COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR APPROVAL OF ITS 2020 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	**)))))**	**CASE NO. 2020-00060**

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR APPROVAL OF ITS 2020 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	**)))))**	**CASE NO. 2020-00061**

DIRECT TESTIMONY OF
ROBERT M. CONROY
VICE PRESIDENT, STATE REGULATION AND RATES
KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: March 31, 2020

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Background

Q. Please state your name, position, and business address.

A. My name is Robert M. Conroy. I am the Vice President of State Regulation and Rates for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") and an employee of LG&E and KU Services Company, which provides services to LG&E and KU (collectively "Companies"). My business address is 220 West Main Street, Louisville, Kentucky, 40202. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes. For almost 15 years, I testified before this Commission in numerous proceedings, including the Companies' most recent base rate cases[1] and the last five environmental cost recovery ("ECR") compliance plan proceedings.[2]

Q. What are the purposes of your testimony?

A. My testimony summarizes the Companies' other witnesses' testimony and the requests for approval of KU's and LG&E's 2020 Environmental Compliance Plans ("2020 Plans"). I will explain why certificates of public convenience and necessity ("CPCNs") are not necessary for facilities contained in the Companies' 2020 Plans. I will also explain why the Companies are seeking environmental surcharge recovery of their 2020 Plans through the Environmental Cost Recovery ("ECR") Surcharge tariff beginning with bills that reflect the expense month September 2020 and note that they will use the 9.725% return on

[1] Case Nos. 2018-00294 (KU) and 2018-00295 (LG&E).

[2] The last five ECR compliance plan proceedings include 2018 (Case No. 2017-00483 (KU)), 2016 (Case Nos. 2016-00026 (KU) and 2016-00027 (LG&E)), 2011 (Case Nos. 2011-00161 (KU) and 2011-00162 (LG&E)), 2009 (Case Nos. 2009-00197 (KU) and 2009-00198 (LG&E)), and 2006 (Case Nos. 2006-00206 (KU) and 2006-00207 (LG&E)).

common equity from the Companies' last rate cases for purposes of calculating the ECR charges.[3] I will also address the financing of the proposed construction of facilities.

Overview of Testimony

Q. Please provide an overview of the testimony of the witnesses supporting the Companies' applications in these proceedings.

A. In addition to my testimony, the Companies are presenting the testimony of four other witnesses in support of these applications. These witnesses and the subjects of their testimonies are:

- Gary H. Revlett, Director, Environmental Affairs, presents testimony discussing the environmental regulations that necessitate the Companies' 2020 Plans and explains how the 2020 Plans' projects will achieve compliance with the environmental regulations.
- R. Scott Straight, Vice President, Project Engineering, presents testimony that describes the engineering and construction aspects of the projects in the Companies' 2020 Plans, and the projects' costs. Also, Mr. Straight sponsors the 2020 Plans.
- Stuart A. Wilson, Director, Energy Planning/Analysis/Forecasting, presents testimony on the cost-effectiveness of the projects in the Companies' 2020 Plans, and presents, as an exhibit, the economic analysis the Companies performed related to the 2020 Plans.
- Andrea M. Fackler, Manager, Revenue Requirement/Cost of Service, presents testimony addressing how the environmental surcharge under the Companies' ECR

[3] *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2018-00294, Order (Ky. PSC Apr. 30, 2019); *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, Case No. 2018-00295, Order (Ky. PSC Apr. 30, 2019).

tariff provisions will be calculated to include the costs of the 2020 Plans, presents the revisions to the monthly ECR reporting forms that the Companies propose and explains why the revisions to the forms are appropriate, details the costs included in base rates, and discusses the bill impact on the Companies' customers.

2020 Plans and Recovery

Q. Please briefly describe why the projects in the 2020 Plans are necessary.

A. As the Companies explained in their 2016 ECR cases, the Companies anticipated that the Environmental Protection Agency's ("EPA") 2015 Effluent Limitations Guidelines ("2015 ELG") Rule would result in additional compliance related expenditures "over the next several years."[4] The Companies are now proposing the projects in the 2020 Plans to comply with the 2015 ELG Rule and will allow for compliance with the recently proposed revisions to the 2015 ELG Rule.[5] The 2015 ELG Rule imposes requirements on the levels of allowable nitrates, nitrites, and selenium that cannot be achieved with the Companies' recently commissioned process water treatment systems at its Ghent, Mill Creek, and Trimble County Generating Stations. Therefore, the Companies need to build additional ELG water treatment systems to treat the effluent coming from the current process water treatment systems to achieve the levels mandated by the 2015 ELG Rule and its 2019 proposed revisions, which are expected to become final later this year.

