

**LOUISVILLE GAS AND ELECTRIC COMPANY**

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

**Case No. 2020-00350**

**Question No. 161**

**Responding Witness: Daniel K. Arbough**

- Q-161. Provide any internal investment proposals prepared for projects included in rate base or CWIP in the past two years.
- A-161. 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		<u>\$6,935k</u>
Total Increase Requested		<u>\$3,105k</u>

- 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
<b>Total</b>		<b>\$ 4,574</b>	<b>\$ 676</b>	<b>\$ 639</b>	<b>\$ 702</b>	<b>\$ 6,591</b>

- 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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>Pre-2019</b>	<b>2019</b>	<b>2020</b>	<b>Post 2020</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>Pre-2019</b>	<b>2019</b>	<b>2020</b>	<b>Post 2020</b>	<b>Total</b>
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.





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 1<sup>st</sup> floor, in addition to 2,516 sq. ft. on the 2<sup>nd</sup> 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 completion. Adding this station for approximately 55 technicians will improve the efficiencies for this necessary task each month.

### **Budget Comparison & Financial Summary**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>Post 2020</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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 1<sup>st</sup> floor and 2<sup>nd</sup> 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  
Chief Financial Officer

Date

\_\_\_\_\_  
Paul W. Thompson  
Chairman, CEO and President

Date

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, ██████████ restarted the dormant paper mill (formerly Mead/Westvaco/Verso) in Wickliffe, KY. The customer's current energy demand and annual projected revenue is ██████████ ██████████

██████████. 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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>Pre 2019</b>	<b>2019</b>	<b>2020</b>	<b>Post 2020</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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.



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~~ **Arbough** 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  
Chief Financial Officer

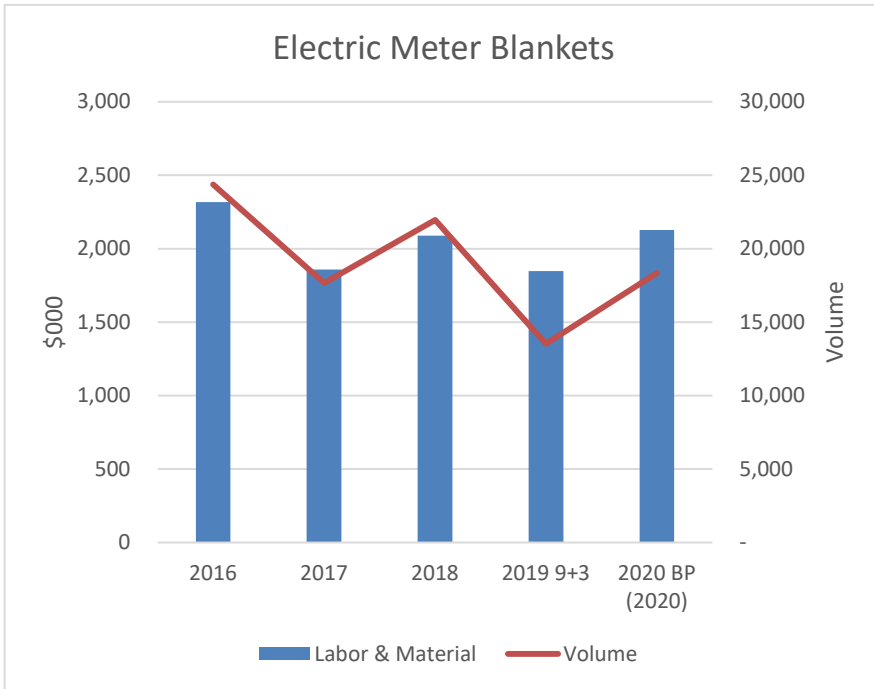
Date

\_\_\_\_\_  
Paul W. Thompson  
Chairman, CEO and President

Date







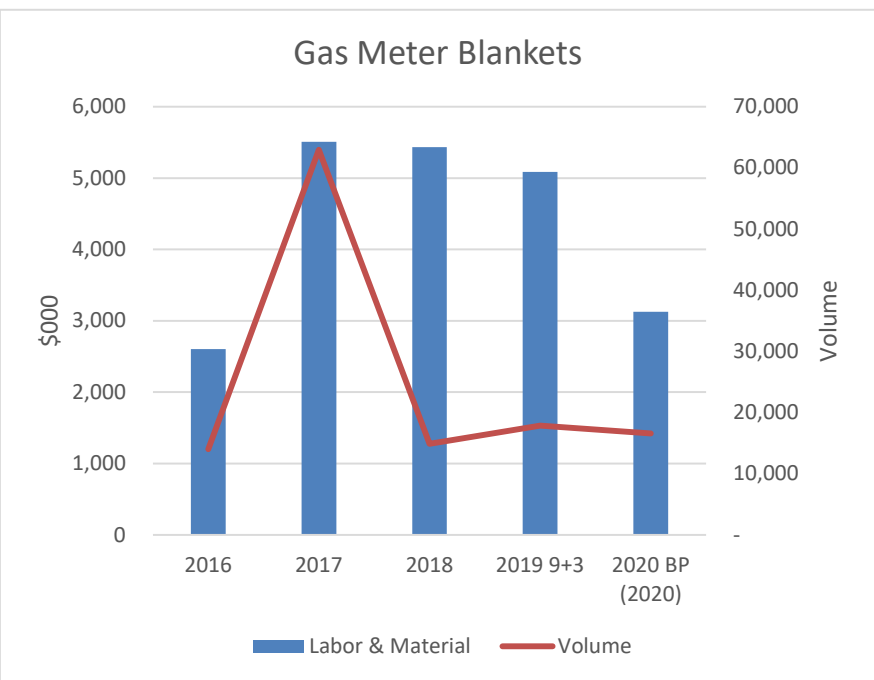
Meter/transformer volumes average 17.9k per year for normal operations.

2016: Failed meter lot purchased 7,000 meters.

2017: Reduced purchase meter plan by 3,400 meters due to planned 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 1<sup>st</sup> 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 1<sup>st</sup> 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 1<sup>st</sup> 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 1<sup>st</sup> floor shower and locker room facilities that were added in the 2015 Fitness Center upgrade).
  - A major flood event in 2018 caused by a 3<sup>rd</sup> 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 9<sup>th</sup> floor and the main Telecom Room on the 2<sup>nd</sup> 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 1<sup>st</sup> floor – both have been renovated.
  - The KU Credit Union on the 1<sup>st</sup> 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 9<sup>th</sup> 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 9<sup>th</sup> floor and the main Telecom Room on the 2<sup>nd</sup> Floor. In total, relocating these would cost approximately \$2.25-2.5M. The Telecom Room on the 2<sup>nd</sup> 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.





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.

### **Why is the project needed?**

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



**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.

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

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  
Chief Financial Officer

Date

\_\_\_\_\_  
Paul W. Thompson  
Chairman, CEO and President

Date



**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.



AGGREGATE CLINICAL PRICING SUMMARY	
<b>VENDOR</b>	
<b>COST CATEGORY</b>	
<i>START-UP COSTS:</i>	
<i>OPERATING COSTS ( [REDACTED] assumes 2 clinics. [REDACTED] only assumes 1 clinic.)</i>	
<i>VARIABLE COSTS</i>	
<b>GRAND TOTAL THREE (3) YEAR COST</b>	
<b>Footnotes:</b>	
<p>[REDACTED]</p> <p>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.</p>	
<p>[REDACTED]</p> <p>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 <b>does not</b> include pre-packaged medications for both locations.</p>	
<p>[REDACTED]</p> <p>[REDACTED] utilizes 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.  <b>Does not</b> include variable costs.</p>	



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

<b>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].</b>			
Sherrie Whitaker Sourcing Lead Date 4/6/2020   4:30 PM EDT	DocuSigned by: <i>Sherrie H. Whitaker</i> BE12FA6D7C624EC	Amanda Faulkner Health & Well-Being Program Lead Date 4/6/2020   5:04 PM EDT	DocuSigned by: <i>Amanda Faulkner</i> 76621C7D581E486
Eboni Edwards Supplier Diversity Manager Date 4/6/2020   4:36 PM EDT	DocuSigned by: <i>Eboni Edwards</i> 7E5902E5B22149B...	DeAnna Hall Manager – Health & Well-Being Date 4/6/2020   5:28 PM EDT	DocuSigned by: <i>DeAnna Hall</i> 4AFB06AD12BF42F...
Stephanie R. Pryor Supply Chain Manager Date 4/6/2020   4:31 PM EDT	DocuSigned by: <i>Stephanie R. Pryor</i> 71A4781FBF1B48A...	Gregory Meiman VP Human Resources Date 4/7/2020   11:17 AM PDT	DocuSigned by: <i>Gregory Meiman</i> 5096C881CE88402...
David L. Cosby, Jr. Director – Supply Chain Date 4/6/2020   4:58 PM EDT	DocuSigned by: <i>David L. Cosby Jr.</i> E2B4B4DA6E57447...		
Kent Blake CFO Date 4/7/2020   11:39 AM PDT	DocuSigned by: <i>Kent Blake</i> C059E669F1EB443...		

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**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.
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**EVALUATION AND SELECTION PROCESS:**

Recommended Contractors:	<p style="text-align: right;">D</p> <p>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.</p>
Benefits from Selection:	<p>1. <b><u>GENERAL SUMMARY:</u></b>  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.</p> <p>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.</p> <p><b>Attached documents: (1) Aggregate Pricing Summary and (2) Award Recommendation Forecast</b></p> <p>2. <b><u>PRICING SUMMARY:</u></b>  <b>Unit Rate Cost Extensions:</b>  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.</p>

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	<p><b>Aggregate Pricing Summary:</b> 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.</p> <p><b>Arbough</b></p> <p>3. <b><u>PROPOSED WORK PLAN:</u></b> <b>Implementation Strategies:</b> 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.</p> <p><b>Account Management:</b> 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.</p> <p><b>Vendor Presentations:</b> 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.</p> <p>4. <b><u>EXPERIENCE:</u></b> <b>Resumes:</b> 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.</p> <p><b>References:</b> Vendors have been in business for over 30 years at a minimum and have vast experience providing services requested by Company.</p> <p>5. <b><u>CONTRACT VALUATION:</u></b> 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.</p>
Contract Term:	April 1, 2019- March 31, 2022
Contract Value:	<p>Proposed Contract Value: [REDACTED]</p> <p>~20% Contingency: [REDACTED]</p> <p><b>Total Approval Amount:</b> [REDACTED]</p>

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**BIDDERS:**

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

**RECOMMENDATION/APPROVAL:**

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

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

CONFIDENTIAL INFORMATION REDACTED

COMPREHENSIVE HEALTH SERVICES AWARD RECOMMENDATION FORECASTS

VENDOR NAME	LAST PRICE PAID				JOINT AWARD RECOMMENDATION
ABSENCE MANAGEMENT SERVICES ANNUAL ESTIMATE	\$				
DRUG AND ALCOHOL TESTING ANNUAL ESTIMATE	\$				
STAFFING SERVICES ANNUAL ESTIMATE	\$				
<b>TOTAL ANNUAL ESTIMATE</b>	<b>\$</b>				
MONTHLY BURN RATE	\$				
Annual \$ Differential from LPP					
Annual % Differential from LPP					
<b>TOTAL 3 YEAR ESTIMATE</b>	<b>\$</b>				
3 Year \$ Differential from LPP					
3 Year % Differential from LPP					



Summary of Medical Savings Calculated by Mercer

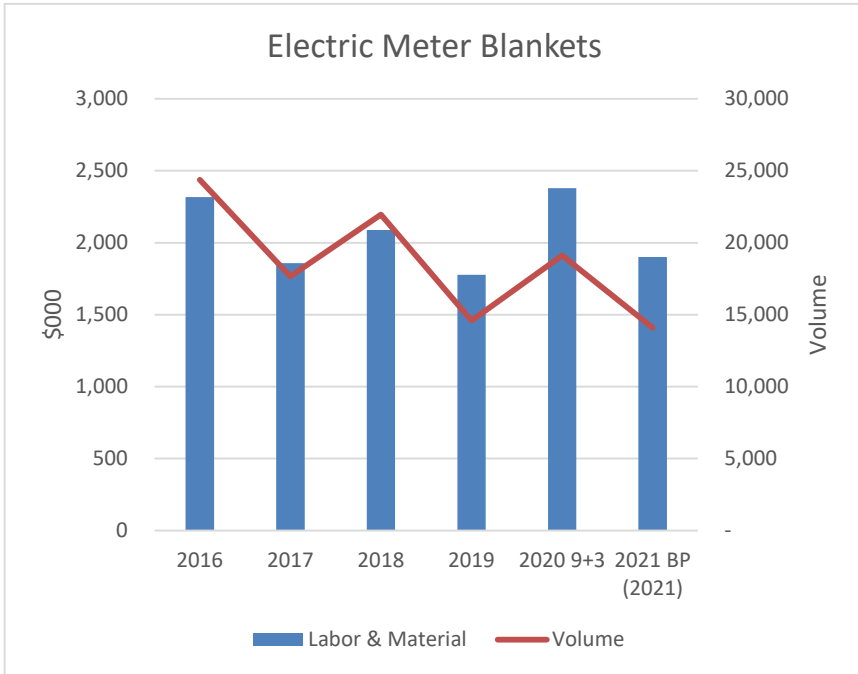
		2021	2022	2023	2024	2025
HR Budget O/S	Physical and Medical Exams (0335)	\$ 250,000	\$ 250,000	\$ 250,000	\$ 250,000	\$ 250,000
Burdens	Worker's Compensation	\$ 187,777	\$ 187,777	\$ 187,777	\$ 187,777	\$ 187,777
Burdens	LG&E and KU Active Medical Plan*	\$ 829,223	\$ 1,088,389	\$ 1,301,335	\$ 1,340,780	\$ 1,381,579
	Occupational Care* **	\$ 250,000	\$ 250,000	\$ 250,000	\$ 250,000	\$ 250,000
		<b>\$ 1,517,000</b>	<b>\$ 1,776,166</b>	<b>\$ 1,989,112</b>	<b>\$ 2,028,557</b>	<b>\$ 2,069,356</b>

*\*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.*







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

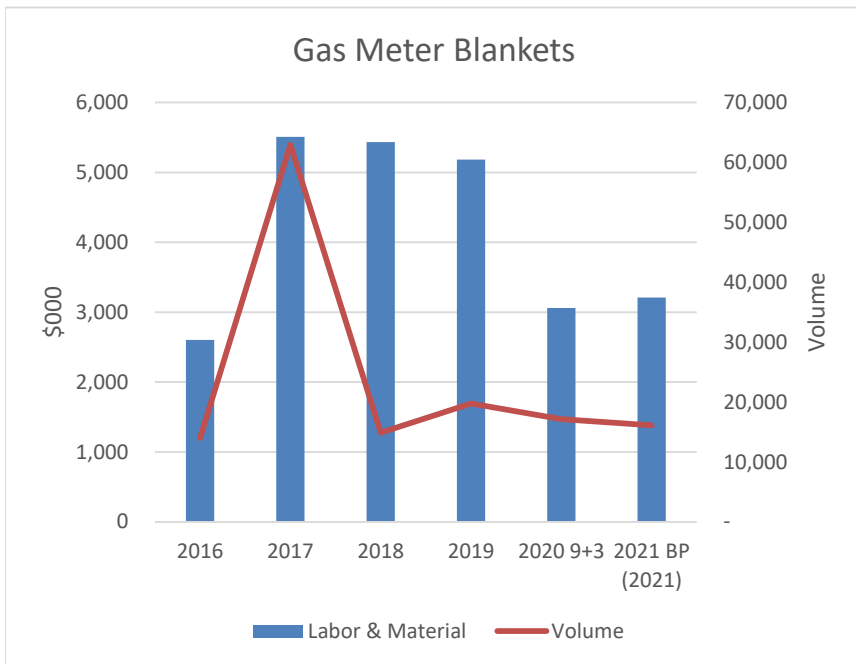
2016: Failed meter lot purchased 7,000 meters.

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	
<b>Electric Meters</b>	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.
<b>Gas Meters</b>	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.
<b>Grand Total</b>	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]  
[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.<sup>1</sup> 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.

<sup>1</sup> 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)**

██████████ 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 ██████████ 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 ██████████ 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 3<sup>rd</sup> 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**

<b>Contract Expenses (\$000s)</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>2024</b>	<b>2025</b>	<b>2026</b>	<b>Total</b>
<b>Amount projected based on contract award estimates</b>	██████	██████	██████	██████	██████	██████	██████
<b>Contingency Amount Projected</b>	██████	██████	██████	██████	██████	██████	██████
<b>Total contract authority estimates to requested at a later date</b>	██████	██████	██████	██████	██████	██████	██████

**Project Financial Summary**

<b>Financial Detail by Year – Capital (\$000s)</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>2024</b>	<b>2025</b>	<b>2026</b>	<b>Total</b>
<b>1. Project Capital Investment Proposed</b>	17,443	58,851	91,796	90,946	78,102	14,929	352,067
<b>2. Project Capital in 2021 BP</b>	16,843	57,010	88,637	87,628	75,052	11,398	336,568
<b>3. Total Capital variance to BP (2-1)<sup>2</sup></b>	(600)	(1,841)	(3,159)	(3,318)	(3,050)	(3,531)	(15,499)

<b>Financial Detail by Year – O&amp;M (\$000s)</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>2024</b>	<b>2025</b>	<b>2026</b>	<b>Total</b>
<b>1. Project O&amp;M Proposed</b>	966	7,344	11,365	9,827	8,698	1,602	39,802
<b>2. Project O&amp;M in 2021 BP</b>	966	7,344	11,365	9,827	8,698	1,602	39,802
<b>3. Total O&amp;M variance to BP (2-1)</b>	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.

<sup>2</sup> 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)**

<u>Alternative</u>	<u>Meter Reading</u>	<u>Field Services</u>	<u>EDO Integration</u>	<u>AMR Becomes Obsolete</u>		<u>AMR Remains Viable</u>		<u>AMR Obsolescence Risk (A less B)</u>
				<u>PVRR (A)</u>	<u>PVRR Delta to Status Quo</u>	<u>PVRR (B)</u>	<u>PVRR Delta to Status Quo</u>	
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.

\_\_\_\_\_ Date  
Kent W. Blake  
Chief Financial Officer

\_\_\_\_\_ Date  
Paul W. Thompson  
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<sup>2</sup> 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<sup>2</sup> 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 work and organizational needs of multiple organizations. Page 2 of 106  
Arbough

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. **Page 3 of 106**  
**Arbough**

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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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<sup>2</sup> 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 private conference rooms, and space for hotel offices and workstations. This recommendation will also include partial renovation of the existing 16k ft<sup>2</sup> 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.





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

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Arbough

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

Attachment 2 to Response to PSC-2 Question No. 161

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 Arbough application to specific locations. Page 10 of 106

	[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] [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.

██████ 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**

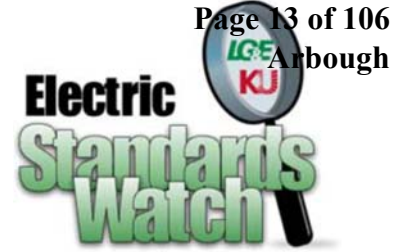
Following approval of the project, the FCI installation labor contract will be awarded to ██████████. The project timeline may be impacted if ██████████ is unable to execute on the UG FCI plan and meet the installation schedules.



