,174
4. Capital Investment 2019 BP	156	3,606	-	-	3,762
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	156	3,606	-	-	3,762
7. Capital Investment variance to BP (4-1)	156	3,606	(3,256)	(3,611)	(3,105)
8. Cost of Removal variance to BP (5-2)	-	-	(8)	(299)	(306)
9. Total Capital and Removal variance to BP (6-3)	156	3,606	(3,264)	(3,910)	(3,412)

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 project was included in the 2019 BP under project 144065. The 2019 BP estimate was based on replacing the conductor, using the existing double circuit structures.

Risks

- The estimated costs of the distribution substation, distribution circuits, and transmission lines are considered high level estimates at this time because the projects have not been formally designed. The costs are based on completed work for other projects of similar scope and size.
- Failure to advance and complete this project in a timely fashion could expose the Company to periods of noncompliance with federally mandated transmission planning standards.
- There are no known environmental risks regarding air, water, lead, asbestos, etc., associated with this project.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 9,001
   The recommended option proposes the installation of a 28 MVA 138-12kV transformer along with other associated substation, distribution, and transmission equipment in and near the Rogers Gap substation in order to change the transmission delivery voltage from 69kV to 138kV

2. Alternative #1: Do Nothing NPVRR: N/A
   As previously discussed, the "do nothing" option is not considered a valid option because it violates the Company's Transmission Planning Guidelines. .

3. Alternative #2: Replace Conductor NPVRR: ($000s) 9,583
   This previously described option considers the replacement of 2.86 miles of 266 ACSR with 795 ACSR conductor in the Adams-Delaplain Tap section of the Adams-Oxford 69kV transmission line. The estimated capital cost of this option is $7,433k. In addition, this option puts [redacted] on a radial feed for approximately 10 weeks which is a risk in serving [redacted] load.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Rogers Gap Distribution Station project for $7,174k to alleviate contingency related transmission conductor overloads on the Adams-Oxford 69kV transmission line and comply with federally mandated standards.

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: November 1, 2019

Project Name: TEP-CR-Ford-Freys Hill

Total Capital Expenditures: $5,159k (Including $494k of contingency and $351k of internal labor)

Total O&M: $0k

Project Number(s): Transmission Lines – LI-000088
Distribution Operations - 159259

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

Prepared/Presented By: Delyn Kilpack

Brief Description of Project

The Ford – Freys Hill Tap 69kV line overloads during planning studies in the Transmission Expansion Plan (TEP) process with a need date of 2019. Subsequent TEP's have confirmed the need for this project. This project was approved by [redacted] the Company's Independent Transmission Organization (ITO).

During the 90/10 summer peak conditions, an outage of the Middletown – Lyndon 69kV line or the Lyndon to Freys Hill 69kV line causes the Ford – Freys Hill Tap 69kV line to overload 100.1% in 2019. The overload is 103.4% in 2027. During the 50/50 summer peak conditions, the overload is 101.5% in 2029.

When the project is completed the summer emergency rating will go from 100 MVA to 132 MVA.

This project was opened for preliminary services in October of 2019 to begin vegetation clearing to gain access to the right of way for surveying and line construction.

Transmission Lines plans to replace 1.7 miles of existing 795 All Aluminum Conductor (ACC) between structure 18 at the Worthington Tap Point to structure 54-1 outside of the Ford substation on the Ford-Freys Hill 69kV line with 954 Aluminum Conductor Steel Reinforced (ACSR), and the existing static wire will be replaced with new optical ground wire (OPGW). In addition to the conductor and static being replaced, forty-one (41) existing wood structures will be replaced with new steel structures. Electric Distribution Operations (EDO) will provide the layout work and transferring of distribution underbuild where needed.

Project Milestones – Transmission Lines	
March-July 2019	Engineering and Design
August 2019	Space reserved for steel pole production with manufacturer
November 2019	Steel Poles Ordered
February 2020	Steel Poles Received
February 2020	Line Construction Begins
June 2020	Line Construction Completed

Project Milestones – Distribution Operations	
November-December 2019	Engineering and Design
April 2020	Materials Ordered
May 2020	Materials Delivered
May 2020	Construction Start
December 2020	Construction Completed

This project was included in the 2019 Business Plan for $2,133k, with estimated spend of $50k in 2019 and $2,083k in 2020. As scope, timing, and certainty of work has evolved, the estimates have been further refined. This project was included in the 2020 BP for $4,535k, with estimated spend of $284k in 2019 and $4,251k in 2020. Subsequent to the 2020 BP, funding was included for self-supporting structurs, vegetation clearing, and the transferring of distribution underbuild. The current total project cost is $5,159k, with estimated spend of $382k in 2019 and $4,777k in 2020. 2019 spend was approved by the Corporate RAC. Incremental spend in 2020 will be funded by a reduction in other transmission and distribution capital projects.

	Transmission Lines	Distribution Operations	Total
Total 2019	$382k	$0k	$382k
Total 2020	$4,439k	$338k	$4,777k
Project Total	$4,821k	$338k	$5,159k
Contingency	10%	20%	

<u>Why is the project needed? What if we do nothing?</u>

The overload of the Ford – Freys Hill Tap 69kV line was identified in the TEP and approved by [redacted] the Company's Independent Transmission Organization (ITO).

The Ford – Freys Hill Tap 69kV line currently consists of 0.69 miles of 795 MCM 61X AAC conductor (verified at 176/176°F). To eliminate the overload, this line section will be replaced with 954 ACSR conductor.

During the 90/10 winter peak conditions, an outage on either the Lyndon to Middletown 69kV line or the Lyndon to Freys Hill 69kV line results in an overload of 100.1% in the 2019 summer and increases to 103.4% in 2027 summer. This overload exists throughout the planning horizon.

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.

[redacted]

Structure replacement will consist of thirty-three (33) single pole structures, three (3) self-supporting steel angle structures, and five (5) self-supporting steel dead end structures. Four span guys and stub poles crossing over [redacted] will be eliminated.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	382	4,265	-	-	4,647
2. Cost of Removal Proposed	-	512	-	-	512
3. Total Capital and Removal Proposed (1+2)	382	4,777	-	-	5,159
4. Capital Investment 2019 BP	50	2,083	-	-	2,133
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	50	2,083	-	-	2,133
7. Capital Investment variance to BP (4-1)	(332)	(2,182)	-	-	(2,513)
8. Cost of Removal variance to BP (5-2)	-	(512)	-	-	(512)
9. Total Capital and Removal variance to BP (6-3)	(332)	(2,694)	-	-	(3,026)

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)	-	-	-	-	-

Risks

Without the recommended re-conductor of the Ford – Freys Hill Tap 69kV line, there is risk of losing load at Ford, Freys Hill, Lyndon and Worthington.

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

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 6,264
   The recommendation is to replace 1.7 miles containing 795 AA conductor with new 954 ACSR conductor, existing static with OPGW, and thirty-eight (38) wood structures will be replaced with new steel structures.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   This alternative puts the customer load at risk and violates the Company's Transmission Planning Guidelines.

3. Alternative #2: Build Redundant Line NPVRR: ($000s) 15,938
   This alternative requires building a second 69kV line from Lyndon – Freys Hill and construct a four breaker 69kV ring bus at Lyndon.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the TEP-CR-Ford-Freys Hill project for $5,159k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<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 for Investment Committee Meeting on: November 1, 2019

Project Name: TEP-CR-Mid Valley-Finchville

Total Capital Expenditures: $6,882k (Including $626k of contingency and $136k of internal labor)

Total O&M: $0k

Project Number(s): Transmission Lines - LI-159243

Business Unit/Line of Business: Transmission

Prepared/Presented By: Delyn Kilpack/Chris Balmer

Brief Description of Project

The Mid Valley Simpsonville - Finchville 69kV line overloads during planning studies. This overload was first identified in the 2019 Transmission Expansion Plan (TEP).

During the 90/10 and 50/50 winter peak conditions, an outage of the Blue Lick 345/161kV transformer results in an overload of the Mid-Valley Simpsonville to Finchville 69 kV line. The 90/10 winter peak overload is 113.8% in 2020. The 50/50 winter peak is 111% in 2020 and the summer peak is 101.3%.

This project will provide a facility rating increase for the 5.13 miles of the Mid Valley Simpsonville - Finchville 69kV line. To eliminate the overload, the upgraded line will increase the rating to a summer rating of 94/119 MVA for the normal and emergency rating. The winter rating will be 144/159 MVA respectively for normal and emergency rating.

Transmission plans to replace a 5.13-mile section of 397 ACSR 26/7 conductor between structure 273A and structure 307 on the Mid Valley-Finchville section of the Mid Valley-Simpsonville 733 69kV Tap with 795 ACSR 26/7, and the existing static wire will be replaced with new optical ground wire (OPGW). In addition to the conductor and static being replaced, thirty-five (35) existing steel towers, and two (2) existing steel single pole structures will be replaced with thirty-six (36) new steel structures.

Project Milestones – Transmission Lines	
May 2019	Engineering and Design
November 2019	Space reserved for steel pole production with manufacturer
January 2020	Steel Poles Ordered
March 2020	Steel Poles Received
March 2020	Line Construction Begins
November 2020	Line Construction Completed

This project was included in the proposed 2020 Business Plan for $5,946k, with estimated spend of $262k in 2019 and $5,684k in 2020. As scope, timing, and certainty of work has evolved, outage constraints identified during the summer months will now require this project to be completed under a spring and fall outage. The current total project cost is $6,882k, with estimated spend of $564k in 2019 and $6,318k in 2020. 2019 spend was approved through the Corporate Resource Allocation Committee. Incremental spend in 2020 will be funded through a reduction in other Transmission capital projects. This project was not included in the 2019 BP.

<u>Why is the project needed? What if we do nothing?</u>
The overload of Mid Valley Simpsonville - Finchville 69kV line was identified in the TEP process and has also been reviewed and approved by [redacted] the Company's Independent Transmission Organization (ITO).

The 5.13-mile, 69 kV line from Mid Valley Simpsonville - Finchville will be reconductored. To eliminate the overload, the ratings will increase to a summer rating of 94/119 MVA for the normal and emergency rating. The winter rating will be 144/159 MVA respectively.

During the 90/10 and 50/50 winter peak conditions, an outage of the Blue Lick 345/161kV transformer results in an overload of the Mid-Valley Simpsonville to Finchville 69 kV line. The 90/10 winter peak overload is 113.8 in 2020. The 50/50 winter peak is 111% in 2020 and the summer peak is 101.3%. This overload exists throughout the planning horizon. [redacted]

Structure replacements will consist of thirty (30) steel H-Frame structures, one (1) custom steel switch structure, and five (5) steel single pole dead-end structures.

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.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	564	5,341	-	-	5,905
2. Cost of Removal Proposed	-	977	-	-	977
3. Total Capital and Removal Proposed (1+2)	564	6,318	-	-	6,882
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)	(564)	(5,341)	-	-	(5,905)
8. Cost of Removal variance to BP (5-2)	-	(977)	-	-	(977)
9. Total Capital and Removal variance to BP (6-3)	(564)	(6,318)	-	-	(6,882)

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)	-	-	-	-	-

Risks

Without the recommended re-conductor of the Mid Valley-Finchville section of the Mid Valley-Simpsonville 733 69kV Tap, there is risk of violating the Company's Planning Guidelines.

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

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 8,374
   The recommendation is to replace 5.13 miles containing 397 ACSR 26/7 conductor with new 795 ACSR 26/7 conductor, existing static with OPGW, and thirty-seven (37) existing structures will be replaced with thirty-six (36) new steel structures.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   This alternative puts customer load at risk and violates the Company's Planning Guidelines.

3. Alternative #2: Construct Redundant Line NPVRR: ($000s) 18,118
   Create a redundant Blue Lick 345/161kV transformer. Construct additional 161kV rung to the west includes 161kV GCB, Switch & Surge Arrestors. Construct 2nd 345/161kV, 420MVA transformer with dedicated 345kV GCB, Switch. Add dedicated 345kV GCB on HV side of existing 345/161kV transformer. Add two 345kV GCB's with dedicated isolation switches. Construct 345kV rung to MT line exit to retain 345kV source under 345/161kV HV GCB breaker failure scenario.

<u>Conclusions and Recommendation</u>
It is recommended that the Investment Committee approve the TEP-CR-Mid Valley-Finchville project for $6,882k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<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 for Investment Committee Meeting on: November 22, 2019

Project Name: TEP Hardin County

Total Capital Expenditures: $27,512k (Including $2,648k of contingency and $909k of internal labor)

Total O&M: $0k

Project Number(s): 144070,157806,LI-000100,LI-000102,LI-161041,SU-000203,SU-000439,161065

Business Unit/Line of Business: Transmission

Prepared/Presented By: Delyn Kilpack

Brief Description of the Project

The Hardin County projects include installation and/or construction of a 2nd Hardin County 345/138 kV transformer, 2nd Hardin County 138/69 kV transformer, and a 2nd Hardin County - Elizabethtown 69 kV line. Other ancillary projects were identified and are listed below. The projects were identified in the Transmission Expansion Plan (TEP) process and are approved by the company's Independent Transmission Organization (ITO). There are significant low voltage violations when studying the outage of the existing Hardin County 345/138 kV transformer. Therefore, these projects are required to meet the requirements of NERC Reliability Standard TPL-001-4 and the Company's Planning Guidelines. Additional work is required at Elizabethtown 69 kV to reconfigure the bus and add a bus tie breaker. This is vital to maintenance efforts, and greatly increases customer reliability. Preliminary engineering has already begun with an expected completion date in 2022. Transmission Planning evaluated these projects to ensure they are adequate throughout the ten-year planning horizon under varying load forecasts.

Joint studies between LG&E/KU and [redacted] were performed in 2017 and 2018 resulting in the following list of projects for LG&E/KU. [redacted] has its own list of related projects.

- 2nd 345/138 kV transformer at Hardin County - SU-000203/157806
- 2nd 138/69 kV transformer at Hardin County - SU-000203
- Split the 69 kV straight bus at Hardin County into two buses with a bus tie breaker - SU-000203
- 2nd 69 kV line from Hardin County to Elizabethtown - LI-000102/SU-000439/157806
- MOT increase of the Elizabethtown – Nelson County 138 kV line - LI-000100
- MOT increase of Elizabethtown – Elizabethtown #2 69 kV line - 144070
- Elizabethtown 69 kV Bus Tie Breaker - SU-000439/157806

Without the Hardin County expansion project, severe low voltage violations are likely under peak load conditions following the loss of the Hardin County 345/138 kV transformer. [redacted]

[redacted]

[redacted]

Table 1 shows the number of voltage criteria vioaltions identifed in the LG&E/KU and EKPC joint study.

[redacted]

Table 2 shows the number of potentially affected customers.

[redacted]

The solution identified is adding a 2nd 345/138 kV transformer. When adding the 2nd 345/138 kV transformer, flows are significantly increased in the 138 kV and 69 kV systems. Therefore, a 2nd 138/69 kV transformer and 2nd 69 kV line are also required.

The risk associated with the identified violations is increased when considering the Hardin County area has positive load growth, compared to other areas of the LG&E or KU systems. Electric Distribution Operations has seen significant growth along Black Branch Road in Hardin County due to expansions from large industrial customers in the area, and significant commercial growth along US Highway 31W. Additionally, KU has seen expansion activities at nearly all distilleries in the area. In response to this growth, KU Distribution has constructed two new substations (Rineyville and Black Branch) and currently has projects under construction to increase capacity at the Barton substation.

[redacted].

[redacted]

[redacted]

[redacted]

The existing and new substation layouts at Hardin County, based on the proposed projects, are shown in Figures 6 and 7 below.

CONFIDENTIAL INFORMATION REDACTED

[redacted]

[redacted]

During project engineering, it was determined that the Elizabethtown 69 kV bus required a bus tie breaker to allow bus outages for maintenance. This includes additional line reconfiguration to best utilize the bus tie. [redacted]

[redacted]

[redacted].

CONFIDENTIAL INFORMATION REDACTED

[redacted]

Adding a 69 kV bus tie breaker requires enlarging the substation, adding two new bays and re-terminaing several LG&E and EKPC lines.   In total, the addition of the bus tie breaker adds $4,310k to the cost of the project.

<u>Project Scope and Milestones</u>

This project will install a 2nd 345/138 kV and 2nd 138/69 kV transformer at Hardin County, build a new 1.3 mile 69 kV line from Hardin County to Elizabethtown, add a 69kV bus tie breaker at Hardin and split the bus, add a 69kV bus tie breaker at Etown and split the bus, increase the maximum operating temperature (MOT) of the Nelson County to Elizabethtown 138 kV line (15.5 miles), increase the MOT of the Elizabethtown to Elizabethtown #2 Tap 69 kV line section (2.24 miles), and relocate approximately 0.6 miles of various lines around the Elizabethtown and Hardin County substations.

	144070 TEP MOT ETOWN ETOWN 2	**157806 TEP Hardin Co Line Work**	**LI-000100 TEP MOT Etown Nelson Co**	**LI-000102 TEP NL Hardin Co Etown New 2nd**	**LI-161041 TEP-NL-Hardin Co-Etown ROW**	**SU-000203 TEP Hardin Co Etwn 69kV 2 Line**	**SU-000439 TEP Etown Bay Add**	**161065 Sale of LG&E Trans-former to KU**
Materials	2020	2021	2021	2020	2020	2020	2020	2020
Construction	2020-2021	2022	2021	2021	-	2020-2022	2020-2022	-

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	1,181	7,262	14,929	3,608	26,980
2. Cost of Removal Proposed	2	132	106	292	532
3. Total Capital and Removal Proposed (1+2)	1,183	7,394	15,035	3,900	27,512
4. Capital Investment 2019 BP	1,050	3,144	11,012	1,999	17,205
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	1,050	3,144	11,012	1,999	17,205
7. Capital Investment variance to BP (4-1)	(131)	(4,118)	(3,917)	(1,609)	(9,775)
8. Cost of Removal variance to BP (5-2)	(2)	(132)	(106)	(292)	(532)
9. Total Capital and Removal variance to BP (6-3)	(133)	(4,250)	(4,023)	(1,901)	(10,307)

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)	-	-	-	-	-

This project will utilize a spare transformer that is currently located at Blue Lick. The net book value of the spare transformer is included in project SU-000203 and the offsetting credit for the same from LG&E to KU is netted with that cost below.

The 2019 BP totals above also include SU-000196 which was budgeted as part of this group of projects but which was later replaced by the other estimates. This project is also included in the 2020 BP for a total of $22,554k with $540k in 2019, $4,600k in 2020, $17,361k in 2021 and $53k in 2022. The shortfall in 2020 will be covered in the RAC Approved 0+12 forecast and the 2021 and 2022 spending will be included in the 2021 BP. The primary reasons for the cost increase above the 2019 and 2020 BPs is due to adding scope at Elizabethtown which includes installing a new control house, adding a bus tie breaker and splitting the bus.

($000s)	144070 TEP MOT ETOWN ETOWN 2	157806 TEP Hardin Co Line Work	LI-000100 TEP MOT Etown Nelson Co	LI-000102 TEP NL Hardin Co Etown New 2nd	LI-161041 TEP-NL-Hardin Co-Etown ROW	SU-000203 TEP Hardin Co Etwn 69kV 2 Line	SU-000439 TEP Etown Bay Add	161065 Sale of LG&E Trans-former to KU	Total
Company Labor	31	77	4	102	-	422	273	-	909
Contract Labor	539	907	57	1,355	40	4,572	2,325	-	9,795
Materials	194	463	53	550	-	7,584	1,810	(1,001)	9,653
Other	-	-	-	0	100	0	0	-	101
Contingency	90	191	16	263	16	1,538	534	-	2,648
Burdens	140	293	28	386	16	2,889	967	(313)	4,406
Gross Capital Expenditure	994	1,931	158	2,656	172	17,005	5,909	(1,314)	27,512
Reimbursement	-	-	-	-		-	-	-	-
Net Capital Expenditure	994	1,932	158	2,656	172	17,005	5,909	(1,314)	27,512
Contingency %	10%	11%	11%	11%	10%	10%	10%	0%	10%

Risks

There is a risk of not getting the outages required to do the construction. Discussions with [redacted] are ongoing and [redacted] has agreed to upgrade one of their 69 kV lines in order to accommodate identified outages. Preliminary engineering is required in order to develop an outage schedule to best mitigate this risk.

A Storm Water Pollution Prevention Plan (SWPPP) will be needed for grading and enlarging the Hardin County substation. In addition, a "Waters of the US" permit may be needed from the Kentucky Division of Water and the US Army Corps of Engineers.

There is risk of a compliance violation of NERC TPL-001-4 if the projects are not built. Also, LG&E/KU and EKPC loads in the Hardin County area would be left at risk. See Figure 1 for the area loads at risk.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 29,564

2. Alternative #1: NPVRR: ($000s) 33,300
   Several alternatives were considered during the TEP process. The 2nd lowest cost alternative is to install a 2nd 345/138 transformer at Hardin County, but instead of adding a 2nd 138/69 transformer, build a new 1.3 mile 138 kV line from Hardin County to Elizabethtown, replace the existing 138/69 transformer at Elizabethtown with a 138/69 185MVA transformer, add a four breaker 138kV ring bus at Hardin, reconfigure the 69kV bus at Hardin, increase the maximum operating temperature (MOT) of the Nelson County to Elizabethtown 138 kV line (15.5 miles), increase the MOT of the Elizabethtown to Elizabethtown #2 Tap section (2.24 miles), and relocating approximately 0.6 miles of various lines around the Elizabethtown and Hardin County substations. This alternative includes splitting the Elizabethtown 69 kV bus with a bus tie breaker for maintenance.

3. Alternative #2: Do Nothing NPVRR: ($000s) N/A
   This alternative puts customer load at risk, violates NERC TPL-001-4 and violates the company's Planning Guidelines.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Hardin County project for $27,512k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<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 for Investment Committee Meeting on: November 22, 2019

Project Name: Bond-Dorchester Pole Replacement

Total Capital Expenditures: $4,581k (Including $416k of contingency and $139k of internal labor)

Total O&M: $0k

Project Number(s): 157638

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Kelly Mefford/Adam Smith

Brief Description of Project

The proposed project is to replace thirty-seven (37) existing wood structures with new steel structures on the Bond-Dorchester 69kV line during a scheduled outage. The scope of work includes the replacement of thirty-six (36) structures identified through inspection. One (1) existing switch structure will be relocated to the Clinch Valley Tap point, and the existing switch will be replaced with one (1) new 2-way switch. In addition, one (1) additional existing wood switch structure will be replaced with a new steel structure to support the installation of one (1) new one-way switch for an emergency tie to the St Paul-Dorchester 69kV line.

Project Milestones	
April 2019	Engineering and Design
September 2019	Space reserved for steel pole production with manufacturer
November 2019	Steel Poles Ordered
January 2020	Steel Poles Received
October 2020	Line Construction Begins
April 2021	Line Construction Completed

This project was included in the 2019 Business Plan (BP) for $2,453k for work to be completed in 2020, using an average per structure cost prior to the completion of detailed engineering analysis. This project is included in the proposed 2020 BP for $5,724k, with estimated spend of $592k in 2019, $2,493k in 2020, and $2,639k in 2021. The estimate used for the 2020BP was based on historical unit costs typical for the structure type and region of the service territory. As detailed engineering was complete, the scope and project plan was further refined and the estimate was updated based on this additional detail. The current total project cost is $4,581k, with spend of $2,200k in 2020, and $2,381k in 2021.

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. A routine inspection was completed in 2017, and a comprehensive visual inspection was completed in 2018. From these inspections, thirty-six (36) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line. In addition, one existing switch will be replaced with a new 2-way switch. This project also includes the replacement of (1) existing wood switch structure with a new steel structure, and the installation of one (1) new one-way switch.

The scope of work consists of installing twenty-four (24) steel H-Frame structures, eight (8) steel single pole structures, two (2) steel three-pole running corners, one (1) steel three-pole dead end structure, two (2) steel switch structures, one (1) 2-way switch, and one (1) new one-way switch.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost 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. 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.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	-	2,167	1,795		3,961
2. Cost of Removal Proposed	-	33	586		619
3. Total Capital and Removal Proposed (1+2)	-	2,200	2,381	-	4,581
4. Capital Investment 2019 BP	-	2,453	-	-	2,453
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	-	2,453	-	-	2,453
7. Capital Investment variance to BP (4-1)	-	287	(1,795)	-	(1,508)
8. Cost of Removal variance to BP (5-2)	-	(33)	(586)	-	(619)
9. Total Capital and Removal variance to BP (6-3)	-	253	(2,381)	-	(2,127)

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)	-	-	-	-	-

This project is included in the proposed 2020 BP.
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.

Risks

Without the proposed replacement of the priority poles on the Bond-Dorchester 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.

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

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 5,759
   The recommendation is to replace thirty-seven (37) structures and install two (2) new switches during a scheduled outage.

2. Alternative #1: Do Nothing NPVRR: ($000s) 8,483
   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 network reliability.