Q. Please describe the 2020 Plans the Companies are proposing in these proceedings.

A. KU's and LG&E's 2020 Plans each contain two new capital projects. More specifically, KU's 2020 Plan contains projects to construct the ELG water treatment system, a

[4] Case Nos. 2016-00026 and 2016-00027, Revlett Direct Testimony at 16 (Ky. PSC filed Jan. 29, 2016).
[5] The proposed revisions to the 2015 ELG Rule are available at https://www.govinfo.gov/content/pkg/FR-2019-11-22/pdf/2019-24686.pdf.

wastewater diffuser, and a Bottom Ash Transport Water ("BATW") recirculation system at Ghent (KU Project 43) and the ELG water treatment system at Trimble County (KU Project 44). LG&E's 2020 Plan contains projects to construct the ELG water treatment system and wastewater diffuser at Mill Creek (LG&E Project 31) and the ELG water treatment system at Trimble County (LG&E Project 32). Trimble County is jointly owned by KU and LG&E and the costs of the construction of the ELG water treatment system at Trimble County will be allocated 48% to KU and 52% to LG&E according to the Companies' proportional shares.

Although the 2015 ELG Rule applies to KU's Brown Generating Station, the Companies are not proposing any compliance projects at this time. Brown does not have the same water usage needs as at Ghent, Trimble County, and Mill Creek. In fact, at Brown, water use is close to a "net neutral," which could mean the possibility of eliminating water discharge at this generation station altogether. And even if that does not happen, the steps that would have to be taken at Brown to comply with the 2015 ELG Rule and the 2019 proposed revisions are minor compared to the other stations and can be completed much more quickly. Therefore, the Companies are delaying a decision at Brown and are not proposing any compliance projects for Brown in these cases.

Q. Please describe KU Project 43 at Ghent.

A. KU Project 43 consists of a new ELG water treatment system at Ghent to be built downstream from the recently completed process water treatment system to handle water flow capacity up to 1,000 gallons per minute. The project also includes the installation of a wastewater diffuser that will extend into the Ohio River to help diffuse the return waters at their point of entry into the river and the BATW recirculation system. Details of the construction are further described in the testimony of Mr. Straight. The total projected capital cost of this project is $216.5 million. Mr. Wilson's testimony and the economic analyses he sponsors demonstrate that this capital investment is economical.

Q. Please describe LG&E Project 32 and KU Project 44 at Trimble County.

A. LG&E Project 32 and KU Project 44 consist of a new ELG water treatment system at Trimble County to be built downstream from the recently completed process water treatment system to handle water flow capacity up to 600 gallons per minute. The total capital cost of the ELG water treatment system at Trimble County is projected to be approximately $99.6 million of which KU and LG&E will be responsible for $74.7 million net.[6] Of the net cost, $35.9 million will be KU and $38.8 million will be LG&E. Details of the construction are further described in the testimony of Mr. Straight. Mr. Wilson's economic analyses show that building these facilities is economical to enable ongoing coal-fired generating operations at Trimble County.

Q. Please describe LG&E Project 31 at Mill Creek.

A. LG&E Project 31 consists of a new ELG water treatment system at Mill Creek downstream from the recently completed process water treatment system to handle water flow capacity up to 600 gallons per minute with conceptual design showing and construction reserving the area necessary to increase the flow capacity to 750 gallons per minute should it be necessary. The project also includes the installation of a wastewater diffuser that will extend into the Ohio River to help diffuse the returned waters at their point of entry into the river. Details of the construction are described in the testimony of Mr. Straight. The

[6] The net capital figure for Trimble County represents the capital investment corresponding to the Companies' total relative ownership of Trimble County Units 1 and 2. Illinois Municipal Electric Agency and Indiana Municipal Power Association collectively own 25 percent of the capacity of both units, and the costs attributable to that portion of units are reflected in the total project cost. The partners share is excluded from recovery in KU's and LG&E's ECR Plans.

total projected capital cost for Mill Creek is $113.9 million. Mr. Wilson's economic analyses show that building these facilities is economical to enable ongoing coal-fired generating operations at Mill Creek.