Date: 7/7/2017

Item: Faulted Circuit Indicator for Underground Conductors

From: Jonathan Wilson



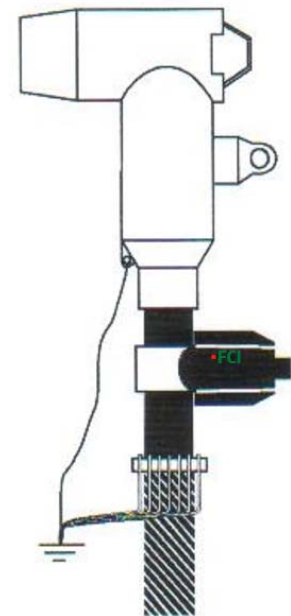
Faulted Circuit Indicators have been used for over fifty years on transmission and distribution circuits to quickly identify the location of faulted equipment.

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

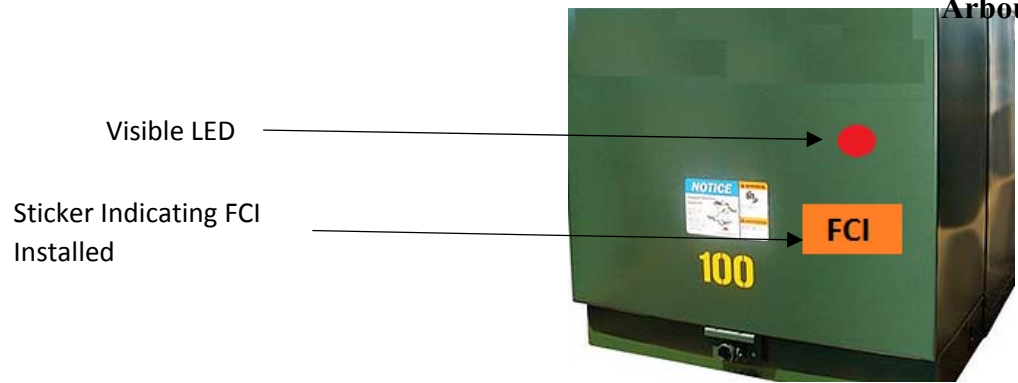


FCI mounted below Loadbreak Elbow

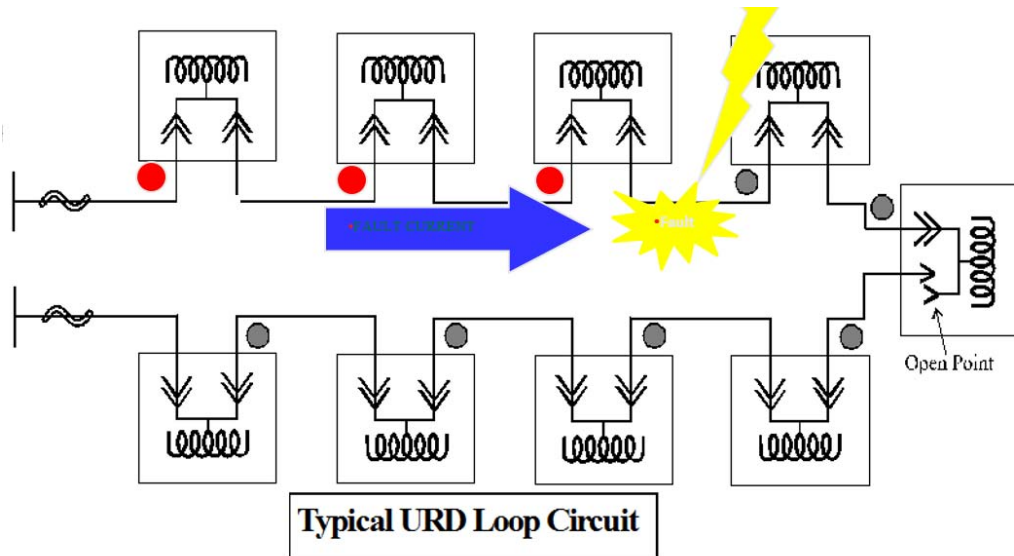
**Using the FCI to locate a fault:**

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.



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

**Attachment 2 to Response to PSC-2 Question No. 161**

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 12kV distribution 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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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.



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:

Transformer	Bus	Top Nameplate kVA Capacity	pF	2019		2020	
				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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currently operates at two locations in the industrial park a combined demand of nearly 10 MW. 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:

Transformer	Bus	Top Nameplate kVA Capacity	pF	2020		2021	
				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.





**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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>Pre-2019</b>	<b>2019</b>	<b>2020</b>	<b>Post 2020</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>Pre-2019</b>	<b>2019</b>	<b>2020</b>	<b>Post 2020</b>	<b>Total</b>
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.



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 11<sup>th</sup> and Broadway to 5<sup>th</sup> 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 the Arbough 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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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**

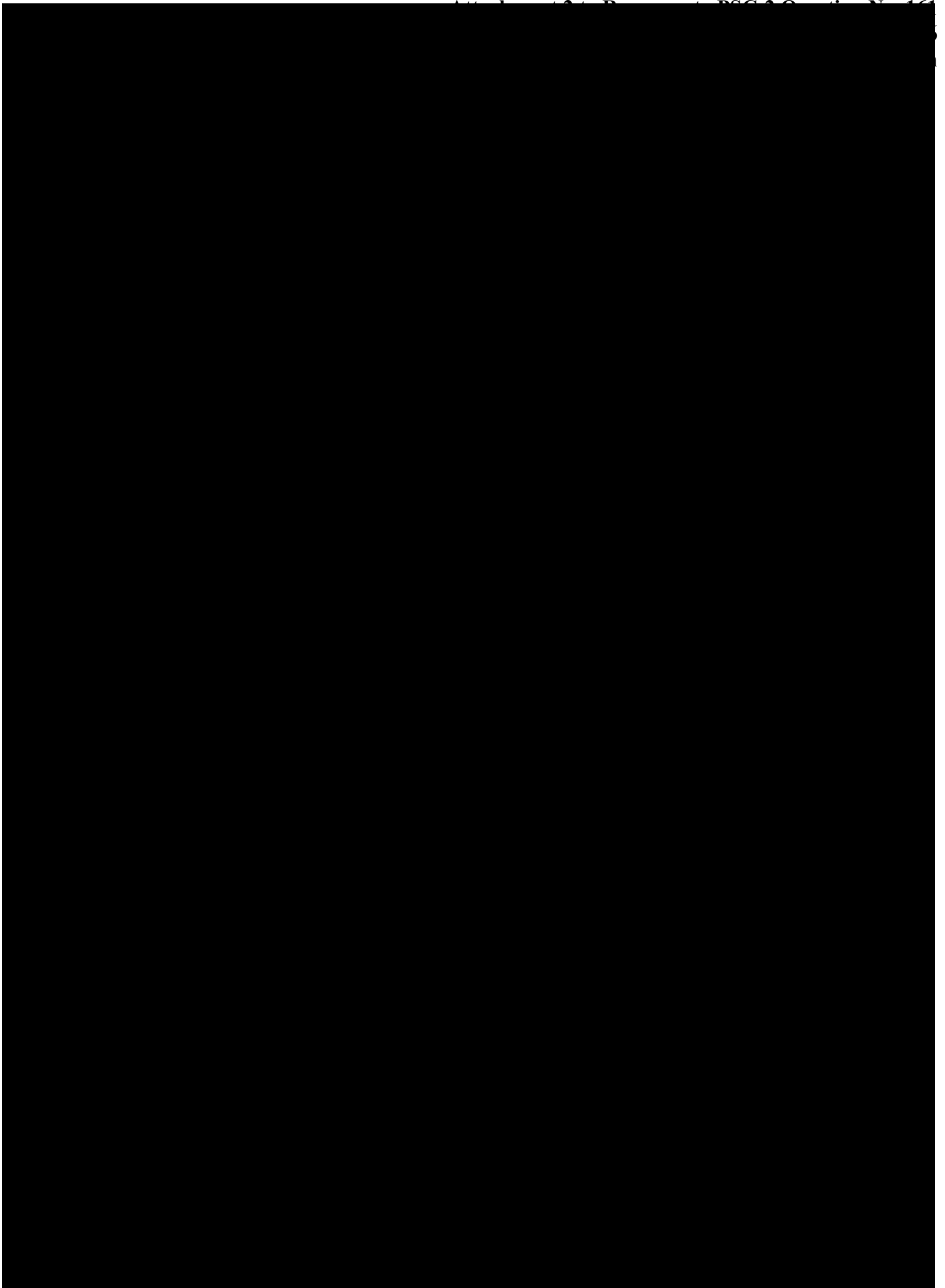
- Not completing this project continues the risk of catastrophic failure and prolonged outages inside the Magazine substation which serves portions of downtown Louisville.
- The cost of the of the project could escalate due to the complex nature of the engineering, design, and construction aspects of this project. Costs are based on similar completed work for other projects of similar scope and size.

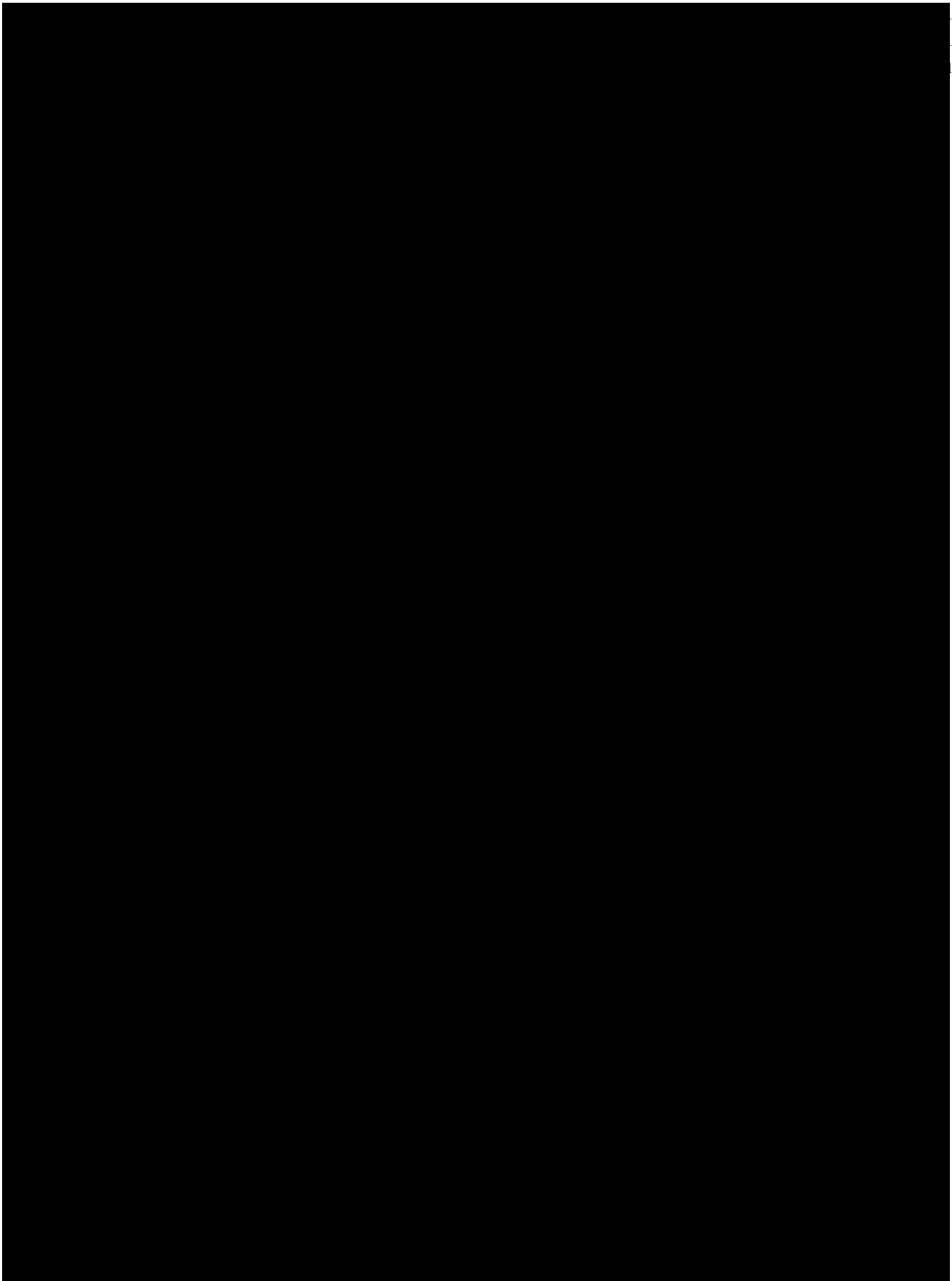
**Alternatives Considered**

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.











[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:**

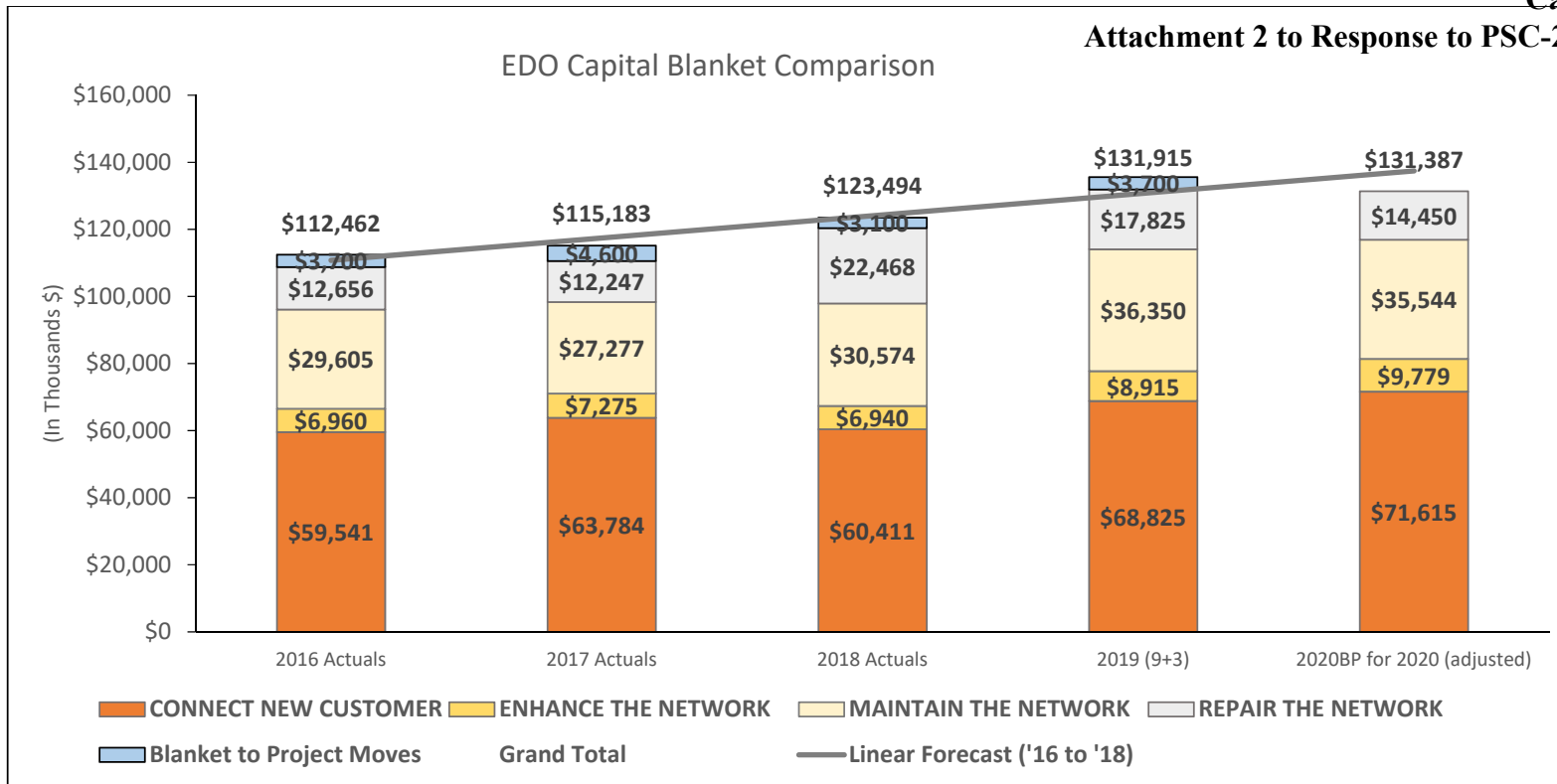
The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

\_\_\_\_\_  
Kent W. Blake  
Chief Financial Officer

\_\_\_\_\_  
Date

\_\_\_\_\_  
Paul W. Thompson  
Chairman, CEO and President

\_\_\_\_\_  
Date



- 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			vs. 2019 Forecast (9+3)			Variance - 2020 BP vs 2019 Forecast
		2019 BP for 2020	Variance Plan over Plan	% Chg	2019 9+3 Forecast	Variance to 2019 9+3	% Chg	
CONNECT NEW CUSTOMER	\$71,615	\$74,528	\$2,912	4%	\$68,825	(\$2,791)	-4.1%	<ul style="list-style-type: none"> <li>\$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)</li> <li>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.</li> <li>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.</li> <li>EDO has not seen yet seen significant increase in demand for new LED lighting and thus recommends reducing New Street Lighting by \$.7 million to \$6.4 million (2.2% over 2019 forecast).</li> <li>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.</li> <li>The total 2020 BP adjustment for New Business is \$1.3 million</li> </ul>
ENHANCE THE NETWORK	\$9,779	\$9,763	(\$16)	0%	\$8,915	(\$864)	-9.7%	<ul style="list-style-type: none"> <li>\$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</li> <li>Public works projects slated for 2020 include KY 146 &amp; English Station, KY 22 &amp; Springcrest, I-71 Oldham Co Interchange, and Billtown Rd.</li> </ul>
MAINTAIN THE NETWORK	\$35,544	\$34,624	(\$919)	-3%	\$36,350	\$806	2.2%	<ul style="list-style-type: none"> <li>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.</li> <li>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</li> <li>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</li> <li>Recommend increasing Maintain the Network in the 2020BP by \$800k (Cap/Recloser Blanket)</li> </ul>
REPAIR THE NETWORK	\$14,450	\$13,351	(\$1,099)	-8%	\$14,125	(\$324)	-2.3%	<ul style="list-style-type: none"> <li>Using 3-year average for storms resulting in \$500k of total variance</li> </ul>
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)
<b>Grand Total</b>	<b>\$131,387</b>	<b>\$132,266</b>	<b>\$879</b>	<b>1%</b>	<b>\$131,915</b>	<b>\$528</b>	<b>0.4%</b>	<ul style="list-style-type: none"> <li>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.</li> <li>Including blanket to project moves, 2020 BP compared to spend projections for 2019 is essentially flat</li> </ul>

\*\* 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		2020 BP Adjustments	
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
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%								\$0
<b>Grand Total</b>		<b>\$131,387</b>	<b>\$132,266</b>	<b>\$879</b>	<b>0.7%</b>	<b>\$131,915</b>	<b>\$528</b>	<b>0.4%</b>	<b>120,150</b>	<b>120,193</b>	<b>105,599</b>	<b>117,954</b>	<b>119,432</b>			<b>\$2,124</b>

\*\* 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.