3. Alternative #2: Replace with Wood NPVRR: ($000s) 6,666
   The next best alternative would be to replace thirty-five (35) structures with wood and two (2) structures with steel. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Bond-Dorchester Pole Replacement project for $4,581k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

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: November 22, 2019

Project Name: Corydon-Green River Steel Pole Replacement

Total Capital Expenditures: $6,052k (Including $550k of contingency and $207k of internal labor)

Total O&M: $0k

Project Number(s): 157639

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Sam Campbell/Adam Smith

Brief Description of Project

The proposed project is to replace one hundred thirty-three (133) existing wood structures on the Corydon-Green River Steel 69kV line with steel during a scheduled outage. The scope of work includes the replacement of one hundred twenty-nine (129) structures identified through a 2018 inspection. The replacement of four (4) adjacent structures is required to accommodate the height of the new structures.

Project Milestones	
July 2019	Engineering and Design
October 2019	Space reserved for steel pole production with manufacturer
January 2020	Steel Poles Ordered to Inventory
March 2020	Steel Poles Received to Inventory
April 2020-January 2020	Preliminary services, vegetation clearing, and material holding site completed
March 2021	Steel Poles Charged from Inventory
April 2021	Line Construction Begins
October 2021	Line Construction Completed

This project was included in the 2019 Business Plan (BP) for $5,658k, with estimated spend of $453.7k in 2019 and $5,204.6k in 2020. As scope, timing, and certainty of work has evolved, the estimates have been further refined. This project was included in the 2020 BP for $5,690k, with estimated spend of $950k in 2020 and $4,740k in 2021. Subsequent to the 2020 BP, four (4) structures were identified to be replaced in order to accommodate the height of the new structures. In addition, funding was included for a material holding site. The current total project cost is $6,052k, with estimated spend of $950k in 2020 and $5,102k in 2021. 2020 spend is included in the proposed 2020 BP. Incremental spend in 2021 will be addressed in the 2021 BP.

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. A routine inspection was completed in 2018, and one hundred twenty-nine (129) 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. Four (4) adjacent structures will also be replaced in order to accommodate the height of the new structures.

The scope of work consists of installing one hundred twenty-six (126) steel Z-Frame structures, four (4) steel single pole running corners, one (1) steel single pole dead end structure, and (2) steel single pole structures.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost 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. 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.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	-	950	4,771		5,721
2. Cost of Removal Proposed	-	-	331		331
3. Total Capital and Removal Proposed (1+2)	-	950	5,102	-	6,052
4. Capital Investment 2019 BP	454	5,205	-	-	5,658
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	454	5,205	-	-	5,658
7. Capital Investment variance to BP (4-1)	454	4,254	(4,771)	-	(63)
8. Cost of Removal variance to BP (5-2)	-	-	(331)	-	(331)
9. Total Capital and Removal variance to BP (6-3)	454	4,254	(5,102)	-	(394)

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)	-	-	-	-	-

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.

Risks

Without the proposed replacement of the priority poles on the Corydon-Green River Steel 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.

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

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 7,410
   The recommendation is to replace one hundred thirty-three (133) wood structures with new steel structures during a scheduled outage.

2. Alternative #1: Do Nothing NPVRR: ($000s) 11,208
   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 network reliability.

3. Alternative #2: Replace with Wood NPVRR: ($000s) 7,911
   The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Corydon-Green River Steel Pole Replacement project for $6,052k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

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: November 22, 2019

Project Name: Imboden-Gorge-Dorchester

Total Capital Expenditures: $5,996k (Including $545k of contingency and $183k of internal labor)

Total O&M: $0k

Project Number(s): 157642

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Gary King/Adam Smith

Brief Description of Project

The proposed project is to replace forty-two (42) existing wood structures with twenty-six (26) steel structures and sixteen (16) wood structures on the Imboden-Gorge-Dorchester 69kV line. The scope of work includes the replacement of thirty-nine (39) structures identified through inspection in 2018. In addition, one (1) two-way switch will be installed, and three (3) adjacent structures will be replaced in order to accommodate the height of the new structures. Approximately 75% of the thirty-nine (39) structures will need to be completed energized when they are replaced due to the inability to provide alternate feeds to the distribution substations during construction.

Project Milestones	
June 2019	Engineering and Design
September 2019	Space reserved for steel pole production with manufacturer
December 2019	Steel Poles Ordered
January 2020	Steel Poles Received
March 2020	Line Construction Begins
June 2021	Line Construction Completed

This project was included in the 2019 Business Plan (BP) for $3,367k using an average per structure cost prior to the completion of detailed engineering analysis. This project is included in the proposed 2020 BP (BP) for $6,562k, with estimated spend of $2,352k in 2020 and $4,210k in 2021. Once detailed engineering analysis was completed, the estimates have been further refined. The current total project cost is $5,996k, with spend of $2,350k in 2020, and $3,646k in 2021.

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. A routine inspection was completed in 2018, and thirty-nine (39) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line. In addition, three (3) adjacent structures will be replaced in order to accommodate the height of the new structures. Sixteen (16) of the thirty-nine (39) structures are being replaced with wood due to the pole height resulting from the lack of an existing static wire.

The scope of work consists of installing nineteen (19) H-Frame structures, five (5) three-pole running corners, five (5) three-pole dead end structures, five (5) single pole structures, four (4) single pole running corners, three (3) single pole dead end structures, one (1) switch structure, and one (1) two-way switch.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost 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. As such, this proposal is to proactively replace them over the course of the next two years, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed	-	2,203	3,384	-	5,587
2. Cost of Removal Proposed	-	147	261	-	408
3. Total Capital and Removal Proposed (1+2)	-	2,350	3,646	-	5,996
4. Capital Investment 2019 BP	-	3,367	-	-	3,367
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	-	3,367	-	-	3,367
7. Capital Investment variance to BP (4-1)	-	1,164	(3,384)	-	(2,221)
8. Cost of Removal variance to BP (5-2)	-	(147)	(261)	-	(408)
9. Total Capital and Removal variance to BP (6-3)	-	1,017	(3,646)	-	(2,629)

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)	-	-	-	-	-

This project is included in the proposed 2020 BP.
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.

Risks

Without the proposed replacement of the priority poles on the Imboden-Gorge-Dorchester 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.

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

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 7,484
   The recommendation is to replace forty-two (42) structures and install one (1) two-way switch. Approximately 75% of the forty-two (42) wood structures will be completed energized when they are replaced. There is no opportunity to complete the project de-energized.

2. Alternative #1: NPVRR: ($000s) 11,105
   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 network reliability.

3. Alternative #2: NPVRR: ($000s) 9,940
   The next best alternative would be to replace all forty-two (42) structures with wood. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Imboden-Gorge-Dorchester pole replacement project for $5,996k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<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 for Investment Committee Meeting on: November 22, 2019

Project Name: ROR-Spare 345/138 450 MVA Transformer

Total Capital Expenditures: $3,777k (Including $270k of contingency including $0k of internal labor, if applicable)

Total O&M: $0k

Project Number(s): 161045

Business Unit/Line of Business: Transmission Substations

Prepared/Presented By: Kyle Burns

Brief Description of Project

This proposal recommends the purchase of a new spare 345/138kV, 450 MVA with an 80 MVA tertiary to replace Mill Creek TR5 and TR6 in case of a failure. This purchase ensures adequate reserves of critical transformers which can have a lead time of more than nine months. The transformer will be ordered during late 2019, delivered during 2020, and completed by the end of 2020.

Why is the project needed? What if we do nothing?

In November 2016, the North American Electric Reliability Corporation's (NERC) Reliability Issues Steering Committee (RISC) issued recommendations to the NERC Board of Trustees outlining strategic priorities of risks to the reliable operation of the bulk power system. Extreme natural events (hurricanes, tornadoes, extreme temperatures, geomagnetic disturbances, earthquakes, etc.) and physical security vulnerabilities are two of the nine risk profiles identified. Extreme natural events, physical attacks and fire are examples of threats that, while having a low probability of occurrence, can have a crippling effect on reliability of the electric grid if they occur at certain locations. An evaluation of the loss of certain critical LG&E and KU (LKE) substations was undertaken to determine the vulnerability of the system to extreme events. That analysis shows that loss of certain key facilities could result in the inability to serve all firm load for extended periods of time. As indicated in the RISC report, "resilience and recovery actions can mitigate exposure from multiple risks." One of the primary recommendations from the RISC analysis is to focus on spare equipment strategies both to identify critical equipment and to consider transportation logistics and requirements for replacing critical assets. NERC has identified the limited availability of large power transformers as a "potential issue for critical infrastructure resilience in the United States". While it is not possible to mitigate every threat, utilities should be prepared to recover from the loss of key critical facilities. Maintaining an adequate inventory of long lead, critical spares is a cost-effective measure to help mitigate the threat of low probability high impact event.

Specific to the LKE system, planning studies have indicated that it will take two 345/138kV 450MVA transformers to recover from a disaster scenario where multiple transformers at a critical substation in the Louisville area are destroyed or severely damaged. Currently there are two spare transformers. There is one spare dual voltage (345/161 and 345/138 transformer stored at a rail siding in Shelbyville and this transformer will be installed at Blue lick in early 2020. There is another 345/138kV 450 MVA transformer stored at NAS substation. The dual voltage transformer is proposed to be replaced with a 345/161 voltage unit under another project request. An additional spare transformer in the 345/138 voltage class is recommended so that LKE has adequate spares to recover from a catastrophic event. Additionally, this unit will be designed with a tertiary sized to allow it to replace either Mill Creek TR5 or TR6. This will be the only replacement transformer within the system capable of replacing either of the Mill Creek units.

There are nineteen 345/138kV transformers in service. Since April of 2011, there have been three 345/138kV transformer failures. The Appendix below shows a graph of the ages of the 345kV transformers in the LKE System. This additional spare can be considered not only a spare to recover from a disaster scenario, but it would also be considered an additional spare in the event of loss of two 345kV transformers within a year. This spare transformer will be located to ensure we maintain the ability to get it to as many critical locations as possible within a reasonable time frame.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed	936	2,841	-	-	3,777
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	936	2,841	-	-	3,777
4. Capital Investment 2019 BP	-	75	2,290	835	3,200
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	-	75	2,290	835	3,200
7. Capital Investment variance to BP (4-1)	(936)	(2,765)	2,290	835	(576)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(936)	(2,765)	2,290	835	(576)

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)	-	-	-	-	-

This project was not included in either the 2019 or 2020 Business Plans, however $3,200k was included in project 152615 in the 2019BP for a Spare 345/138kV transformer, as reflected above. 152615 was also included in the 2020BP for $3,253k with all spending in 2021. The 2019 spending will be covered in the 2019 RAC Approved 11+1 forecast and the 2020 spending will be covered in the 2020 RAC Approved 0+12 forecast.

Risks

Alternate transformer designs will be considered to address transportation concerns. An attempt will be made to limit the overall shipping dimensions and weight, which may introduce additional costs.

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 4,178
   It is recommended that a spare 345/138, 450 MVA transformer be purchased to reduce the potential risk to the Transmission system.

2. Alternative #1: NPVRR: ($000s) 5,997
   An alternative to LKE's spare is to purchase a highly optimized transformer specifically designed for High Impact Low Frequency (HILF) events. These types of transformers reduce the installation time by weeks but have a much shorter life due to design. These transformers are new in design true to the nature of the response and reliability has not yet been proven.

3. Alternative #2: Do Nothing NPVRR: ($000s) N/A
   This is not recommended as this is a strategic initiative to mitigate a low probability, very high consequence risk and to ensure adequate spares for the 345/138 kV systems to mitigate the risk of transformer failure from routine causes.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the ROR Spare 345/138 450 MVA Transformer project for $3,777k to ensure adequate reserves of critical transformers.

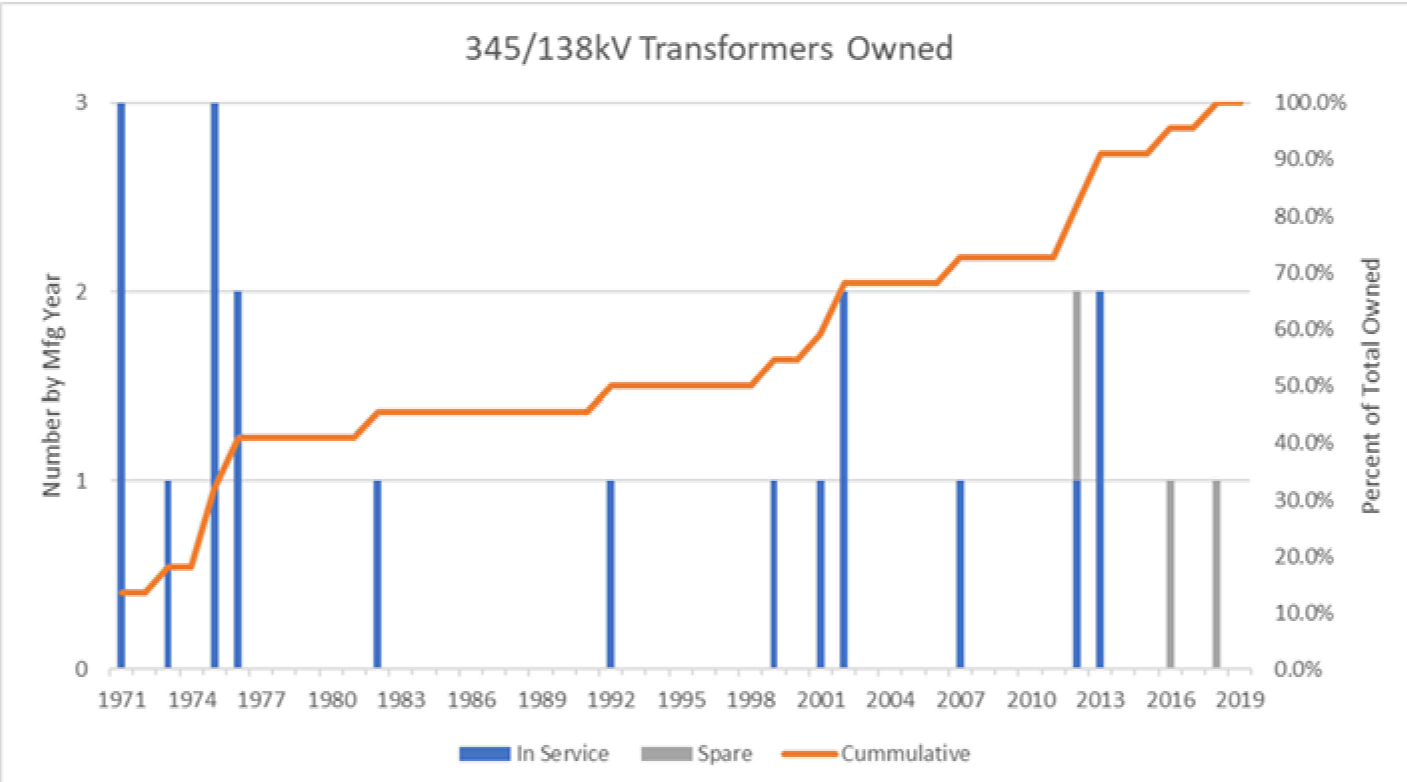
<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

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	

APPENDIX

Age of installed 345/138kV Transformers on the LKE system:



Investment Proposal for Investment Committee Meeting on: November 22, 2019

Project Name: ROR-Spare 345/161 450 MVA Transformer

Total Capital Expenditures: $3,777k (Including $270k of contingency including $0k of internal labor, if applicable)

Total O&M: $0k

Project Number(s): 161044

Business Unit/Line of Business: Transmission Substations

Prepared/Presented By: Kyle Burns

Brief Description of Project

This proposal recommends the purchase of a new spare 345/161 kV, 450 MVA to replace Alcalde T01, Blue Lick TRANS-2 and Pineville T02 in case of a failure. This purchase ensures adequate reserves of critical transformers which can have a lead time of more than nine months. The transformer will be ordered during late 2019, delivered during 2020, and completed by the end of 2020.

Why is the project needed? What if we do nothing?

In November 2016, the North American Electric Reliability Corporation's (NERC) Reliability Issues Steering Committee (RISC) issued recommendations to the NERC Board of Trustees outlining strategic priorities of risks to the reliable operation of the bulk power system. Extreme natural events (hurricanes, tornadoes, extreme temperatures, geomagnetic disturbances, earthquakes, etc.) and physical security vulnerabilities are two of the nine risk profiles identified. Extreme natural events, physical attacks and fire are examples of threats that, while having a low probability of occurrence, can have a crippling effect on reliability of the electric grid if they occur at certain locations. An evaluation of the loss of certain critical LG&E and KU (LKE) substations was undertaken to determine the vulnerability of the system to extreme events. That analysis shows that loss of certain key facilities could result in the inability to serve all firm load for extended periods of time. As indicated in the RISC report, "resilience and recovery actions can mitigate exposure from multiple risks." One of the primary recommendations from the RISC analysis is to focus on spare equipment strategies both to identify critical equipment and to consider transportation logistics and requirements for replacing critical assets. NERC has identified the limited availability of large power transformers as a "potential issue for critical infrastructure resilience in the United States". While it is not possible to mitigate every threat, utilities should be prepared to recover from the loss of key critical facilities. Maintaining an adequate inventory of long lead, critical spares is a cost-effective measure to help mitigate the threat of low probability high impact event.

Specific to the LKE system, planning studies have indicated that the loss of one of two 345/161 kV 450MVA transformers will cause transmission system issues on the Bulk Electric System

(BES). Currently there is one spare dual voltage (345/161 kV and 345/138 kV) transformer stored at a rail siding in Shelbyville. This transformer will be installed at Blue Lick in early 2020. Therefore, we will not have a 345/161 kV 450 MVA spare after early 2020. An additional spare transformer is recommended so that LKE has adequate spares to recover from a catastrophic event.

Because the existing transformer is dual voltage and provides spare capability for multiple voltage classes, this replacement request is limited to the 345/161 kV voltage class. A second project request will cover the 345/138 kV voltage class. This spare transformer will be located at the Blue Lick transmission substation. to ensure we maintain the ability to get it to critical locations within a reasonable time frame.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	936	2,841	-	-	3,777
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	936	2,841	-	-	3,777
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)	(936)	(2,841)	-	-	(3,777)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(936)	(2,841)	-	-	(3,777)

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)	-	-	-	-	-

This project was not included in either the 2019 or 2020 Business Plans. The 2019 spending will be covered in the 2019 RAC Approved 10+2 forecast and the 2020 spending will be covered in the 2020 RAC Approved 0+12 forecast. The 2019BP included a spare 345/138kV transformer however, due to subsequent analysis, this size spare is recommended as well.

Risks

Alternate transformer designs will be considered to address transportation concerns. An attempt will be made to limit the overall shipping dimensions and weight, which may introduce additional costs.

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 4,178
   It is recommended that a spare 345/161 kV, 450 MVA transformer be purchased to reduce the potential risk to the Transmission system.

2. Alternative #1: NPVRR: ($000s) 6,541
   An alternative to LKE's spare is to move the existing dual voltage (345/161:345/138) transformer in service at 345/138 at West Frankfort 211-T01 to any of the following locations Alcalde, Blue Lick or Pineville in case of a failure. It will take 16-20 weeks to disconnect, move and energize the transformer to any of the above locations. Then we will move the spare 345/138 kV transformer at North American Stainless (NAS) to West Frankfort. Then order a new spare to replace NAS.

3. Alternative #2: Do Nothing NPVRR: ($000s) N/A
   This is not recommended as this is a strategic initiative to mitigate a low probability, very high consequence risk and to ensure adequate spares for the 345/161 kV systems to mitigate the risk of transformer failure from routine causes.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Spare 345/161 kV 450 MVA Transformer project for $3,777k to ensure adequate reserves of critical transformers.

<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 for Investment Committee Meeting on: November 22, 2019

Project Name: TEP-Blue Lick Transformer Replacement

Total Capital Expenditures: $4,504k

Total O&M: $0k

Project Number(s): Transmission Subs – SU-000347 and 161066

Business Unit/Line of Business: Transmission

Prepared/Presented By: Delyn Kilpack

<u>Brief Description of Project</u>

The existing Blue Lick 345/161kV transformer overloads during planning studies for two different contingencies. A new, higher rated transformer is required to replace the existing transformer and mitigate the overloads. The contingency causing the most severe overload is loss of the Hardin County 345/161 kV transformer and the next worst contingency is loss of the Mill Creek to Hardin County 345 kV line.

The overload of the Blue Lick 345/161 kV transformer was identified in the TEP process and has been reviewed and approved by [redacted], the Company's Independent Transmission Organization (ITO). Operationally, post-contingent overloads have been identified on the Blue Lick 345/161 kV transformer requiring generation redispatch to mitigate.

Overloads under 50/50 and 90/10 winter peak conditions are shown in Table 1 below. This table assumes the proposed Hardin County Project is in service in 2022, which eliminates the violation in 2023 and 2028 for the loss of the Hardin County 345/161 kV transformer. However, the overload still occurs for the loss of the Mill Creek to Hardin County 345 kV line.

Table 1 Post Contingent Loading on Blue Lick 345/161 kV Transformer

Flow Results					
		50/50 Winter		90/10 Winter	
Year	Contingency	Flow (MVA)	% of Rating	Flow (MVA)	% of Rating
2020	Hardin County 345/161 Transformer	324.7	100.20%	340.1	105.00%
2023	Hardin County 345/161 Transformer	274.6	84.80%	290.1	89.50%
2028	Hardin County 345/161 Transformer	284.8	87.90%	301.2	93.00%

Flow Results					
Year	Contingency	50/50 Winter		90/10 Winter	
		Flow (MVA)	% of Rating	Flow (MVA)	% of Rating
2020	Mill Creek to Hardin County 345 kV Line	322.5	99.50%	337.5	104.20%
2023	Mill Creek to Hardin County 345 kV Line	310.5	95.80%	326.6	100.80%
2028	Mill Creek to Hardin County 345 kV Line	320.9	99.00%	336.6	103.90%

The new transformer has a nameplate rating of 450 MVA and provides the needed capacity for summer and winter as shown in Table 2 below.

Table 2: New Ratings

	Winter	Off-Peak	Summer
Normal	585	523	405
Emergency	607	566	515

Project Milestones:

- Preliminary Engineering 2020
- Material in 2021
- Construction in 2021
- Estimated In-Service in May 2021

Why is the project needed? What if we do nothing?

The overload of the Blue Lick 345/161 kV transformer was identified in the TEP process and has also been reviewed and approved by the ITO. This project is required to meet the requirements of NERC Reliability Standard TPL-001-4 and the Company's Planning Guidelines.

Additionally, post-contingent overloads have been identified on the Blue Lick 345/161 kV transformer in operational situations requiring generation redispatch to mitigate.

The overloaded transformer, and contingency that results in the issues are shown in Figure 1 below.

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[redacted]

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	92	1,347	2,830	-	4,269
2. Cost of Removal Proposed	-	-	235	-	235
3. Total Capital and Removal Proposed (1+2)	92	1,347	3,065	-	4,504
4. Capital Investment 2019 BP	-	178	3,126	-	3,304
5. Cost of Removal 2019 BP	-	22	388	-	410
6. Total Capital and Removal 2019 BP (4+5)	-	200	3,513	-	3,714
7. Capital Investment variance to BP (4-1)	(92)	(1,169)	296	-	(965)
8. Cost of Removal variance to BP (5-2)	-	22	152	-	174
9. Total Capital and Removal variance to BP (6-3)	(92)	(1,147)	448	-	(791)

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)	-	-	-	-	-

This project will utilize a spare transformer that is currently located at Ghent. The net book value of the spare transformer is included in project SU-000347 and the offsetting credit for the same from KU to LG&E is netted with that cost below.

Project	Description	2019	2020	2021	Total
SU-000347	TEP-BL 345/161kV Transf Repl	92	5,050	3,065	8,207
161066	Sale of KU Xfmr to LGE	-	(3,703)	-	(3,703)
	Total	92	1,347	3,065	4,504

This project was included in the 2020 BP for a total of $4,834k with $229k in 2019, $4,580k in 2020, and $25k in 2021. The shortfalls in 2019 and 2020 will be funded in the 2019 RAC Approved 11+1 and 2020 RAC Approved 0+12 forecasts, respectively. The 2021 spending will be covered in the 2021 BP. The reason for the higher spending is due to the addition of a firewall, breaker, and protection panel upgrades that were not originally estimated.

Risks

Without the recommended transformer replacement, there is risk of violating NERC Reliability Standard TPL-001-4 and the Company's Planning Guidelines.

Transformer 2 will need Oil Spill Prevention and Preparedness (SPCC) measures added.

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 4,705
   The recommendation is to replace 240 MVA transformer at Blue Lick with a 450 MVA transformer

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   This alternative puts customer load at risk and violates NERC Reliability Standards and the Company's Planning Guidelines.