Q. How do the Companies propose to recover the cost of the projects in their 2020 Plans?

A. The Companies propose to recover the cost of the projects in their 2020 Plans through each of the Companies' Rate Schedule ECR filed with this application and proposed to be effective for bills that reflect the expense month September 2020 (i.e., six months after the filing of the application in this proceeding, in accordance with KRS 278.183(2)).

Q. Why is it appropriate for the Companies to recover the costs of their 2020 Plan projects through their ECR mechanisms?

A. The relevant part of Kentucky's ECR statute states:

> [A] utility shall be entitled to the current recovery of its costs of complying with . . . those federal, state, or local environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal in accordance with the utility's compliance plan . . . .

As Mr. Revlett explains in his testimony, the ELG projects are needed to comply with the EPA's proposed rulemaking on changes to the 2015 ELG Rule applicable to both flue gas desulfurization wastewater and BATW used in conjunction with the Companies' steam generating units. Therefore, it is appropriate for the Companies to recover the costs of the 2020 Plan projects through their ECR mechanisms because the projects are necessary to comply with federal environmental requirements.

Q. Will the installation of the projects in the 2020 Plans replace or cause existing facilities to be removed from service?

A. No, they will not. As Mr. Revlett describes further in his testimony, the projects in the 2020 Plans are required to comply with the 2015 ELG Rule and the recently proposed revisions, which imposes new requirements on the Companies for wastewater treatment. The 2020 Plan projects will work in conjunction with the projects constructed to comply with other federal and state environmental requirements.

Q. Are the Companies seeking CPCNs for the projects in the 2020 Plans?

A. No. The Companies evaluated the need for CPCNs for the projects in the 2020 Plans in accordance with their evaluation process and determined that CPCNs are not required.

Q. Please describe the Companies' evaluation process to determine if CPCNs are necessary.

A. KRS 278.020(1) and 807 KAR 5:001, Section 15(3) identify the facilities for which a CPCN is not required. The Commission has distilled its regulation into a review of three factors, concluding that a CPCN is not necessary for projects that do not result in the wasteful duplication of utility plant, do not compete with the facilities of other public utilities, and do not involve capital expenditures that would materially affect the existing financial condition of the utility.[7] The Companies' evaluation process is centered on an analysis of these three factors as they have been described in Kentucky law and regulations, Commission orders, and Commission Staff Opinions. The Companies further described their CPCN evaluation process in their 2018 rate cases.[8]

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[7] *The Application of Northern Kentucky Water District (A) For Authority to Issue Parity Revenue Bonds in the Approximate Amount of $16,545,000; and (B) A Certificate of Convenience and Necessity for the Construction of Water Main Facilities*, Case No. 2000-00481, Order at 4 (Ky. PSC Aug. 30, 2001) (referring to Section 15(3) prior to revisions in 807 KAR 5:001 resulted in renumbering).

[8] *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2018-00294, Post-Hearing Brief at 16-17 (Ky. PSC filed Apr. 1, 2019); *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, Case No. 2018-00295, Post-Hearing Brief at 16-17(Ky. PSC filed Apr. 1, 2019); *see also* Case No. 2018-00294, KU's Response to DR 49 of Commission Staff's Second Request for Information, KU's Response to DR 20 of the Commission Staff's Third Request for Information; Case No. 2018-0295, LG&E's Response to DR 58 of Commission Staff's Second Request for Information, LG&E's Response to DR 20 of the Commission Staff's Third Request for Information.

The projects in the 2020 Plans do not result in the wasteful duplication of utility plant as they are new facilities required to comply with federal environmental regulations. The projects do not compete with the facilities of existing public utilities as they are all constructed on the property of the Companies for their generating facilities. Regarding financial materiality, if a project's expected cost represents less than five percent of current net utility plant, the Companies consider it as having no material effect on their financial condition and conclude that no CPCN is required.[9] The capital cost of the Ghent project represents only 3.1%[10] of KU's net utility plant; the Mill Creek project represents only 2.6%[11] of LG&E's net electric utility plant; and the Trimble County project represents only 0.5%[12] of KU's net utility plant and 0.9%[13] of LG&E's net electric utility plant. Thus, the projects do not meet the CPCN financial materiality criterion used by the Companies in determining whether to request a CPCN.