## Attachment 2 to Response to PSC-2 Question No. 161

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: Page 40 of 106  
Arbough

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)	-	-	-	-	-

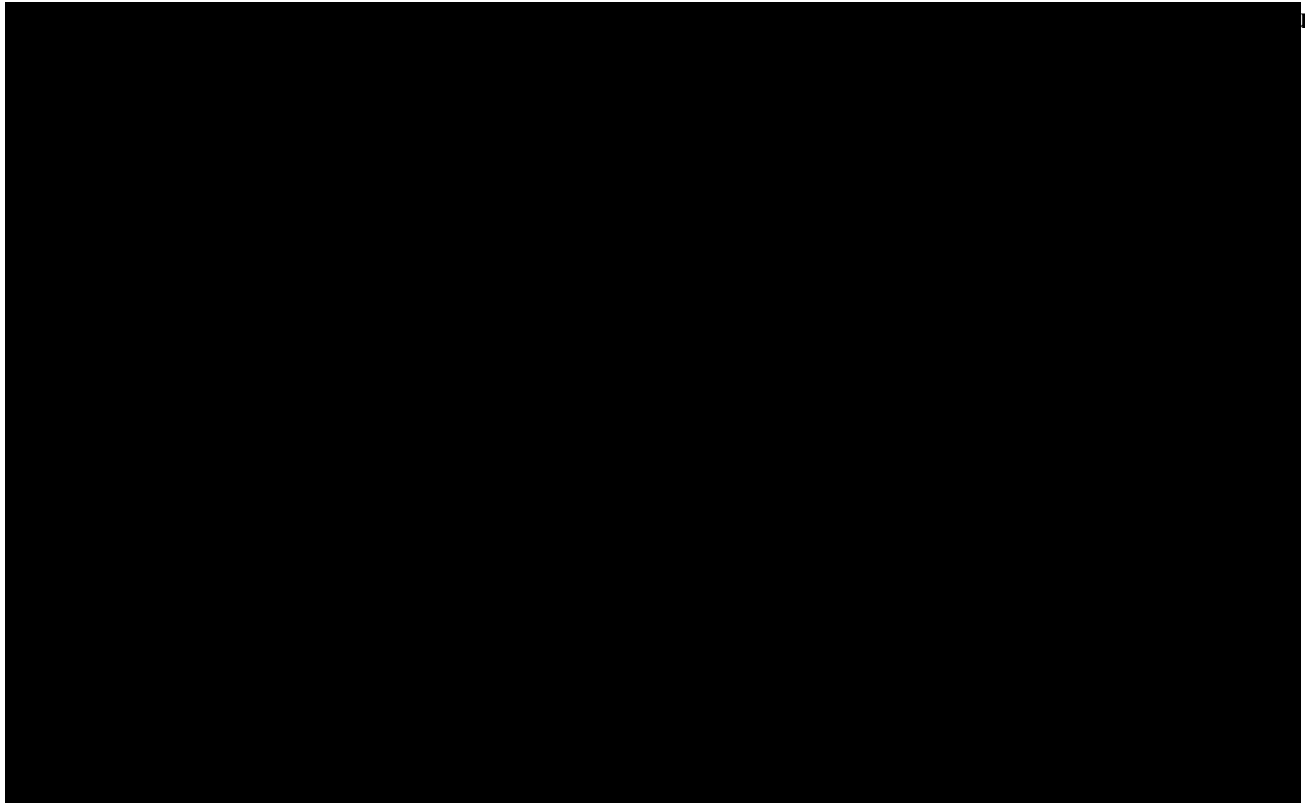
**Risks**

- 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.

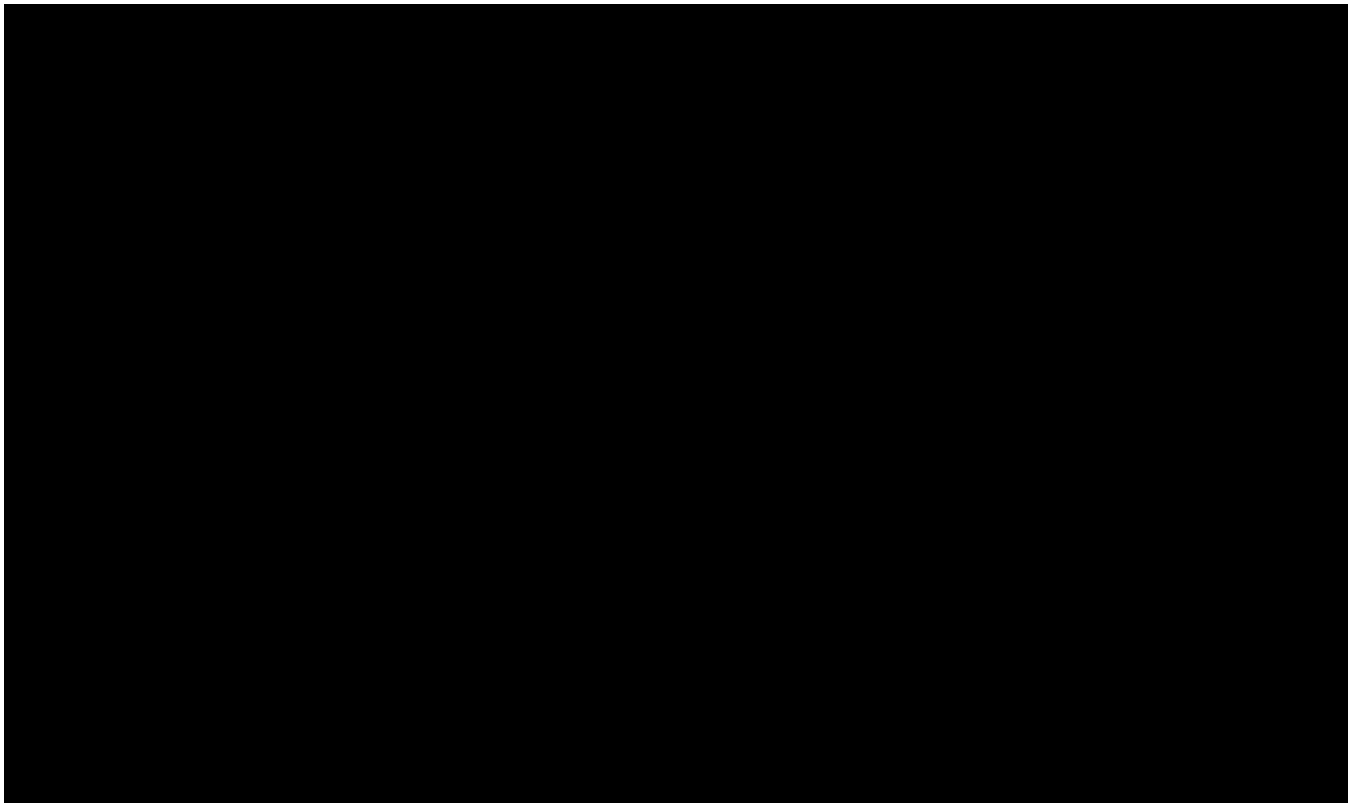
**Alternatives Considered**

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.





Existing Station Configuration



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
	(124-5)	7	6.9	99%	4.7	67%	1270
	(124-6)	14	8.3	59%	7.5	54%	988
	(124-7)	14	10.2	73%	9.5	68%	983
total			25.4		21.7		3241
	(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
						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

Attachment 2 to Response to PSC-2 Question No. 161

adequate contingency capacity, the failure of one of the transformers addressed by thisPage 47 of 106 project could result in extended total outage time for some customers of up to 30 hours untilArbough 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).



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 these investments is \$2,838k. **Page 51 of 106**  
**Arbough**

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.



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 quantify the amount of PILC cable in the network and the condition of ducts and manholes. **Page 54 of 106**  
Arbough

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) <i>Estimated</i>	\$11,871,897	12	12,000
2020 (#155363) <i>Proposed</i>	\$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 average 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.

**Budget Comparison & Financial Summary**

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. **Arbough**

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.



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 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. Page, 59 of 106  
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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

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

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 **Arbough**

### **Budget Comparison & Financial Summary**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>Post 2022</b>	<b>Total</b>
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)	-	-	-	-	-

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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  
Chief Financial Officer

Date

\_\_\_\_\_  
Paul W. Thompson  
Chairman, CEO and President

Date

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

## Attachment 2 to Response to PSC-2 Question No. 161

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. Page 64 of 106

**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

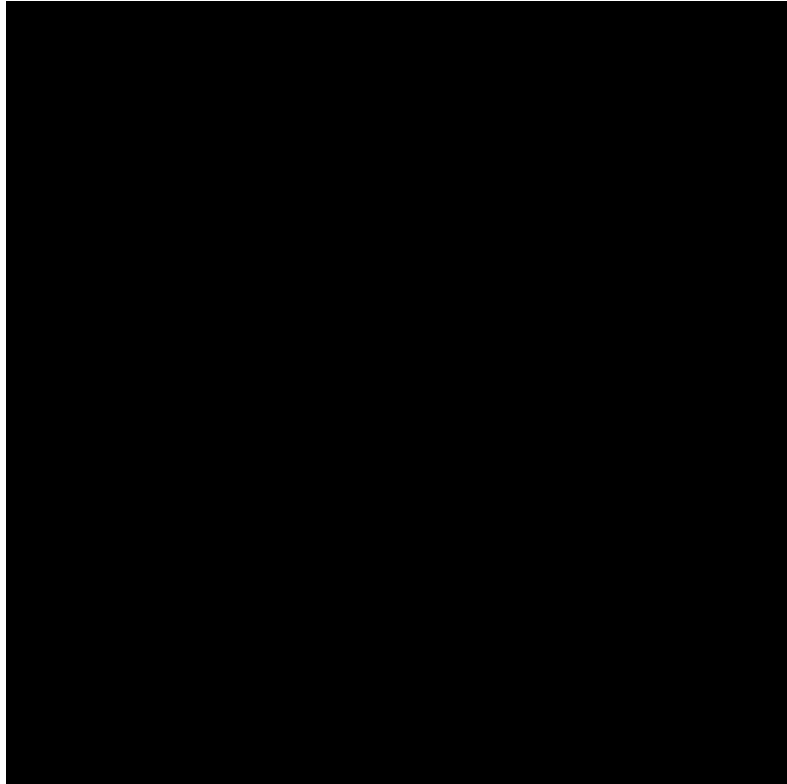
Modify the existing 69kV transmission tap at Versailles Bypass Substation to provide separate transmission sources for the two Versailles Bypass Substation transformers. The recommended option includes Cost of Unserved Energy of \$179k in 2019 and \$91k in 2020 at \$17.89/KwH given planned outage needs and risks of failures.

2. **Alternative #1:**

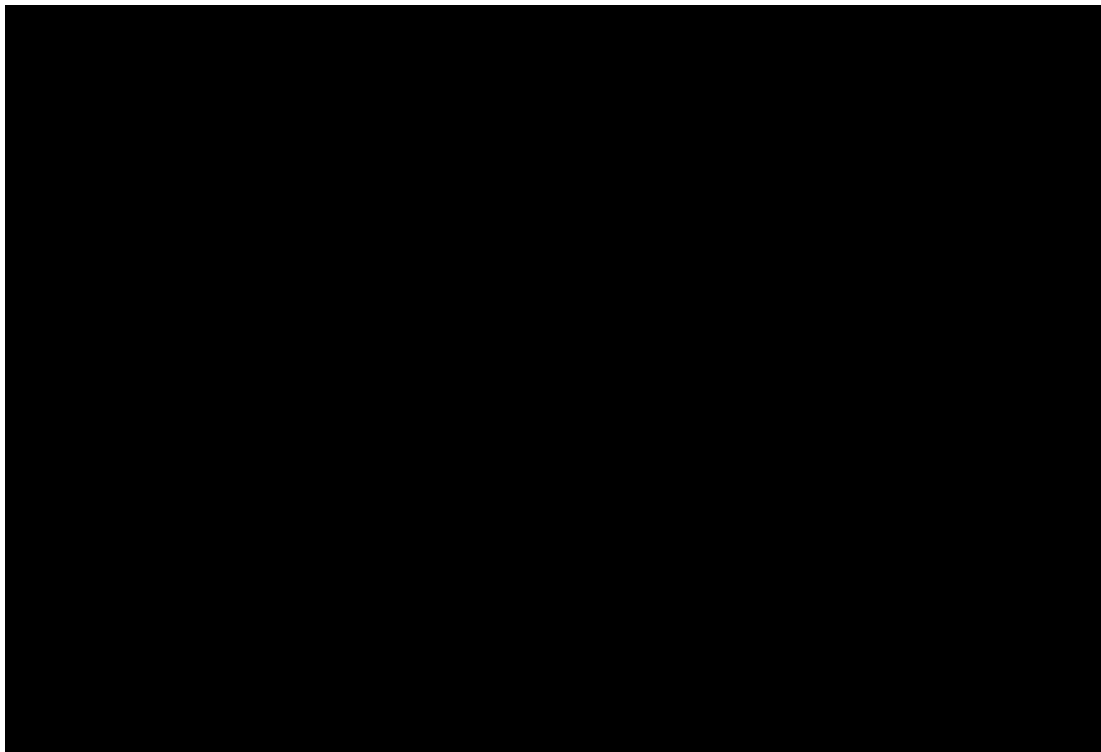
NPVRR: \$3,560k

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.





Existing Substation Configuration



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.

██████████ owns property around the original planned location for the Paynes Mill substation. After the original project was approved, ██████████ 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. ██████████ 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.

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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. Page 68 of 106  
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## 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.





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)	-	-	-	-	-



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.

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	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]  
[REDACTED]  
[REDACTED]  
[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 N1DT deficiencies/concerns in the Georgetown area are expected to be addressed upon

completion of the next planned substation improvement project currently scheduled in 2024, although the improvement is expected to be accelerated to 2022-2023 because of new business growth in the area. Page 75 of 106

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:

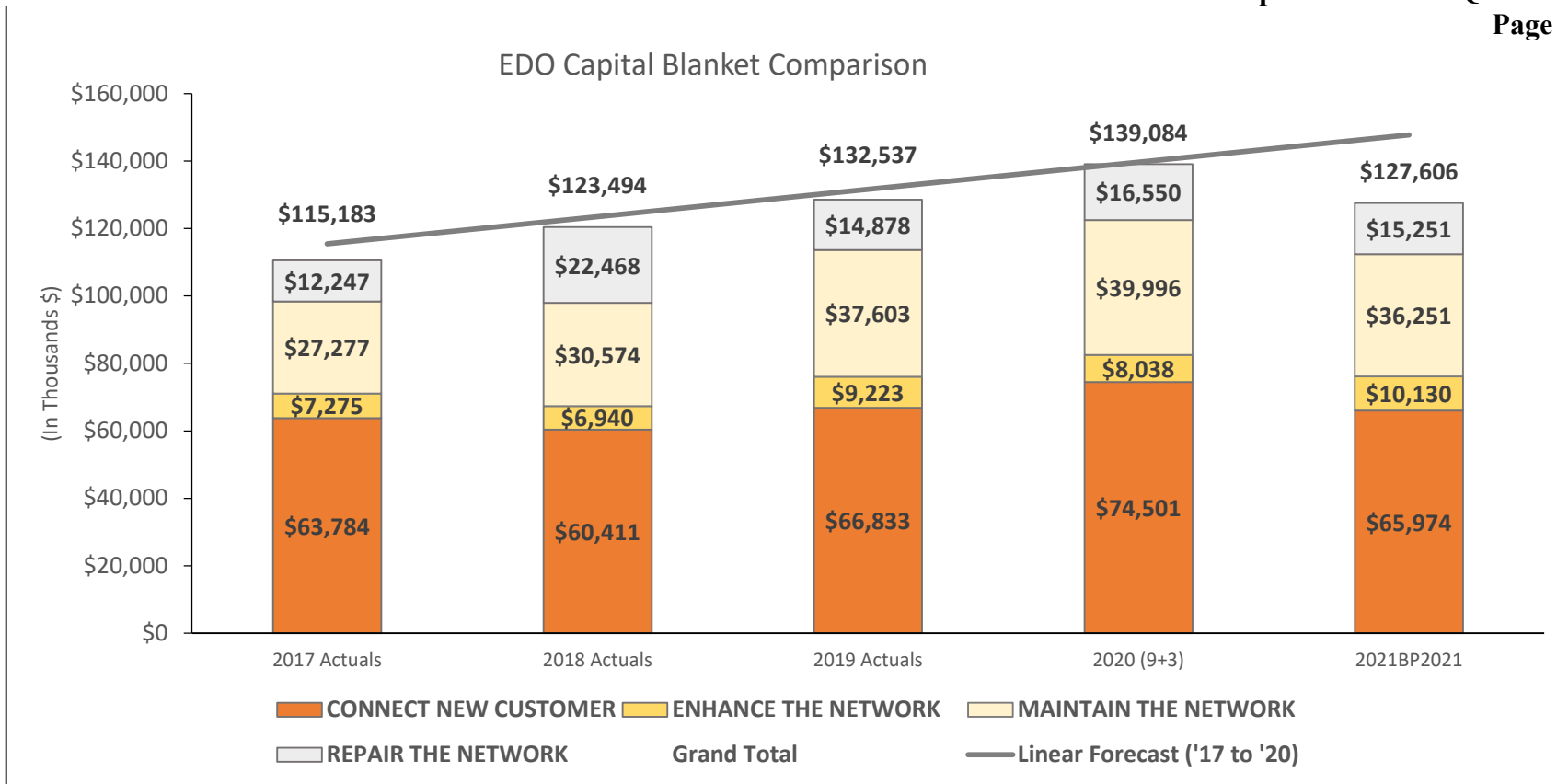
NPVRR: \$15,722k

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.









- 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%	<ul style="list-style-type: none"> <li>In March 2020 New Business categories other than Transformers were decreased 10% from 2020 BP for 2021 figures due to anticipated economic downturn from the COVID-19 pandemic</li> <li>\$1,295k has been moved from New Vault blanket to Vault projects (variance to forecast include Vault projects = \$9,822k)</li> </ul>
ENHANCE THE NETWORK	\$10,130	\$10,129	(\$0)	0.0%	\$8,038	(\$2,092)	-26.0%	<ul style="list-style-type: none"> <li>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)</li> <li>\$1,127k moved from Public Works blankets to Public Works projects</li> <li>\$585k moved from Sys Enhance blanket to project for (WHAS-11116)</li> <li>Variance to forecast including Public Works projects and Sys Enhance project = \$38k, Enhance the Network category is essentially flat compared to forecast and 2020 Business Plan</li> </ul>
MAINTAIN THE NETWORK	\$36,251	\$35,648	(\$603)	-1.7%	\$39,996	\$3,745	9.4%	<p><b>2021BP vs forecast</b></p> <ul style="list-style-type: none"> <li>9+3 Forecast for Repair/Replace Pole is \$3 million over 2021 BP as LG&amp;E Ops secured additional \$3 million in funding in 2020 to address backlog of defective poles</li> <li>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)</li> <li>Repair Defective Equipment (CRDD) is utilized based on need and varies year/year. CRRD OH has seen fluctuations between \$600k 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 fluctuations in 2020</li> </ul> <p><b>2021 BP vs 2020 BP</b></p> <ul style="list-style-type: none"> <li>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 corresponding 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)</li> </ul>
REPAIR THE NETWORK	\$15,251	\$14,913	(\$338)	-2.3%	\$16,550	\$1,299	7.8%	<p><b>2021BP vs forecast</b></p> <ul style="list-style-type: none"> <li>Repair 3rd Party Damage spend is up 28% over historic 3 year average</li> </ul> <p><b>2021 BP vs 2020BP</b></p> <ul style="list-style-type: none"> <li>Lexington Trouble expenditure analysis described above also resulted in a \$300k addition to Capital Trouble Orders Blanket</li> <li>Using 3-year average for storms</li> </ul>
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))
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2021 Capital Request (in Thousands \$)															
		2021 BP			vs. 2020 BP for 2021			vs. 2020 Forecast (9+3)			2020 WRS				
<u>Blanket Project Number/Description</u>		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%
<b>Total Connect New Customer (CN)</b>		<b>\$65,974</b>	<b>\$72,656</b>	<b>\$6,681</b>	<b>9.2%</b>	<b>\$74,501</b>	<b>\$8,527</b>	<b>11.4%</b>	<b>29,286</b>	<b>30,605</b>	<b>24,894</b>	<b>31,845</b>	<b>30,579</b>		
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%
<b>Total Enhance Network (EN)</b>		<b>\$10,130</b>	<b>\$10,129</b>	<b>(\$0)</b>	<b>0.0%</b>	<b>\$8,038</b>	<b>(\$2,092)</b>	<b>-26.0%</b>	<b>2,518</b>	<b>2,736</b>	<b>1,869</b>	<b>2,336</b>	<b>2,530</b>		
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%
<b>Total Maintain Network (MN)</b>		<b>\$36,251</b>	<b>\$35,648</b>	<b>(\$603)</b>	<b>-1.7%</b>	<b>\$39,996</b>	<b>\$3,745</b>	<b>9.4%</b>	<b>54,391</b>	<b>52,372</b>	<b>36,645</b>	<b>45,806</b>	<b>50,857</b>		
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
<b>Total Repair Network (RN)</b>		<b>\$15,251</b>	<b>\$14,913</b>	<b>(\$338)</b>	<b>-2.3%</b>	<b>\$16,550</b>	<b>\$1,299</b>	<b>7.8%</b>	<b>32,907</b>	<b>34,033</b>	<b>43,584</b>	<b>43,818</b>	<b>36,919</b>		
<b>Grand Total</b>		<b>\$127,606</b>	<b>\$133,346</b>	<b>\$5,740</b>	<b>4.3%</b>	<b>\$139,084</b>	<b>\$11,475</b>	<b>8.3%</b>	<b>119,102</b>	<b>119,746</b>	<b>106,992</b>	<b>123,806</b>	<b>120,884</b>		

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.