3. Alternative #2: NPVRR: ($000s) 19,926
   An alternative for Blue Lick was to add a second redundant Blue Lick 345/161kV transformer. This alternative includes converting the Blue Lick 345 kV bus into a breaker and a half scheme, and converting the 161 kV bus into a three breaker ring bus.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Blue Lick 345/161 kV transformer replacement project for $4,504k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<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 for Investment Committee Meeting on: November 22, 2019

Project Name: TEP-Hoover Cap Bank

Total Capital Expenditures: $2,129k (Including $185k of contingency including $95k of internal labor, if applicable)

Total O&M: $0k

Project Number(s): SU-000445, LI-160527, Distribution 160938

Business Unit/Line of Business: Transmission

Prepared/Presented By: Delyn Kilpack, Mgr. Trans Strategy & Planning

Brief Description of Project

Post-contingent voltage violations were first identified at the Lemons Mill and Georgetown 69kV substations during the 2019 Transmission Expansion Plan (TEP). This project will add a 69kV, 36.0 MVAR capacitor at Hoover to eliminate the low voltage violations at Lemons Mill and Georgetown 69kV. This will supply reactive power (VAR) support and improve voltage in the area.

The Lines portion of this project will consist of the installation of two permanent steel dead-end structures going into both sides of the substation, as well as the installation of a temporary line around the west side of the station during construction for the new capacitor bank.

Why is the project needed? What if we do nothing?

Low voltage violations at the Lemons Mill and Georgetown 69 kV substations were identified in the TEP process and violate the Company's approved Planning Guidelines. The project is currently under review by [redacted], the Company's Independent Transmission Organization (ITO).

During 2019 winter peak studies, the loss of the Adams to Georgetown 69kV line results in low voltages below the acceptable threshold. This violation also occurs in the winter of 2020 for the loss of the Georgetown to Lemons Mill 69kV line. [redacted]

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed	90	2,015	18	-	2,123
2. Cost of Removal Proposed	-	7	-	-	7
3. Total Capital and Removal Proposed (1+2)	90	2,022	18	-	2,129
4. Capital Investment 2019 BP	177	903	-	-	1,080
5. Cost of Removal 2019 BP	42	112	-	-	155
6. Total Capital and Removal 2019 BP (4+5)	219	1,016	-	-	1,234
7. Capital Investment variance to BP (4-1)	87	(1,112)	(18)	-	(1,043)
8. Cost of Removal variance to BP (5-2)	42	106	-	-	148
9. Total Capital and Removal variance to BP (6-3)	129	(1,006)	(18)	-	(895)

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)	-	-	-	-	-

This project was partially included in the 2019BP in project SU-000349 TEP Lemons Mill 69kV Cap Bank which was cancelled and replaced by this project. The 2019 spending was approved in the 9+3 RAC approved forecast. Of the three projects, SU-000445 was the only project included in the 2020BP with spending in 2019 ($578k) and 2020 ($617k). The 2020 shortfall will be covered by the 2020 RAC Approved 0+12 forecast. The 2021 spending will be included in the 2021 BP.

	Trans Subs SU-000445	Trans Lines LI-160527	Distribution 160938	Total
Company Labor	47	19	28	94
Materials	418	90	17	525
Contract Labor	735	248	-	983
Contingency	143	42	-	185
Other	-	-	10	10
Burdens	235	68	29	332
	1,578	467	84	2,129

Risks

There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project. If the project is completed outside of the optimal window there is a risk of customers experiencing low voltages during winter peak conditions if the critical contingency were to occur. However, this risk can be mitigated by increasing generation at the Brown Plant during the contingency in the near term – but generation redispatch such as this is not an acceptable long term solution per our Planning Guidelines.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 2,381
   Install a capacitor at Hoover 69kV

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   The alternative of Do Nothing puts the customer load at risk and violates the Company's Planning Guidelines.

3. Alternative #2: NPVRR: ($000s) 7,743
   Add a second 69kV line from Adams – Lemons Mill.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the TEP-Hoover 69kV Cap Bank project for $2,129k to reliably serve customers in the Lemons Mill and Georgetown area and to meet the LG&E/KU Planning Guidelines in a least cost manner.

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	

Appendix – Exhibit A

[redacted]

Investment Proposal for Investment Committee Meeting on: November 22, 2019

Project Name: Transmission Blankets - 2020

Total Expenditures: $3,723k

Project Number(s): Various

Business Unit/Line of Business: Transmission

Prepared/Presented By: Kyle Burns

Brief Description of Project

Transmission uses Blankets to budget and account for annual routine unidentified work. Capital Blankets are comprised of a multitude of individual small projects necessitating capital investment. Transmission subdivides its Blankets into distinct categories for lines and substations. These categories align with primary work drivers for Transmission.
Annual blanket budgets are based on historical trends and operational input from the managers within Transmission. Blanket spend is monitored and forecast on a monthly basis based on known work identified throughout the year.

Transmission is requesting approval for $3,723k in blankets for 2020, a $12,370k decrease from the 2019 Business Plan for 2020. This decrease is due primarily to moving pole replacement and other lines projects out of blankets and into individually budgeted projects.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the 2020 Transmission blanket projects for $3,723k to help manage the Transmission work budgeted for 2020.

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

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[redacted]

Blanket Description	2020 BP	vs. 2019 BP			vs. 2019 Forecast (9+3)			Variance - 2020 BP vs 2019 Forecast	Projects & Amounts
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]									
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]									
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		

Investment Proposal for Investment Committee Meeting on: January 29, 2020

Project Name: Olin-Tip Top Conductor Replacement

Total Capital Expenditures: $15,770k (Including $1,413k of contingency and $516k of internal labor)

Total O&M: $0k

Project Number(s): Transmission Lines: Phase I – 148822 & Phase II – LI-160418
Distribution Operations: 159680

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: John Doll/Adam Smith

Brief Description of Project

The proposed project is to replace 13.1 miles of overhead transmission line with conductor that is over 90+ years old and beyond its expected useful life. Performance of this line has diminished, with the most recent conductor failure occurring in 2019. Louisville Gas and Electric Brandenburg substation serves over 1,400 customers with 6.0 MVA of load. In addition, Monument Chemical substation serves 8.2 MVA of load. This project will improve reliability, maintain system integrity, and reduce the risk of failures and unplanned transmission interruptions to [redacted].

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 was included as part of the Transmission System Improvement Plan to replace aging infrastructure.

Transmission Lines plans to replace the 13.1 miles of 3/0 aluminum conductor steel reinforced (ACSR) conductor in the Tip Top-Brandenburg-Monument Chemical 69kV line in two phases. The existing conductor will be replaced with 397 ACSR 26/7, and a new optical ground wire (OPGW) will be installed. In addition, one hundred seventy eight (178) wood structures will be replaced with new steel structures. Distribution Operations will provide the layout work and transferring of underbuilt distribution conductors where needed.

Project Milestones – Transmission Lines	
July 2018-July 2019	Engineering and Design
July 2019	Space reserved for steel pole production with manufacturer
September 2019	Steel Poles Ordered
March 2020	Steel Poles Received
June 2020	Line Construction Begins
September 2021	Line Construction Completed

Project Milestones – Distribution Operations	
June 2019	Engineering and Design
March 2020	Materials Ordered
March 2020	Materials Delivered
April 2020	Construction Start
December 2021	Construction Completed

	Transmission Lines	Distribution Operations	Total
Total 2019	$549k	$0k	$549k
Total 2020	$4,962k	$558k	$5,520k
Total 2021	$9,027k	$674k	$9,701k
Project Total	$14,538k	$1,232k	$15,770k
Contingency	10%	8%	

<u>Why is the project needed? What if we do nothing?</u>
The existing 13.1 miles of 69kV line between Tip Top-Brandenburg and Brandenburg-Monument Chemical substations contains the original 3/0 ACSR conductor installed in 1925. Non-destructive testing was performed on the conductor in October 2019 and revealed that it was in marginal to poor condition. Testing showed that the conductor had less than 90% of its original rated breaking strength remaining, signs of heavy surface rust, and medium pitting. This circuit has experienced a total of 21 interruptions since 2012. The initiating events of these interruptions consist of lightning strikes, weather, vegetation, and component failures. The most recent event occurred in March 2019 and was caused by a conductor failure. In addition, a routine inspection was completed in 2019 and one hundred twenty-two (122) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line. Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System.

In July of 2019, 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 plan. Geotechnical services have begun in order to provide geotechnical reports to support drilled shaft foundation design. In addition, easement information has been provided for the entire corridor. The transmission line design was provided to all departments involved for comment and review.

Approximately half of the conductor rebuild is within rolling hills and wooded terrain, while the remaining portion runs along rural and relatively sparse residential properties. Structures lie on both private, public, and federal lands. Company owned easement, KYTC owned road right of way, and leased property from Fort Knox will be used to access the structures.

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 communities and businesses along the route.

The structure design consists of one hundred sixty-seven (167) steel single pole structures, two (2) steel three-pole dead end structures, three (3) steel single pole dead end structures, one (1) custom steel metering structure, two (2) steel self-supporting structures, and three (3) steel H-frame structures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	546	4,362	8,137	-	13,045
2. Cost of Removal Proposed	4	1,158	1,564	-	2,725
3. Total Capital and Removal Proposed (1+2)	549	5,520	9,701	-	15,770
4. Capital Investment 2020 BP	331	4,403	9,128	-	13,862
5. Cost of Removal 2020 BP	-	577	1,408	-	1,985
6. Total Capital and Removal 2020 BP (4+5)	331	4,980	10,535	-	15,846
7. Capital Investment variance to BP (4-1)	(215)	41	991	-	817
8. Cost of Removal variance to BP (5-2)	(4)	(581)	(156)	-	(740)
9. Total Capital and Removal variance to BP (6-3)	(219)	(540)	835	-	76

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

2019 spend was approved by the Corporate Resource Allocation Committee. Incremental spend in 2020 will be funded by a reduction in other capital projects. Spend in 2021 will be addressed in the 2021 BP.

Risks

- Without the proposed replacement of the existing conductor in the Tip Top-Brandenburg-Monument Chemical 69kV line, the company risks increased exposure to line outages. The conductor along the 13.1 mile section has deteriorated 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 1,300 customers, reducing their reliability until the repairs are complete.

- 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.
- There are no known environmental risks regarding air, water, lead, asbestos, etc., associated with this project.
- Risks associated with project timeline:
  - Winter and early spring weather impacts could pose significant delays, including issues with structure access and rough terrain.
  - Loss of existing crews providing mutual assistance during major storm events outside of the LKE footprint.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 18,483
   The recommendation is to replace 13.1 miles containing 3/0 conductor with new 397 ACSR 26/7 conductor and install new OPGW. In addition, one hundred seventy-eight (178) 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: NPVRR: ($000s) 22,008
   The Next Best Alternative would be to construct a new 15 mile transmission line. Constructing a new route would require the purchase of new right of way 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.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Olin-Tip Top conductor replacement project for $15,770k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<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 for Investment Committee Meeting on: January 29, 2020

Project Name: REL Hartford-Big Rivers Interconnection Right of Way

Total Capital Expenditures: $658k (Including $60k of contingency and $6k of internal labor)

Total O&M: $0k

Project Number(s): LI-160379

Business Unit/Line of Business: Transmission

Prepared/Presented By: Chris Balmer

<u>Brief Description of Project</u>

This right of way (ROW) purchase project is necessary to complete a larger transmission reliability project (REL Hartford-Big Rivers Interconnection – LI-159067) to be proposed in the next month or two. This ROW purchase project is being proposed to the Investment Committee prior to the larger reliability project to ensure adequate time for ROW acquisition and maintain the schedule of the reliability project.

The reliability project will propose construction of a new 69kV transmission line of approximately 2 miles in length from the Company's Hartford substation and interconnect with [redacted] The new interconnection will be operated with an open switch under normal conditions. Cost estimates for this reliability project are still being developed; however, the current estimate is about $3,000k and incremental to this ROW purchase project.

The reliability project will provide an alternate source to 3,700 customers currently served by the Ohio County to Hartford 69kV radial line. The Ohio County to Hartford line ranks as the sixth worst SAIDI performing line over the past 5 years. The new interconnection will allow for quicker restoration times during an outage and is expected to minimize and eliminate future SAIDI events for these customers. In addition, the new interconnection will allow us to perform maintenance or upgrades along the existing Ohio County to Hartford 69 kV line without interrupting customers or providing an alternate feed. During past outages in the area, we have had to radialize a substantial amount of load to mitigate potential N-1 issues. The new interconnection could eliminate the need to put that additional load at risk.

[redacted] has already agreed to allow the interconnection. A Transmission Lines Access Agreement was signed on October 28, 2019 to allow LG&E and KU site access to [redacted] equipment and connect the new 69kV tap (Hartford Tap) to their Beda-Centertown 69kV line. A revised Interconnection Agreement (IA) with [redacted] will be executed and filed with FERC prior to the energization of the new interconnection. Kentucky PSC approval is not required for construction of the new line.

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This project was included in the proposed 2020 BP for $100k with all spend to occur in 2019. Subsequent to the 2020 BP, the estimates have been further refined. Incremental spend in 2020 will be funded by a reduction in other Transmission capital projects.

[redacted]

[redacted]

[redacted]

<u>Why is the project needed? What if we do nothing?</u>

This ROW purchase is needed to support a transmission project to improve reliability to 3,700 customers by providing an alternative source from a new interconnection with [redacted]. The existing KU Beaver Dam, Beaver Dam North, and Hartford substations are served from the 7.14 mile long Ohio County to Hartford radial line, which is historically a very poor performing line. [redacted]. The new interconnection is expected to significantly improve customer reliability and enhance the customer experience. Customers are likely to experience many interruptions in the future without this project.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	1	657	-	-	658
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	1	657	-	-	658
4. Capital Investment 2020 BP	100	-	-	-	100
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	100	-	-	-	100
7. Capital Investment variance to BP (4-1)	99	(657)	-	-	(558)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	99	(657)	-	-	(558)

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

Risks

1. Acquisition costs could be higher than the estimates provided in this proposal.
2. Time to acquire the ROW could delay construction of the new interconnection. This could occur from opposition to the new line, and/or landowner negotiations.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the REL Hartford-Big Rivers Interconnection Right of Way project for $658k to support the REL Hartford-Big Rivers Interconnection project.

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
Chief Financial Officer

Paul W. Thompson Date
Chairman, CEO and President

Investment Proposal for Investment Committee Meeting on: January 29, 2020

Project Name: Tip Top-Monument Chemical Pole Replacement

Total Capital Expenditures: $4,860k (Including $442k of contingency and $21k of internal labor)

Total O&M: $0k

Project Number(s): LI-159222

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: John Doll/Adam Smith

Brief Description of Project

The proposed project is to replace seventy-two (72) existing wood structures with new steel structures on the Tip Top-Monument Chemical 69kV line during a scheduled outage. The scope of work includes the replacement of sixty-one (61) structures identified through inspection. Eleven (11) structures will be replaced in order to accommodate the height of the new structures.

Project Milestones	
April 2019	Engineering and Design
September 2019	Space reserved for steel pole production with manufacturer
November 2019	Steel Poles Ordered
February 2020	Steel Poles Received
March 2020	Line Construction Begins
July 2020	Line Construction Completed

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. A routine inspection was completed in 2019 and sixty-one (61) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line. In addition, eleven (11) structures will be replaced in order to accommodate the height of the new structures.

The scope of work consists of installing sixty-two (62) steel horizontal post framesets, five (5) steel guyed running corners, and five (5) steel guyed vertical dead end structures.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost 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. 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.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	248	3,909	-		4,157
2. Cost of Removal Proposed	29	675	-		703
3. Total Capital and Removal Proposed (1+2)	276	4,584	-	-	4,860
4. Capital Investment 2020 BP	264	5,119	-	-	5,383
5. Cost of Removal 2020 BP	3	735	-	-	738
6. Total Capital and Removal 2020 BP (4+5)	267	5,854	-	-	6,121
7. Capital Investment variance to BP (4-1)	16	1,210	-	-	1,226
8. Cost of Removal variance to BP (5-2)	(26)	60	-	-	35
9. Total Capital and Removal variance to BP (6-3)	(9)	1,270	-	-	1,261

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

2019 spend was approved by the RAC. 2020 spend is included in the 2020 Business Plan.

Risks

Without the proposed replacement of the priority poles on the Tip Top-Monument Chemical 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.

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

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 5,893
   The recommendation is to replace seventy-two (72) wood structures with steel during a scheduled outage.

2. Alternative #1: NPVRR: ($000s) 9,013
   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 network reliability.

3. Alternative #2: NPVRR: ($000s) 6,278
   The next best alternative would be to replace all seventy-two (72) structures with wood. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Tip Top-Monument Chemical pole replacement project for $4,860k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<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 for Investment Committee Meeting on: February 27, 2020

Project Name: Harlan Y-Pocket 69kV Pole Replacement

Total Capital Expenditures: $10,022k (Including $911k of contingency and $138k of internal labor)

Total O&M: $0k

Project Number(s): Transmission Lines: LI-158881
Distribution Operations: CRPOLE416

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Addam Gooch/Adam Smith

Brief Description of Project

The proposed project is to replace eighty-two (82) existing wood structures with steel on the Harlan Y-Pocket 69kV line. The scope of work includes the replacement of fifty-three (53) structures identified through inspection in 2018. In addition, twenty-nine (29) adjacent structures will be replaced in order to accommodate the height of the new structures. Due to the difficulty in obtaining an extended outage, approximately 50% of the eighty-two (82) structures will need to be completed energized when they are replaced.

Of the eighty-two (82) structures being replaced, sixty-five (65) are in Kentucky, and seventeen (17) are in Virginia. A Certificate of Public Convenience and Necessity was not required for this project.

Project Milestones – Transmission Lines	
April 2019	Engineering and Design
September 2019	Space reserved for steel pole production with manufacturer
March 2020	Steel Poles Ordered
May 2020	Steel Poles Received
June 2020	Line Construction Begins
June 2021	Line Construction Completed

Distribution Operations will provide the layout work and transferring of underbuilt distribution where needed.

Project Milestones – Distribution Operations	
February 2020	Engineering and Design
March 2020	Materials Ordered
May 2020	Materials Received

June 2020	Construction Start
November 2020	Construction Completed

Why is the project needed? What if we do nothing?

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 inspection of the Harlan Y-Pocket 69kV line was completed in 2018, and fifty-three (53) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line. In addition, twenty-nine (29) adjacent structures will be replaced in order to accommodate the height of the new structures.

The scope of work consists of installing forty-four (44) steel H-frame structures, twenty-four (24) steel 3-pole dead end structures, three (3) steel 3-pole angle structures, three (3) steel single pole dead end structures, two (2) steel single pole angle structures, and six (6) steel single pole tangent structures.

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. 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.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	**2020**	**2021**	**2022**	**Post 2022**	**Total**
1. Capital Investment Proposed	3,605	5,505	-	-	9,110
2. Cost of Removal Proposed	395	517	-	-	912
3. Total Capital and Removal Proposed (1+2)	4,000	6,022	-	-	10,022
4. Capital Investment 2020 BP	3,337	2,654	-	-	5,990
5. Cost of Removal 2020 BP	664	323	-	-	987
6. Total Capital and Removal 2020 BP (4+5)	4,001	2,977	-	-	6,977
7. Capital Investment variance to BP (4-1)	(268)	(2,852)	-	-	(3,120)
8. Cost of Removal variance to BP (5-2)	269	(194)	-	-	75
9. Total Capital and Removal variance to BP (6-3)	1	(3,045)	-	-	(3,044)

Financial Detail by Year - O&M ($000s)	**2020**	**2021**	**2022**	**Post 2022**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Subsequent to the 2020 BP, detailed engineering was completed and eight (8) additional structures were identified for replacement to accommodate the height increases of the new structures. Detailed engineering also identified that thirteen (13) of the defective structures needed to be converted from suspension to tension structures supported by down guys. In addition, 50% of the structures will be replaced energized, and additional funding was identified for controls required to comply with a detailed environmental assessment for work to be completed in Virginia. Incremental funding in 2021 will be addressed in Transmission's 2021 Business Plan.

	Transmission Lines	Distribution Operations	Total
Total 2020	$3,987k	$13k	$4,000k
Total 2021	$6,008k	$14k	$6,022k
Project Total	$9,995k	$27k	$10,022k
Contingency	10%	10%	

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.

Risks

Without the proposed replacement of the priority poles on the Harlan Y-Pocket 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.

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

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $12,517
   The recommendation is to replace eighty-two (82) existing wood structures with steel. Approximately 50% of the eighty-two (82) structures will be completed energized when they are replaced. If the opportunity to replace the structures de-energized would occur, it would reduce the project cost by $505k and the NPVRR by $610k.

2. Alternative #1: NPVRR: ($000s) $18,559
   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 network reliability.

3. Alternative #2: NPVRR: ($000s) $15,101
   The next best alternative would be to replace all eighty-four (84) structures with wood. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Harlan Y-Pocket pole replacement project for $10,022k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<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 for Investment Committee Meeting on: February 27, 2020

Project Name: REL Hartford-Big Rivers Interconnection

Total Capital Expenditures: $3,214k (Including $292k of contingency and $118k of internal labor)

Total O&M: $0k

Project Number(s): LI-159067 – Transmission Lines
161498 – Distribution Operations
LI-160379 – Transmission Lines Easement Acquisition

Business Unit/Line of Business: Transmission

Prepared/Presented By: Chris Balmer

<u>Brief Description of Project</u>

This reliability project proposes construction of a new 69kV transmission line, approximately two miles in length, from the Company's Hartford substation to a new interconnect with an existing 69kV line within [redacted] The new interconnection will be operated with an open switch under normal conditions. The new switch will have remote monitoring and control capability.

The project will provide an alternate source to 3,700 customers currently served by the Ohio County to Hartford 69kV radial line. This line ranks as the sixth worst SAIDI performing line over the past 5 years. The new interconnection will allow for quicker restoration times during an outage and is expected to minimize and potentially eliminate future SAIDI events for these customers. In addition, the new interconnection will allow the Company to perform maintenance or upgrades along this line without interrupting customers or providing an alternate feed. During past outages in the area, we have had to radialize a substantial amount of load to mitigate potential N-1 issues. The new interconnection could eliminate the need to put that load at risk in the future.

[redacted] has already agreed to allow the interconnection. A Transmission Lines Access Agreement was signed on October 28, 2019 to allow LG&E and KU site access to BREC equipment and connect the new 69kV tap (Hartford Tap) to their Beda-Centertown 69kV line. A revised Interconnection Agreement (IA) with [redacted] will be executed and filed with FERC prior to the energization of the new interconnection. Kentucky PSC approval is not required for construction of the new line.

This project was approved for $98k in February of 2019 for preliminary engineering to ensure the project could remain on schedule to meet the desired in-service date. Separately, the project for the easement acquisition (LI-160379) was approved by the Investment Committee in January of 2020 for funding in the amount of $658k.

	Transmission Lines	Distribution Operations	Transmission Lines Easement Acquisition	Total
Total 2019	$155k	$0k	$1k	$156k
Total 2020	$1,301k	$40k	$657k	$1,998k
Total 2021	$1,060k	$0k	$0k	$1,060k
Project Total	$2,516k	$40k	$658k	$3,214k
Contingency	10%	10%	10%	

Transmission Lines will install 2.14 miles of new 69kV line beginning at the Hartford substation and interconnect with Big Rivers. Also included in the scope of this project is the installation of thirty-two (32) new steel structures, a motor operated switch at the new tap point, and two motor operated switches at the Hartford tap. In addition, Telecom has requested the installation of OPGW to eliminate the temporary radio link for communications.

Project Milestones – Transmission Lines	
September 2019	Engineering and Design
March 2020	Materials Ordered
September 2020	Materials Received
September 2020	Construction Start
June 2021	Construction Completed

Distribution Operations will provide the layout work and the transfer of underbuilt distribution conductors where needed.

Project Milestones – Distribution Operations	
January 2020	Engineering and Design
February 2020	Materials Ordered
September 2020	Materials Received
September 2020	Construction Start
June 2021	Construction Completed

CONFIDENTIAL INFORMATION REDACTED

[redacted]

<u>Why is the project needed? What if we do nothing?</u>

This project will provide an alternate source to 3,700 customers currently served by the Ohio County to Hartford 69kV radial line. The Ohio County to Hartford line ranks as the sixth worst SAIDI performing line over the past 5 years. The new interconnection will allow for quicker restoration times during an outage and is expected to minimize and potentially eliminate future SAIDI events for these customers. In addition, the new interconnection will allow the Company to perform maintenance or upgrades along the existing Ohio County to Hartford 69 kV line without interrupting customers or providing an alternate feed. During past outages in the area, we have had to radialize a substantial amount of load to mitigate potential N-1 issues. The new interconnection could eliminate the need to put that additional load at risk.

If we do nothing, customers will be put at risk of sustained outages either due to forced outages or when planned work is needed on the Ohio County to Hartford 69 kV line.