Q. Notwithstanding the Companies' position on the need for CPCNs, do the Companies' Applications provide the necessary information for the Commission to grant CPCNs?

A. Yes. I would reiterate that CPCNs should not be required for the projects in the 2020 Plans. But the Companies' Applications in these proceedings do contain the information required

[9] *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2018-00294, Post-Hearing Brief at 16-17 (Ky. PSC filed Apr. 1, 2019); *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, Case No. 2018-00295, Post-Hearing Brief at 16-17(Ky. PSC filed Apr. 1, 2019).

[10] As reported in KU's 2019 Annual Report to the Commission, as of December 31, 2019, KU had total net utility plant of $6,912,079,873. Project 43 is projected to cost $216.5 million. Therefore, ($216,500,000/$6,912,079,873) = 3.1%.

[11] As reported in LG&E's 2019 Annual Report to the Commission, as of December 31, 2019, LG&E had total net electric utility plant of $4,392,912,894. Project 31 is projected to cost $113.9 million. Therefore, ($113,900,000/$4,392,912,894) = 2.6%.

[12] $35,900,000/$6,912,079,873= 0.5%.

[13] $38,800,000/$4,392,912,894 = 0.9%.

by 807 KAR 5:001, Section 15(2) in order for the Commission to grant CPCNs for the projects if it determines CPCNs are necessary.

Q. How do the Companies plan to finance the 2020 Plan projects?

A. The Companies expect to finance the costs of the new facilities with a combination of new debt and equity. The mix of debt and equity used to finance the project will be determined so as to allow the Companies to maintain their strong investment-grade credit ratings. To the extent that tax-exempt financing may be available for these projects, the Companies anticipate using such opportunities to the extent that they are reasonably cost-effective. Note that the Companies do not engage in project financing.

Return on Equity

Q. What return on common equity are the Companies currently using in their ECR tariffs?

A. The Companies currently use a 9.725% return on common equity consistent with the Commission approved return on equity of 9.725% for both KU and LG&E in their 2018 base rate cases.[14]

Q. What return on common equity are the Companies requesting in this proceeding?

A. The Companies are requesting a continuation of the 9.725% return on common equity. The Commission's recent review and approval in the Companies' ECR two-year review cases confirmed the use of 9.725% return on common equity.[15]

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[14] *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2018-00294, Order (Ky. PSC Apr. 30, 2019); *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, Case No. 2018-00295, Order (Ky. PSC Apr. 30, 2019).

[15] *Electronic Examination by the Public Service Commission of the Environmental Surcharge Mechanism of Kentucky Utilities Company for the Two-Year Billing Period Ending April 30, 2019*, Case No. 2019-00205, Order (Ky. PSC Oct. 22, 2019); *Electronic Examination by the Public Service Commission of the Environmental Surcharge Mechanism of Louisville Gas and Electric Company for the Two-Year Billing Period Ending April 30, 2019*, Case No. 2019-00206, Order (Ky. PSC Oct. 22, 2019).

Q. Is the 9.725% return on common equity consistent with the return on common equity approved by other commissions for other vertically integrated electric utilities?

A. Yes. On January 31, 2020, S&P Global Market Intelligence released its report of major rate case decisions in 2019. The report indicates that 9.73% was the average return on common equity for vertically integrated electric utilities in 2019. The report shows that the Companies' 9.725% ROE continues to compare favorably with the current national average.

<u>Conclusion and Recommendation</u>

Q. What is your conclusion and recommendation to the Commission?

A. I recommend that the Commission approve the Companies' 2020 Plans and applications for cost recovery of their compliance costs through the Rate Schedule ECR tariffs, and the continuing use of the 9.725% ROE for ECR purposes.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Robert M. Conroy

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 17th day of March 2020.