<b>Key Tasks / Milestones</b>	<b>Duration:</b>
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]

**Centralized Location Enhances Reliability and Customer Experience**

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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.

**Budget Comparison & Financial Summary**

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]

█ 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.

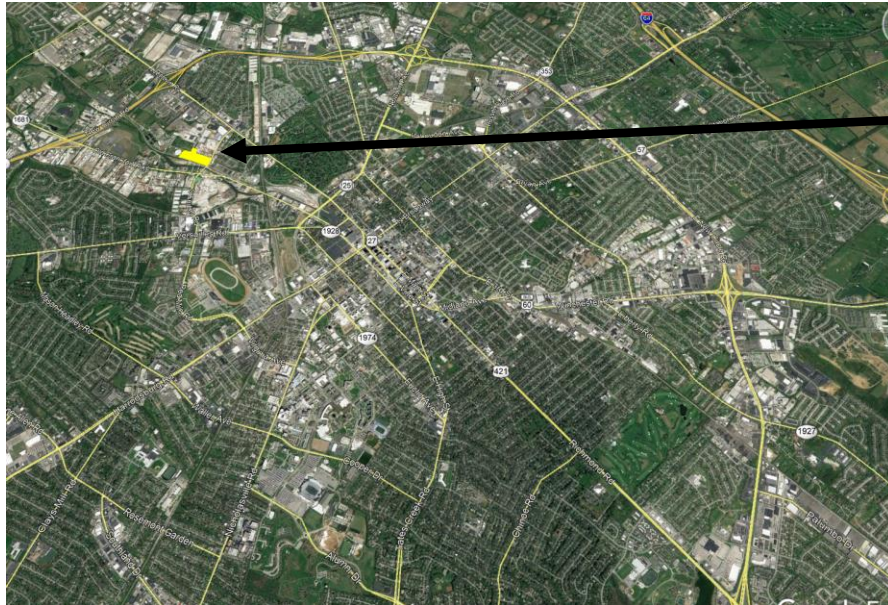
1. Recommendation: Relocate to a Consolidated Facility NPVRR: \$27,408k  
Relocate EDO operations and Transmission from Limestone and CS operations from Loudon to a single property that will house the operations of both current facilities. This alternative addresses all operational needs. The Loudon 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.



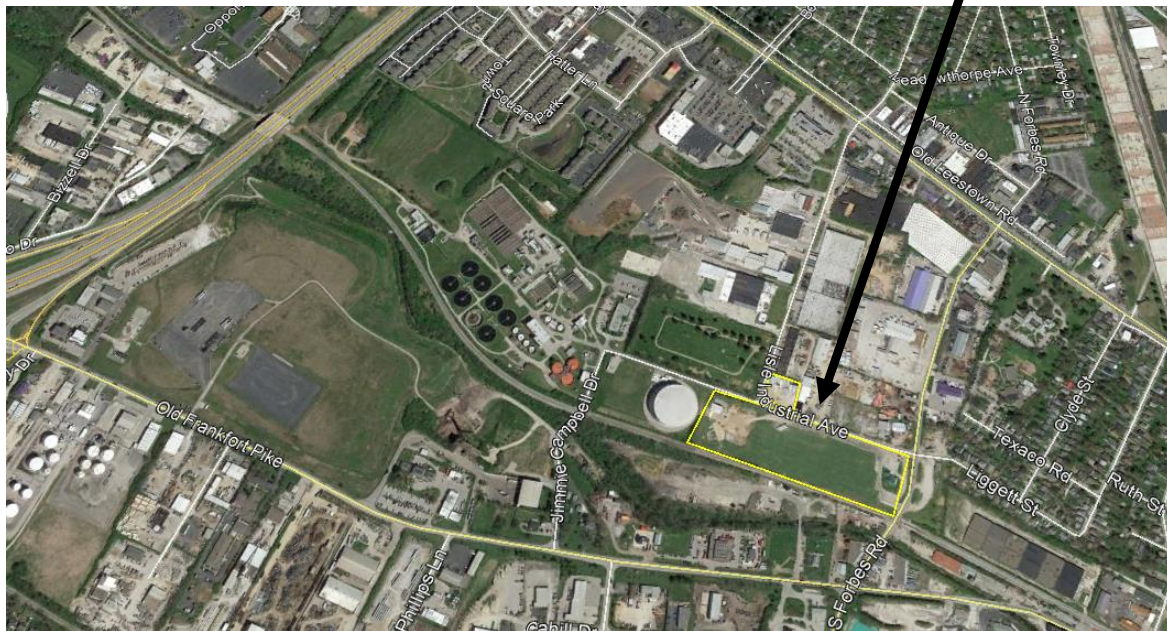


[REDACTED]

- 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**

Arbough

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>Post 2022</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>Post 2022</b>	<b>Total</b>
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. Page 91 of 106  
Arbough

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.

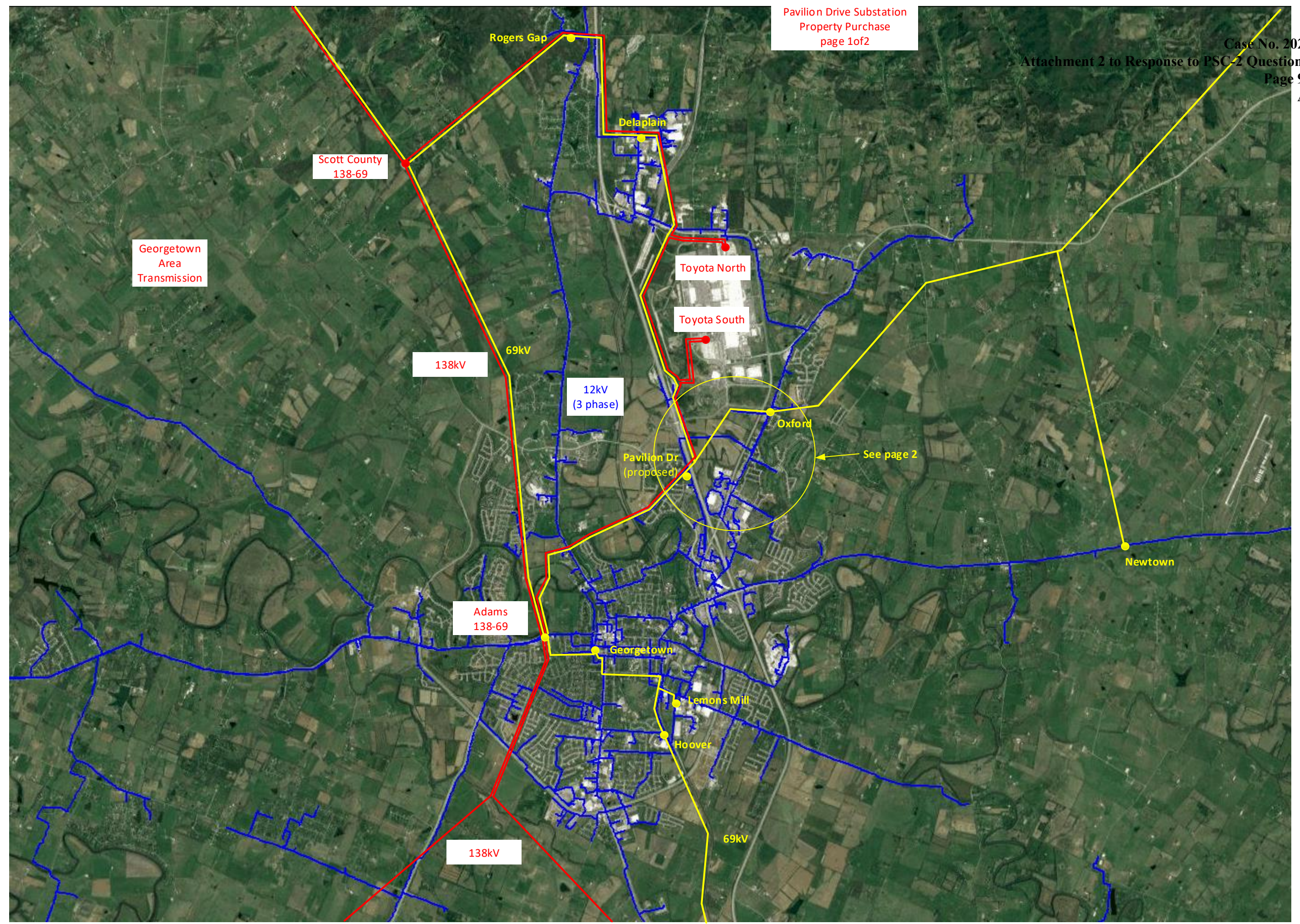
3. Alternative #2:

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.







Georgetown  
Area  
Transmission

Scott County  
138-69

138kV

69kV

12kV  
(3 phase)

Toyota North

Toyota South

Pavilion Dr  
(proposed)

See page 2

Newtown

Adams  
138-69

Georgetown

Lemons Mill

Hoover

138kV

69kV







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) <i>Estimated (2020FC 9+3)</i>	\$10,917,634	9.5	12,000
2021 (#142487) <i>Proposed</i>	\$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 and manhole system, highlights the need to continue the replacement program funding specifically to address secondary and primary PILC cables. Page 07 of 106  
Arbough

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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>Post 2023</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>Post 2023</b>	<b>Total</b>
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. **Arbough**

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.



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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>Post 2023</b>	<b>Total</b>
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)	-	-	-	-	-

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>Post 2023</b>	<b>Total</b>
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.



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]. [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.



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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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. **Arbough**

**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.





**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		<u>\$10,043 k</u>
Total Increase Requested		<u>\$ 2,748 k</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.
- 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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>Pre-2019</b>	<b>2019</b>	<b>2020</b>	<b>Post 2020</b>	<b>Total</b>
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

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>Pre-2019</b>	<b>2019</b>	<b>2020</b>	<b>Post 2020</b>	<b>Total</b>
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.



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<sub>2</sub>S) scavenging systems. Project scope includes installation of contactor vessels, piping, valves, fittings, and H<sub>2</sub>S scavenger media to remove H<sub>2</sub>S 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<sub>2</sub>S), a toxic and corrosive gas that must be removed before storage gas is supplied to the gas distribution system. H<sub>2</sub>S 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<sub>2</sub>S 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<sub>2</sub>S scavenging technology using a dry expendable media is proposed. The H<sub>2</sub>S scavenger technology is less complex requiring only vertical contactor towers filled with a non-regenerative dry iron oxide granulated media. Natural gas containing H<sub>2</sub>S flows thru the contactor towers, H<sub>2</sub>S 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<sub>2</sub>S scavenging technology provides a lower lifecycle cost and additional benefits including: reduced operational complexity resulting in increased reliability, reduced H<sub>2</sub>S 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<sub>2</sub>S 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.

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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<sub>2</sub>S scavenger technology is very low. H<sub>2</sub>S 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<sub>2</sub>S scavenger technology was also installed at Center Compressor Station in 2016 for treatment of gas withdrawn from Center Storage Field. The H<sub>2</sub>S 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<sub>2</sub>S 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<sub>2</sub>S exposure risks, reduced environmental risk, eliminates H<sub>2</sub>S in Magnolia Upper storage field pipelines, and decreases required workforce size.
2. Alternative #1: NPVRR: \$39k  
Install seventy and forty five H<sub>2</sub>S 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<sub>2</sub>S 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<sub>2</sub>S exposure risks, reduced environmental risk, decreases required workforce size, but does not eliminate H<sub>2</sub>S 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<sub>2</sub>S scavenger vessels, higher environmental risks, higher H<sub>2</sub>S exposure risk, and do not eliminate H<sub>2</sub>S 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<sub>2</sub>S 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  
Chief Financial Officer

Date

\_\_\_\_\_  
Paul W. Thompson  
Chairman, CEO and President

Date

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<sub>2</sub>S) scavenging systems. Project scope includes the replacement of Muldraugh Compressor Station amine purification plants #2 and #3 with six vertical H<sub>2</sub>S 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<sub>2</sub>S), a toxic and corrosive gas that must be removed before storage gas is supplied to the gas distribution system. H<sub>2</sub>S 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<sub>2</sub>S 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<sub>2</sub>S scavenging technology using a dry expendable granular media is proposed. The H<sub>2</sub>S scavenger technology is less complex requiring only vertical contactor towers filled with a non-regenerative dry iron oxide granulated media. Natural gas containing H<sub>2</sub>S flows thru the contactor towers, H<sub>2</sub>S 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<sub>2</sub>S scavenging technology provides a lower lifecycle cost and additional benefits including: reduced operational complexity resulting in increased reliability, reduced H<sub>2</sub>S

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<sub>2</sub>S levels and installing six H<sub>2</sub>S 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<sub>2</sub>S 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.

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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<sub>2</sub>S scavenger technology is very low. H<sub>2</sub>S 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<sub>2</sub>S scavenger technology was also installed at Center Compressor Station in 2016 for treatment of gas withdrawn from Center Storage Field. The H<sub>2</sub>S 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<sub>2</sub>S 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<sub>2</sub>S scavenger vessels, keep amine plant #1 operating as base load unit. The following benefits are provided: decreased operational complexity, increased reliability, decreased H<sub>2</sub>S exposure risks, reduced sulfur dioxide (SO<sub>2</sub>) 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<sub>2</sub>S scavenger vessels, higher environmental risks, and higher H<sub>2</sub>S 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<sub>2</sub>S 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  
Chief Financial Officer

Date

\_\_\_\_\_  
Paul W. Thompson  
Chairman, CEO and President

Date

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

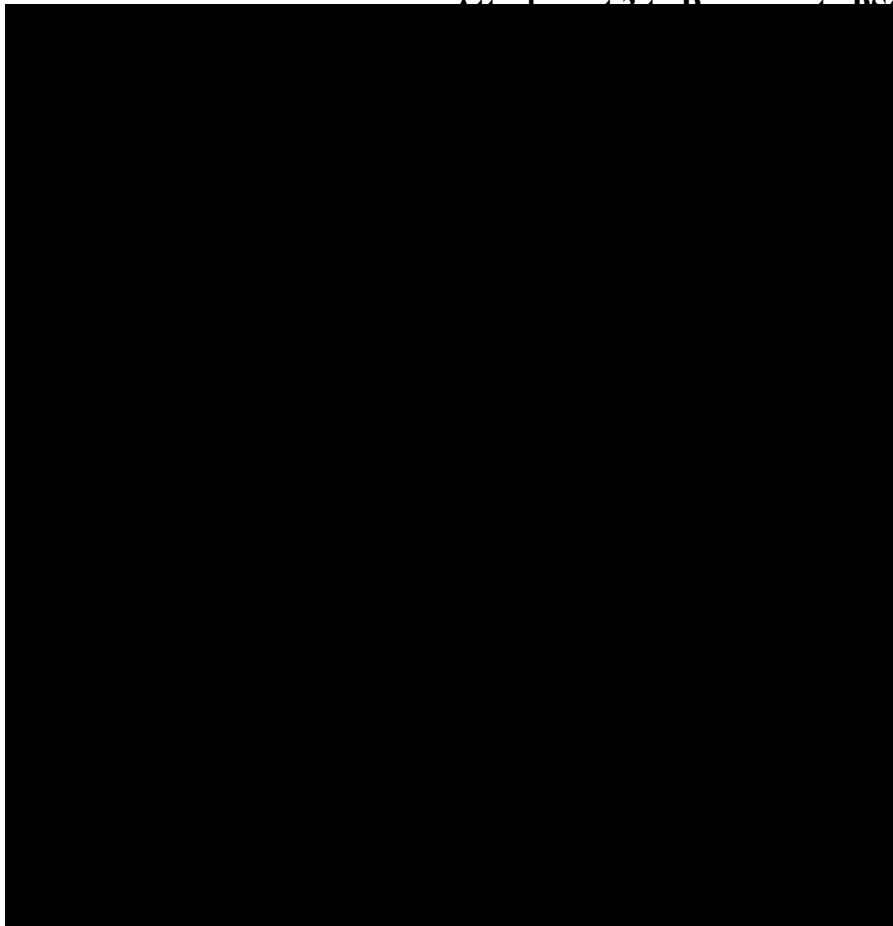
**Description of Incremental Ask**

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.



The revised project costs still result in this alternative being the recommended action.

### **Budget Comparison & Financial Summary**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>Pre-2019</b>	<b>2019</b>	<b>2020</b>	<b>Post 2020</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>Pre-2019</b>	<b>2019</b>	<b>2020</b>	<b>Post 2020</b>	<b>Total</b>
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.





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		<u>\$12,184k</u>
Total Increase Requested		<u>\$2,480k</u>

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.