<u>Budget Comparison & Financial Summary</u>

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	156	1,994	1,016	-	3,166
2. Cost of Removal Proposed	-	4	44	-	48
3. Total Capital and Removal Proposed (1+2)	156	1,998	1,060	-	3,214
4. Capital Investment 2020 BP	176	1,303	702	-	2,181
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	176	1,303	702	-	2,181
7. Capital Investment variance to BP (4-1)	21	(691)	(314)	-	(985)
8. Cost of Removal variance to BP (5-2)	-	(4)	(44)	-	(48)
9. Total Capital and Removal variance to BP (6-3)	21	(695)	(358)	-	(1,033)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The 2020 overrun will be covered through reductions in other Transmission projects in coordination with the Resource Allocation Committee (RAC). The 2021 overrun will be covered by Transmission in the 2021 BP.

<u>Risks</u>

- Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.
- Acquisition of the required easements could cause schedule delays and/or increase the estimated overall cost of the project when including the previously approved easement acquisition project (LI-160379).

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 4,050
   Pursue construction of the proposed interconnection with [redacted]. This project is proposed in connection with the approved Transmission System Improvement Plan.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   This alternative is not advisable as it puts customer load at risk on an historically poor performing line of the transmission system.

3. Alternative #2: Construct Alternate Route NPVRR: ($000s) 5,682
   This alternative would construct a new 3.95 mile transmission line which adds incremental costs in addition to the proposed project cost.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the REL Hartford-Big Rivers Interconnection project for $3,214k to improve customer reliability.

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

CONFIDENTIAL INFORMATION REDACTED

[redacted]

Investment Proposal for Investment Committee Meeting on: April 28, 2020

Project Name: Dorchester-St Paul Pole Replacement

Total Capital Expenditures: $6,185k (Including $562k of contingency including $112k of internal labor)

Total O&M: $ 0 k

Project Number(s): 157636

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Sam Campbell/Adam Smith

Brief Description of Project

The proposed project is to replace fifty (50) wood structures, on the Dorchester to St Paul 69kV line with new steel structures during a scheduled outage. The scope of work includes the replacement of fifty (50) structures identified through inspection in 2017.

All fifty (50) structures are located in Virginia. A Certificate of Public Convenience and Necessity is not required for this work.

Project Milestones – Transmission Lines	
April 2019	Engineering and Design
September 2019	Space reserved for steel pole production with manufacturer
May 2020	Steel Poles Ordered
December 2020	Steel Poles Received
February 2021	Line Construction Begins
August 2021	Line Construction Completed

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. A routine climbing inspection was completed in 2017, and fifty (50) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line.

The scope of work consists of installing three (3) steel single pole dead end structures, four (4) double circuit steel H-frame structures, twenty-three (23) standard steel H-frame structures, six (6) steel three-pole running corners, one (1) steel single pole running corner, five (5) two-pole tangent H-frame structures, six (6) three-pole dead end structures, and two (2) steel light angle H-frame structures.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost 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. This alternative would also have a negative impact on network reliability. 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.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	1,291	4,058	-	-	5,349
2. Cost of Removal Proposed	-	836	-	-	836
3. Total Capital and Removal Proposed (1+2)	1,291	4,894	-	-	6,185
4. Capital Investment 2020 BP	65	4,894			4,960
5. Cost of Removal 2020 BP	-	1,060			1,060
6. Total Capital and Removal 2020 BP (4+5)	65	5,954	-	-	6,019
7. Capital Investment variance to BP (4-1)	(1,226)	837	-	-	(390)
8. Cost of Removal variance to BP (5-2)	-	224	-	-	224
9. Total Capital and Removal variance to BP (6-3)	(1,226)	1,060	-	-	(166)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Incremental spend in 2020 was approved by RAC in the 2+10 forecast.

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.

Risks

Without the proposed replacement of the priority poles on the Dorchester to St. Paul 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.

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

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 7,605
   The recommendation is to replace all fifty (50) wood structures with new steel structures during a scheduled outage.

2. Alternative #1: NPVRR: ($000s) 11,454
   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 network reliability.

3. Alternative #2: NPVRR: ($000s) 9,530
   The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Dorchester-St Paul pole replacement project for $6,185k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

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: May 26, 2020

Project Name: Corydon-Green River Steel Pole Replacement

Total Capital Expenditures: $4,924k (Including $448k of contingency and $99k of internal labor)

Total O&M: $ 0 k

Project Number(s): LI-161860

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Sam Campbell/Adam Smith

Brief Description of Project

The proposed project is to replace one hundred eleven (111) existing wood structures on the Corydon-Green River Steel 69kV line with steel during a scheduled outage. The scope of work includes the replacement of one hundred five (105) structures identified through a 2018 inspection. The replacement of six (6) adjacent structures is required to accommodate the height of the new structures.

Of the structures being installed, there are ninety seven (97) steel Z-Frame structures, eight (8) steel standard H-frame structures, five (5) steel single pole running corners, and one (1) custom steel dead end H-frame structure.

Project Milestones	
March 2020	Engineering and Design
June 2020	Space reserved for steel pole production with manufacturer
October 2020	Steel Poles Ordered to Inventory
December 2020	Steel Poles Received to Inventory
January 2021-April 2021	Preliminary services, vegetation clearing, and material holding site completed
April 2021	Steel Poles Charged from Inventory
May 2021	Line Construction Begins
December 2021	Line Construction Completed

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. A routine inspection was completed in 2018, and one hundred five (105) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line. Six (6) adjacent structures will also be replaced in order to accommodate the height of the new structures.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost 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. This alternative would also have a negative impact on network reliability. 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.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	-	4,570	-	-	4,570
2. Cost of Removal Proposed		353	-	-	353
3. Total Capital and Removal Proposed (1+2)	-	4,924	-	-	4,924
4. Capital Investment 2020 BP	-	-	4,924	-	4,924
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	-	-	4,924	-	4,924
7. Capital Investment variance to BP (4-1)	-	(4,570)	4,924	-	353
8. Cost of Removal variance to BP (5-2)	-	(353)	-	-	(353)
9. Total Capital and Removal variance to BP (6-3)	-	(4,924)	4,924	-	0

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project was included in the 2020 Business Plan (BP) under project K9-2022. This project is being accelerated as part of the 2021 BP, supporting efforts to address the defective transmission pole backlog. The spend in 2021 will be addressed in the 2021 BP.

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.

Risks

Without the proposed replacement of the priority poles on the Corydon-Green River Steel 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.

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

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 6,348
   The recommendation is to replace one hundred eleven (111) wood structures with new steel structures during a scheduled outage.

2. Alternative #1: Do Nothing NPVRR: ($000s) 9,118
   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 network reliability.

3. Alternative #2: Replace with Wood NPVRR: ($000s) 6,647
   The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Corydon-Green River Steel Pole Replacement project for $4,924k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<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 for Investment Committee Meeting on: May 26, 2020

Project Name: Pineville-Rocky Branch Right of Way

Total Capital Expenditures: $2,977k (Including $466k of contingency and $30k of internal labor)

Total O&M: $ 0 k

Project Number(s): LI-161704

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Adam Smith

Brief Description of Project

Transmission Lines seeks funding authority of $2,977k to acquire the permanent easement rights of way for the existing Pineville-Cary- Rocky Branch 69kV transmission circuit.

In 1923 the Company utilized 99-year rights of way ("ROW") lease agreements to secure land rights to construct, operate and maintain the Pineville-Cary-Rocky Branch circuit that currently consists of 16.51 miles of line and 106 structures. While it is not known why permanent easements were not secured in 1923, it is assumed that there was a concern at that time regarding the rule against perpetuity which does not exist anymore in case law. This project will acquire permanent easement ROW in Bell County for the existing Pineville-Cary-Rocky Branch 69kV circuit. The project will ensure the Company maintains its needed access rights to construct, maintain, and operate this transmission line and prevent the unnecessary relocation of existing transmission facilities. The current lease ROW agreements expire in 2023 at which time the Company will not have secure property access rights to these transmission facilities. The project will secure the needed ROW widths that currently exist in the expiring leases and not seek to expand the current ROW footprint. This project's activities are limited to surveying, landowner negotiation, and easement acquisition. There is no construction activity associated with this project.

This project was submitted for the approval of preliminary services in the amount of $100k for surveying and land evaluation services in April of 2020.

Why is the project needed? What if we do nothing?

As a result of an encroachment investigation completed in 2019, it was discovered that the landowner's encroachment was not on a presumed permanent easement but a 99-year ROW lease. This finding resulted in further research along the Pineville-Cary-Rocky Branch line that discovered the entire circuit's land access rights were covered under separate 99-year leases. The current lease agreement, which cover 91 parcels with 74 different landowners, will expire in 2023. At that time the Company will not have a secured legal claim to access its facilities for maintenance, repair, or construction within the current leased ROW. If the Company does not secure the appropriate access to its facilities, the current landowners could require the Company to remove its facilities.

As a result of additional preliminary research, the 99-year ROW lease issue was discovered on the KU Park - Middlesboro 69kV and KU Park - Bimble 69kv transmission lines. Separate approval will be sought for those projects. At this time no additional transmission lines originating from the Pineville area were determined to possess 99-year leases.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	685	2,292	-	-	2,977
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	685	2,292	-	-	2,977
4. Capital Investment 2020 BP	-	-	-	-	-
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(685)	(2,292)	-	-	(2,977)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(685)	(2,292)	-	-	(2,977)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project was not included in the 2020 Business Plan (BP). The need for this project was discovered after the 2020 BP was complete. Funding in 2020 was included in the RAC approved 3+9 forecast. Funding in 2021 will be addressed by Transmission in the 2021 BP.

Risks

Acquisition costs could be higher than the estimates provided in this proposal. Should attempts to negotiate agreements with current property owners be exhausted, condemnation could be executed, resulting in acquisition delays. An estimate of $6.5k per acre was utilized for easement cost estimates. A property valuation assessment will be completed as part of the project to refine this figure but is not able to be completed at this time due to the closure of the county clerk's office as a result of the COVID-19 pandemic. Additionally, a 5% assumption was utilized to calculate the number of condemnation cases and assumes a standard condemnation expense. The actual figures could vary substantially if 3rd party legal firms become engaged in the landowner negotiations.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 4,578
   Secure the permanent easement ROW for the Pineville-Cary-Rocky Branch 69kV circuit. This approach will ensure the Company possesses the legal rights to continue to operate and maintain these assets to serve its customers.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   The Do Nothing alternative would result in expired leases, resulting in Company having to wait to fifteen (15) years to make a "prescriptive rights" claim for legal access to the current landowner's property that the circuit exists. This approach carries and unquantifiable cost because the cost of remediation to a potential future issue is unknown. Additionally, one (1) landowner is aware of this issue as a result of the 2019 encroachment issue and has inquired about this issue. This level of uncertainty and risk is not a recommended alternative from customer experience, regulatory, or legal perspective.

3. Alternative #2: Construct Alternate Route NPVRR: ($000s) 42,015
   The identification of an alternate route and construction of a new 69kV line is not a viable option from a cost or regulatory perspective. This alternative would still require land acquisition and not result in a less expensive option from that perspective either.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Pineville-Rocky Branch ROW project for $2,977k to support future line maintenance and construction along the Pineville-Cary-Rocky Branch 69kV circuit.

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: June 30, 2020

Project Name: Morganfield-Nebo Static Replacement

Total Capital Expenditures: $5,486k (Including $490k of contingency and $217k of internal labor)

Total O&M: $ 150 k related to Telecom

Project Number(s): 148854

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Ronnie Bradford/Adam Smith

Brief Description of Project

The proposed project is to replace 23.5 miles of static wire that is over 90+ years old and beyond its expected useful life. Performance of this wire has diminished, with the most recent failure occurring in 2014. This project will improve reliability, maintain system integrity, and reduce the risk of failures and unplanned transmission interruptions to the Earlington, Nebo, and Morganfield 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 lives was included as part of the Transmission System Improvement Plan to replace aging infrastructure.

Transmission Lines plans to replace the 23.5 miles of 3/8" steel static between the Morganfield and Nebo substations with optical ground wire (OPGW). In addition, steel static peaks will be replaced on eighty-five (85) of the existing steel towers and three (3) lattice towers will be replaced with steel poles. This project also includes a complete below grade inspection and coatings for all tower legs, with tower member reinforcements when required. This work will be completed during a scheduled outage.

In February of 2019, this 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.

Project Milestones – Transmission Lines	
February 2019-May 2020	Engineering and Design
July 2020	Materials Ordered
August 2020-September 2020	Steel Poles Received
October 2020	Line Construction Begins
April 2021	Line Construction Completed

Why is the project needed? What if we do nothing?

The existing 23.5 miles of 69kV line between Nebo and Morganfield substations contains the original 3/8" static wire installed in 1927. Aerial patrol inspections of this line revealed that the existing static wire is in poor mechanical condition and has reached the end of its useful life. The wire has corroded, become brittle, and does not have its original design strength. Due to the conditions of this wire, there is a risk of additional failures that will expose the transmission network to further unscheduled outages.

This project will complete the fiber path from Earlington North to Nebo to Morganfield. The 13.2 miles between Earlington North and Nebo were completed on a previous project (Project 147999 Earlington North-Nebo static replacement). Completion of this route will support Telecom's efforts to offset expensive leased line costs currently being used for the Morganfield Call Center. Transitioning to a company owned fiber route will provide greater network bandwidth to the Morganfield Call Center and office, the capability to expand the internal network throughout the Morganfield area, and increase the overall reliability as compared to the existing leased line. The company will also have greater control over making any necessary repairs to the fiber path from damage occurring during major system events. In addition, this communication path could potentially be provided for Distribution Automation, and other use cases for 5 additional substations.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	31	1,701	3,288	-	5,020
2. Cost of Removal Proposed			466	-	466
3. Total Capital and Removal Proposed (1+2)	31	1,701	3,754	-	5,486
4. Capital Investment 2020 BP	26	1,387	1,529	-	2,941
5. Cost of Removal 2020 BP	-	179	269	-	448
6. Total Capital and Removal 2020 BP (4+5)	26	1,566	1,798	-	3,389
7. Capital Investment variance to BP (4-1)	(5)	(314)	(1,759)	-	(2,079)
8. Cost of Removal variance to BP (5-2)	-	179	(197)	-	(18)
9. Total Capital and Removal variance to BP (6-3)	(5)	(135)	(1,956)	-	(2,097)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	56	56	22	15	150
2. Project O&M 2020 BP	56	56	56	169	338
3. Total Project O&M variance to BP (2-1)	-	-	34	154	188

Subsequent to the 2020 Business Plan (BP), detailed engineering along with complete scope development increased the planned work for this project. This project now includes a complete below grade inspection and coating for all tower legs. 2020 spend was approved by the

Resource Allocations Committee. 2021 spend will be funded through the reduction of other Transmission projects in the 2021 BP.

The O&M savings of $154k in the Post 2021 column reflects the termination of a leased Telecom DS3 line through AT&T, for the years 2022 through 2024 (at an annual cost of $56k) replaced with approximately $5k annual expenses associated with the OPGW fiber connection. Telecom will reduce the 2021 BP to reflect this savings.

Risks

- Without the proposed replacement of the existing static wire in the Morganfield-Nebo 69kV line, the company risks increased exposure to line outages. The wire along the 23.5 miles has deteriorated over time and is beyond its expected useful life. The wire has corroded and does not have its original design strength. Unplanned outages are often time-consuming and costly when it comes to repairs.
- 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.
- Risks associated with project timeline:
  - Winter and early spring weather impacts could pose significant delays, including issues with structure access across agriculture operations.
  - Loss of existing crews providing mutual assistance during major storm events outside of the LKE footprint.
- There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 6,572
   The recommendation is to replace 23.5 miles of static wire with new OPGW. In addition, steel static peaks will be replaced on eighty-five (85) of the existing steel towers and three (3) lattice towers will be replaced with steel poles. The additional expense is a prudent strategic investment in this one-time opportunity to be able to complete a company-owned fiber path between Earlington and Morganfield. This project will allow Telecom to reduce ongoing expense costs associated with the leased communication line and provide the company greater certainty and operational control over the communication path between Earlington and Morganfield.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   This option is not advisable as this wire 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: NPVRR: ($000s) 6,339
   This alternative would be to splice failed sections as needed. Without the proposed replacement of the existing static wire in the Morganfield-Nebo 69kV line, the

company risks increased exposure to line outages due to this 90+ year old asset. 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. While the splice does reconnect the damaged wire, repairing the static wire does not address the poor mechanical condition of the wire. This alternative is not recommended because it would forfeit the benefits of the previous OPGW investments on the other section of this line.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Morganfield-Nebo Static Replacement project for $5,486k to improve 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: June 30, 2020

Project Name: TEP-CR-Ashbottom-South Park

Total Capital Expenditures: $3,531k (Including $316k of contingency and $157k of internal labor)

Total O&M: $ 0 k

Project Number(s): Transmission Lines: 157188 ($3,479k)
Distribution Operations: 162420 ($52k)

Business Unit/Line of Business: Transmission

Prepared/Presented By: Delyn Kilpack

Brief Description of Project

The Ashbottom - South Park 69kV line overloads in planning studies required for the Transmission Expansion Plan (TEP) required by the companies Planning Guidelines. This project was approved by [redacted], the Company's Independent Transmission Organization (ITO).

During the 90/10 summer peak conditions, an outage of the Mud Lane 138/69 transformer and Mud Lane 138 kV bus causes the Ashbottom - South Park 69kV line to overload 100.2% in 2020. The overload is 107.1% in 2029. During the 50/50 summer peak conditions, the overload is 100.7% in 2027. Transmission planning guidelines require a corrective action plan when post-contingent flows exceed 100% of the emergency rating through the end of the ten year planning horizon.

When the project is completed the summer emergency rating will go from 133 MVA to 143 MVA thus resolving the overload issue. The maximum post-contingent flow will be 93.2% under 90/10 summer peak conditions in 2030 according to the latest TEP models.

This project was opened for preliminary services in March of 2019 for engineering services to further develop the project scope and estimate to support this large capital 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 along the route.

Transmission Lines plans to replace 1.4 miles of existing 1272 MCM 61X All Aluminum Conductor with 1272 MCM 45X7 Aluminum Conductor Steel Reinforced, and the existing static wire will be replaced with new optical ground wire. In addition to the conductor and static being replaced, twenty-seven (27) existing wood structures that do not have adequate structural capacity to meet NESC Heavy loading will be replaced with new steel structures. Of these twenty-seven (27) structures, five (5) will be relocated out of a wetland area into the Railroad right of way.

Project Milestones – Transmission Lines	
March 2020-May 2020	Engineering and Design
May 2020	Space reserved for steel pole production with manufacturer
September 2020	Steel Poles Ordered
November 2020	Steel Poles Received
January 2021	Line Construction Begins
November 2021	Line Construction Completed

Electric Distribution Operations (EDO) will provide the layout work and transferring of distribution underbuild where needed.

Project Milestones – Distribution Operations	
March 2020-September 2020	Engineering and Design
November 2020	Materials Ordered
November 2020	Materials Delivered
December 2020	Construction Start
November 2021	Construction Completed

Project Cost

	Transmission Lines	Distribution Operations	Total
Total 2020	$114k	$7k	$121k
Total 2021	$3,365k	$45k	$3,410k
Project Total	$3,479k	$52k	$3,531k
Contingency	10%	0%	

<u>Why is the project needed? What if we do nothing?</u>

The overload of the Ashbottom - South Park 69kV line was identified in the TEP and approved by [redacted], the Company's Independent Transmission Organization (ITO). If the project is not constructed, it will be in violation of the Company's Transmission Planning Guidelines and put customer load at risk.

[redacted]

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	121	3,092	-	-	3,213
2. Cost of Removal Proposed	-	318	-	-	318
3. Total Capital and Removal Proposed (1+2)	121	3,410	-	-	3,531
4. Capital Investment 2020 BP	117	3,578	-	-	3,696
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	117	3,578	-	-	3,696
7. Capital Investment variance to BP (4-1)	(4)	486	-	-	482
8. Cost of Removal variance to BP (5-2)	-	(318)	-	-	(318)
9. Total Capital and Removal variance to BP (6-3)	(4)	169	-	-	165

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Incremental spend in 2020 was covered through reductions to other Transmission projects and approved by the Resource Allocations Committee.

Risks

Without the recommended re-conductor of the Ashbottom - South Park 69kV line, the Company will be in violation of the its Transmission Planning Guidelines and the TEP process. Not completing this project also places customer load at risk of interruption.

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

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 4,273
   The recommendation is to replace 1.4 miles containing 1272 MCM 61X AA conductor with new 1272 MCM 45X7 ACSR conductor, the existing static wire with OPGW, and the replacement of twenty-seven (27) existing wood structures with new steel structures.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   This alternative puts customer load at risk and violates the Company's Transmission Planning Guidelines.

3. Alternative #2: Add Second Transformer NPVRR: ($000s) 8,637
   Add a second 138/69 transformer at Mud Lane and install two 138 kV breakers. One breaker to be installed on the high side of each of the transformers.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the TEP-CR-Ashbottom-South Park project for $3,531k to comply with the Company's Transmission Planning Guidelines, Transmission Expansion Plan, and improve customer reliability.

<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 for Investment Committee Meeting on: July 29, 2020

Project Name: Lebanon-Lebanon Upgrade (TEP)
TEP-NL-Lebanon-Lebanon ROW (Lines)

Total Capital Expenditures: $13,004k (Including $1,151k of contingency and $511k of internal labor)

Total O&M: $ 0 k

Project Number(s): Construction ($12,255k)
157211 - Lines Overhead
SU-000425 – Substations Protection and Controls
SU-000440 – Substations Line
162253 – Distribution Operations

Rights of Way ($749k)
LI-160928 – Transmission Lines ROW

Business Unit/Line of Business: Transmission

Prepared/Presented By: Delyn Kilpack

Brief Description of Project

The Lebanon-Lebanon South Transmission Expansion Plan (TEP) project is the least cost solution to solve a thermal overload and low voltage problem identified in the Transmission Expansion Plan (TEP). For the loss of either the Lebanon to Lebanon Industrial line or the Lebanon Industrial to Lebanon East line, reliability to approximately nine- thousand customers and 46 MWs of load served in the area is at risk. The overloaded line and area with low voltage are shown in Appendix A.

The Company's Independent Transmission Organization (ITO), [redacted] approved a similar project as part of the 2018 TEP (Alternative #2). The ITO will need to approve the revised project. Notification to the ITO will be provided in July and approval is expected, primarily since the revised project is less expensive.

The project includes construction of a new 2.04 mile 69kV line, utilizing single and double circuit construction, between the existing Lebanon and Lebanon East substations. The new line will consist of the installation of forty (40) new steel structures, the removal of forty (40) wood and five (5) steel structures, and the installation of four (4) new switches with motor operators. While 2.04 miles of new 556 ACSR 26/7 and OPGW will be installed, 0.61 miles of existing conductor will be removed. Kentucky Public Service Commission approval of the new line is not required.

This project was approved for a total of $613k during February 2019 for preliminary engineering services to further identify the project requirements and develop the project scope. A revision was submitted for an additional $89k funding in March of 2020 to allow for preliminary engineering services to continue prior to the Investment Committee meeting scheduled for July of 2020. Separately, the Transmission Lines easement acquisition was approved through the AIP process during October 2019.

LG&E/KU organized a meeting with Marion County judicial personnel and Lebanon City officials to describe the project in June 2020. The feedback from the information meeting was positive.

Project Milestones – Transmission Lines	
January 2019-September 2019	Engineering and Design
January 2020	Space reserved for steel pole production with manufacturer
August 2020	Steel Poles Ordered
March 2021	Steel Poles Received
June 2021	Line Construction Begins
March 2022	Line Construction Completed

Transmission Substations will install a new control house at the Lebanon Substation (#43). This project (associated with project # SU-000425) aligns with the Transmission System Improvement Plan (TSIP) and will provide improvements in protection and control systems at Lebanon (#43). Additionally, the existing house would not accommodate the new line panel required for the TEP project. The scope of work will consist of installing a new DFR panel, a new RTU panel, two (2) new transformer differential panels, two (2) new bus differential panels, two (2) new breaker control panels, four (4) new line relaying panels, as well as two (2) blank panels for telecom equipment in the new control building. In addition, three (3) circuit breakers, six (6) 69kV disconnect switches, one (1) 138kV high voltage switch, and PT junction boxes will also be replaced and connected to the new control house with new cable trench, conduit, and cabling. This additional protection and control project was not part of the TEP, however it is aligned with our TSIP. Completing these projects together will allow for greater resource efficiencies for design and construction.

[redacted] In addition, a new 69kV box structure, circuit breaker, and line terminal will be constructed at the Lebanon Substation to accommodate the new 69kV circuit.

Project Milestones – Transmission Substations	
August 2019-October 2020	Engineering and Design
July 2020	Materials Ordered
June 2021	Materials Received
January 2021	Construction Start
August 2022	Construction Completed

Distribution Operations will provide the layout and transferring of distribution underbuilt where needed.

February 2020-March 2020	Engineering and Design
October 2021	Material Ordered
October 2021	Materials Received
December 2021	Construction Start
Spring 2022	Construction Completed

Why is the project needed? What if we do nothing?

The 2018 TEP identified an overload of the Campbellsville Tap – Taylor County 69kV line and low voltage on the Lebanon Industrial 69kV, Lebanon East substations. This project is needed to eliminate the overload and low voltage situation, safely and reliably serve customer load in the area, and is required per the Company's Transmission Planning Guidelines.