Judy Schooler

Notary Public

Notary Public, ID No. 603967

My Commission Expires:

7/11/2022

APPENDIX A

Robert M. Conroy

Vice President, State Regulation and Rates
Kentucky Utilities Company
Louisville Gas and Electric Company
220 West Main Street
Louisville, Kentucky 40202

Previous Positions

Director, Rates	Feb 2008 – Feb 2016
Manager, Rates	April 2004 – Feb 2008
Manager, Generation Systems Planning	Feb. 2001 – April 2004
Group Leader, Generation Systems Planning	Feb. 2000 – Feb. 2001
Lead Planning Engineer	Oct. 1999 – Feb. 2000
Consulting System Planning Analyst	April 1996 – Oct. 1999
System Planning Analyst III & IV	Oct. 1992 - April 1996
System Planning Analyst II	Jan. 1991 - Oct. 1992
Electrical Engineer II	Jun. 1990 - Jan. 1991
Electrical Engineer I	Jun. 1987 - Jun. 1990

Professional/Trade Memberships

Registered Professional Engineer in Kentucky, 1995
Edison Electric Institute - Rates and Regulatory Affairs Committee
Southeastern Energy Exchange - Rates and Regulation Committee

Education

Essentials of Leadership, London Business School, 2004
Masters of Business Administration
    Indiana University (Southeast campus), December 1998
Center for Creative Leadership, Foundations in Leadership program, 1998.
Bachelor of Science in Electrical Engineering;
    Rose Hulman Institute of Technology, May 1987

Civic Activities

Olmstead Parks Conservancy – Board of Directors – 2016 – current
Leadership Kentucky – Class of 2016
Financial Research Institute – Advisory Board Member – 2016 – current

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR APPROVAL OF ITS 2020 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	**)))))**	**CASE NO. 2020-00060**
ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR APPROVAL OF ITS 2020 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	**)))))**	**CASE NO. 2020-00061**

DIRECT TESTIMONY OF
GARY H. REVLETT
DIRECTOR, ENVIRONMENTAL AFFAIRS
KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: March 31, 2020

Q. Please state your name, position, and business address.

A. My name is Gary H. Revlett. I am Director of Environmental Affairs for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") and an employee of LG&E and KU Services Company, which provides services to KU and LG&E (collectively "Companies"). My business address is 220 West Main Street, Louisville, Kentucky, 40202. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes. I previously testified before this Commission in the last four environmental cost recovery ("ECR") compliance plan proceedings.[1] I also testified in Case No. 2011-00375[2] in which the Commission issued a Certificate of Public Convenience and Necessity ("CPCN") for the construction of a combined cycle combustion turbine at the Cane Run Generating Station. I testified in Case No. 2014-00002[3] in which the Commission issued a CPCN for the construction of a solar photovoltaic facility at the E.W. Brown Generating Station. And I testified in Case No. 2015-00194[4] in which the Commission confirmed the issuance of CPCNs for landfills at the Ghent and Trimble County Generating Stations. In

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[1] The last four ECR compliance plan proceedings include: 2018 (Case No. 2017-00483 (KU)), 2016 (Case Nos. 2016-00026 (KU) and 2016-00027 (LG&E)), 2011 (Case Nos. 2011-00161 (KU) and 2011-00162 (LG&E)), 2006 (Case Nos. 2006-00206 (KU) and 2006-00208 (LG&E)).

[2] *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and Site Compatibility Certificate for the Construction of a Combined Cycle Combustion Turbine at the Cane Run Generating Station and the Purchase of Existing Simple Cycle Combustion Turbine Facilities From Bluegrass Generation Company, LLC in Lexington, Kentucky*, Case No. 2011-00375.

[3] *In re the Matter of: Joint Application Of Louisville Gas And Electric Company And Kentucky Utilities Company For Certificates Of Public Convenience And Necessity For The Construction Of A Combined Cycle Combustion Turbine At The Green River Generating Station And A Solar Photovoltaic Facility At The E.W. Brown Generating Station*, Case No. 2014-00002.