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>Pre-2019</b>	<b>2019</b>	<b>2020</b>	<b>Post 2020</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>Pre-2019</b>	<b>2019</b>	<b>2020</b>	<b>Post 2020</b>	<b>Total</b>
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M Variance to BP (2-1)	-	-	-	-	-



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 work can 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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>Post 2022</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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  
Chief Financial Officer

Date

\_\_\_\_\_  
Paul W. Thompson  
Chairman, CEO and President

Date



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:**

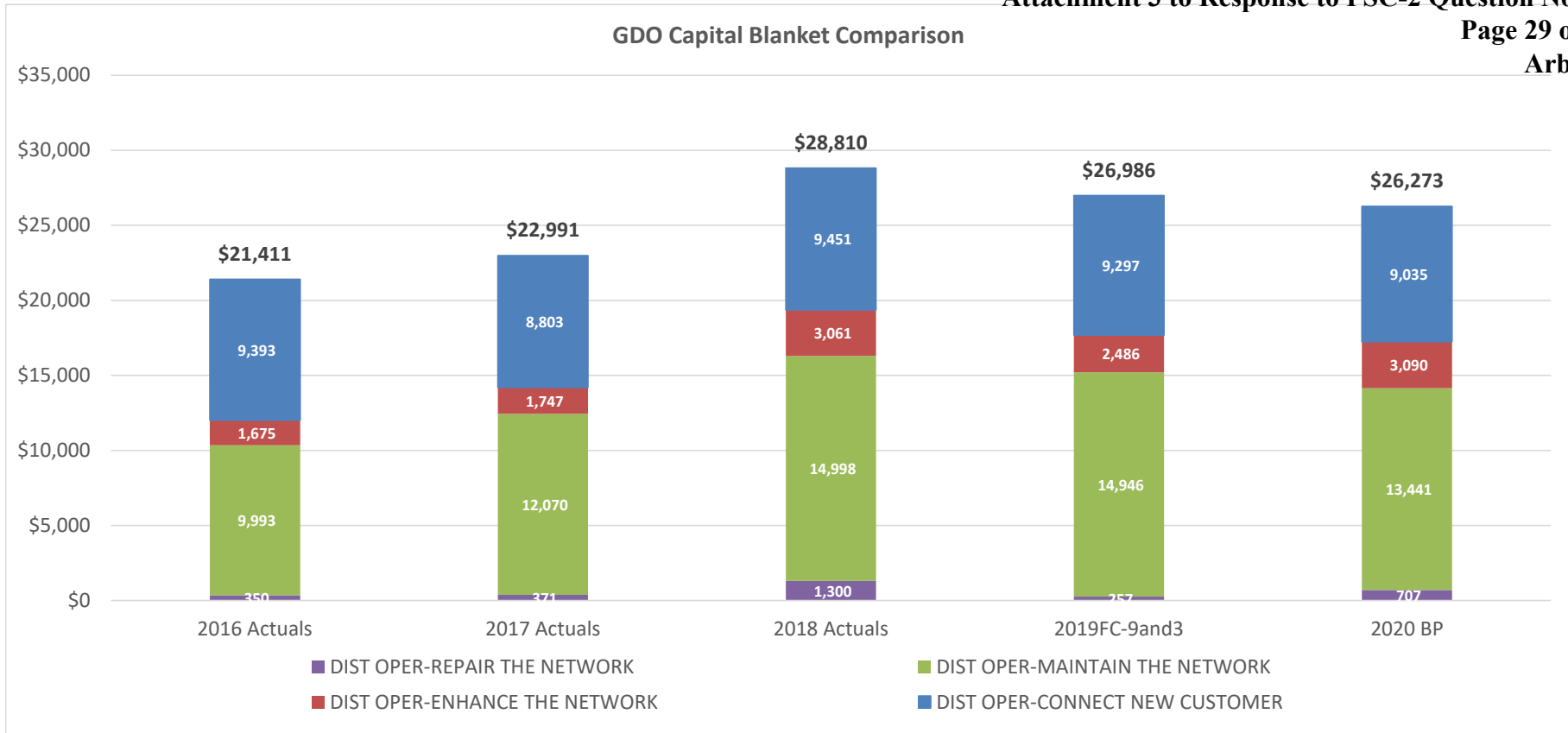
The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

\_\_\_\_\_  
Kent W. Blake  
Chief Financial Officer

\_\_\_\_\_  
Date

\_\_\_\_\_  
Paul W. Thompson  
Chairman, CEO and President

\_\_\_\_\_  
Date



**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	
<b>DIST OPER-CONNECT NEW CUSTOMER</b>								
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%	
<b>DIST OPER-CONNECT NEW CUSTOMER TOTAL</b>	<b>9,035</b>	<b>8,893</b>	<b>-118</b>	<b>-1%</b>	<b>9,297</b>	<b>258</b>	<b>3%</b>	
<b>DIST OPER-ENHANCE THE NETWORK</b>								
CFTCUS-Gas Control FT Customer Conversions	90	90	-1	-1%	44	-47	-107%	
CKYTGR - 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.
<b>DIST OPER-ENHANCE THE NETWORK TOTAL</b>	<b>3,090</b>	<b>2,224</b>	<b>-865</b>	<b>-39%</b>	<b>2,486</b>	<b>-603</b>	<b>-24%</b>	
<b>DIST OPER-MAINTAIN THE NETWORK</b>								
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.
<b>DIST OPER-MAINTAIN THE NETWORK TOTAL</b>	<b>13,441</b>	<b>13,431</b>	<b>-10</b>	<b>0%</b>	<b>14,946</b>	<b>1,504</b>	<b>10%</b>	
<b>DIST OPER-REPAIR THE NETWORK</b>								
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.
<b>DIST OPER-REPAIR THE NETWORK TOTAL</b>	<b>707</b>	<b>389</b>	<b>-318</b>	<b>-82%</b>	<b>257</b>	<b>-450</b>	<b>-175%</b>	
<b>REPORT TOTAL</b>	<b>26,273</b>	<b>24,937</b>	<b>-1,311</b>	<b>-5%</b>	<b>26,986</b>	<b>709</b>	<b>3%</b>	

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)
<b>Total</b>	<b>\$100,860</b>			<b>\$93,953</b>				<b>\$99,672</b>		<b>\$103,690</b>	

\*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).

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>Post 2022</b>	<b>Total</b>
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)	-	-	-	-	-

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>Post 2022</b>	<b>Total</b>
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



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		<u>\$12,722k</u>
Total Increase Requested		<u>\$538k</u>

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.

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>Pre-2019</b>	<b>2019</b>	<b>2020</b>	<b>Post 2020</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>Pre-2019</b>	<b>2019</b>	<b>2020</b>	<b>Post 2020</b>	<b>Total</b>
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 will 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  
Chief Financial Officer

Date

\_\_\_\_\_  
Paul W. Thompson  
Chairman, CEO and President

Date

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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Total</b>
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.



# 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)

Google Earth

Image Landsat / Copernicus

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60 mi

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.



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**

Arbough

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 **Arbough**  
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 alternative 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.



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**

Arbough

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 through 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.

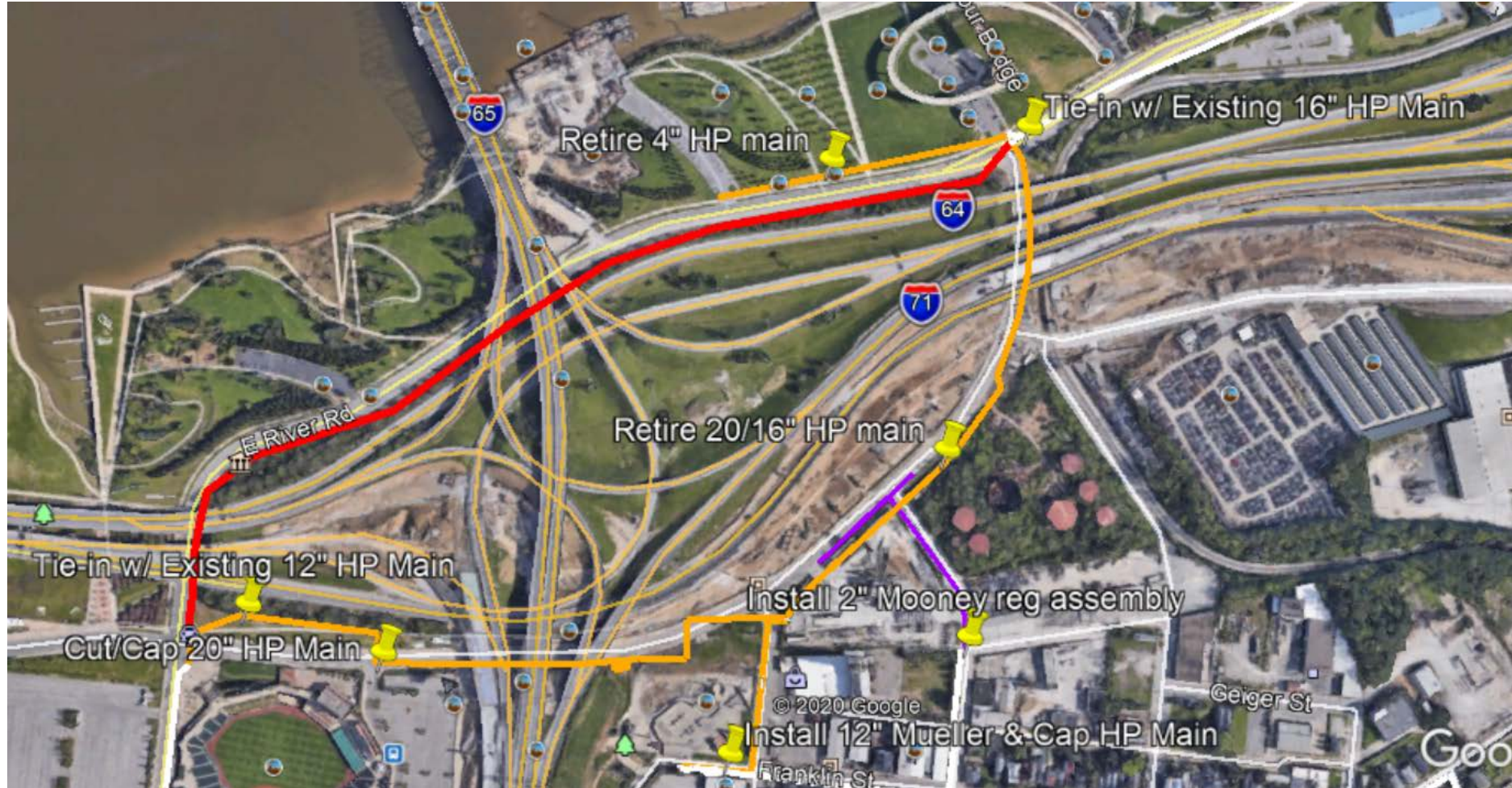
2. Alternative #1: NPVRR: (\$000s) N/A

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.



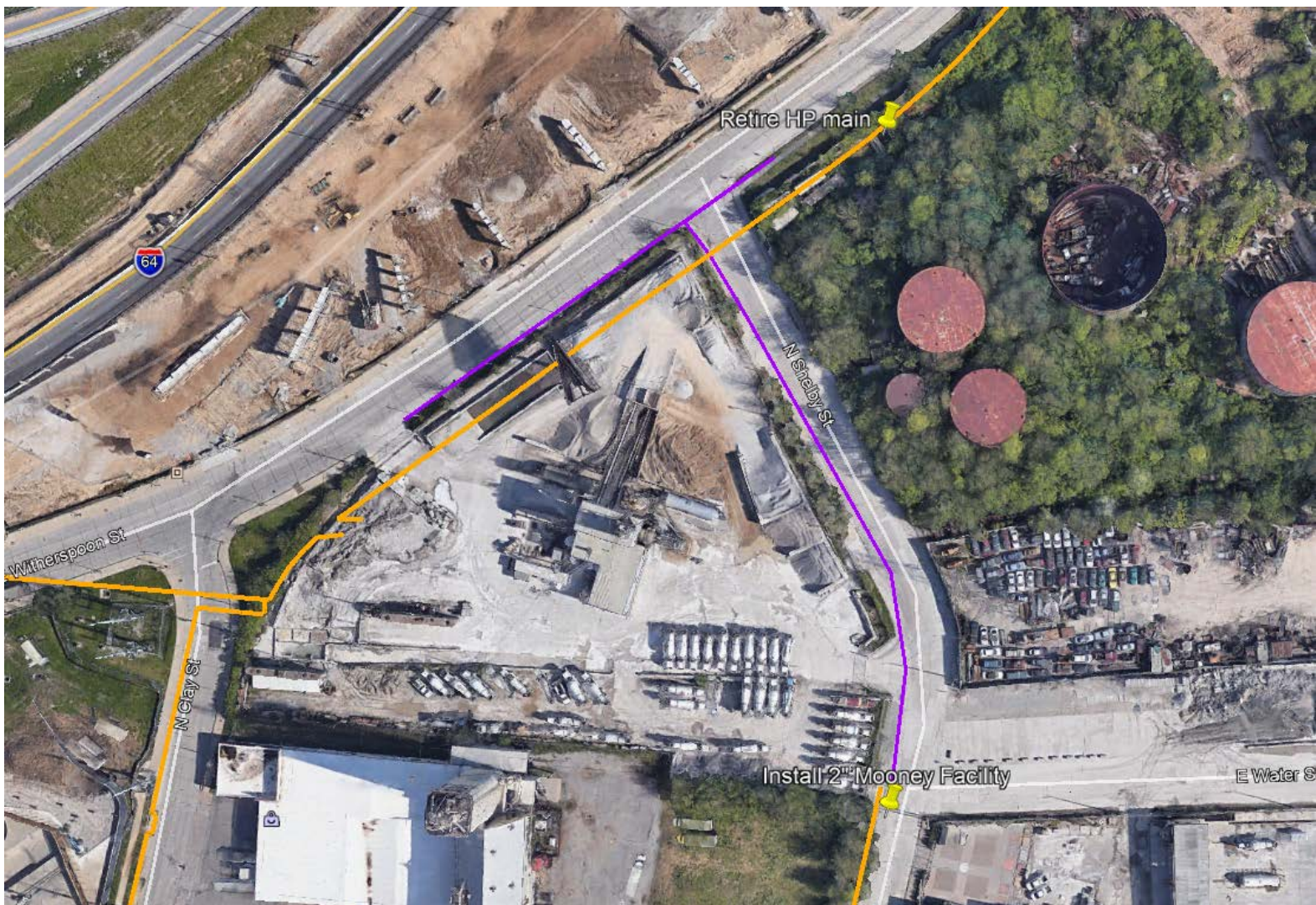
# Witherspoon Project Overview





# Witherspoon MP Pipeline Overview

Case No. 2020-00350  
Attachment 5 to Response to PSC-2 Question No. 161  
Page 60 of 100  
Arbough



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

**Description of Incremental Ask**

Original Approved Capital Expenditures	\$10,043k
Revised Capital Expenditures Requested including Amendment	\$17,649k
Total Amendment Requested	\$7,606k

- 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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>Pre-2020</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>Pre-2020</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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.



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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>Pre-2020</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>Pre-2020</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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.





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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>Post 2022</b>	<b>Total</b>
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  
Chief Financial Officer

Date

\_\_\_\_\_  
Paul W. Thompson  
Chairman, CEO and President

Date

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] group 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 through 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.

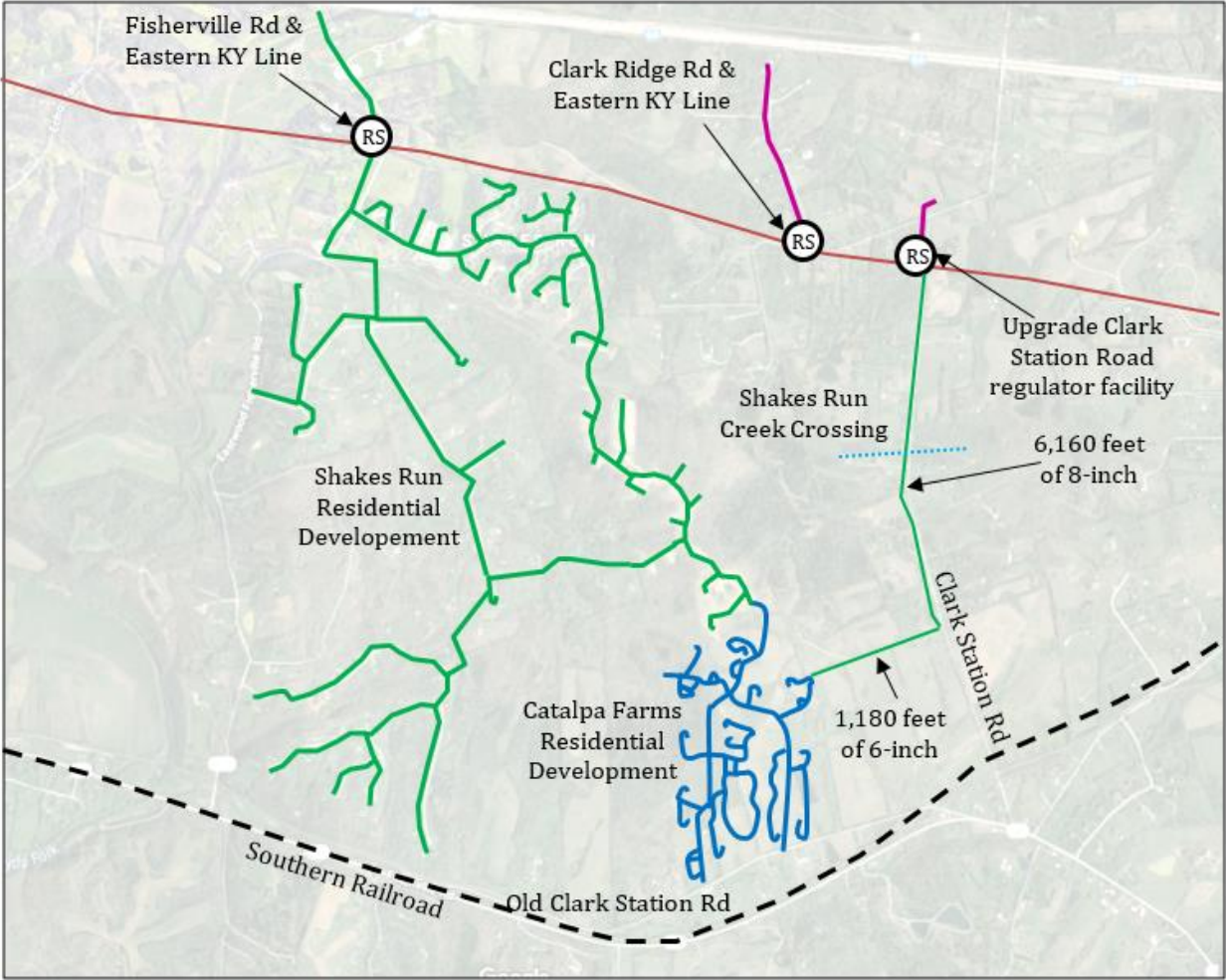
\_\_\_\_\_  
Kent W. Blake  
Chief Financial Officer

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 ██████████ 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 primarily 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.





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	<u>\$153,250k</u>
Total Amendment Requested	<u>\$71,141k</u>

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**

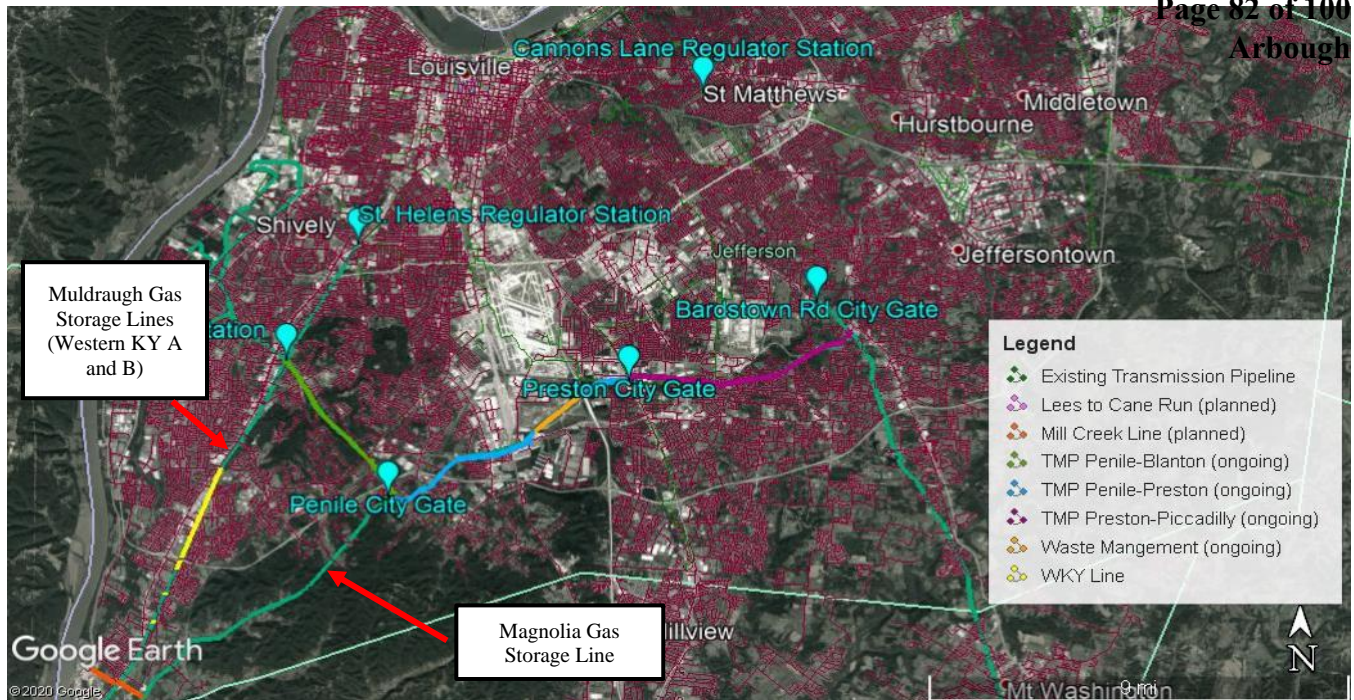
The three transmission pipeline segments proposed to be replaced were installed between 1957 and 1972, using the prevailing materials and construction methods of that time. These pipeline segments are critical for LG&E to reliably serve its customers. The three pipeline segments connect the following 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 2<sup>nd</sup> 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).