If the project is not constructed, customer load is at risk and the Company is in violation of its Transmission Planning Guidelines, as approved by the ITO.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	418	2,013	6,418	3,364	12,213
2. Cost of Removal Proposed	-	-	643	149	792
3. Total Capital and Removal Proposed (1+2)	418	2,013	7,060	3,513	13,004
4. Capital Investment 2020 BP	282	3,226	8,627	948	13,082
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	282	3,226	8,627	948	13,082
7. Capital Investment variance to BP (4-1)	(136)	1,213	2,209	(2,417)	870
8. Cost of Removal variance to BP (5-2)	-	-	(643)	(149)	(792)
9. Total Capital and Removal variance to BP (6-3)	(136)	1,213	1,567	(2,566)	78

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

Incremental spend in 2022 will be funded by a reduction in other Transmission capital projects.

$000s	Trans Lines Construction 157211	Trans Lines ROW LI-160928	Trans Subs Protection SU-000425	Trans Subs Line SU-000440	Dist Ops 162253	Total
Total 2019	$170	$175	$0	$73	$0	$418
Total 2020	$229	$574	$488	$722	$0	$2,013
Total 2021	$4,193	$0	$1,001	$1,866	$0	$7,060
Total 2022	$1,768	$0	$1,231	$385	$129	$3,513
Project Total	$6,360	$749	$2,720	$3,046	$129	$13,004
Contingency	10%	5%	10%	9%	10%	

This project contains a 9% 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.

Risks

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

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 14,422
   As described above.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   This alternative is not recommended since it puts customer load at risk and violates the Company's Transmission Planning Guidelines.

3. Alternative #2: Alternate Route NPVRR: ($000s) 22,571
   The alternative would consist of the construction of a new 4.25 mile 69kV line, utilizing single and double circuit construction, between the existing Lebanon and Lebanon South substations. In addition, a new transmission switching station would be constructed near Lebanon South to include a 69kV low profile, four breaker ring bus with line exits to Taylor County, Lebanon Intercounty REA, Lebanon and Lebanon South.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Lebanon-Lebanon Upgrade project for $13,004k to improve 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	

CONFIDENTIAL INFORMATION REDACTED

[redacted]

CONFIDENTIAL INFORMATION REDACTED

[redacted]

[redacted]

Investment Proposal for Investment Committee Meeting on: August 27, 2020

Project Name: Lebanon-Taylor County Pole Replacement

Total Capital Expenditures: $5,939k (Including $540k of contingency and $252k of internal labor)

Total O&M: $ 0 k

Project Number(s): Transmission Lines - LI-161721 ($5,784k)
Distribution Operations – 163507 ($155k)

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Tony Mount/Adam Smith

Brief Description of Project

The proposed project is to replace one hundred fifteen (115) existing wood structures with steel structures on the Lebanon-Taylor County 69kV line during a scheduled outage. The scope of work includes the replacement of ninety-nine (99) structures identified through inspection in 2019. In addition, sixteen (16) adjacent structures will be replaced in order to accommodate the height of the new structures.

In July of 2020, this transmission project was opened for $726k to support preliminary engineering for project scope and development, and vegetation clearing.

Project Milestones – Transmission Lines	
July 2020	Engineering and Design
July 2020	Space reserved for steel pole production with manufacturer
September 2020	Steel Poles Ordered
December 2020	Steel Poles Received to Inventory
January 2021	Steel Poles Charged from Inventory
January 2021	Line Construction Begins
June 2021	Line Construction Completed

Distribution Operations will provide the layout work and transferring of underbuilt distribution where needed.

Project Milestones – Distribution Operations	
May 2020-July 2020	Engineering and Design
January 2021	Materials Charged from Inventory
January 2021	Construction Start
July 2021	Construction Completed

Why is the project needed? What if we do nothing?

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 inspection of the Lebanon-Taylor County 69kV line was completed in 2019, and ninety-nine (99) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line. In addition, sixteen (16) adjacent structures will be replaced in order to accommodate the height of the new structures.

The scope of work consists of installing ninety-three (93) steel single pole tangent structures, seven (7) steel single pole angle structures, and fifteen (15) steel H-frame tangent structures.

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. This alternative would also have a negative impact on network reliability. 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.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	48	5,135	-	-	5,183
2. Cost of Removal Proposed	-	756	-	-	756
3. Total Capital and Removal Proposed (1+2)	48	5,891	-	-	5,939
4. Capital Investment 2020 BP	-	-	-	6,419	6,419
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	-	-	-	6,419	6,419
7. Capital Investment variance to BP (4-1)	(48)	(5,135)	-	6,419	1,236
8. Cost of Removal variance to BP (5-2)	-	(756)	-	-	(756)
9. Total Capital and Removal variance to BP (6-3)	(48)	(5,891)	-	6,419	480

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project was included in the 2020 Business Plan (BP) under project K9-2025 for $6,419k. This project is being accelerated as part of the 2021 BP, supporting efforts to limit forced outage risks while the Lebanon-Lebanon Upgrade project (157211) is being constructed. 2020 spend was covered through reductions in other Transmission projects and approved by the Resource Allocations Committee. The spend in 2021 will be covered through reductions in other Transmission projects within 2021 BP. The project contains a 10% contingency ($526k- Lines and $14k-Distribution) 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.

	Transmission Lines	Distribution Operations	Total
Total 2020	$48k	$0k	$48k
Total 2021	$5,736k	$155k	$5,891
Project Total	$5,784k	$155k	$5,939k
Contingency	10%	10%	

Risks
Without the proposed replacement of the priority poles on the Lebanon-Taylor County 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.
There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) $7,183
   The recommendation is to replace one hundred fifteen (115) existing wood structures with steel during a scheduled outage.

2. Alternative #1: Do Nothing NPVRR: ($000s) $11,028
   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 network reliability.

3. Alternative #2: Replace with Wood NPVRR: ($000s) $7,487
   The next best alternative would be to replace all one hundred fifteen (115) structures with wood. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Lebanon-Taylor County pole replacement project for $5,939k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<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 for Investment Committee Meeting on: September 29, 2020

Project Name: KU Park-Middlesboro Right of Way

Total Capital Expenditures: $1,909k (Including $174k of contingency and $37k of internal labor)

Total O&M: $ 0 k

Project Number(s): LI-162350

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Adam Smith/Paul Weis

Brief Description of Project

Transmission Lines seeks funding authority of $1,909k to acquire the permanent easement rights of way for the existing KU Park-Middlesboro 69kV transmission circuit.

In 1923, the Company utilized 99-year rights of way ("ROW") lease agreements to secure land rights to construct, operate and maintain the KU Park-Middlesboro circuit that currently consists of 13.1 miles of line and 101 structures. While it is not known why permanent easements were not secured in 1923, it is assumed that there was a concern at that time regarding the rule against perpetuity which does not exist anymore in case law. This project will acquire permanent easement ROW in Bell County for the existing KU Park-Middlesboro 69kV circuit. The project will ensure the Company maintains its needed access rights to construct, maintain, and operate this transmission line and prevent the unnecessary relocation of existing transmission facilities. The current lease ROW agreements begin to expire in 2022 at which time the Company will not have secure property access rights to these transmission facilities. The project will secure the needed ROW widths that currently exist in the expiring leases and not seek to expand the current ROW footprint. This project's activities are limited to surveying, landowner negotiation, and easement acquisition. There is no construction activity associated with this project.

This project was submitted for the approval of preliminary services in the amount of $110k for surveying and land evaluation services in May of 2020.

Why is the project needed? What if we do nothing?

As a result of an encroachment investigation completed in 2019 on a near-by transmission line, it was discovered that the landowner's encroachment was not on a presumed permanent easement but a 99-year ROW lease. This finding resulted in further research of all the transmission lines originating from the Pineville transmission station (KU Park). The KU Park-Middlesboro line was determined to be covered under separate 99-year leases for access and use rights. The current lease agreements, which cover 84 parcels with 71 different landowners, will begin to expire in 2022. At that time the Company will not have a secured legal claim to access its facilities for maintenance, repair, or construction within the current leased ROW. If the

Company does not secure the appropriate access to its facilities, the current landowners could require the Company to remove its facilities.

The 99-year ROW lease issue was discovered on the Pineville-Cary-Rocky Branch 69kV, KU Park - Bimble 69kV, and a 2 mile portion of the Bimble – London 69kV transmission lines. Separate approval will be sought for those projects. At this time no additional transmission lines originating from the Pineville area have been determined to possess 99-year leases.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	99	1,202	607	-	1,909
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	99	1,202	607	-	1,909
4. Capital Investment 2020 BP	-	-	-	-	-
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(99)	(1,202)	(607)	-	(1,909)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(99)	(1,202)	(607)	-	(1,909)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project was not included in the 2020 Business Plan (BP). The need for this project was discovered after the 2020 BP was complete. Funding in 2020 was included in the RAC approved forecast. Funding in 2021 and 2022 was addressed by Transmission in the 2021 BP and is funded by reductions in other Transmission capital projects.

Risks

Acquisition costs could be higher than the estimates provided in this proposal. Should attempts to negotiate agreements with current property owners be exhausted, condemnation could be executed, resulting in acquisition delays. An estimate of $4,500 per acre was utilized for easement cost estimates based upon the property valuation assessment completed as part of the Pineville – Rock Branch project. Additionally, a 5% assumption was utilized to calculate the number of potential condemnation cases and assumes a standard condemnation expense. The actual figures could vary substantially if 3rd party legal firms become engaged in the landowner negotiations.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 2,846
   Secure the permanent easement ROW for the KU Park-Middlesboro 69kV circuit. This approach will ensure the Company possesses the legal rights to continue to operate and maintain these assets to serve its customers.

2. Alternative #1: NPVRR: ($000s) N/A
   The Do Nothing alternative would result in expired leases, resulting in Company having to wait to fifteen (15) years to make a "prescriptive rights" claim for legal access to the current landowner's property where the circuit exists. This approach carries an unquantifiable cost because the cost of remediation to a potential future issue is unknown. Additionally, area local officials and landowners are aware of this issue and there is local knowledge of this project with the initiation of the Pineville – Rocky Branch project. This level of uncertainty and risk is not a recommended alternative from customer experience, regulatory, or legal perspective.

3. Alternative #2: Construct Alternate Route NPVRR: ($000s) 29,037
   The identification of an alternate route and construction of a new 69kV line is not a viable option from a cost or regulatory perspective. This alternative would still require land acquisition and not result in a less expensive option.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the KU Park-Middlesboro ROW project for $1,909k to support future line maintenance and construction along the KU Park-Middlesboro 69kV circuit.

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: September 29, 2020

Project Name: Eastwood-Simpsonville Expansion Plan Conductor Replacement

Total Capital Expenditures: $3,791k (Including $350k of contingency including $130k of internal labor)

Total O&M: $ 0 k

Project Number(s): Transmission Lines – LI-159249 ($3,140k)
Distribution Operations – 163504 ($651k)

Business Unit/Line of Business: Transmission

Prepared/Presented By: Delyn Kilpack

Brief Description of Project

The Eastwood – Simpsonville 69 kV line overloads in planning studies required for the Transmission Expansion Plan (TEP) which in turn are required by the Companies Planning Guidelines. This project was approved by [redacted] the Company's Independent Transmission Organization (ITO).

During the 90/10 and 50/50 customer forecasts for winter peak conditions, an outage of the Blue Lick 345/161kV transformer causes the Eastwood – Simpsonville 69 kV line to overload 106.1% (50/50 2021 winter) and 110.2% (90/10 2021 winter). The overloads remain throughout the ten year planning horizon.

When the project is completed, the winter emergency rating will go from 101 MVA to 141 MVA thus resolving the overload issue for the entire ten year period. The maximum post-contingent flow will be 89.1% (90/10 2029 winter).

This project was opened for preliminary services in June of 2020 for $242k for engineering services to further develop the project scope and estimate to support this capital 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 customers, community, and businesses along the route.

Transmission Lines plans to replace 3.53 miles of existing 397.5 Aluminum Conductor Steel Reinforced (ACSR) with 556.5 (ACSR), and the existing static wire will be replaced with new optical ground wire (OPGW). In addition to the conductor and static being replaced, fifty-two (52) existing wood structures that do not have adequate structural capacity to meet NESC Heavy loading will be replaced with new steel structures.

Project Milestones – Transmission Lines	
June-August 2020	Engineering and Design
August 2020	Space reserved for steel pole production with manufacturer
October 2020	Steel Poles Ordered
December 2020	Steel Poles Received
January 2021	Line Construction Begins
June 2022	Line Construction Completed

Electric Distribution Operations (EDO) will provide the layout work and transferring of distribution underbuild where needed.

Project Milestones – Distribution Operations	
May-August 2020	Engineering and Design
December 2020	Materials Ordered
January 2021	Materials Delivered
January 2021	Construction Start
August 2021	Construction Completed

Project Cost

	Transmission Lines	Distribution Operations	Total
Total 2020	$246k	$0k	$246k
Total 2021	$2,162k	$651k	$2,813k
Total 2022	$732k	$0	$732k
Project Total	$3,140k	$651k	$3,791k
Contingency	10%	10%	

<u>Why is the project needed? What if we do nothing?</u>
The overload of the Eastwood-Simpsonville 69kV line was identified in the TEP and approved by [redacted], the Company's Independent Transmission Organization (ITO). If the project is not constructed, customer load will be at risk and it will be in violation of the Company's Transmission Planning Guidelines.

[redacted]

[redacted]

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	185	2,443	664	-	3,292
2. Cost of Removal Proposed	61	369	69	-	499
3. Total Capital and Removal Proposed (1+2)	246	2,812	732	-	3,791
4. Capital Investment 2020 BP	187	3,705	-	-	3,891
5. Cost of Removal 2020 BP	63	570	-	-	633
6. Total Capital and Removal 2020 BP (4+5)	250	4,275	-	-	4,525
7. Capital Investment variance to BP (4-1)	2	1,261	(664)	-	599
8. Cost of Removal variance to BP (5-2)	2	201	(69)	-	134
9. Total Capital and Removal variance to BP (6-3)	4	1,462	(732)	-	734

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Incremental spend in 2022 is funded by a reduction in other Transmission Capital projects in the proposed 2021 BP.

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.

Risks

Without the recommended re-conductor of the Eastwood-Simpsonville 69kV line, the Company will put customer load at risk and be in violation of its Transmission Planning Guidelines and the TEP process.

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

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 4,610
   Transmission Lines plans to replace 3.53 miles of existing 397.5 Aluminum Conductor Steel Reinforced (ACSR) with 556.5 (ACSR), and the existing static wire will be replaced with new optical ground wire (OPGW). In addition to the conductor and static being replaced, fifty-two (52) existing wood structures will be replaced with new structures.

2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   This alternative puts customer load at risk and violates the Company's Transmission Planning Guidelines.

3. Alternative #2: Construct New Line NPVRR: ($000s) 23,262
   Build a new 69kV line from the LG&E Middletown 69 kV substation to the KU Finchville 69 kV substation, approximately 12.3 miles. This project would require purchase of new 69kV ROW or expansion of existing 69 kV ROW, all new 69 kV structures, and 795 ACSR MCM conductor or an equivalent. Expansion of both the Middletown and Finchville 69 kV substations to accommodate the additional 69 kV line exits, breakers and all other associated terminal equipment would also be necessary.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the TEP-CR-Eastwood-Simpsonville project for $3,791k to comply with the Company's Transmission Planning Guidelines, Transmission Expansion Plan, and improve customer reliability.

<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 for Investment Committee Meeting on: October 27, 2020

Project Name: PCH, PBR Clark County Proactive Control House and Breaker Replacements

Total Capital Expenditures: $4,090k (Including $348k of contingency including $110k of internal labor)

Total O&M: $ 0k

Project Number(s): SU-000323

Business Unit/Line of Business: Transmission Substations

Prepared/Presented By: Keith Yocum

Brief Description of Project

As part of the Transmission System Improvement Plan (TSIP), this project is a combination of several system integrity programs to address assets in need of replacement at Clark County substation. Clark County has assets operating at 138kV and 69kV that have been in service for longer than 50 years. The programs and project specific information are as follows:

- Improve Protection and Control Systems – A new control building will be installed for the Transmission assets, along with the related protection and control system components (relay panels, batteries, etc.). The existing electromechanical type control and protective relay systems will be replaced with modern, microprocessor-based systems that will ensure reliable operation as well as provide added data for analysis of system events.
- Install Digital Fault Recorder (DFR) for improved system analysis.
- Replace Substation Breakers - Three (3) 69kV and two (2) 138kV oil-filled circuit breakers will be removed and replaced with modern SF6 insulated breakers. The modern breakers are reliable and require less maintenance over time than the legacy oil type circuit breakers. Elimination of the oil circuit breakers reduces the risk of oil contamination due to failure or accidental release.
- Replace Substation Disconnect Switches – Five (5) 69kV 3-phase high voltage disconnect switches will be replaced. The switches targeted for replacement are at an age where failure is common, often during operation. Additionally, one (1) 69kV and one (1) 138kV high-side Potential Transformer (PT) fused disconnects will be removed. This equipment is a common point of failure, resulting in an increased risk of bus outages.
- Replace Substation Line Arresters – Two (2) 69kV and two (2) 138kV sets of line surge arresters. Surge arrestors are being replaced to provide open breaker protection due to lightning strikes.
- Replace Substation Insulators – Six (6) 3-phase cantilever cap & pin type insulators will be replaced with station post type insulators. The cap and pin type insulators have a known history of failure due to radial cracks in the porcelain.

Why is the project needed? What if we do nothing?

The project is needed to modernize this substation and ensure reliable operation. The existing equipment and systems are outdated and have reached their end of life. As described in the TSIP: "System integrity and modernization projects and programs are designed to replace a comprehensive slate of poor performing, obsolete, and end-of-life assets. These programs will reduce the aggregate age of the inventory and ensure that critical assets remain serviceable to support the system. Programs are designed to remove and replace problem assets prior to failure through systematic replacement. Detailed inspections will serve as the central driver for logical and timely asset replacements. Replacement priorities will be determined through assessment of a number of conditional factors in addition to age and, when possible, replacement priorities will be determined by testing and inspections."

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	505	390	1,247	1,803	3,944
2. Cost of Removal Proposed	-	-	-	147	147
3. Total Capital and Removal Proposed (1+2)	505	390	1,247	1,949	4,090
4. Capital Investment 2021 BP	261	635	1,247	1,803	3,945
5. Cost of Removal 2021 BP	-	-	-	147	147
6. Total Capital and Removal 2021 BP (4+5)	261	635	1,247	1,949	4,092
7. Capital Investment variance to BP (4-1)	(244)	245	-	-	1
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(244)	245	-	-	1

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks

- Increased Customer Outages: Aged protection equipment that has failed in place can result in remote clearing of the fault by other equipment on the system and thus result in larger impacts to customer reliability by producing larger outage areas on the system. Failure of breakers, insulators, and other equipment targeted in this project can also require remote clearing of the fault.
- Misoperations: System misoperation rate is correlated with relay age and model. Proactive replacements are prioritized based on installed systems and statistics associated with these factors. The LKE transmission system is seeing a reduction of misoperations since the start of proactive relay replacements. General Electric GCX electromechanical relays are statistically the most prone for misoperations. This

project will remove two 69kV line panels and one 138kV line panel currently utilizing GCX relays.

- Expensive Repairs: Failure of this aging equipment can result in incremental damage to transformers on the system and other equipment. Proactive replacement of this equipment will minimize the potential of this incremental collateral damage.
- Environmental Impacts: As represented in the TSIP, failed equipment, such as transformers, can result in large financial impacts due to environmental cleanup costs associated with oil-filled equipment failing violently. There is also a risk due to asbestos potentially in the control cable and other material in the control house. Materials suspected to contain asbestos will be managed by qualified personnel.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 4,173

2. Alternative #1: NPVRR: ($000s) 4,532
   The alternative consists of performing the recommended scope of work over a period of five years. Performing all the work at once is preferred because delaying the work leaves LKE open to failure of the equipment which could result in unnecessary outages, additional damage/stress on transmission equipment, and decreased system reliability. Additionally, it reduces engineering and construction labor costs due to efficiencies gained in performing some functions once instead multiple times. This alternative assumes one breaker failure and oil cleanup prior to breaker replacements.

3. Alternative #2: Do Nothing NPVRR: ($000s) N/A
   This is not a viable alternative. Oil circuit breakers and other equipment of this vintage will eventually fail with a high likelihood of that happening soon. The system is experiencing occasional, unpredictable failures of the pilot wire line relaying and cap and pin insulators of the types proposed to be replaced and the same will eventually happen here if the equipment is not replaced.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the PCH, PBR Clark County project for $4,090k to enhance the reliability of the 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	

[redacted]

[redacted]

Exhibit C: Major Replaced Equipment Age

Equipment	Install Date
Control House	1965
Oil Circuit Breaker 604	1956
Oil Circuit Breaker 614	1965
Oil Circuit Breaker 608	1968
Oil Circuit Breaker 714	1965
Oil Circuit Breaker 724	1957

Investment and Contract Proposal for Investment Committee Meeting on: October 27, 2020

Project Name: Commonwealth Solar Generator Interconnection Agreement and Project
Contract Name (Good/Service): Large Generator Interconnection Agreement – [redacted]

Selected Vendor(s): Not Applicable

Contract Authorization Requested: $ 9,854k (Including $896k of contingency)

Contract Term:

Total Capital Expenditures Requested: $ 9,854k (gross), $8,825k (net) (Including $896k of contingency and $541k of internal labor)
Total O&M: $0k

Project Number(s): 163635 Interconnection Subs, 163640 Network Facilities Subs, and 163641 Network Facilities Lines
Business Unit/Line of Business: Transmission

Prepared/Presented By: Ashley Vinson

Brief Contract/Project Description

Louisville Gas & Electric and Kentucky Utilities (LG&E/KU) are required to provide open access generation interconnection service as detailed in the FERC approved Open Access Transmission Tariff (OATT) and administered by the Independent Transmission Organization (ITO), [redacted].

On January 15, 2019 [redacted] (customer) proposed the interconnection of a new 110MW solar generating facility in [redacted]. [redacted] and LG&E/KU have performed all necessary studies related to this request and [redacted] has granted interconnection service to the customer, subject to the terms and conditions of the Large Generator Interconnection Agreement (LGIA). The LGIA describes, among other things, the required Transmission Interconnection Facilities and Network Facilities that the Company is obligated to construct to accommodate the interconnection of the solar facility. In addition, the LGIA includes cost estimates and the allocation of costs between the Customer and LG&E/KU.

The total cost of construction that LG&E/KU are obligated to perform is estimated to not exceed $9,854k. The Customer is obligated to pay for actual costs of LG&E/KU's construction of the Transmission Interconnection Facilities which collectively make up an estimated $1,030k of the total. This estimate also includes an allocation of common costs, such as the substation fence, grounding, and associated labor. The cost of Network Facilities are paid for by LG&E/KU and are estimated to be $8,824k.

In order to provide the required generation interconnection service granted to customer by the ITO, this request is for Investment Committee approval of the LGIA and project approval of up

to $9,854k, which includes a 10% contingency. This contingency covers increases in actual costs beyond the estimate. This work is not included in the 2021 BP because the customer indicated they would suspend the agreement upon execution of the LGIA which delays performing the work for up to three years. Funding will be included in future BPs when greater certainty exists that the project will be constructed. [redacted] retains the option to terminate the LGIA; however, the customer must provide acceptable security to ensure LG&E/KU is reimbursed for incurred construction costs if the generation interconnection does not become operational.

Interconnection Facilities
The new interconnection facility will be constructed approximately 0.4 miles south of the Interconnection Customer's (IC's) new generation facility. The interconnection facilities include 138kV structure and equipment necessary to terminate the generator lead line and to provide metering. The IC will be responsible for the design, construction, and permitting of the 138kV transmission line from their interconnection facilities to the Point of Change of Ownership (PCO) at the [redacted]

The Customer is obligated to pay for actual costs of LG&E/KU's construction of the Transmission Interconnection Facilities upon completion of the project.

Network Facilities
The network facilities include a new 138kV interconnection station, a 138kV loop from the existing Brown Plant to Lebanon 138kV transmission line, and a new 125' tall microwave tower and associated Telecom facilities. The new network interconnection facility will be a three (3) breaker ring bus arrangement with three (3) 138kV lines (Lebanon, Brown Plant/Danville North, & Generator Interconnect).

The OATT allows two payment options for required Network Facilities:

1. LG&E/KU may pay for these Network Upgrades itself and include them in rates upon the equipment being placed in service, while requiring the Customer to provide appropriate security (letter of credit or parent guarantee), or
2. LG&E/KU may require the Customer to front the costs of Network Upgrades, and then pay back these costs, plus interest based on the prime rate, to the Customer after the solar facility is in service, and *then* include the costs in rates at the point in which equipment is paid for in full.

It is recommended that LG&E/KU go with the first option because funding can be secured at a lower interest rate than the prime rate.

Station
[redacted]

Why is the project needed? What if we do nothing?