[4] *Investigation of Kentucky Utilities Company's and Louisville Gas and Electric Company's Respective Need for and Cost of Multiphase Landfills at the Trimble County and Ghent Generating Stations*, Case No. 2015-00194.

addition to testifying, I have been the responsible witness for many of the data responses the Companies have filed with the Commission in those and other proceedings.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to identify the environmental regulatory requirements that cause the need for the pollution control projects in the Companies' 2020 Environmental Compliance Plans ("2020 Plans") and demonstrate how those projects will allow the Companies to comply with these environmental regulations. (A copy of the 2020 Plan for each utility is attached to the Applications in these cases.). The projects identified in the 2020 Plans are necessary for the Companies' compliance with United States Environmental Protection Agency's ("EPA") 2015 Effluent Limitations Guidelines Rule ("2015 ELG Rule") which was issued in November 2015 and became effective in January 2016.[5] The Companies' projects are necessary to comply with the 2015 ELG Rule and will also allow for compliance with recently proposed revisions to the 2015 ELG Rule.[6]

More specifically, the 2015 ELG Rule imposes requirements on the levels of allowable nitrates, nitrites, and selenium that cannot be achieved with the Companies' recently commissioned process water treatment systems at its Ghent, Trimble County, and Mill Creek Generating Stations. Therefore, as described below, the Companies need to build additional ELG water treatment systems to treat the effluent coming from the current process water treatment systems to achieve the levels mandated by the 2015 ELG Rule and its 2019 proposed revisions, which are expected to become final later this year.

Q. Are you sponsoring any exhibits?

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[5] 40 CFR 423.

[6] The proposed revisions to the 2015 ELG Rule may be found at https://www.govinfo.gov/content/pkg/FR-2019-11-22/pdf/2019-24686.pdf.

A. No.

Q. Please describe environmental regulation as it exists today.

A. Environmental regulation and compliance remain expensive, complicated, ongoing, and daily efforts at our facilities and for our operations. The passage of the initial Clean Air Act ("CAA"), the Clean Water Act ("CWA"), and the Resource Conservation and Recovery Act ("RCRA"), and all subsequent amendments to and revisions of these and other environmental laws and regulations have significantly increased the Companies' environmental compliance obligations over time. Environmental regulation has experienced even more significant change over the past several years. During this time, the number and breadth of environmental regulations has expanded such that today, environmental compliance is a complex and costly endeavor. Nonetheless, the Companies continue their culture of compliance on an everyday basis.

As a starting point, the CAA, the CWA, and the RCRA (and their amendments) are the core laws from which almost all environmental regulations have originated. The CWA establishes the basic structure for regulating discharges of pollutants into the waters of the United States and regulating quality standards for surface waters. The basis of the CWA was enacted in 1948 in a law called the Federal Water Pollution Control Act. In 1972, it was significantly reorganized and expanded and then became known as the CWA. The CWA made it unlawful to discharge any pollutant from a point source into navigable waters without a permit.

EPA's National Pollutant Discharge Elimination System ("NPDES") permit program controls the discharge permitting process. For the Companies and by agreement between the EPA and the Commonwealth of Kentucky, permits are issued and enforced by

Kentucky's Department for Environmental Protection, Division of Water, under the Kentucky Pollutant Discharge Elimination System ("KPDES").[7] This means that, for purposes of this case, the KPDES permits the Companies have for their Ghent, Trimble County, and Mill Creek Generating Stations already reflect the 2015 ELG Rule requirements and will be further impacted when the proposed revisions to the ELG Rule become final. In other words, the ELG Rule's requirements for all pollutants will be imposed and enforced via revisions to the relevant KPDES permits.

Q. Please describe the 2015 ELG Rule, which is the existing rule.

A. In my direct testimony in the Companies' 2016 ECR cases,[8] I described the 2015 ELG Rule as "extremely complex and lengthy," and it is. I also said:

> Speaking at a high-level, the ELG regulations establish new limits for arsenic, mercury, selenium, and nitrates in flue gas desulfurization wastewater. The ELG regulations also provide that bottom ash transport water and fly ash transport water cannot be discharged except for very narrow exceptions and water cannot be used to transport flue gas mercury control waste. These new regulations are significant and are anticipated to result in additional compliance related expenditures over the next several years.
>
> Power plants must begin to comply with the ELG regulations "as soon as possible beginning November 1, 2018 but no later than December 31, 2023." Practically speaking, this means that plants must begin to comply between 2018 and 2023 depending on when the plant needs a new or renewed Kentucky Pollutant Discharge Elimination System Permit under the CWA.