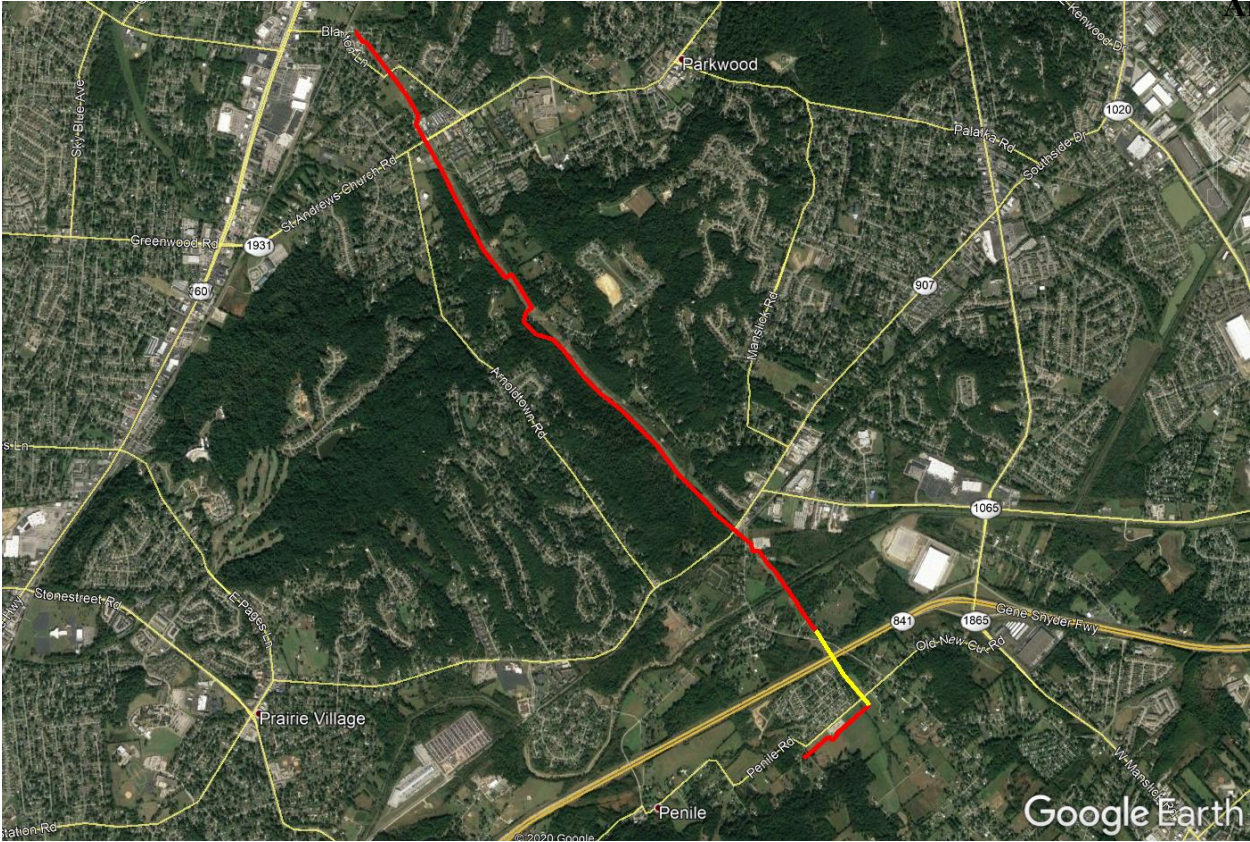
The map also illustrates the three segments proximity to populated areas as demonstrated by the density of the distribution pipelines (shown in red). The project has required significant new easements to accommodate HDDs that in some cases would be much more difficult to obtain in the future due to the 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**

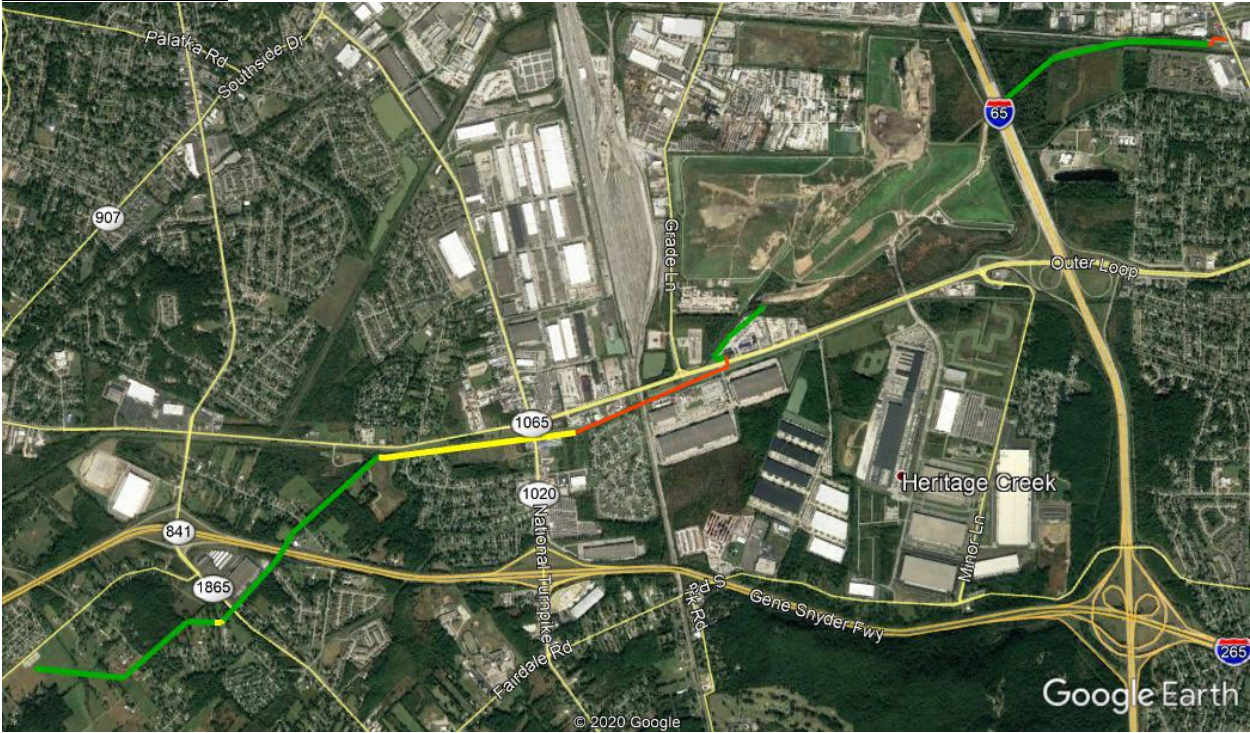
As of mid-August, approximately 5.3 miles of pipeline has been installed. Pipeline installation to date has been on the Penile to Preston and Preston to Piccadilly segments. Work has started on the HDD installations for the Penile to Blanton segment. The progress maps below show completed (green), in-progress (yellow) and remaining (red) sections of the project.



Penile to Blanton:



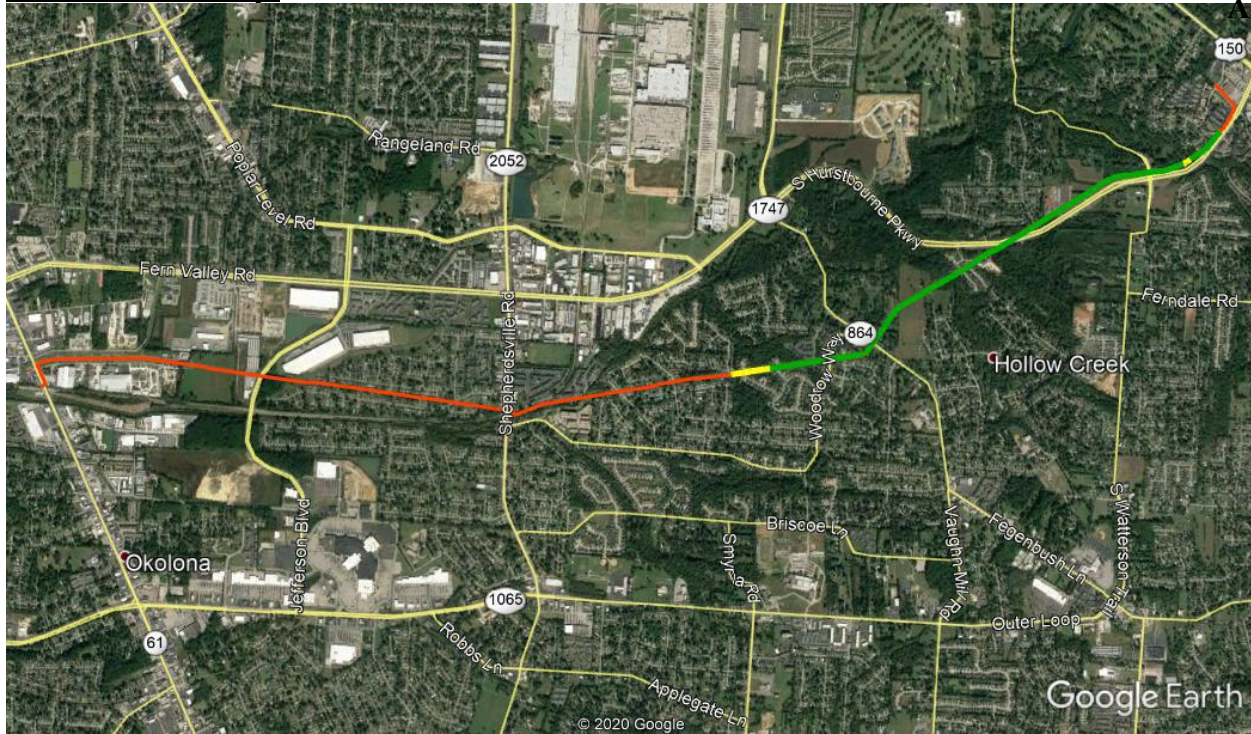
Penile to Preston:





Preston to Piccadilly:

Arbough



**Project Schedule**

An updated project schedule is shown below:

Name	Duration	2019				2020				2021				2022	
		Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2
Perform 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
<b>Penile to Blanton Ln TMPPENBLN</b>	210	1,556	1,626	17,223	21,356	968	<b>42,939</b>
<b>Penile to Preston TMPPENPRS</b>	2,230	3,928	13,996	17,769	3,739	0	<b>41,663</b>
<b>Preston to Piccadilly TMPPRSPIC</b>	311	2,673	16,920	22,896	24,143	799	<b>67,742</b>
<b>Property Penile-Blanton TMPPROP1</b>	257	0	0	4	0	0	<b>261</b>
<b>Property Penile-Preston TMPPROP2</b>	0	43	252	0	0	0	<b>295</b>
<b>EDO Relocations Penile-Blanton TMP-EDO</b>	0	0	0	350	0	0	<b>350</b>
<b>Total</b>	<b>3,008</b>	<b>8,200</b>	<b>32,795</b>	<b>58,242</b>	<b>49,238</b>	<b>1,767</b>	<b>153,250</b>

Note: 2017-2019 costs are actual amounts. 2020 costs are based on actual amounts through June 2020 with the remaining months estimated.

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>Pre-2020</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>Pre-2020</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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.



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 upgraded 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

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

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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>Post 2022</b>	<b>Total</b>
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)	-	-	-	-	-

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>Post 2022</b>	<b>Total</b>
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.





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 1<sup>st</sup>, 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 steel 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**

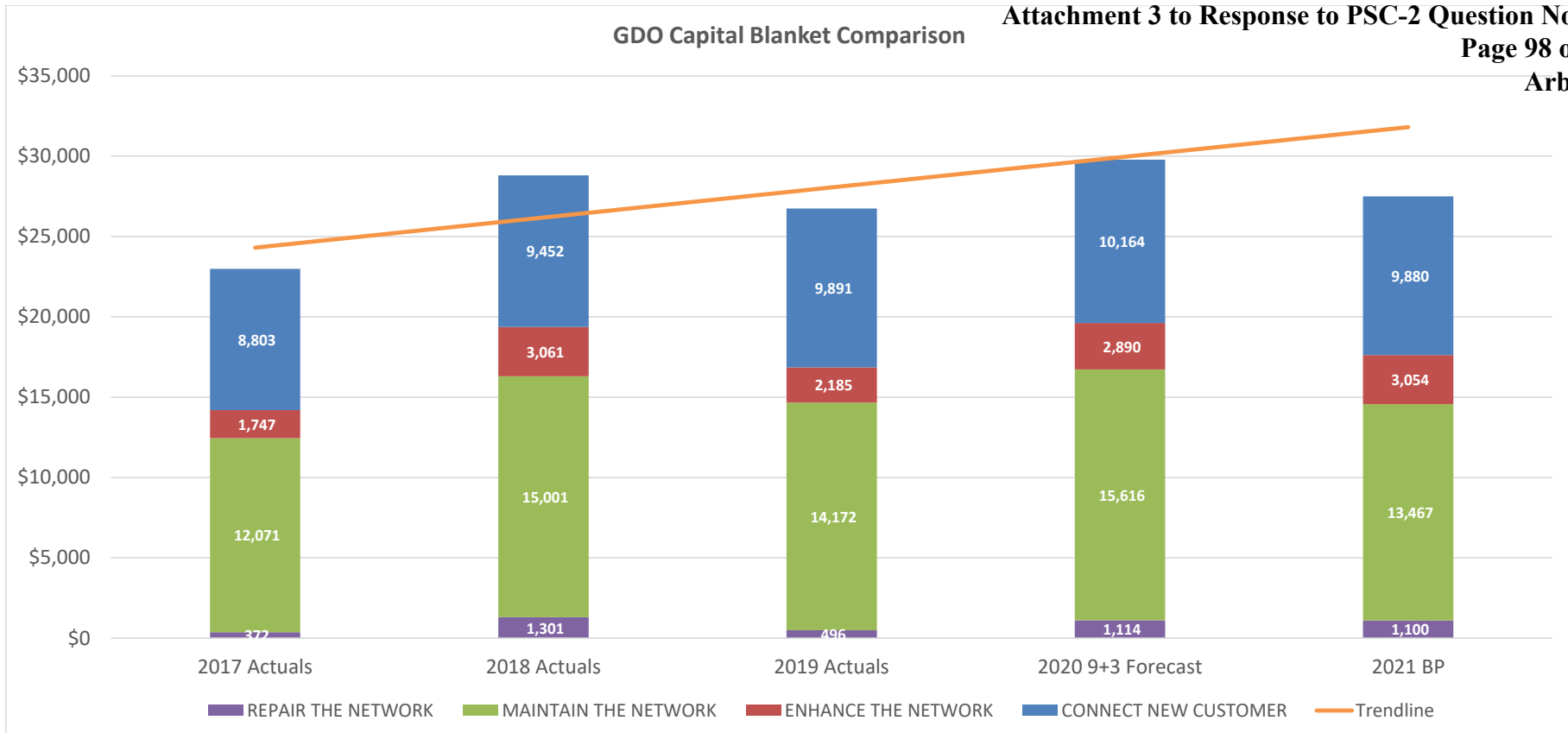
<b>Financial Detail by Year - Capital (\$000s)</b>	<b>Pre-2020</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
1. Capital Investment Proposed		8,812	4,115		12,927
2. Cost of Removal Proposed		2,913	1,372		4,285
3. Total Capital and Removal Proposed (1+2)	-	11,725	5,487	-	17,212
4. Capital Investment 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)	-	-	-	-	-

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>Pre-2020</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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.







**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 \$)

Arbough

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	
<b>CONNECT NEW CUSTOMER</b>								
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
<b>CONNECT NEW CUSTOMER TOTAL</b>	<b>9,880</b>	<b>9,309</b>	<b>-571</b>	<b>-6%</b>	<b>10,164</b>	<b>319</b>	<b>3%</b>	
<b>ENHANCE THE NETWORK</b>								
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.
<b>ENHANCE THE NETWORK TOTAL</b>	<b>3,054</b>	<b>3,167</b>	<b>113</b>	<b>4%</b>	<b>2,890</b>	<b>-164</b>	<b>-6%</b>	
<b>MAINTAIN THE NETWORK</b>								
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.



Arbough

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.
<b>MAINTAIN THE NETWORK TOTAL</b>	<b>13,467</b>	<b>14,128</b>	<b>661</b>	<b>5%</b>	<b>15,616</b>	<b>2,149</b>	<b>14%</b>	
<b>REPAIR THE NETWORK</b>								
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.
<b>REPAIR THE NETWORK TOTAL</b>	<b>1,100</b>	<b>730</b>	<b>-370</b>	<b>-51%</b>	<b>1,114</b>	<b>14</b>	<b>1%</b>	
<b>REPORT TOTAL</b>	<b>27,501</b>	<b>27,334</b>	<b>-167</b>	<b>-1%</b>	<b>29,784</b>	<b>2,318</b>	<b>8%</b>	

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]. [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**

Arbough

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)	██████████	██████████	██████████	██████████
Preform Splice	Not Included	██████████	██████████	N/A
Spare Belt	Included	██████████	██████████	N/A
Spare Belt	1,522 ft (464m)	1,522 ft (464m)	1,522 ft (464m)	N/A
Installation Contractor	██████████	██████████ ██████████ ██████████ ██████████	██████████ ██████████ ██████████ ██████████	N/A
Installation Cost	██████████	██████████	██████████	N/A
Material & Installation Cost	██████████	██████████	██████████	N/A
Scraper and Skirt Rubber	██████████	██████████	██████████	N/A
KU Labor	\$57k	\$57k	\$57k	N/A
Overland Scope Development/Review	██████████	██████████	██████████	N/A
Burdens	\$45k	\$46k	\$46k	N/A
Contingency	\$403k	\$493k	\$543k	N/A
Total Cost	██████████	██████████	██████████	N/A

The GH CCR Pipe Conveyor Belt material is not under contract at this time. The technical and project team preference is the ██████████ proposal. The ██████████ is a high abrasion resistance compound specifically formulated for pipe conveyors. ██████████ 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.

<b>New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.</b>		
#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.





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 15<sup>th</sup>, 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**

Arbough

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 1<sup>st</sup> 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.