LG&E/KU is obligated to provide generator interconnection service as required by FERC, detailed in the LG&E/KU OATT, and administered by [redacted] as the ITO. The customer has met the applicable requirements to-date and has been granted generator interconnection status by [redacted]. The next required step is to execute the LGIA. Doing nothing would likely result in a FERC complaint filed by the customer stating LG&E/KU did not follow the OATT and allow the generator to interconnect. The customer would certainly prevail in such a proceeding; therefore, doing nothing is not a viable option.

The new facility will be located in Marion County, KY and interconnect with LG&E/KU's Brown Plant to Lebanon 138kV line. See Figure 1 immediately below. This project will have minimal impact on reliability and/or the customer experience.

Figure 1

[redacted]

Contract Bid Summary

Once Customer agrees to the terms in the LGIA, this project will be bid as required. LG&E/KU plan to execute the Large Generator Interconnection Agreement with the Customer in November 2020. The Customer has indicated that they are likely to suspend the agreement, effectively "pausing" the project, and provide LG&E/KU notice to proceed at some later date (not to exceed 36 months from date agreement it is executed). The project is estimated to take approximately twenty-four months from the customer's written notice to proceed and provision of security until construction is complete and the unit achieves commercial operation status.

<u>Contract Financial Summary</u>

Contract expenses ($k)	2020	2021	2022	2023	2024	Post 2024	Total
Amount requested based on contract award estimates	-	51	2,526	6,381	-	-	8,958
Contingency Amount Requested	-	-	-	896	-	-	896
Total contract authority requested	-	51	2,526	7,277	-	-	9,854
Interconnection Reimbursement	-	-	-	(1,030)	-	-	(1,030)
Net contract	-	51	2,526	6,247	-	-	8,824

This project is currently not included in any Business Plan. The customer has the right to suspend for up to three years. If the customer elects to proceed with the project, we will seek funding within Transmission or through the RAC.

The projects 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. Contingency is calculated at 10% of the total project cost after burdens are applied.

The contract does not include built in escalators.

Project Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	-	51	2,526	7,277	9,854
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	-	51	2,526	7,277	9,854
4. Capital Investment 2020 BP	-	-	-	-	-
5. Cost of Removal 2020 BP	-	-	-	-	-
6. Total Capital and Removal 2020 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	-	(51)	(2,526)	(7,277)	(9,854)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	(51)	(2,526)	(7,277)	(9,854)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

($'000s)	163635 Subs Interconnection Facilities (100% Reimbursable)	163640 Subs Network Facilities	163641 Lines Network Facilities	Total
Company Labor	42	499	-	541
Contract Labor	286	2,782	700	3,768
Materials	446	2,409	291	3,146
Contingency	94	689	113	896
Burdens	162	1,201	140	1,503
Gross Capital Expenditures	1,030	7,580	1,244	9,854
Reimbursement	(1,030)	-	-	(1,030)
Net Capital Expenditures	-	7,580	1,244	8,824
Contingency	10%	10%	10%	10%

Risks

- Actual costs could deviate from the estimate. A conceptual design has been developed, however there is not sufficient information available at this conceptual stage to develop a detailed scope and project execution plan. This uncertainty necessitated the need to make several assumptions that influenced the estimated cost;

however, it is not feasible at this stage to reduce these assumptions and the associated financial risk. The customer is required to pay the actual cost of the Transmission Interconnection Facilities and will be required to provide security for the Network Facilities.

- Customer does not proceed with the generation interconnection and does not achieve commercial operations of the solar facility. This is primarily a financial risk and is minimized since the Customer is providing security for the Transmission Interconnection Facilities and Network Facilities. If the commercial operation date is not achieved, LG&E/KU are allowed to recover any funds spent via the security provided by the Customer.

Project Alternatives Considered

LG&E/KU is obligated to offer generator interconnection service as it is a requirement in the FERC approved OATT and the ITO, [redacted], has granted service. To provide non-discriminatory generation interconnection service, the recommendation is designed and proposed consistent with Companies' interconnection guidelines and similarly to the previously approved projects and executed LGIAs [redacted].

Conclusions and Recommendation

It is recommended that the Investment Committee approve the [redacted] project for $9,854k as well as the Large Generator Interconnection Agreement – [redacted] for $9,854k to satisfy its Open Access Transmission Tariff obligations, and to maintain system integrity and reliability.

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced:

The Capital project spending and contract authority requests included in this Investment Proposal have 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 the capital project and contract authority requests.

Kent W. Blake Chief Financial Officer	Date	Paul W. Thompson Chairman, CEO and President	Date

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
[redacted] Large Generator Interconnection Agreement

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the Large Generator Interconnection Agreement contract for $9,854k [redacted]

Sourcing Leader		Proponent/Team Leader	
Supplier Diversity Manager		Manager Ashley Vinson	
Manager - Supply Chain or Commercial Operations		Director – Supply Chain or Commercial Operations	
Director Chris Balmer		Vice President Beth McFarland	

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Appendix A

[redacted]

Appendix B

Figure 3

Conceptual Substation Layout

[redacted]

Figure 4

Project location map

[redacted]

Investment Proposal for Investment Committee Meeting on: October 27, 2020

Project Name: Crab Orchard Tap Conductor Replacement

Total Capital Expenditures: $4,288k (Including $406k of contingency and $145k of internal labor)

Total O&M: $ 0 k

Project Number(s): LI-160059 – Lines Construction ($4,110k)
LI-163809 – Lines ROW ($178k)

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Addam Gooch/Adam Smith

Brief Description of Project

The proposed project is to replace 2.81 miles of overhead transmission line and conductor that is over 50+ years old and beyond its expected useful life. Kentucky Utilities Crab Orchard substation serves over 604 customers with 3.14 MVA of load. This project will improve reliability, maintain system integrity, and reduce the risk of failures and unplanned transmission interruptions to Crab Orchard 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 lives was included as part of the Transmission System Improvement Plan to replace aging infrastructure.

Transmission Lines plans to replace the 2.81 miles of 2/0 aluminum conductor steel reinforced (ACSR) conductor in the Crab Orchard 775 69kV tap with 397 ACSR 26/7. In addition, thirty-eight (38) wood and steel structures will be replaced with twenty-four (24) new steel structures. Structure spotting considerations resulted in the elimination of fourteen (14) existing structures. Due to the limitations of obtaining an extended outage, a portable substation will be utilized to limit customer impact, and a new line will be constructed parallel to the existing line, while the existing line remains energized. Right of way will be acquired on project LI-163809 to expand the existing right of way corridor to support completion of this project.

Project Milestones – Transmission Lines	
June 2020-September 2020	Engineering and Design
September 2020	Space reserved for steel pole production with manufacturer

November 2020	Steel Poles Ordered
February 2021	Steel Poles Received
March 2021	Line Construction Begins
June 2022	Line Construction Completed

Why is the project needed? What if we do nothing?

The existing 2.81 miles of 69kV line in the Crab Orchard 775 tap contains the original 2/0 ACSR conductor installed in 1962. Non-destructive testing was performed on the conductor in 2018 and revealed that it was in marginal to poor condition. Testing showed that the conductor had less than 85% of its original rated breaking strength remaining, signs of heavy surface rust, and medium pitting.

In July of 2020, the transmission project was opened for $553k to support preliminary engineering and project scope development. Preliminary engineering included design development, structure design and selection, and development of the construction plan. Geotechnical services have begun in order to provide geotechnical reports to support drilled shaft foundation design. In addition, easement information has been provided for the entire corridor. The transmission line design was provided to all departments involved for comment and review.

The structure design consists of nineteen (19) tangent steel H-frame structures, one (1) single pole angle structure, two (2) steel single pole dead end structures, one (1) self-supporting single steel dead end structure, and one (1) steel self-supporting switch structure.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	489	2,540	733	-	3,762
2. Cost of Removal Proposed	-	158	367	-	526
3. Total Capital and Removal Proposed (1+2)	489	2,698	1,101	-	4,288
4. Capital Investment 2021 BP	308	2,540	861	-	3,709
5. Cost of Removal 2021 BP	-	158	426	-	585
6. Total Capital and Removal 2021 BP (4+5)	308	2,698	1,287	-	4,294
7. Capital Investment variance to BP (4-1)	(180)	(0)	128	-	(53)
8. Cost of Removal variance to BP (5-2)	-	-	59	-	59
9. Total Capital and Removal variance to BP (6-3)	(180)	(0)	187	-	6

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Incremental spend in 2020 will be funded by a reduction in other Transmission capital projects in the 2020 9+3 Forecast.

Risks

- A communication plan will be developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the communities and businesses along the route.
- There are no known environmental risks regarding air, water, lead, asbestos, etc., associated with this project.
- All highway and railroad crossing permits will be granted by the Kentucky Transportation Cabinet (KYTC), and associated railroads.
- A portable substation will be utilized to minimize customer impact during construction.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 5,261
   The recommendation is to replace 2.81 miles containing 2/0 conductor with new 397 ACSR 26/7 conductor and replace thirty-eight (38) existing wood and steel structures with twenty-four (24) 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: NPVRR: ($000s) 6,896
   The Next Best Alternative would be to construct a new 3.0 mile transmission line. Constructing a new route would require the purchase 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.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Crab Orchard Conductor Replacement project for $4,288k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

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 27, 2020

Project Name: PR Harlan Y Proactive Control House Replacement

Total Capital Expenditures: $4,122k (Including $374k of contingency including $183k of internal labor)

Total O&M: $ 0k

Project Number(s): SU-000130

Business Unit/Line of Business: Transmission Substations

Prepared/Presented By: Keith Yocum

<u>Brief Description of Project</u>

As part of the Transmission System Improvement Plan (TSIP), this project is a combination of several system integrity programs to address assets in need of replacement at Harlan Y substation. Harlan Y has assets operating at 161kV and 69kV that have been in service for longer than 50 years. The substation serves as a hub for the Harlan area and contains many Distribution circuits. The programs and project specific information are as follows:

- Improve Protection and Control Systems – A new control building will be installed for the Transmission assets, along with the related protection and control system components (relay panels, batteries, etc.). The existing electromechanical type control and protective relay systems will be replaced with modern, microprocessor-based systems that will ensure reliable operation as well as provide added data for analysis of system events. High-speed relaying will be implemented on three of the four 161kV lines via digital communication schemes over the Telecom network further increasing reliability. Additionally, Harlan Y substation is adjacent to Martin's Fork; one of two rivers that make up the Cumberland River. Due to the floodplain of this river, the new control house will be constructed atop piers that will raise the floor level above the 100-year floodplain. The existing 69kV control house currently subsides within the 100-year floodplain while the existing 161kV substation is elevated above the floodplain. The existing 69kV and 161kV control houses will be demolished once the new control house is in service.
- Replace Substation Breakers - Two (2) 69kV oil-filled circuit breakers will be removed and replaced with modern SF6 insulated breakers. The modern breakers are reliable and require less maintenance over time than the legacy oil type circuit breakers. Elimination of the oil circuit breakers reduces the risk of oil contamination due to failure or accidental release.
- Replace Substation Disconnect Switches – One (1) 69kV 3-phase high voltage disconnect switch will be replaced. This switch is supported by cap & pin insulators which are targeted for replacement due to a high risk of failure. A high-side Potential Transformer disconnect will also be removed as this equipment is a common point of failure, resulting in an increased risk of bus outages.

- Replace Substation Line Arresters – Two (2) 69kV sets of line surge arresters. Surge arrestors are being replaced to provide open breaker protection due to lightning strikes.
- Replace Substation Fence – Due to aged conditions of the fence, and the need to expand the fence around the location of the new control house, this project will include a full replacement of the fence with approximately 1200 feet of 7-foot tall chain-link fencing per substation standards.

Due to the FERC 7 factor test, a 69kV breaker and the associated relay panel will be transferred to Distribution. A separate project number and AIP for these assets will be provided at full approval.

[redacted]

Why is the project needed? What if we do nothing?

The project is needed to modernize this substation and ensure reliable operation. The existing equipment and systems are 50+ years old, are outdated and have reached their end of life. As described in the TSIP: "System integrity and modernization projects and programs are designed to replace a comprehensive slate of poor performing, obsolete, and end-of-life assets. These programs will reduce the aggregate age of the inventory and ensure that critical assets remain serviceable to support the system. Programs are designed to remove and replace problem assets prior to failure through systematic replacement. Detailed inspections will serve as the central driver for logical and timely asset replacements. Replacement priorities will be determined through assessment of a number of conditional factors in addition to age and, when possible, replacement priorities will be determined by testing and inspections."

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	1	770	1,823	1,473	-	4,066
2. Cost of Removal Proposed	-	-	-	55	-	55
3. Total Capital and Removal Proposed (1+2)	1	770	1,823	1,528	-	4,122
4. Capital Investment 2021 BP	1	525	2,068	1,524	-	4,117
5. Cost of Removal 2021 BP	-	-	-	-	-	-
6. Total Capital and Removal 2021 BP (4+5)	1	525	2,068	1,524	-	4,117
7. Capital Investment variance to BP (4-1)	-	(245)	245	51	-	51
8. Cost of Removal variance to BP (5-2)	-	-	-	(55)	-	(55)
9. Total Capital and Removal variance to BP (6-3)	-	(245)	245	(5)	-	(4)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-	-

Incremental spend in 2020 will be funded by a reduction in other Transmission capital projects in the 2020 9+3 Forecast. The higher spend in 2022 will be funded by a reduction in other Transmission capital projects during the 2022 BP.

Risks

- Increased Customer Outages: Aged protection equipment that has failed in place can result in remote clearing of the fault by other equipment on the system and thus result in larger impacts to customer reliability by producing larger outage areas on the system. Failure of breakers, insulators, and other equipment targeted in this project can also require remote clearing of the fault.
- Misoperations: System misoperation rate is correlated with relay age and model. Proactive replacements are prioritized based on installed systems and statistics associated with these factors. The LKE transmission system is seeing a reduction of misoperations since the start of proactive relay replacements. General Electric GCX electromechanical relays are statistically the most prone for misoperations. This project will remove three 69kV line panels currently utilizing GCX relays.
- Expensive Repairs: Failure of this aging equipment can result in incremental damage to transformers on the system and other equipment. Proactive replacement of this equipment will minimize the potential of this incremental collateral damage.
- Environmental Impacts: As represented in the TSIP, failed equipment, such as transformers, can result in large financial impacts due to environmental cleanup costs associated with oil-filled equipment failing violently.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 4,183

2. Alternative #1: NPVRR: ($000s) 4,270
   The alternative consists of performing the recommended scope of work over a period of five years. Performing all the work at once is preferred because it reduces engineering and construction labor costs due to efficiencies gained in performing some functions once instead multiple times. Additionally, delaying the work leaves LKE open to failure of the equipment which could result in unnecessary outages, additional damage/stress on transmission equipment, and decreased system reliability.

3. Alternative #2: Do Nothing NPVRR: ($000s) N/A
   This is not a viable alternative. Oil circuit breakers and other equipment of this vintage will eventually fail with a high likelihood of that happening soon. The system is experiencing occasional, unpredictable failures of the pilot wire line relaying and cap and pin insulators of the types proposed to be replaced and the same will eventually happen here if the equipment is not replaced.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the PR Harlan Y Control House project for $4,122k to enhance the reliability of the 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	

Appendix

Exhibit A: Harlan Y Scope Outline

[redacted]

Exhibit B: Harlan Y Substation Overview

[redacted]

Exhibit C: FEMA Floodplain Map

[redacted]

Exhibit D: Major Replaced Equipment Age

Equipment	Install Date
161kV Control House	1956
69kV Control House	Unknown per Cascade data. At least 1961
Oil Circuit Breaker 618	1961
Oil Circuit Breaker 624	1965

Investment Proposal for Investment Committee Meeting on: October 27, 2020

Project Name: TEP-Maximum Operating Temperature-Elizabethtown-Elizabethtown 5

Total Capital Expenditures: $2,082k (Including $189k of contingency and $78k of internal labor)

Total O&M: $ 0 k

Project Number(s): Transmission Lines - LI-159248 ($1,868k)
Distribution Operations – 163596 ($214k)

Business Unit/Line of Business: Transmission

Prepared/Presented By: Delyn Kilpack

Brief Description of Project

The Elizabethtown - Elizabethtown 5 69kV line overloads in Transmission Expansion Plan (TEP) studies. This project is required by the Companies' Transmission Planning Guidelines and was approved by [redacted], the Company's Independent Transmission Organization (ITO).

During the 90/10 summer peak, and base case conditions (without a generator or transmission outage) the Elizabethtown - Elizabethtown 5 69kV line overloads to 101.8% of normal rating in 2021. The overload is 109.6% in 2029. The Companies' Transmission Planning Guidelines require a project when the overload exceeds 100% of the normal rating through the end of the ten year planning horizon.

When the Maximum Operating Temperature upgrade (MOT) project is completed, the summer normal rating will go from 49 MVA to 52 MVA thus resolving the overload issue.

This project was opened for preliminary services in August of 2020 for $87k for engineering services to further develop the project scope and estimate to support this large capital project.

In order to increase the line MOT, (30) structures/poles will require replacement to maintain required clearance. Specifically, this project involves the replacement of twenty-five (25) existing wood structures with new steel structures, and five (5) existing wood stub poles with five (5) new steel sub poles. This work also involves working within state/county road right of way and on railroad property.

Project Milestones – Transmission Lines	
August 2020-September 2020	Engineering and Design
September 2020	Space reserved for steel pole production with manufacturer
November 2020	Steel Poles Ordered
March 2021	Steel Poles Received

April 2021	Line Construction Begins
September 2021	Line Construction Completed

Electric Distribution Operations will provide the layout work and transferring of distribution underbuild where needed.

Project Milestones – Distribution Operations	
July 2020-September 2020	Engineering and Design
November 2020	Materials Ordered
March 2021	Materials Delivered
April 2021	Construction Start
September 2021	Construction Completed

<u>Project Cost</u>

	Transmission Lines	Distribution Operations	Total
Total 2020	$87k	$0	$87k
Total 2021	$1,781k	$214k	$1,995
Project Total	$1,868k	$214k	$2,082
Contingency	10%	10%	

<u>Why is the project needed? What if we do nothing?</u>
The overload of the Elizabethtown - Elizabethtown 5 69kV line was identified in the TEP and approved by [redacted], the Company's Independent Transmission Organization (ITO). If the project is not constructed, it will be in violation of the Company's Transmission Planning Guidelines and put customer load at risk.

[redacted]

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	**2020**	**2021**	**2022**	**Post 2022**	**Total**
1. Capital Investment Proposed	87	1,669	-	-	1,757
2. Cost of Removal Proposed	-	325	-	-	325
3. Total Capital and Removal Proposed (1+2)	87	1,995	-	-	2,082
4. Capital Investment 2021 BP	87	2,270	-	-	2,357
5. Cost of Removal 2021 BP	-	254	-	-	254
6. Total Capital and Removal 2021 BP (4+5)	87	2,524	-	-	2,611
7. Capital Investment variance to BP (4-1)	-	601	-	-	601
8. Cost of Removal variance to BP (5-2)	-	(71)	-	-	(71)
9. Total Capital and Removal variance to BP (6-3)	-	529	-	-	529

Financial Detail by Year - O&M ($000s)	**2020**	**2021**	**2022**	**Post 2022**	**Total**
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks

Without the recommended MOT upgrade of the Elizabethtown - Elizabethtown 5 69kV line, the Company will be in violation of the its Transmission Planning Guidelines and the TEP process. Not completing this project also places customer load at risk of interruption.

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

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 2,525
   The recommendation is to replace twenty five (25) existing wood structures with new steel structures, and five (5) existing wood stub poles with five (5) new steel stub poles.
2. Alternative #1: NPVRR: ($000s) N/A
   This alternative puts customer load at risk and violates the Company's Transmission Planning Guidelines.

3. Alternative #2: NPVRR: ($000s) 4,206
   Build a new 69kV line from the KU Elizabethtown 69kV substation to the Elizabethtown 5 69 kV substation, approximately 3 miles. This project would require purchase of a new, or expansion of existing 69kV ROW, all new 69kV structures, and 556.5 MCM 26X7 ACSR conductor or an equivalent. Expansion of both the Elizabethtown and Elizabethtown (5) 69kV substations to accommodate the additional 69 kV line exits, breakers and all other associated terminal equipment would also be necessary.

<u>Conclusions and Recommendation</u>
It is recommended that the Investment Committee approve the TEP-MOT-Elizabethtown-Elizabethtown 5 project for $2,082k to comply with the Company's' Transmission Planning Guidelines, Transmission Expansion Plan, and improve customer reliability.

<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 and Contract Proposal for Investment Committee Meeting on: October 27, 2020

Project Name: [redacted] Solar Generator Interconnection Agreement and Project
Contract Name (Good/Service): Large Generator Interconnection Agreement – [redacted]

Selected Vendor(s): Not Applicable

Contract Authorization Requested: $ 10,966k (Including $997k of contingency)

Contract Term:

Total Capital Expenditures Requested: $ 10,966k (gross), $9,955k (net) (Including $997k of contingency and $562k of internal labor)
Total O&M: $0k

Project Number(s): 163672 Interconnection Subs, 163673 Network Facilities Subs, and 163674 Network Facilities Lines
Business Unit/Line of Business: Transmission

Prepared/Presented By: Ashley Vinson

Brief Contract/Project Description

Louisville Gas & Electric and Kentucky Utilities (LG&E/KU) are required to provide open access generation interconnection service as detailed in the FERC approved Open Access Transmission Tariff (OATT) and administered by the Independent Transmission Organization (ITO), [redacted]

On February 6, 2019 [redacted] (customer) proposed the interconnection of a new 104MW solar generating facility in [redacted]. [redacted] and LG&E/KU have performed all necessary studies related to this request and TranServ has granted interconnection service to the customer, subject to the terms and conditions of the Large Generator Interconnection Agreement (LGIA). The LGIA describes, among other things, the required Transmission Interconnection Facilities and Network Facilities that the Company is obligated to construct to accommodate the interconnection of the solar facility. In addition, the LGIA includes cost estimates and the allocation of costs between the Customer and LG&E/KU.

The total cost of construction that LG&E/KU are obligated to perform is estimated to not exceed $10,966k. The Customer is obligated to pay for actual costs of LG&E/KU's construction of the Transmission Interconnection Facilities which collectively make up an estimated $1,011k of the total. This estimate also includes an allocation of common costs, such as the substation fence, grounding, and associated labor. The cost of Network Facilities are paid for by LG&E/KU and are estimated to be $9,955k.

In order to provide the required generation interconnection service granted to customer by the ITO, this request is for Investment Committee approval of the LGIA and project approval of up

to $10,966k, which includes a 10% contingency. This contingency covers increases in actual costs beyond the estimate. This work is not included in the 2021 BP becasue the customer indicated they would suspend the agreement upon execution of the LGIA which delays performing the work for up to three years. Funding will be included in future BPs when greater certainty exists that the project will be constructed. [redacted] retains the option to terminate the LGIA; however, the customer must provide acceptable security to ensure LG&E/KU is reimbursed for incurred construction costs if the generation interconnection does not become operational.

Interconnection Facilities
The new interconnection facility will be constructed adjacent to the Interconnection Customer's (IC's) generation facility. The interconnection facilities include 161kV structures and equipment necessary to terminate the generator lead line and to provide metering. The IC will be responsible for the design, construction, and permitting of the 161kV transmission line from their facilities to the Point of Change of Ownership (PCO) at the [redacted] Solar Station. [redacted]

The Customer is obligated to pay for actual costs of LG&E/KU's construction of the Transmission Interconnection Facilities upon completion of the project.

Network Facilities
The network facilities include a new 161kV interconnection station, a 161kV loop connection to the existing Grahamville to Wickcliffe 161kV transmission line, and a new 195' tall microwave tower and associated Telecom facilities. The new network interconnection facility will be a three (3) breaker ring bus arrangement with three (3) 161kV lines (Grahamville, Wickcliffe, & Generator Interconnect)

The OATT allows two payment options for required Network Facilities:

1. LG&E/KU may pay for these Network Upgrades itself and include them in rates upon the equipment being placed in service, while requiring the Customer to provide appropriate security (letter of credit or parent guarantee), or
2. LG&E/KU may require the Customer to front the costs of Network Upgrades, and then pay back these costs, plus interest based on the prime rate, to the Customer after the solar facility is in service, and *then* include the costs in rates at the point in which equipment is paid for in full.

It is recommended that LG&E/KU go with the first option because funding can be secured at a lower interest rate than the prime rate.

Station
[redacted]

<u>Why is the project needed? What if we do nothing?</u>

LG&E/KU is obligated to provide generator interconnection service as required by FERC, detailed in the LG&E/KU OATT, and administered by [redacted] as the ITO. The customer has met the applicable requirements to-date and has been granted generator interconnection status by [redacted]. The next required step is to execute the LGIA. Doing nothing would likely result in a FERC complaint filed by the customer stating LG&E/KU did not follow the OATT and allow the generator to interconnect. The customer would certainly prevail in such a proceeding; therefore, doing nothing is not a viable option.

The new facility will [redacted] and interconnect with LG&E/KU's Grahamville to Wickcliffe 161kV line. See Figure 1 immediately below. This project will have minimal impact on reliability and/or the customer experience.

Figure 1

[redacted]

<u>Contract Bid Summary</u>

Once Customer agrees to the terms in the LGIA, this project will be bid as required. LG&E/KU plan to execute the Large Generator Interconnection Agreement with the Customer in Novermber 2020. The Customer has indicated that they are likely to suspend the agreement, effectively "pausing" the project, and provide LG&E/KU notice to proceed at some later date (not to exceed 36 months from date agreement it is executed). The project is estimated to take approximately twenty-four months from the customer's written notice to proceed and provision of security until construction is complete and the unit achieves commercial operation status.

Contract Financial Summary

Contract expenses ($k)	2020	2021	2022	2023	2024	Post 2024	Total
Amount requested based on contract award estimates	-	219	7,518	2,232	-	-	9,969
Contingency Amount Requested	-	-	-	997	-	-	997
Total contract authority requested	-	219	7,518	3,229	-	-	10,966
Interconnection Reimbursement	-	-	-	(1,011)	-	-	(1,011)
Net contract	-	219	7,518	2,218			9,955

This project is currently not included in any Business Plan. The customer has the right to suspend for up to three years. If the customer elects to proceed with the project, we will seek funding within Transmission or through the RAC.

The projects 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. Contingency is calculated at 10% of the total project cost after burdens are applied.

The contract does not include built in escalators.

Project Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	-	219	7,518	3,229	10,966
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	-	219	7,518	3,229	10,966
4. Capital Investment 2021 BP	-	-	-	-	-
5. Cost of Removal 2021 BP	-	-	-	-	-
6. Total Capital and Removal 2021 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	-	(219)	(7,518)	(3,229)	(10,966)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	(219)	(7,518)	(3,229)	(10,966)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

($'000s)	163672 Subs Interconnection Facilities (100% Reimbursable)	163673 Subs Network Facilities	163674 Lines Network Facilities	Total
Company Labor	27	535	-	562
Contract Labor	265	2,690	996	3,951
Materials	472	2,836	467	3,775
Contingency	92	738	167	997
Burdens	155	1,315	211	1,681
Gross Capital Expenditures	1,011	8,114	1,841	10,966
Reimbursement	(1,011)	-	-	(1,011)
Net Capital Expenditures	-	8,114	1,841	9,955
Contingency	10%	10%	10%	10%

Risks

- Actual costs could deviate from the estimate. A conceptual design has been developed, however there is not sufficient information available at this conceptual stage to develop a detailed scope and project execution plan. This uncertainty necessitated the need to make several assumptions that influenced the estimated cost; however, it is not feasible at this stage to reduce these assumptions and the associated financial risk. The customer is required to pay the actual cost of the Transmission Interconnection Facilities and will be required to provide security for the Network Facilities.

- Customer does not proceed with the generation interconnection and does not achieve commercial operations of the solar facility. This is primarily a financial risk and is minimized since the Customer is providing security for the Transmission Interconnection Facilities and Network Facilities. If the commercial operation date is not achieved, LG&E/KU are allowed to recover any funds spent via the security provided by the Customer.

<u>Project Alternatives Considered</u>

LG&E/KU is obligated to offer generator interconnection service as it is a requirement in the FERC approved OATT and the ITO, [redacted] has granted service. To provide non-discriminatory generation interconnection service, the recommendation is designed and proposed consistent with Companies' interconnection guidelines and similarly to the previously approved projects and executed LGIAs with [redacted]

Conclusions and Recommendation
It is recommended that the Investment Committee approve the [redacted] Solar project for $10,966k as well as the Large Generator Interconnection Agreement – [redacted] for $10,966k to satisfy its Open Access Transmission Tariff obligations, and to maintain system integrity and reliability.

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

Approval Confirmation for Capital Projects Greater Than $2 million and Contract Authority Greater Than $10 million bid, or $2 million sole sourced:

The Capital project spending and contract authority requests included in this Investment Proposal have 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 the capital project and contract authority requests.

Kent W. Blake Chief Financial Officer	Date	Paul W. Thompson Chairman, CEO and President	Date

AWARD RECOMMENDATION APPROVALS – Attachment for IC Proposal

SUBJECT:
[redacted] Solar Large Generator Interconnection Agreement

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the Large Generator Interconnection Agreement contract for $10,966k with [redacted]

Sourcing Leader		Proponent/Team Leader	
Supplier Diversity Manager		Manager Ashley Vinson	
Manager - Supply Chain or Commercial Operations		Director – Supply Chain or Commercial Operations	
Director Chris Balmer		Vice President Beth McFarland	

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Appendix A

[redacted]

Appendix B

[redacted]

Investment Proposal for Investment Committee Meeting on: November 20, 2020

Project Name: Dorchester-Arnold Pole Replacement

Total Capital Expenditures: $3,938k (Including $352k of contingency and $125k of internal labor)

Total O&M: $ 0 k

Project Number(s): LI-158882

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Andrew Bailey/Adam Smith

Brief Description of Project

The proposed project is to replace thirty-three (33) existing wood structures with steel on the Dorchester-Arnold 161kV line during a scheduled outage. The scope of work includes the replacement of thirty-three (33) structures identified through inspection in 2018.

Of the thirty-three (33) structures being replaced, six (6) are in Kentucky and twenty-seven (27) are in Virginia. A Certificate of Public Convenience and Necessity (CPCN) is required for the section of line located in Virginia. The CPCN was filed on 06/02/2020 and Virginia Commission staff issued a report to the Virginia Commission supporting the Company's proposed project on 09/30/2020. The Company has requested commission approval on or before 11/30/2020.

This project was opened for preliminary services in October of 2019 for $494k for engineering services to further develop the project scope and estimate to support this large capital project.

Project Milestones – Transmission Lines	
October 2019-August 2020	Engineering and Design
August 2020	Space reserved for steel pole production with manufacturer
December 2020	Steel Poles Ordered
January 2021	Steel Poles Received
February 2021	Line Construction Begins
July 2021	Line Construction Completed

Why is the project needed? What if we do nothing?

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 inspection of the Dorchester-Arnold 161kV line was completed in 2018 and thirty-three

(33) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line.

The scope of work consists of installing thirty (30) steel H-frame structures, and three (3) steel 3-pole angle structures.

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. This alternative would also have a negative impact on network reliability. 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.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	**2019**	**2020**	**2021**	**Post 2021**	**Total**
1. Capital Investment Proposed	28	25	3,309	-	3,361
2. Cost of Removal Proposed	-	-	577	-	577
3. Total Capital and Removal Proposed (1+2)	28	25	3,886	-	3,938
4. Capital Investment 2021 BP	28	25	3,309	-	3,361
5. Cost of Removal 2021 BP	-	-	577	-	577
6. Total Capital and Removal 2021 BP (4+5)	28	25	3,886	-	3,938
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 2021 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

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.

Risks

Without the proposed replacement of the priority poles on the Dorchester-Arnold 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.

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

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 4,469
   The recommendation is to replace thirty-three (33) existing wood structures with steel during a scheduled outage.

2. Alternative #1: Do Nothing NPVRR: ($000s) 6,836
   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 network reliability.

3. Alternative #2: NPVRR: ($000s) 4,675
   The next best alternative would be to replace all thirty-three (33) structures with wood. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Dorchester-Arnold pole replacement project for $3,938k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

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: November 20, 2020

Project Name: Dorchester-Pocket North Pole Replacement

Total Capital Expenditures: $10,672k (Including $970k of contingency and $249k of internal labor)

Total O&M: $ 0 k

Project Number(s): LI-158883

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: John Doll/Adam Smith

Brief Description of Project

The proposed project is to replace eighty-nine (89) existing wood structures with steel on the Dorchester-Pocket North 161kV line during a scheduled outage. The scope of work includes the replacement of eighty-five (85) structures identified through inspection in 2018. In addition, four (4) adjacent structures will be replaced in order to accommodate the height of the new structures.

All eighty-nine (89) structures being replaced are in Virginia. A Certificate of Public Convenience and Necessity (CPCN) is required for this project. The CPCN was filed on 06/02/2020 and Virginia Commission staff issued a report to the Virginia Commission supporting the Company's proposed project on 09/30/2020. The Company has requested commission approval on or before 11/30/2020.

This project was opened for preliminary services in October of 2019 for $698k for engineering services to further develop the project scope and estimate to support this large capital project.

Project Milestones – Transmission Lines	
October 2019-August 2020	Engineering and Design
August 2020	Space reserved for steel pole production with manufacturer
December 2020	Steel Poles Ordered
June 2021	Steel Poles Received
October 2021	Line Construction Begins
October 2022	Line Construction Completed

Why is the project needed? What if we do nothing?

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 inspection of the Dorchester-Pocket North 161kV line was completed in 2018, and eighty-five (85) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line. In addition, four (4) structures will be replaced in order to accommodate the height of the new structures.

The scope of work consists of installing sixty-nine (69) standard steel H-frame structures, five (5) steel tangent H-frame structures, six (6) steel three pole guyed running angle structures, six (6) steel dead end H-frame structures, and three (3) steel light angle H-frame structures.

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. This alternative would also have a negative impact on network reliability. 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.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	5	588	4,356	4,136	9,085
2. Cost of Removal Proposed	-	-	569	1,019	1,588
3. Total Capital and Removal Proposed (1+2)	5	588	4,925	5,155	10,672
4. Capital Investment 2021 BP	5	588	4,357	4,589	9,538
5. Cost of Removal 2021 BP	-	-	569	1,019	1,588
6. Total Capital and Removal 2021 BP (4+5)	5	588	4,926	5,608	11,126
7. Capital Investment variance to BP (4-1)	-	0	1	453	454
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	0	1	453	454

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

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.

Risks

Without the proposed replacement of the priority poles on the Dorchester-Pocket North 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.

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

<u>Alternatives Considered</u>

1. Recommendation: NPVRR: ($000s) 11,881
   The recommendation is to replace eighty-nine (89) existing wood structures with steel during a scheduled outage.

2. Alternative #1: Do Nothing NPVRR: ($000s) 17,364
   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 network reliability.

3. Alternative #2: Replace with Wood NPVRR: ($000s) 12,251
   The next best alternative would be to replace all eighty-nine (89) structures with wood. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

<u>Conclusions and Recommendation</u>

It is recommended that the Investment Committee approve the Dorchester-Pocket North pole replacement project for $10,672 to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<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: November 20, 2020

Project Name: Harlan Y-Pocket North Pole Replacement

Total Capital Expenditures: $2,360k (Including $215k of contingency and $91k of internal labor)

Total O&M: $ 0 k

Project Number(s): LI-160075

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Nick Poston/Adam Smith

Brief Description of Project

The proposed project is to replace twelve (12) existing wood structures with steel on the Harlan Y-Pocket North 161kV line during a scheduled outage. The scope of work includes the replacement of twelve (12) structures identified through inspection in 2018.

Of the twelve (12) structures being replaced, seven (7) are in Kentucky, and five (5) are in Virginia. A Certificate of Public Convenience and Necessity (CPCN) is required for the section of line in Virginia. The CPCN was filed on 06/02/2020 and Virginia Commission staff issued a report to the Virginia Commission supporting the Company's proposed project on 09/30/2020. The Company has requested commission approval on or before 11/30/2020.

This project was opened for preliminary services in October of 2019 for $386k for engineering services to further develop the project scope and estimate to support this large capital project.

Project Milestones – Transmission Lines	
October 2019-August 2020	Engineering and Design
August 2020	Space reserved for steel pole production with manufacturer
October 2020	Steel Poles Ordered
May 2021	Steel Poles Received
August 2021	Line Construction Begins
September 2021	Line Construction Completed

Why is the project needed? What if we do nothing?

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 inspection of the Harlan Y-Pocket North 161kV line was completed in 2018, and twelve (12) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line.

The scope of work consists of installing seven (7) steel H-frame structures, three (3) steel 3-pole dead end structures, and two (2) steel 3-pole running corners.

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. This alternative would also have a negative impact on network reliability. 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.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	-	67	1,967	-	2,033
2. Cost of Removal Proposed	-	-	327	-	327
3. Total Capital and Removal Proposed (1+2)	-	67	2,294	-	2,360
4. Capital Investment 2021 BP	-	67	1,967	-	2,033
5. Cost of Removal 2021 BP	-	-	327	-	327
6. Total Capital and Removal 2021 BP (4+5)	-	67	2,294	-	2,360
7. Capital Investment variance to BP (4-1)	-	(0)	-	-	(0)
8. Cost of Removal variance to BP (5-2)	-	-	0	-	0
9. Total Capital and Removal variance to BP (6-3)	-	(0)	0	-	(0)

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

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.

Risks

Without the proposed replacement of the priority poles on the Harlan Y-Pocket North 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.

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

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 2,859

   The recommendation is to replace twelve (12) existing wood structures with steel during a scheduled outage.

2. Alternative #1: Do Nothing NPVRR: ($000s) 4,371
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 network reliability.

3. Alternative #2: NPVRR: ($000s) 3,896
The next best alternative would be to replace all twelve (12) structures with wood. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Harlan Y-Pocket North pole replacement project for $2,360k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

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: November 20, 2020

Project Name: KU Park-Bimble-London Right of Way

Total Capital Expenditures: $746k (Including $68k of contingency and $26k of internal labor)

Total O&M: $ 0 k

Project Number(s): LI-162349

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Paul Weis

Brief Description of Project

Transmission Lines seeks funding authority of $746k to acquire the permanent easement rights of way for the existing KU Park-Bimble 69kV transmission circuit and a portion of the Bimble-London 69kV transmission circuit.

In 1923, the Company utilized 99-year rights of way ("ROW") lease agreements to secure land rights to construct, operate and maintain the KU Park-Bimble circuit and a portion of the Bimble-London circuit located to the northwest of the Bimble substation. While it is not known why permanent easements were not secured in 1923, it is assumed that there was a legal concern at that time regarding the rule against perpetuity that does not currently exist in case law. This project will acquire permanent easement ROW in Knox County for the existing KU Park-Bimble-London 69kV circuits. The project will ensure the Company maintains its needed access rights to construct, maintain, and operate these transmission lines and prevent the unnecessary relocation of existing transmission facilities. The current lease ROW agreements begin to expire in 2022 at which time the Company will not have secure property access rights to these transmission facilities. The project will secure the needed ROW widths that currently exist in the expiring leases and not seek to expand the current ROW footprint. This project's activities are limited to surveying, landowner negotiation, and easement acquisition. There is no construction activity associated with this project.

This project was submitted for the approval of preliminary services in the amount of $110k for title research and land evaluation services in May of 2020.

Why is the project needed? What if we do nothing?

As a result of an encroachment investigation completed in 2019 on a near-by transmission line, it was discovered that the landowner's encroachment was not on a presumed permanent easement but a 99-year ROW lease. This finding resulted in further research of all the transmission lines originating from the Pineville transmission station (KU Park). Portions of the KU Park-Bimble-London lines were determined to be covered under separate 99-year leases for access and use rights. At various times in the 1920's, 1963 and 1974 permanent easements were secured for portions of these circuits. The current lease agreements, which cover 47 parcels with 43 different landowners over 3.25 line miles, will begin to expire in Q3 2022. At that time the

Company will not have a secured legal claim to access its facilities for maintenance, repair, or construction within the current leased ROW. If the Company does not secure the appropriate access to its facilities, the current landowners could require the Company to remove its facilities. Prescriptive rights are not applicable due to the current active 99-year term of the agreements.

At this time no additional transmission lines originating from the Pineville area or extending north to the E.W. Brown plant have been determined to possess 99-year leases.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	61	464	222	-	746
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	61	464	222	-	746
4. Capital Investment 2021 BP	99	1,020	453	-	1,573
5. Cost of Removal 2021 BP	-	-	-	-	-
6. Total Capital and Removal 2021 BP (4+5)	99	1,020	453	-	1,573
7. Capital Investment variance to BP (4-1)	39	556	232	-	826
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	39	556	232	-	826

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks

Acquisition costs could be higher than the estimates provided in this proposal. Should attempts to negotiate agreements with current property owners be exhausted, condemnation could be executed, resulting in acquisition delays. An estimate of $4,500 per acre was utilized for easement cost estimates based upon the property valuation assessment completed as part of the Pineville – Rock Branch ROW project. Additionally, a 5% assumption was utilized to calculate the number of potential condemnation cases and assumes a standard condemnation expense. The actual figures could vary substantially if 3rd party legal firms become engaged in the landowner negotiations.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 1,116
   Secure the permanent easement ROW for the KU Park-Bimble-London 69kV circuits. This approach will ensure the Company possesses the legal rights to continue to operate and maintain these assets to serve its customers.

2. Alternative #1: NPVRR: ($000s) N/A
   The Do Nothing alternative would result in expired leases, resulting in the Company having to wait fifteen (15) years to make a "prescriptive rights" claim for legal access to the current landowner's property where the circuit exists. This approach carries an

unquantifiable cost because the cost of remediation to a potential future issue is unknown. Additionally, area local officials and landowners are aware of this issue and there is local knowledge of this project with the initiation of the Pineville – Rocky Branch project. This level of uncertainty and risk is not a recommended alternative from customer experience, regulatory, or legal perspective.

3. Alternative #2: NPVRR: ($000s) 16,587
   The identification of an alternate route and construction of a new 69kV line is not a viable option from a cost or regulatory perspective. This alternative would still require land acquisition and not result in a less expensive option from that perspective either.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the KU Park-Bimble Right of Way project for $746k to support future line maintenance and construction along the KU Park-Bimble-London 69kV circuits.

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: November 20, 2020

Project Name: Millersburg-Murphysville Conductor Replacement

Total Capital Expenditures: $27,498k (Including $2,500k of contingency and $977k of internal labor)

Total O&M: $ 0 k

Project Number(s): LI-162670 – Transmission Lines Phase I
LI-162671 – Transmission Lines Phase II

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: David Todd/Adam Smith

Brief Description of Project

The proposed project is to replace 25.2 miles of overhead transmission line conductor that is over 90+ years old and beyond its expected useful life. Kentucky Utility Sardis substation serves over 517 customers with 2.08 MVA of load. This project will improve reliability, maintain system integrity, and reduce the risk of failures and unplanned transmission interruptions to the Millersburg and Murphysville 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 lives was included as part of the Transmission System Improvement Plan to replace aging infrastructure.

Transmission Lines plans to replace the 25.2 miles of 3/0 aluminum conductor steel reinforced (ACSR) conductor in the Millersburg-Murphysville EKPC 69kV line in two phases. The existing conductor will be replaced with 397 ACSR 26/7, and an optical ground wire (OPGW) will be installed. In addition, one hundred seventy-eight (178) wood structures will be replaced with one hundred sixty-seven (167) new steel structures. Structure spotting considerations resulted in the elimination of eleven (11) existing wood structures. Eight (8) existing steel structures will remain. Distribution Operations will provide the layout work and transferring of underbuilt distribution conductors where needed.

This project will be completed in two phases:
Phase I – Murphysville-Sardis – 4.21 Miles
Phase II – Sardis-Millersburg – 20.98 Miles

Project Milestones – Transmission Lines	
April 2019-August 2020	Engineering and Design
September 2020	Space reserved for steel pole production with manufacturer
December 2020	Steel Poles Ordered
March 2021	Steel Poles Received
March 2021	Phase I Line Construction Begins
December 2021	Phase I Line Construction Completed
January 2022	Phase II Line Construction Begins
December 2023	Phase II Line Construction Completed

Why is the project needed? What if we do nothing

The existing 25.19 miles of 69kV line between Millersburg and Murphysville substations contains the original 3/0 ACSR conductor installed in 1928. Non-destructive testing was performed on the conductor in 2019 and revealed that it was in marginal to poor condition. Testing showed that the conductor had less than 85% of its original rated breaking strength remaining, signs of heavy surface rust, and medium pitting. This circuit has experienced a total of 39 interruptions since 2012. The initiating events of these interruptions consist of lightning strikes, weather, and equipment component failures.

In July of 2019, the transmission project was opened for $1,216k under project number 139958 to support preliminary engineering, project scope development, and site clearing. Preliminary engineering included design development, structure design and selection, and development of the construction plan. Geotechnical services have begun in order to provide geotechnical reports to support drilled shaft foundation design. In addition, easement information has been provided for the entire corridor. The transmission line design was provided to all departments involved for comment and review.

The structure design consists of one hundred eight (108) standard steel H-frame structures, thirty-four (34) custom steel H-frame structures, five (5) self-supporting steel single pole dead end structures, one (1) self-supporting custom steel switch structures, fourteen (14) steel three pole dead end structures, four (4) steel single pole dead end structures, and one (1) steel Z-frame structure.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	808	226	11,461	14,038	26,533
2. Cost of Removal Proposed	19	-	161	785	964
3. Total Capital and Removal Proposed (1+2)	827	226	11,622	14,823	27,498
4. Capital Investment 2021 BP	808	948	11,460	12,039	25,255
5. Cost of Removal 2021 BP	19	13	371	3,685	4,087
6. Total Capital and Removal 2021 BP (4+5)	827	961	11,830	15,724	29,342
7. Capital Investment variance to BP (4-1)	-	722	(2)	(1,999)	(1,278)
8. Cost of Removal variance to BP (5-2)	-	13	210	2,900	3,123
9. Total Capital and Removal variance to BP (6-3)	-	735	208	901	1,844

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project is included in the 2021 Business Plan (BP) under project 139958.

Risks

- A communication plan will be developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the communities and businesses along the route.
- There are no known environmental risks regarding air, water, lead, asbestos, etc., associated with this project.
- All highway and railroad crossing permits will be granted by the Kentucky Transportation Cabinet (KYTC), and associated railroads.
- An outage will be obtained so no customers will be out of service for the duration of the work.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 30,387
   The recommendation is to replace 25.19 miles containing 3/0 conductor with new 397 ACSR 26/7 conductor and install new OPGW. In addition, one hundred seventy-eight (178) wood structures will be replaced with one hundred sixty seven (167) new steel structures.

2. Alternative #1: 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: NPVRR: ($000s) 59,477
The Next Best Alternative would be to construct a new 27 mile transmission line which would parallel the existing line. Constructing a new route would require the purchase 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.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Millersburg-Murphysville Conductor Replacement project for $27,498k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

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: November 20, 2020

Project Name: Transmission Blankets - 2021

Total Expenditures: $4,700k

Project Number(s): Various

Business Unit/Line of Business: Transmission

Prepared/Presented By: Kyle Burns

Brief Description of Project

Transmission uses Blankets to budget and account for annual routine unidentified work. Capital Blankets are comprised of a multitude of individual small projects necessitating capital investment. Transmission subdivides its Blankets into distinct categories for lines and substations. These categories align with primary work drivers for Transmission.
Annual blanket budgets are based on historical trends and operational input from the managers within Transmission. Blanket spend is monitored and forecast on a monthly basis based on known work identified throughout the year.

Transmission is requesting approval for $4,700k in blankets for 2021, a $613k increase from the 2020 Business Plan for 2021. This increase is due primarily to additional pole replacement funding in the blanket to help address the pole backlog, however this remains only 1.3% of the funding in the 2021 BP to address the pole backlog with most of the funding in specific pole replacement projects.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the 2021 Transmission blanket projects for $4,700k to help manage the Transmission work budgeted for 2021.

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	

[redacted]

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Transmission
2021 BP - Transmission Capital Blankets
$000s

[redacted]

Investment Proposal for Investment Committee Meeting on: November 20, 2020

Project Name: Walker Proactive Control House Replacement

Total Capital Expenditures: $3,323k (Including $302k of contingency including $89k of internal labor)
Total O&M: $ 0k

Project Number(s): SU-000325

Business Unit/Line of Business: Transmission Substations

Prepared/Presented By: Keith Yocum

Brief Description of Project

A Transmission System Improvement Plan (TSIP) 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. As part of the TSIP, this project is a combination of several system integrity programs to address assets in need of replacement at Walker substation. Walker has assets operating at 161kV and 69kV that have been in service for longer than 50 years. The programs and project specific information are as follows:

- Improve Protection and Control Systems – A new control building will be installed for the Transmission assets, along with the related protection and control system components (relay panels, batteries, etc.). The existing electromechanical type control and protective relay systems will be replaced with modern, microprocessor-based systems that will ensure reliable operation as well as provide added data for analysis of system events. The lines exiting this station have had 87 Unknown events since 2012 with the Princeton to Walker double-circuit line having the 1st and 3rd worst Unknown rate on the Transmission system.
- Install Digital Fault Recorder (DFR) for improved system analysis and assistance with event cause coding. DFRs are also remotely accessible and can provide timely information to operating personnel as to the potential cause and location of the fault. Additionally, due to uncommon substation configuration, an additional relay panel will be installed at the nearby Earlington North Substation to improve protection of the 161kV line connecting the two stations. Currently, the 161/69kV transformer at Walker has no high-side breaker and its differential extends to Earlington North.
- Replace Substation Breaker – One (1) 69kV oil-filled circuit breaker will be removed and replaced with a modern SF6 insulated breaker. The modern breakers are reliable and require less maintenance over time than the legacy oil type circuit breakers. Elimination of the oil circuit breakers also reduces the risk of oil contamination due to failure or accidental release.
- Replace Substation Disconnect Switches – Two (2) 161kV 3-phase high voltage disconnect switches will be replaced. The switches targeted for replacement are at an age

where failure is common, often during operation. Additionally, one (1) 69kV high-side Potential Transformer (PT) fused disconnect will be removed. This equipment is a common point of failure, resulting in an increased risk of bus outages.