<b>Project Cost Build Up (\$000)</b>				
<b>Description</b>	<b>Total</b>	<b>CAP</b>	<b>O&amp;M</b>	<b>Comments</b>
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	
Misc. Consumables & Activities	\$250	\$250		-Processed to the Contract
Company Labor	\$100	\$100		-Scaffolding & Crane inspection.
Contingency	\$500	\$500		-I&C and Electrical support
Burdens	\$559	\$559		-2.6% of total project
				-Capital burdens
<b>Non-LTSA Spend</b>	<b>\$1,409</b>	\$1,409		
<b>Total Project Spend:</b>	[REDACTED]	[REDACTED]	[REDACTED]	

\*Includes Contract Spend to Date (see table below)

\*\*Includes Contract Spend to Date (see table below) and Assumes 1<sup>st</sup> quarter 2019 LTSA invoice with 2% escalation.



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]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

- <sup>1</sup> Removal of sales tax and removal of booking of mandatory spare parts.
- <sup>2</sup> Removal of sales tax for new and expanded exemption.
- <sup>3</sup> Escalation increase due to significant spend being in later years.
- <sup>4</sup> 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 2<sup>nd</sup> 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.





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]

[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] ultimately assumed control / ownership of [REDACTED]. In 2016, [REDACTED] [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.





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, ■■■ 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, ■■■ will bear the first ■■■ of the cost, up to a maximum of ■■■ in any one calendar year. The collateral damage limit is subject to escalation up to the cap of the lesser ■■■ 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 ■■■ as part of this agreement. Many of the parts required to be replaced are considered proprietary to ■■■, 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 ■■■ fleet, there has not been enough demand to warrant a third party market. It is believed that over 90% of the ■■■ GT24 fleet is in some type of agreement with the OEM for parts and services.

Efforts were made to lower ■■■ 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 ■■■ 7FA units. As a result, ■■■ reduced its pricing on the order by \$10 million. In addition, ■■■ included the XL upgrade to extend service intervals, and included additional coverages throughout the term. Final negotiation attempts reduced ■■■ 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.

**Approval Confirmation for Contract Authority Greater Than or Equal to \$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 Investment Committee. Pursuant to the Authority Limit Matrix, the signatures below are also required for approval of this contract authority request.

  
\_\_\_\_\_  
Kent W. Blake  
Chief Financial Officer

*Dot for  
10-31-17*

  
\_\_\_\_\_  
Paul W. Thompson  
President and Chief Operating Officer

  
\_\_\_\_\_  
Victor A. Stafferi  
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]

<b>Sourcing Leader</b>	N/A	<b>Proponent</b>	
		Greg Wilson Supervisor-Production	<i>Greg Wilson</i> 10/26/2017
<b>Supplier Diversity Manager</b>	N/A	<b>Manager</b>	
		Jerry Arnold Manager-Production	<i>Jerry Arnold</i> 10/27/17
<b>Commercial Operations</b>		<b>Commercial Operations</b>	
Bob Barnett Manager - Commercial Operations	<i>Bob Barnett</i> 10/26/17	Joe Clements Director - Power Gen. Commercial Operations	<i>Joe Clements</i> 10/31/2017
<b>Director</b>		<b>Vice President</b>	
Jeff Fraley General Manager, EW Brown	<i>Jeffrey D. Fraley</i> 10/27/17	Ralph Bowling VP Power Production	<i>Ralph Bowling</i> 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.

**From:** Elzy, Tammy **Attachment 4 to Response to PSC-2 Question No. 161**  
**Sent:** Tuesday, October 31, 2017 8:43 AM **Page 21 of 183**  
**To:** Cosby, David; Novak, Lana **Arbough**  
**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](mailto: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.O'Brien@lge-ku.com>; Quinn, Julie <Julie.Quinn@lge-ku.com>; Whelan, Chris <Chris.Whehan@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	
<b>Name</b>	KENT BLAKE	<b>Name</b>	DAN ARBOUGH
<b>Location</b>	LG&E Center 15th floor	<b>Location</b>	LG&E Center 10th floor
<b>Department</b>	Chief Financial Officer	<b>Department</b>	Treasurer
<b>Company</b>	LG&E and KU Services Company	<b>Company</b>	LG&E and KU Services Company
<b>Phone</b>	502/627-2573	<b>Phone</b>	502/627-4956
<b>E-Mail</b>	<a href="mailto:KENT.BLAKE@LGE-KU.COM">KENT.BLAKE@LGE-KU.COM</a>	<b>E-Mail</b>	<a href="mailto:DAN.ARBOUGH@LGE-KU.COM">DAN.ARBOUGH@LGE-KU.COM</a>
<b>Cell Phone</b>	N/A	<b>Cell Phone</b>	N/A
<b>Pager</b>	N/A	<b>Pager</b>	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 14 <sup>th</sup> , 2019 |
| ○ Project Complete                    | November 5 <sup>th</sup> , 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**

Arbough

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.

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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  
Chief Financial Officer

\_\_\_\_\_  
Paul W. Thompson Date  
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.

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.



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 probability 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]	[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)	-	-	-	-	-



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.



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.

\_\_\_\_\_ Date  
Kent W. Blake  
Chief Financial Officer

\_\_\_\_\_ Date  
Paul W. Thompson  
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:**

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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.**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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.



Appendix A

Arbough

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 20<sup>th</sup> 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]  
[REDACTED] A pre-bid meeting was conducted on December 12, 2018. [REDACTED]  
[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.





lowest cost proposal was eliminated due to the major areas of concern listed below:

- 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. execution plan for Unit 1 includes stick building large portions of the structure, rather than the pre-built bent building method 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.
- did not include any site preparation work or costs in their proposals.
- References supplied by have experienced structural vibration and performance issues following rebuilds completed by Two of the three references stated that the towers did not meet their performance guarantees.
- Only one of the reference cooling tower rebuilds provided by was a complete rebuild which included the replacement of the entire structure and all associated mechanical equipment.
- did not include the required dedicated safety person in their proposal.
- cannot provide the requested full access to the fan gear reducers to ensure maintenance access and personnel safety.
- proposal for Unit 1 would result in an addition of approximately 7 feet of pump head, 3 more feet than the tower.
- proposed schedule LDs of \$20k per day are half of s proposed LDs.

Pricing Sheet		Enexio US LLC			EvapTech Inc.		
Item #	Item Description	1	EA	\$			
1	GH4 Labor & Equipment						
	<b>TOTAL BASE BID</b>			\$			\$
7	<b>Man-Hours to Complete Rebuild of Unit 4 (N2)</b>						
8	<b>Man-Hours to Complete Rebuild of Unit 1 (N2)</b>						
9	<b>Labor Normalization Based on Man-Hour Differential (N3)</b>			\$			\$
	<b>Total Normalized Bid</b>			\$			\$
	<b>Notes</b>	N1. 2017 contract amount for the Unit 3 rebuild minus all electrical scope items was a total of less than their current Unit 4 proposal. N2. provided man-hour estimates favorably compare to the actual man-hours required for the Ghent Unit 3 rebuild that they performed. provided man-hours are concerning when compared to the aforementioned Unit 3 rebuild. N3. provided T&M labor rate average The most common daily subsistence rate is \$106.00/day. By assuming ten hour work days, the calculated comprehensive average hourly rate is . 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**

Arbough

[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],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)	-	-	-	-	-

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

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  
Chief Financial Officer

\_\_\_\_\_  
Paul W. Thompson Date  
Chairman, CEO and President

**Attachment 4 to Response to PSC-2 Question No. 161**  
**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 5<sup>th</sup>, 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  
Chief Financial Officer

Date

\_\_\_\_\_  
Paul W. Thompson  
Chairman, CEO and President

Date

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]
[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  
Chief Financial Officer

\_\_\_\_\_  
Paul W. Thompson Date  
Chairman, CEO and President

**Attachment 4 to Response to PSC-2 Question No. 161**  
**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**

Arbough

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  
Chief Financial Officer

\_\_\_\_\_  
Date

\_\_\_\_\_  
Paul W. Thompson  
Chairman, CEO and President

\_\_\_\_\_  
Date

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 4<sup>th</sup> 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.

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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  
Chief Financial Officer

Date

\_\_\_\_\_  
Paul W. Thompson  
Chairman, CEO and President

Date

**Appendix**

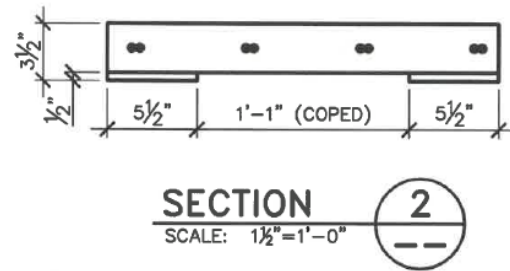
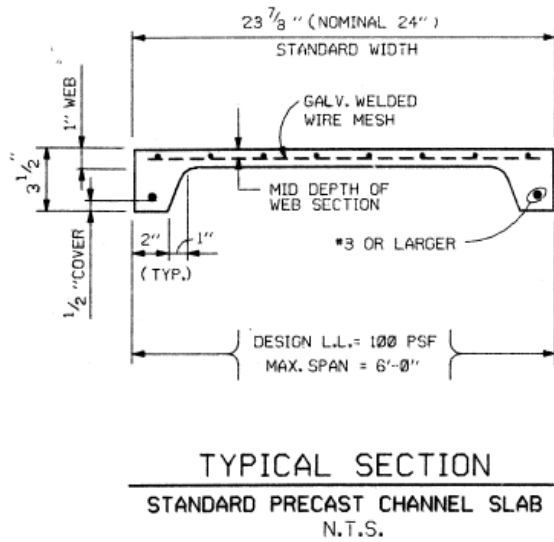
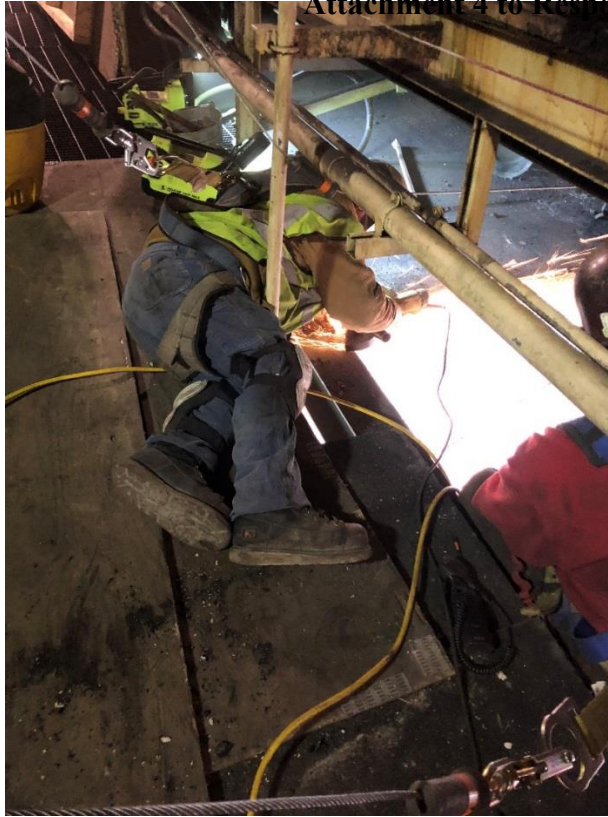


Figure 2. Cross-section of typical existing floor panel.

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

Project 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
- 4<sup>th</sup> 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.

#### **Budget Comparison & Financial Summary**

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.

<b>Financial Detail by Year - Capital (\$000s) Net</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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.



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)

**Business Plan Considerations**

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)
[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]

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



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]	[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] [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 LTFC 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:

- LTFC 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 LTFC 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

### 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, CK7 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]	[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.

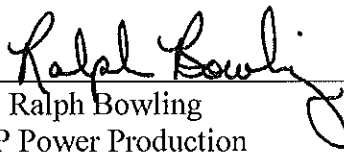
• Other Alternatives Considered


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]

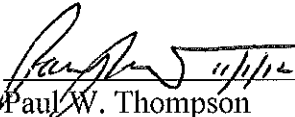
Conclusions and Recommendation

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

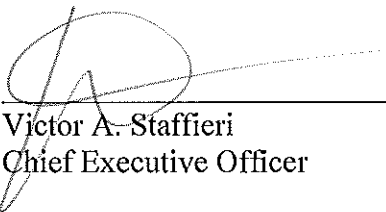
  
D. Ralph Bowling  
VP Power Production

  
Joseph Clements  
Director Pwr. Gen. Comm. Ops.

  
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

**Attachment 4 to Response to PSC-2 Question No. 161**  
**APPENDIX B – CALCULATION OF DEFERRED ACCOUNT ACTIVITY** Page 77 of 183

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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 <sup>1</sup>	Labor (29%)	Total	Material (71%)	Sales Tax <sup>1</sup>	Labor (29%)	Total
23,680	15,320	919	6,257	22,496	806	48	329	1,184

<sup>1</sup>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]

[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]
	[REDACTED]	No Bid	No Bid
<b>Base Price – 4 rows of L0 buckets</b>	[REDACTED]		
<b>Alternative 2* – Install the buckets at [REDACTED]</b>	[REDACTED]		
<b>Cost for Letters of Credit (estimated)</b>	[REDACTED]		
<b>Total Cost – includes Base Price <i>plus Option 2 and LOCs</i></b>	[REDACTED]		
<b>Alternative 1* – Install the buckets at the station</b>	[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.

**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]
[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.)

<b>Financial Detail by Year - Capital (\$000s Net)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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 ██████████ and recommended a Parent Guarantee be obtained. We know from previous contracts with ██████████ that a parent guarantee is not the best option because of their ██████████ ownership. Therefore the contract will require a letter or progress letters of credit equal to or greater than payments made.



Attachment 4 to Response to PSC-2 Question No. 161  
**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.



Figure 1. Comparison of bucket leading edge erosion from 2012 to 2019

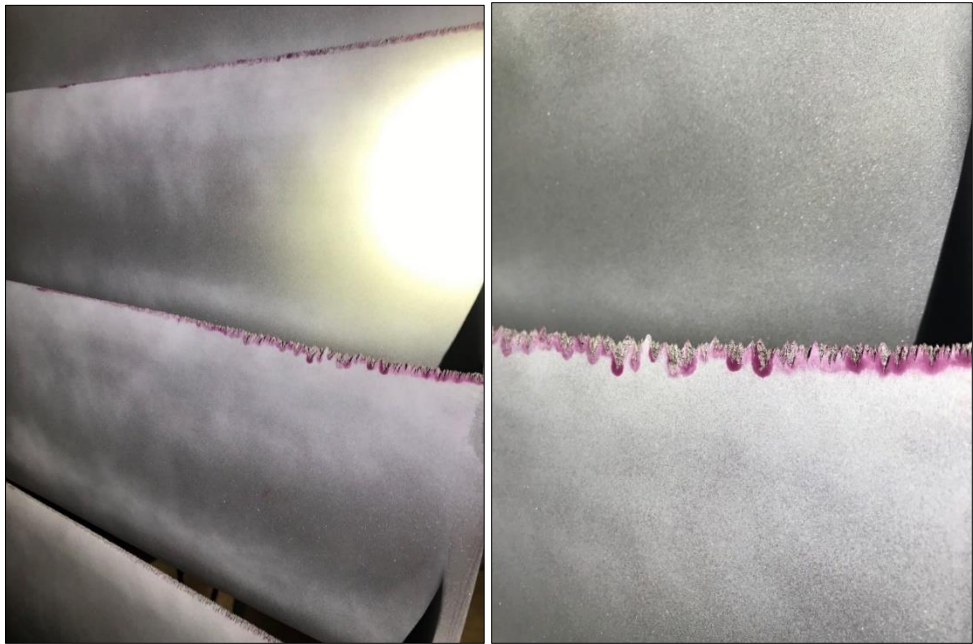


Figure 2. Leading edge erosion in 2019



*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.



██████████ 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 ██████████ 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*

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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)

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

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 LTFC 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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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:

<b>Annual Tube Failure Rate Increase (%)</b>	<b>NPVRR (\$000s)</b>
10	42,837
20	80,975
30	112,642
40	126,270
50	143,877



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 6<sup>th</sup> and ends May 8<sup>th</sup>, 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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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.





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 project 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.**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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.



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: Competitively 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.





Attachment 4 to Response to PSC-2 Question No. 161  
**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
2. Alternative #1: Delay Project One (1) Year
3. Alternative #2: Do Nothing

NPVRR: (\$000s) \$3,707k  
 NPVRR: (\$000s) \$3,732k  
 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



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 DTLS 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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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  
Chief Financial Officer

\_\_\_\_\_  
Paul W. Thompson Date  
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 Kjølby

**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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>Pre-2020</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>Pre-2020</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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) \$4,558 |
| 2. Next Best Alternative:  | NPVRR: (\$000s) \$4,568 |
| <ul style="list-style-type: none"> <li>• The Next Best Alternative is delaying the project until 2022</li> <li>• Inflation of 2% a year is considered.</li> </ul>  |                         |
| 3. Do Nothing:   | NPVRR: (\$000s) \$4,623 |
| <ul style="list-style-type: none"> <li>• The Do Nothing alternative is not completing this project.</li> <li>• 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.</li> </ul> |                         |

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  
Chief Financial Officer

Date

---

Paul W. Thompson  
Chairman, CEO and President

Date

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.

████████████████████ 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 ██████ is proposed. Additionally, with the outbreak of the COVID-19 virus, minimizing additional contract personnel on-site is preferred. Since ██████ 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 ██████ 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.

**Attachment 4 to Response to PSC-2 Question No. 161**  
**Why is the project needed? What if we do nothing?**

█ released Technical Information Letter █ in May 1991 identifying several types of leaks for █ 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, █ which recommends █, 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.

\_\_\_\_\_ Date  
 Kent W. Blake  
 Chief Financial Officer

\_\_\_\_\_ Date  
 Paul W. Thompson  
 Chairman, CEO and President



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Attachment 4 to Response to PSC-2 Question No. 161

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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]

[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.

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Attachment 4 to Response to PSC-2 Question No. 161

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**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

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basis. Liquidated damages have been included in Attachment 4 for Responder PSC 2 Question No. 161 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. **Arbough**

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.

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**Attachment 4 to Response to PSC-2 Question No. 161**

The following table summarizes the evaluated costs and recommended contract value. 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.

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	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Total Evaluated Cost All 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
	<b>Total</b>		[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
	<b>Total</b>		[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

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Case No. 2020-00350

**Financial Summary**

**Attachment 4 to Response to PSC-2 Question No. 161**

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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)	[REDACTED]	[REDACTED]	[REDACTED]
Property Damage – Turbine Components	[REDACTED]	[REDACTED]	[REDACTED]
Umbrella Insurance	[REDACTED]	[REDACTED]	[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.

CONFIDENTIAL INFORMATION REDACTED

Case No. 2020-00350

Attachment 4 to Response to PSC-2 Question No. 161  
 Page 125 of 183  
 Arbough

- [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.

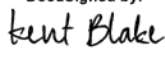
**Conclusions and Recommendation**


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:  
  
 12/21/2018 | 10: 05 AM PST  
 C055E680F1EB443  
 Kent W. Blake  
 Chief Financial Officer

DocuSigned by:  
  
 12/26/2018 | 7: 03 AM PST  
 57E11AF682314EE...  
 Paul W. Thompson  
 Chairman, CEO and President

CONFIDENTIAL INFORMATION REDACTED

Case No. 2020-00350

**AWARD RECOMMENDATION APPROVALS** PSC-2 Question No. 161

**- Attachment for IC Proposal**

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Arbough


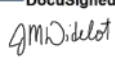

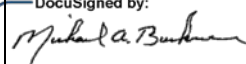

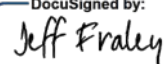
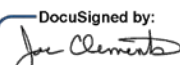



**SUBJECT:**

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]

[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] and [REDACTED] should final negotiations with [REDACTED] fail.

Contracts Administrator Ross Lerch Date 12/18/2018   10: 19	DocuSigned by:  AM EST FDB0E4F7...	General Manager Mill Creek Joe Didelot Date 12/18/2018   9: 51	DocuSigned by:  AM PST 74B3803FAB724DC...
Commercial Operations Manager Bob Barnett Date 12/17/2018   8: 48	DocuSigned by:  AM EST BE2121BBD7EA431...	General Manager Trimble County Mike Buckner Date 12/18/2018   7: 44	DocuSigned by:  AM PST CF839BC5CADD4A1...
Manager Turbine / Generator Maint. KR Noonan Date 12/17/2018   9: 43	DocuSigned by:  AM EST 42D1C1830E654F9...	General Manager EW Brown Jeff Fraley Date 12/18/2018   12: 58	DocuSigned by:  PM EST F830E2617BEE4A0...
Director - Supply Chain/Commercial Operations Date 12/18/2018   10: 49	DocuSigned by:  AM EST 39D42989FEA84C9...	General Manager Ghent Steve Turner Date 12/18/2018   7: 06	DocuSigned by:  AM PST 8AD647306F3F4A0...
Director -Generation Services Mike Drake Date 12/18/2018   3: 08	DocuSigned by:  M EST 6D27173501AD4A6...	Vice President Mike Production Ralph Bowling Date 12/18/2018   3: 16	DocuSigned by:  PM EST 901D57ABEB06435...

CONFIDENTIAL INFORMATION REDACTED

**Attachment 1 - Fleet T/G Contract Account Summary** Response to PSC-2 Question No. 161

	2018	2019	2020	2021	Total
2018 incremenatl blade					
<b>2019</b>					
Mill Creek 1 - Major					
KU Ghent 2 Major with Valve					
LG&E Mill Creek 3 Major with Valve					
KU EW Brown 3 Major with Valve & FPT incremntal blade					
Ghent 1 FPT					
Ghent 4 Valve					
Trimble County 1 Valve					
<b>2020</b>					
KU Ghent 4 Major					
Ghent 1 Valve					
Trimble County 2 FPT and valve					
Ghent 3 Valve					
Mill Creek 2 Valve					
<b>2021</b>					
Ghent 1 Major					
Trimble County 1 FPT					
Mill Creek 1 Valve					
Summary - Awarded EWB 3					
<b>2018</b>					
<b>2019</b>					
subtotal cap + Opex + SP repairs					
Total Contingency					
<b>2020</b>					
subtotal cap + Opex + SP repairs					
Total Contingency					
<b>2021</b>					
subtotal cap + Opex + SP repairs					
Total Contingency					
<b>total contract</b>					
<b>total contingency</b>					
<b>total rounded</b>					
<b>Total Contract</b>					
<b>Total Contingency</b>					





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&amp;E ERS Website

Attachment 4 to Response to PSC-2 Question No. 161

Sent: Monday, December 17, 2018 12:15 PM

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Subject: Delegation Of Authority Notification For MICHAEL DRAKE to MICHAEL GOSEKAMP

Arbough

**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		Authority being delegated to	
<b>Name</b>	MICHAEL DRAKE	<b>Name</b>	MICHAEL GOSEKAMP
<b>Location</b>	LG&E Center 8th floor	<b>Location</b>	LG&E Center 8th floor
<b>Department</b>	Dir Generation Services	<b>Department</b>	Dir Generation Services
<b>Company</b>	LG&E and KU Services Company	<b>Company</b>	LG&E and KU Services Company
<b>Phone</b>	502/627-4075	<b>Phone</b>	502/627-2312
<b>E-Mail</b>	<a href="mailto:MICHAEL.DRAKE@LGE-KU.COM">MICHAEL.DRAKE@LGE-KU.COM</a>	<b>E-Mail</b>	<a href="mailto:MICHAEL.GOSEKAMP@LGE-KU.COM">MICHAEL.GOSEKAMP@LGE-KU.COM</a>
<b>Cell Phone</b>	N/A	<b>Cell Phone</b>	6033722015
<b>Pager</b>	N/A	<b>Pager</b>	

**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<sub>x</sub>) 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<sub>x</sub> 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
- 3<sup>rd</sup> Quarter 2020 Issue Contract for removal/installation labor
- 4<sup>th</sup> 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.

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

In order to continue to meet NO<sub>x</sub> emission limits, it is recommended to replace the GH1 Layer 2 SCR catalysts before catalyst deactivation results in NO<sub>x</sub> 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<sub>x</sub> removal rates and minimize ammonia slip.

**Budget Comparison & Financial Summary**

Arbough

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<sub>x</sub> emission limit:* If the proposed catalyst layer is not replaced, there is a risk that NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> emissions non-compliance



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.



A ■ 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. ■ is aware of the issue and has provided an 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 ■ 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**

Arbough

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]	[REDACTED]	[REDACTED]

**Contract Financial Summary**

Contract expenses (\$k)	2020	2021	Total
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[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**

Arbough

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.



**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.

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.





**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:



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:**

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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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>Post 2022</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>Post 2022</b>	<b>Total</b>
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.



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 3<sup>rd</sup> and ends May 1<sup>st</sup>, 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:

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
<b>Total</b>	<b>464</b>

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  
Chief Financial Officer

\_\_\_\_\_  
Paul W. Thompson Date  
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 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, issued Technical Information Letter (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, 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.

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.



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:**

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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**

- |  |  |
|--|--|
| <ol style="list-style-type: none"> <li>1. Recommendation:</li> <li>2. Structural Refurbishment:</li> <li>3. Do Nothing (Run until failure):</li> </ol> | <p>NPVRR: (\$000s) 5,193</p> <p>NPVRR: (\$000s) 5,619</p> <p>NPVRR: (\$000s) 5,773</p> |
|--|--|

- 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.

\_\_\_\_\_ Date  
 Kent W. Blake  
 Chief Financial Officer

\_\_\_\_\_ Date  
 Paul W. Thompson  
 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:**

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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.

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>Post 2022</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>Post 2022</b>	<b>Total</b>
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



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.



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<sub>x</sub>) 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 aid in compliance with NO<sub>x</sub> 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 1<sup>st</sup> 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).

**Attachment 4 to Response to PSC-2 Question No. 161**  
**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<sub>x</sub> 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<sub>x</sub> 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                            |
| • 1 <sup>st</sup> Quarter 2021 | Issue PO for new sonic horns and associated material                |
| • 1 <sup>st</sup> Quarter 2021 | Issue PO for catalyst and sonic horn installation                   |
| • 2 <sup>nd</sup> Quarter 2021 | Issue PO for Industrial cleaning of the SCR                         |
| • 2 <sup>nd</sup> 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                           |

**Attachment 4 to Response to PSC-2 Question No. 161**

**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<sub>x</sub> emissions will increase and pose a risk to the unit's reliability. Additionally, there is a risk that NO<sub>x</sub> 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 aids in NO<sub>x</sub> 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<sub>x</sub> 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 NO<sub>x</sub> 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  
Chief Financial Officer

\_\_\_\_\_  
Paul W. Thompson Date  
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



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** Attachment 4 to Response to PSC-2 Question No. 161

- 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  
Chief Financial Officer

\_\_\_\_\_  
Paul W. Thompson Date  
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 12<sup>th</sup> 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.

**Attachment 4 to Response to PSC-2 Question No. 161**  
**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 mechanical stress, thermal cycles, 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. That project included replacement corner panels with partial Inconel 622 overlay, which were supplied by [REDACTED], proving successful OEM supply of these panels.

Failing to complete this project will 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**

Arbough

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 firm, 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 completing the project is 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 have reviewed and approved this 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 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 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 approval of the GH1 Burner Corner Tube Replacement project for \$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 Date  
Chief Financial Officer

\_\_\_\_\_  
Paul W. Thompson Date  
Chairman, CEO and President

**AWARD RECOMMENDATION APPROVALS**  
**– Attachment for IC Proposal**

**SUBJECT:**

Ghent 1 Burner Corner Tube Material 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 SSA Ghent 1 Burner Corner Tube Material Contract for [REDACTED] (inclusive of \$113k contingency) to [REDACTED].

Sourcing Leader		Proponent/Team Leader	
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 included as 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.



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<sup>st</sup> quarter of 2021.

### **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 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 “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 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.

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 18<sup>th</sup>, 2021
- Project Complete October 21<sup>st</sup>, 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.

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>Post 2023</b>	<b>Total</b>
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

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>Post 2022</b>	<b>Total</b>
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.





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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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	-	-	-

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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.



**PowerPlan Upgrade Project and Contract Investment Proposal**

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.

<b>Risk Event</b>	<b>Cause</b>	<b>Result</b>
Inaccurate/delayed information for decision making	Human error/manual processes	<ul style="list-style-type: none"> <li>• Suboptimal strategic planning decisions based on inaccurate forecasted financial statements</li> <li>• Inaccurate cost of service assumptions resulting in incorrect rate for customers</li> <li>• Brand damage</li> </ul>
Incorrect SEC financial statements	Human error/manual processes	<ul style="list-style-type: none"> <li>• Rework required for restatement</li> <li>• Additional external audit fees</li> <li>• Control failures</li> <li>• Brand damage</li> </ul>
Inability to close the books	Technical issue(s) cannot be resolved in-house and PowerPlan support has expired	<ul style="list-style-type: none"> <li>• Delayed reporting to PPL</li> <li>• Increased manual workarounds</li> <li>• Delayed issuance of SEC financial statements</li> <li>• Brand damage</li> </ul>
Inaccurate rate case information	Human error/manual processes	<ul style="list-style-type: none"> <li>• Brand damage</li> <li>• Incorrect cost recovery, potentially to the detriment of customers</li> <li>• Rework required to correct filings</li> </ul>

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<sup>1</sup>. 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**

<b>Contract expenses (\$k)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>Post 2023</b>	<b>Total</b>
<b>Amount requested based on contract award estimates</b>	\$1,495	\$748					\$2,243
<b>Contingency Amount Requested</b>	\$126	\$253					\$379
<b>Total contract authority requested</b>	\$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	<u>379</u>
Grand Total	<u>\$2,622</u>

<sup>1</sup> “PowerPlan Software” survey conducted August 2018 and “Fixed Asset Accounting Systems” survey conducted December 2018

**Project Financial Summary**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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
<u>Property tax</u>	<u>\$ 80k</u>
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.



**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 circuit 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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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)	-	-	-	-	-

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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.

### Alternatives Considered

LKS, in conjunction with Burns & McDonnell, conducted a 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.

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Kent W. Blake  
Chief Financial Officer

Date

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Paul W. Thompson  
Chairman, CEO and President

Date

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

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

- 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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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”





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**

<b>Contract expenses (\$k)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>Post 2023</b>	<b>Total</b>
<b>Amount requested based on contract award estimates</b>	\$990k	\$691k					\$1,680k
<b>Contingency Amount Requested</b>	\$69k	\$69k					\$138k
<b>Total contract authority requested</b>	\$1059k	\$760k					\$1,819k

A breakdown of contract costs is summarized below (in \$000s):

System Upgrade	\$1,381
Licenses	300
Contingency on Capital Spend	<u>138</u>
Grand Total	<u>\$1,819</u>

**Project Financial Summary**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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
<u>CWIP (property tax)</u>	<u>\$ 25k</u>
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.

**Project Alternatives Considered**

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.



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?**

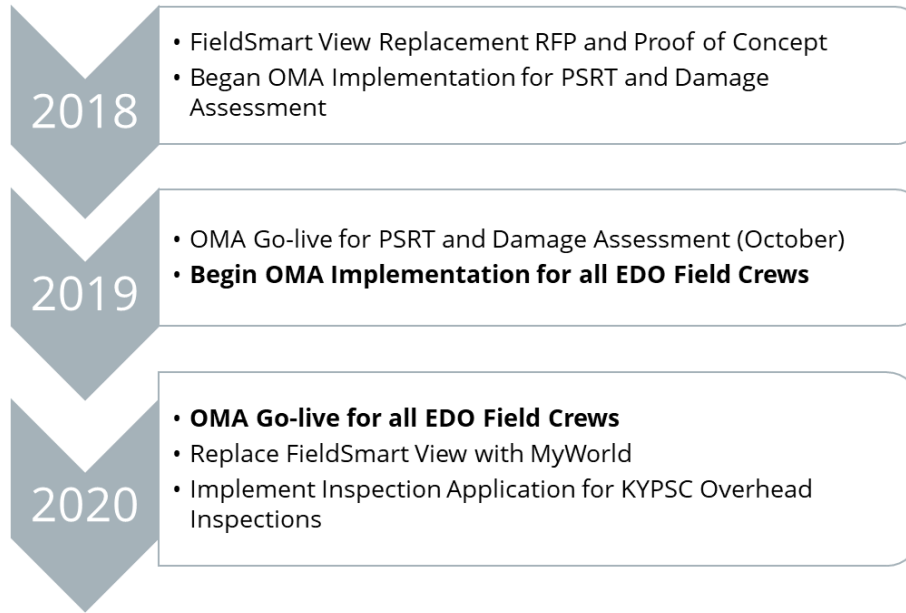
Customer outages are managed using Oracle Utilities' Network Management System (NMS). Distribution Control Center (DCC) operators and Public Safety Response Team (PSRT) dispatchers dispatch events from the NMS to field crews who use Panasonic ToughBooks running ABB's Service Suite and GE's FieldSmart 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.



**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  
Chief Financial Officer

Date

\_\_\_\_\_  
Paul W. Thompson  
Chairman, CEO and President

Date

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. **Arbough**

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.

<b>Contract expenses (\$k)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>Post 2023</b>	<b>Total</b>
<b>Amount requested based on contract award estimates</b>	\$1,966	\$530	\$530	\$530	\$440	0	\$3,996
<b>Contingency Amount Requested</b>	\$0	\$0	\$0	\$200	\$200	\$0	\$400
<b>Total contract authority requested</b>	\$1,966	\$530	\$530	\$730	\$640	\$0	\$4,396

**Project Financial Summary**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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.





**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 Ebony 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 4<sup>th</sup> 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**

<b>Contract expenses (\$k)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>Post 2023</b>	<b>Total</b>
<b>Amount requested based on contract award estimates</b>	2,253	1,253	1,253	1,278			6,037
<b>Contingency Amount Requested</b>	0	0	0	0			
<b>Total contract authority requested</b>	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



**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?**

Arbough

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]. [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**

<b>Cost Summary Phase I (\$k)</b>		
SI Labor	2,534	3,214
SI Travel	369	559
<b>Subtotal of SI Cost</b>		

**Bid Evaluation Summary Phase I**

<b>Bid Criteria</b>	<b>Maximum Score</b>	<b>Schneider Electric</b>			<b>RAMTeCH</b>
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	
	<b>100</b>		<b>83</b>	<b>100</b>	

**Contract Financial Summary**

<b>Contract expenses (\$k)</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Total</b>
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:

<b>Capital cost (\$000)</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>Total</b>
<b>Phase I</b>	\$ 900				\$ 900
<b>Phase II</b>	\$ 11,230	\$ 3,131			\$ 14,361
<b>Phase III</b>		\$ 4,739	\$ 7,000	\$ 2,400	\$ 14,139
<b>Total</b>	\$ 12,130	\$ 7,870	\$ 7,000	\$ 2,400	
<b>2019 BP</b>	\$ 12,000	\$ 8,000	\$ 7,000	\$ 2,400	\$ 29,400
<b>Variance to '19 BP</b>	\$ (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.



**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 Ebony 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 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. 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





**Combined Project and Contract Investment Proposal for Oracle Upgrade Project**

Arbough

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<sup>1</sup> 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

<sup>1</sup> 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<sup>2</sup>, 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

<sup>2</sup> 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 3<sup>rd</sup> 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] [REDACTED] [REDACTED] [REDACTED] [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.

<b>Section/Questions</b>	<b>[REDACTED]</b>	<b>[REDACTED]</b>
MBE/WBE designation	Large	Large
	<b>Weighted Score</b>	<b>Weighted Score</b>
<b>Grand Total of Scores</b>	<b>100</b>	<b>84</b>
<b>Supplier Rank</b>	<b>1</b>	<b>2</b>
Work Plan	33	33
Resumes	10	10
Timeline	24	24
Pricing	29	13
Clarifications	5	5
<b>Grand Total of Scores</b>	<b>100</b>	<b>84</b>
<b>Supplier Rank</b>	<b>1</b>	<b>2</b>
<b>Total Cost</b>	<b>[REDACTED]</b>	<b>[REDACTED]</b>

**Contract Financial Summary**

<b>Contract expenses (\$k)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>Post 2023</b>	<b>Total</b>
<b>Amount requested based on contract award estimates</b>							
-Assessment (O&M)	\$563k	\$0	\$0				\$563k
-Phase 0 (Capital)	\$282k	\$642k	\$0				\$924k
-Implementation (O&M)	\$ 0	\$666k	\$167k				\$833k
-Implementation (Capital)	\$ 0	\$10,187k	\$1,969k				\$12,156k
<b>Total</b>	<b>\$845k</b>	<b>\$11,495k</b>	<b>\$2,136k</b>				<b>\$14,476k</b>
<b>Contingency Amount Requested</b>	\$0	\$0	\$1,299k				\$1,299k
<b>Total contract authority requested</b>	<b>\$845k</b>	<b>\$11,495k</b>	<b>\$3,435k</b>				<b>\$15,775k</b>

**Project Financial Summary**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Post 2021</b>	<b>Total</b>
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. **Arbough**

<b>Project O&amp;M</b>	<b>2020</b>	<b>2021</b>	<b>2022-2024</b>	<b>Total</b>
<b><i>Business Plan O&amp;M</i></b>				
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
<b><i>Current O&amp;M in Business Plan</i></b>	<b><i>\$1,655k</i></b>	<b><i>\$1,617k</i></b>	<b><i>\$3,734k</i></b>	<b><i>\$7,006k</i></b>
<b><i>Incremental O&amp;M</i></b>				
██████████	\$666k	\$250k	\$0	\$916k
Internal O&M (backfilled labor)	\$173k	\$89k	\$0	\$262k
New Support and Maintenance	\$144k	\$149k	\$487k	\$780k
<b><i>Incremental O&amp;M</i></b>	<b><i>\$983k</i></b>	<b><i>\$488k</i></b>	<b><i>\$487k</i></b>	<b><i>\$1,958k</i></b>
<b>Total Project O&amp;M</b>	<b>\$2,638k</b>	<b>\$2,105k</b>	<b>\$4,221k</b>	<b>\$8,964</b>

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
<b>Total</b>		<b>\$974k</b>	<b>\$711k</b>	<b>\$1,685k</b>

**Credit Review**

- A credit review was conducted on [REDACTED] the parent of [REDACTED] which identified no risks. [REDACTED] has signed a Parent Guaranty for [REDACTED]

**Project Alternatives Considered**

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.



**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 Ebony 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<sup>1</sup>

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.

<sup>1</sup> 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**

<b>Contract expenses (\$k)</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>2024</b>	<b>Post 2024</b>	<b>Total</b>
<b>Amount requested based on contract award estimates</b>	\$700	\$1,600					\$2,300
<b>Contingency Amount Requested</b>	\$0	\$200					\$200
<b>Total contract authority requested</b>	\$700	\$1,800					\$2,500

**Project Financial Summary**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>Post 2022</b>	<b>Total</b>
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)

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>Post 2022</b>	<b>Total</b>
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.



**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 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**

<b>Financial Detail by Year - Capital (\$000s)</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>Post 2023</b>	<b>Total</b>
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

<b>Financial Detail by Year - O&amp;M (\$000s)</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>Post 2023</b>	<b>Total</b>
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.