- Replace Substation Line Arresters – Four (4) 69kV sets and one (1) 161kV set of line surge arresters will be replaced. Surge arrestors are being replaced to provide open breaker protection due to lightning strikes.
- Replace Substation Insulators – Six (6) 3-phase cap and pin insulators will be replaced with station post type insulators. The cap and pin type insulators have a known history of failure due to radial cracks in the porcelain.

[redacted]

Why is the project needed? What if we do nothing?

The project is needed to modernize this substation and ensure reliable operation. The existing equipment and systems are 50+ years old, are outdated and have reached their end of life. As described in the TSIP: "System integrity and modernization projects and programs are designed to replace a comprehensive slate of poor performing, obsolete, and end-of-life assets. These programs will reduce the aggregate age of the inventory and ensure that critical assets remain serviceable to support the system. Programs are designed to remove and replace problem assets prior to failure through systematic replacement. Detailed inspections will serve as the central driver for logical and timely asset replacements. Replacement priorities will be determined through assessment of a number of conditional factors in addition to age and, when possible, replacement priorities will be determined by testing and inspections."

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	387	1,248	1,623	-	3,258
2. Cost of Removal Proposed	-	-	66	-	66
3. Total Capital and Removal Proposed (1+2)	387	1,248	1,688	-	3,323
4. Capital Investment 2020 BP	172	851	2,121	-	3,144
5. Cost of Removal 2020 BP	-	-	52	-	52
6. Total Capital and Removal 2020 BP (4+5)	172	851	2,173	-	3,196
7. Capital Investment variance to BP (4-1)	(215)	(397)	498	-	(114)
8. Cost of Removal variance to BP (5-2)	-	-	(14)	-	(14)
9. Total Capital and Removal variance to BP (6-3)	(215)	(397)	485	-	(127)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2020 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The unfunded capital in 2020 and 2021 will be funded through the reduction of other Transmission projects and coordinated through the Corporate RAC process.

Risks

- Increased Customer Outages: Aged protection equipment that has failed in place can result in remote clearing of the fault by other equipment on the system and thus result in larger impacts to customer reliability by producing larger outage areas on the system. Failure of breakers, insulators, and other equipment targeted in this project can also require remote clearing of the fault.
- Misoperations: System misoperation rate is correlated with relay age and model. Proactive replacements are prioritized based on installed systems and statistics associated with these factors. The LKE transmission system is seeing a reduction of misoperations since the start of proactive relay replacements. General Electric GCX electromechanical relays are statistically the most prone for misoperations. This project will remove three (3) 69kV line panels currently utilizing GCX relays.
- Expensive Repairs: Failure of this aging equipment can result in incremental damage to transformers on the system and other equipment. Proactive replacement of this equipment will minimize the potential of this incremental collateral damage.
- Environmental Impacts: As represented in the TSIP, failed equipment, such as transformers, can result in large financial impacts due to environmental cleanup costs associated with oil-filled equipment failing violently.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 3,540

2. Alternative #1: NPVRR: ($000s) 3,627
   The alternative consists of performing the recommended scope of work over a period of five years. Performing all the work at once is preferred because it reduces engineering and construction labor costs due to efficiencies gained in performing some functions once instead multiple times. Additionally, delaying the work leaves LKE open to failure of the equipment which could result in unnecessary outages, additional damage/stress on transmission equipment, and decreased system reliability.

3. Alternative #2: Do Nothing NPVRR: ($000s) N/A
   This is not a viable alternative. Oil circuit breakers and other equipment of this vintage will eventually fail with a high likelihood of that happening soon. The system is experiencing occasional, unpredictable failures of the pilot wire line relaying and cap and pin insulators of the types proposed to be replaced and the same will eventually happen here if the equipment is not replaced.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the PCH Walker project for $3,323k to enhance the reliability of the 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	

Appendix

[redacted]

Exhibit B: Walker Substation Overview

[redacted]

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[redacted]

Exhibit D: Major Replaced Equipment Age

Equipment	**Install Date**
Control House	1956
Oil Circuit Breaker 698	1966

Investment Proposal for Investment Committee Meeting on: December 18, 2020

Project Name: Clifty Creek 345kV Power Circuit Breaker Replacement

Total Capital Expenditures: $2,253k (Including $0k of contingency and $20k of internal labor)
Total O&M: $ 0k

Project Number(s): 152224

Business Unit/Line of Business: Transmission Substations

Prepared/Presented By: Keith Yocum

Brief Description of Project

This project includes the replacement of (2) 345kV power circuit breakers within the Clifty Creek Substation which is owned and operated by Indiana-Kentucky Electric Corporation (IKEC), a subsidiary of OVEC. The project was originally approved for $1,306k in August 2018 and has been delayed and is now being revised to correspond with a recently updated and signed interconnection agreement between LKE and [redacted]. Per the interconnect agreement, the assets to be replaced are physically located and maintained in the state of Indiana by Indiana-Kentucky Electric Corporation (IKEC)-Clifty Creek personnel adding complexity to this project. Due to this circumstance, engineering and material costs escalated to conform with American Electric Power (AEP)/Ohio Valley Electric Corporation (OVEC) standards. Revised estimates are higher due to the following:

- The 2019 construction phase of this project was originally planned to coincide with the Clifty Creek - Trimble Co 345kV line reactor installation while employing [redacted] construction forces at a lower installed cost due to their familiarity with all tasks and risks involved in completion of this project. [redacted] elected to cease this construction path due to business reasons.
- The 2021 construction estimates, to perform this work, are exceedingly higher based on the selected LKE construction business partner's unfamiliarity with the location and the assumed risks. This location is also a designated CIP location and will require [redacted] supervision while on-site.
- This original recommendation remains as the best alternative for completing this work due to the cost increases in this estimate would also be incurred in the alternative estimate.

Why is the project needed? What if we do nothing?

The (2) 345kV breakers that are being targeted for replacement are part of a program to replace aging and obsolete transmission assets. The replacement of these breakers will reduce the risk of a potential failure and improve reliability of the Transmission system. The two (2) aging 345kV breakers are air blast type circuit breaker vintage 1975. In addition to age, these breakers have a history of maintenance issues and spare parts are limited. Asset Management has identified these two breakers as overdue for replacement. The replacement of these breakers will reduce risk of a potential failure and improve the reliability of the Transmission system.

The two (2) 345kV breakers are LG&E assets, however they are located in the Clifty Creek substation which is owned and operated by Indiana-Kentucky Electric Corporation (IKEC). IKEC is responsible for operation of the DL and DL2 circuit breakers, therefore it is recommended that IKEC standard Siemens SPS2-362-63 SF6 type circuit breakers be purchased for this project.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	Pre-2020	2020	2021	Post 2021	Total
1. Capital Investment Proposed	1,130	28	1,058	-	2,216
2. Cost of Removal Proposed	-	-	36	-	36
3. Total Capital and Removal Proposed (1+2)	1,130	28	1,095	-	2,253
4. Capital Investment 2021 BP	1,130	28	1,095	-	2,253
5. Cost of Removal 2021 BP	-	-	-	-	-
6. Total Capital and Removal 2021 BP (4+5)	1,130	28	1,095	-	2,253
7. Capital Investment variance to BP (4-1)	0	-	36	-	36
8. Cost of Removal variance to BP (5-2)	-	-	(36)	-	(36)
9. Total Capital and Removal variance to BP (6-3)	0	-	-	-	0

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Risks

Completing the project involves risk related to high voltage substation construction work. Delaying this project exposes our system to the continuing risk of impacts from other potential transmission failures.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 2,349
   It is recommended that the breakers be replaced to reduce the potential risk to the Transmission system.
2. Alternative #1: NPVRR: ($000s) 2,538
   The next best alternative is to replace all of the identified equipment gradually over a period of several years instead of completing the numerous replacements in one time period. Intermittently completing the required work is not recommended as inherent risks will remain for extended durations. Additionally, this alternative will result in a loss of efficiency that comes with packaging similar work at one location.
3. Alternative #2: 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 System Improvement Plan.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Clifty Creek 345kV Power Circuit Breaker Replacement project for $2,253k to enhance the reliability of the 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: December 18, 2020

Project Name: Elihu-Wofford Conductor Replacement

Total Capital Expenditures: $37,907k (Including $3,446k of contingency and $1,471k of internal labor)

Total O&M: $ 0 k

Project Number(s): LI-160440 – Transmission Lines Phase I
LI-160441 – Transmission Lines Phase II
LI-160442 – Transmission Lines Phase III

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: David Todd/Adam Smith

Brief Description of Project

Electric Transmission requests approval to replace 32.9 miles of overhead transmission line conductor that is over 85 years old and beyond its expected useful life. Performance of this line has diminished with 29 interruptions since 2012, and major conductor failures occurring in 2012 and 2013. Non-destructive testing was performed on this conductor and revealed that it was in marginal to poor condition. In addition, this project will also replace one hundred forty-nine (149) defective wood structures. Out of approximately 470 transmission circuits, this line ranks in the top 15 overall in terms of event counts which are defined as any circuit interruption. This line serves two East Kentucky Power Cooperative (EKPC) substations, Mount Victory substation which serves 674 customers with 2.61 MVA of load and Cumberland Falls substation serving 1,974 customers with 13.88 MVA of load. This project will improve reliability, maintain network integrity and functionality, and reduce the risk of failures and unplanned transmission interruptions to the Somerset, Mt. Victory, and Williamsburg 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 lives was included as part of the Transmission System Improvement Plan to replace aging infrastructure.

Transmission Lines plans to replace the 32.9 miles of 3/0 aluminum conductor steel reinforced (ACSR) conductor in the Elihu-Wofford 69kV line in three phases. The existing conductor will be replaced with 397 ACSR 26/7, and a new optical ground wire (OPGW) will be installed. In addition, two hundred eighty-one (281) wood structures will be replaced with two hundred thirty-six (236) new steel structures. Structure spotting considerations resulted in the elimination of forty-five (45) existing wood structures. The work will be completed in three phases:

Phase I – Wofford-Cumberland Falls – 8.3 Miles
Phase II – Elihu-Mt. Victory – 10.9 Miles
Phase III – Cumberland Falls – Mt. Victory – 13.7 Miles

Project Milestones – Transmission Lines	
April 2018-August 2020	Engineering and Design
September 2020	Space reserved for steel pole production with manufacturer
December 2020	Steel Poles Ordered
January 2021	Steel Poles Received
April 2021	Phase I Line Construction Begins
December 2021	Phase I Line Construction Completed
January 2022	Phase II Line Construction Begins
December 2022	Phase II Line Construction Completed
January 2023	Phase III Line Construction Begins
March 2024	Phase III Line Construction Completed

Why is the project needed? What if we do nothing?

The existing 32.9 miles of 69kV line between the Elihu and Wofford substations contains the original 3/0 ACSR conductor installed in 1935. Non-destructive testing was performed on the conductor in 2019 and revealed that it was in marginal to poor condition. Testing showed that the conductor had less than 85% of its original rated breaking strength remaining, signs of heavy surface rust, and medium pitting. In addition, a routine inspection was completed in 2019, and one hundred forty-nine (149) structures were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line. This circuit has experienced a total of 29 interruptions since 2012. The initiating events of these interruptions consist of lightning strikes, conductor failures, trees falling into the line, and several unknown events, with the most recent event occurring in 2020.

In April of 2018, the transmission project was opened for $725k to support preliminary engineering and project scope development. Preliminary engineering included design development, structure design and selection, and development of the construction plan. This project was submitted for revision in July of 2019 for $1,958k to allow vegetation clearing to proceed, providing access to the right-of-way for environmental assessments, geotechnical assessments, surveying, and ultimately the future line construction. In addition, easement information has been provided for the entire corridor. The transmission line design was provided to all departments involved for comment and review.

The structure design consists of one hundred seventy-nine (179) standard steel H-frame structures, four (4) steel three pole running corners, sixteen (16) steel guyed dead end structures, thirty-five (35) custom steel H-frame structures, and two (2) custom steel self-supporting switch structures.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	777	900	7,908	26,458	36,043
2. Cost of Removal Proposed	-	-	171	1,693	1,864
3. Total Capital and Removal Proposed (1+2)	777	900	8,079	28,151	37,907
4. Capital Investment 2021 BP	777	900	7,800	24,333	33,810
5. Cost of Removal 2021 BP	-	-	406	4,956	5,362
6. Total Capital and Removal 2021 BP (4+5)	777	900	8,206	29,289	39,172
7. Capital Investment variance to BP (4-1)	-	-	(108)	(2,125)	(2,233)
8. Cost of Removal variance to BP (5-2)	-	-	234	3,264	3,498
9. Total Capital and Removal variance to BP (6-3)	-	-	126	1,139	1,265

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

Risks

- A communication plan will be developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the communities and businesses along the route.
- There are no known environmental risks regarding air, water, lead, asbestos, etc., associated with this project.
- All interstate, highway, and railroad crossing permits will be granted by the Kentucky Transportation Cabinet (KYTC), and associated railroads.
- An outage will be obtained so no customers will be out of service for the duration of the work.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 39,772
   The recommendation is to replace 32.9 miles containing 3/0 conductor with new 397 ACSR 26/7 conductor and install new OPGW. In addition, two hundred eighty-one (281) wood structures will be replaced with two hundred thirty-six (236) 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: NPVRR: ($000s) 75,795
   The Next Best Alternative would be to construct a new 35 mile transmission line which would parallel the existing line. Constructing a new route would require the purchase 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.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Elihu-Wofford Conductor Replacement project for $37,907k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

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: December 18, 2020

Project Name: Mount Washington-Fairmount Pole Replacement

Total Capital Expenditures: $5,897k (Including $536k of contingency and $123k of internal labor)

Total O&M: $ 0 k

Project Number(s): LI-161140

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: John Doll/Adam Smith

Brief Description of Project

The proposed project is to replace one hundred thirty-seven (137) existing wood structures on the Mount Washington EKPC-Watterson-Fairmount 69kV line with steel during a scheduled outage. The scope of work includes the replacement of one hundred eighteen (118) structures identified through a 2019 inspection. The replacement of nineteen (19) adjacent structures is required to accommodate the height of the new structures.

Project Milestones	
October-November 2020	Engineering and Design
November 2020	Space reserved for steel pole production with manufacturer
January 2021	Steel Poles Ordered
March 2021	Steel Poles Received
April 2021	Line Construction Begins
March 2022	Line Construction Completed

Why is the project needed? What if we do nothing?

Above ground pole inspections are performed by the company at defined intervals in order to identify issues that may impact the integrity and reliability of the Transmission System. A routine inspection was completed in 2019, and one hundred eighteen (118) structures (approximately 30% on those inspected) were identified as priority poles and determined to need replacement in order to ensure the integrity and reliability of this line. Nineteen (19) adjacent structures will also be replaced in order to accommodate the height of the new structures.

The alternative of do nothing would require replacing poles upon failure which would result in a much higher long term replacement cost 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. This alternative would also have a negative impact on transmission network reliability. 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.

Of the structures being installed, there are one hundred twenty-six (126) steel single pole tangent structures, seven (7) steel single pole angle structures, three (3) steel single pole dead end structures, and one (1) steel three-pole dead end structure.

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	-	3,089	1,957	-	5,046
2. Cost of Removal Proposed	-	331	520	-	851
3. Total Capital and Removal Proposed (1+2)	-	3,420	2,477	-	5,897
4. Capital Investment 2021 BP	-	3,104	1,678		4,783
5. Cost of Removal 2021 BP	-	331	216		547
6. Total Capital and Removal 2021 BP (4+5)	-	3,435	1,894	-	5,329
7. Capital Investment variance to BP (4-1)	-	15	(278)	-	(264)
8. Cost of Removal variance to BP (5-2)	-	-	(304)	-	(304)
9. Total Capital and Removal variance to BP (6-3)	-	15	(582)	-	(568)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2021 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Subsequent to the 2021 BP planning, nineteen (19) structures were identified to need replacement in order to accommodate the height of the new structures. Incremental funding in 2022 will be funded by a reduction in other Transmission capital projects.

Risks

Without the proposed replacement of the priority poles on the Mount Washington-Fairmount 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.

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

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.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 7,470
   The recommendation is to replace one hundred thirty-seven (137) wood structures with new steel structures during a scheduled outage.

2. Alternative #1: Do Nothing NPVRR: ($000s) 10,904
   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 network reliability.

3. Alternative #2: Replace with Wood NPVRR: ($000s) 8,687
   The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) annually which is in line with market cost increases over the last 15 years.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Mount Washington-Fairmount Pole Replacement project for $5,897k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

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: December 18, 2020

Project Name: Substation IP Connectivity

Total Capital Expenditures: $2,147k (Including $159k of contingency and $32k of internal labor)

Total O&M: $ 712k

Project Number(s): SU-000383 IP Connectivity-KU Trans, SU-000497 IP Connectivity-LG&E Trans, SU-000498 IP Connectivity KU IT, and SU-000499 IP Connectivity LG&E IT

Business Unit/Line of Business: Transmission Substation

Prepared/Presented By: Syd Ulis/Brent Birchell

Brief Description of Project

Transmission Substations is proposing a technology development project to add Internet Protocol (IP) connectivity to six (6) electric substations (See Appendix A for the list of substations). This proposed project will compare two different technologies which will provide remote monitoring, access, and data acquisition to transmission substations and will enhance electronic safeguards necessary for IP connectivity. The information and intelligence obtained will be used to determine the long-term strategy towards establishing transmission substation IP connectivity in the normal course of business. The substations selected are classified as Low Critical Infrastructure Protection (CIP) Impact. The Low category only requires for inbound and outbound communications to the system to be monitored and controlled. Technologies proven during this technology development can be applied towards Medium CIP stations as IP connectivity is expanded. The lessons learned by evaluating multiple configurations across the six (6) substations will be incorporated into future engineering design practices. The security focus of this project will align with the company's cyber security strategy for Industrial Control System/Operational Technology (ICS-OT).

Over time, the nature of the equipment in electric substations has changed from electro-mechanical devices which have no data storage capabilities and no vulnerabilities other than physical attack, to current modern day devices which can store critical data and report that data back to central locations for analysis. These modern Intelligent Electronic Devices (IEDs) are electronic and have cyber security vulnerabilities associated with them because they utilize operating systems and firmware to control and perform the functions for which they are designed. Consequently, these Operational Technologies (OT) have many of the characteristics of Information Technologies (IT) such as passwords, configuration files, user accounts, data storage, and logs and require security efforts for critical infrastructure such as access monitoring and patching. Due to the characteristics and criticality of these devices to the transmission system, access must be protected both physically and electronically.

Electric substations that have an existing and established LG&E-KU telecommunication network will be the targeted sites for the initial roll out of IP connectivity in order to minimize network construction and compliance costs. Operationally, this allows for LG&E-KU Transmission to seek information and experience around the cost and benefits of IP connectivity at minimal practical cost. [redacted]

IP connectivity allows for Transmission to develop expertise in programs that offset O&M costs around security efforts such as locally changing passwords, retrieving logs, and gathering event data and configuration baselines. With IP connectivity, Transmission can automate maintenance activities such as password changes and configuration retrieval. Asset Management will use real time data to build and explore use cases that model trends of major equipment and proactively address trending issues prior to failure. Real time data will also be used by both the Planning and Reliability groups to select and prioritize projects that address problem areas within the Transmission System.

- Milestones:
    - December 2020 - Complete preliminary design work on six substations
    - January 2021 - Initialization of project resources
    - February 2021 - June 2021
        - Design and install substation equipment
        - Purchase network equipment
    - July 2021
        - Set up centralized system
        - Install network devices IED management system
        - Initialize maintenance agreements with software and equipment providers

Once this project is completed, baseline infrastructure will be in place for IP Connectivity to grow organically as projects are constructed.

<u>Why is the project needed? What if we do nothing?</u>
IP connectivity allows for remote access to a variety of substation IEDs. Remote access allows for real time troubleshooting and remote management of the devices that are critical to the reliability of the bulk electric system (BES). In addition to real time data access, the network infrastructure provides the capability to perform remote maintenance and investigations quickly and more efficiently due to eliminating drive time and reducing associated costs.

Substations are dependent on the physical security of the IEDs within the substation environment as there are currently no capabilities to deploy security best practices for electronic security. With IP connectivity, the substations can also be secured electronically. IP connectivity decreases the cost for security best practices for device monitoring through a Centralized Security Solution (CSS).

To obtain the full benefits of an IP network, the existing Supervisory Control and Data acquisition (SCADA) connection back to the Energy Mangement System (EMS) will utilize the same physical route of the remote access connection. These networks will be logically separated and secured.

Initiating an IP connectivity technology development project allows for LG&E-KU Transmission to begin to address security challenges associated with IEDs. The Transmission Substation Compliance/Automation group will develop expertise in administering secure remote access and

SCADA communications. This project will allow LG&E-KU to develop best practices for IP connecting all transmission substations outside of the test lab environment via a CSS.

- Future benefits from the project include:
    - Remote access which allows for real time troubleshooting/verification:
        - Rapid retrieval of settings which will cut down on engineering and technician travel time.
        - Automated retrieval of fault records, Sequence of Events (SOE), and oscillography.
        - Mass device configuration changes can be implemented faster and avoid recurrence of mis-operations.
        - Quicker outage restoration via fault location analysis and hence lower System Average Interruption Duration Index (SAIDI).
        - Phasor Measurement Units (PMU) deployment at LG&E-KU will improve understanding of the dynamic nature and performance of the grid, thus increasing model accuracy.
        - The ability to retrieve asset monitoring information for predictive maintenance.
    - Enhanced electronic security from the CSS:
        - Allow automatic authentication into IEDs and log device account access.
        - Provide secure remote engineering access, auto-login, command filtering.
        - Grant access to individual accounts, individual Microsoft® Active Directory accounts, or Active Directory groups.
        - Retrieve and store configuration files in a centralized database.
        - Maintain a history of configuration changes in an auditable database.
        - Remote password management.
        - Generate operation and compliance reports. All user operations are logged.
        - Publish logs to the Security Information and Event Management (SIEM) system for processing, monitoring, and storage.

Assumptions:

- If selected hardware solutions do not work at the intended locations, the hardware could be moved to other locations, but the labor cost to install at the initial location would be written-off to O&M, no O&M write-offs are assumed in this project.
- The engineering design will be assigned to one of the Transmission Engineering Procurement and Construction Management (EPCM) contractors and physical construction/commissioning will be done with internal labor.
- Sensitive work will be completed by Transmission Substation Compliance Automation. This will include:
    - CSS configuration
    - RTU configuration
    - RTU field support

Budget Comparison & Financial Summary

Financial Detail by Year - Capital ($000s)	2020	2021	2022	Post 2022	Total
1. Capital Investment Proposed	-	2,104	-	-	2,104
2. Cost of Removal Proposed	-	43	-	-	43
3. Total Capital and Removal Proposed (1+2)	-	2,147	-	-	2,147
4. Capital Investment 2021 BP	-	1,902	-		1,902
5. Cost of Removal 2021 BP	-	43	-	-	43
6. Total Capital and Removal 2021 BP (4+5)	-	1,945	-	-	1,945
7. Capital Investment variance to BP (4-1)	-	(202)	-	-	(202)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	(202)	-	-	(202)

Financial Detail by Year - O&M ($000s)	2020	2021	2022	Post 2022	Total
1. Project O&M Proposed	-	134	289	289	712
2. Project O&M 2021 BP	-	138	283	291	712
3. Total Project O&M variance to BP (2-1)	-	4	(6)	2	-

Incremental spend will be covered through other reductions within Transmission.

Risks

- Introduction of IP connectivity to the substation's control devices increases the threat vectors to the BES and non-BES systems. This risk is mitigated through implementation of planned security practices.
- Rapidly changing technology can increase equipment obsolescence and shorten equipment life cycles due to unsupported firmware.

Alternatives Considered

1. Recommendation: NPVRR: ($000s) 2,410
2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
   There are no other viable alternatives that would allow us to meet the strategic objectives and adhere to, or meet, the security and compliance requirements.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Substation IP Connectivity project for $2,147k to implement Internet Protocol (IP) connectivity to allow for remote management of substation devices to six (6) transmission substations that are critical to the reliability of the bulk electric system (BES).

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	

Appendix A. Substation List[1]

Owner	Sub Name
LGE	Blue Lick
LGE	Canal
LGE	Middletown 138
KU	West Cliff
KU	West Shelby
KU	Viley Road

[1] Taken from "Substation IP Cost (12).xlsx" located at:
https://projects.sp.lgeenergy.int/sites/SubsIPConnect/default.aspx

[redacted]