Q. Did the ECR projects the Companies proposed in their 2016 ECR cases allow for full compliance with the 2015 ELG Rule?

A. No, and they were not intended to. Those projects were primarily intended to achieve compliance with the Coal Combustion Residuals Rule ("CCR Rule"). With respect to the

[7] See KRS Chapter 224.70 and 401 KAR Chapter 5, generally.
[8] Case Nos. 2016-00026 and 2016-00027, Revlett Direct Testimony, p.16 (January 29, 2016).

2015 ELG Rule, Companies' witness John N. Voyles, Jr. testified as follows in the 2016 ECR cases:

> At this time determinations regarding changes to the Companies' generating fleet for compliance with . . . ELG are premature.
>
> As for the impact of the ELG regulations, the Companies are evaluating the new guidelines for discharge limitations as they pertain to the Companies' generating fleet process wastewater streams. Further engineering must be completed to evaluate the generating fleet wastewater streams to ensure the compliance alternatives identified are determined to be the lowest reasonable cost compliance plans.
>
> While the Companies are not proposing projects in the 2016 Plan to comply with . . . ELG, certain of the emission reductions and changes to the effluent discharges of process waters achieved by the proposed Projects may ultimately help with these new rules.[9]

So, while the 2015 ELG Rule had just been enacted when the Companies filed their 2016 ECR cases, the Companies constructed process water treatment systems at Brown, Ghent, Trimble, and Mill Creek Generating Stations to comply with the CCR Rule. But, importantly, as Mr. Voyles and I said in 2016, the 2015 ELG Rule was going to result in additional compliance related expenditures "over the next several years," which is precisely why the Companies are filing these cases now.

Q. Please describe the important parts of 2015 ELG Rule.

A. The 2015 ELG Rule imposed certain limitations for various pollutants and the 2019 proposed revisions alter those limitations. The revisions are targeted at flue gas desulfurization ("FGD") wastewater limits and bottom ash transport water ("BATW") wastewater limits. At their essence for the Companies' purposes, the proposed revisions to the 2015 ELG Rule for arsenic, mercury, selenium, and nitrates/nitrites for FGD

[9] Case Nos. 2016-00026 and 2016-00027, Voyles Direct Testimony, pp. 9-10 (January 29, 2016).

wastewater are set forth in the following table. The proposed limits for arsenic and selenium are slightly increased, but are more stringent for mercury and nitrates/nitrites:

Parameter	2015 Rule Daily Maximum	Proposed Rule Daily Maximum	2015 Rule Monthly Avg	Proposed[10] Rule Monthly Avg
Arsenic (ug/L)	11	18	8	9
Mercury (ng/L)	788	85	356	31
Selenium (ug/L)	23	76	12	31
Nitrate/Nitrite (mg/L)	17.0	4.6	4.4	3.2

For BATW wastewater, the revisions include: a maximum of 10% volumetric discharge daily (over a 30-day rolling average) to maintain system balance due to maintenance events, storm water, upsets exceeding system spares/redundancies, and chemistry/corrosion control issues. However, best management practices must be used to minimize discharges.

Q. Are the Companies currently in compliance with the 2015 ELG Rule's limits for arsenic, mercury, selenium and nitrates/nitrites?

A. For arsenic and mercury, the process water treatment systems the Companies built as a result of the 2016 ECR cases (which use a *chemical* precipitation treatment process to treat for arsenic and mercury) allow for near compliance. However, as we said in the 2016 ECR cases, we have known that additional construction would be necessary to comply with the 2015 ELG Rule's requirements regarding selenium and nitrates/nitrites. And this is true under either the 2015 ELG Rule or the 2019 proposed revisions to the rule. We simply cannot achieve compliance for selenium and nitrates/nitrites without the *biological*

[10] The proposed daily and monthly limitations are set forth at 84 Fed. Reg. 64663.

treatment facilities we are requesting in this case. It is also important to understand that although we are not required to be in compliance yet, the compliance deadlines are approaching as described below.

Q. Are you certain that the 2015 ELG Rule and its proposed revisions apply to the Companies?

A. Yes. Like the currently effective 2015 ELG Rule, the proposed revisions apply to the Companies. Under "Purpose of the Rule" section, it states:

> Coal-fired facilities are impacted by several environmental regulations. One of these regulations, the Steam Electric Power Generating ELG was promulgated in 2015 . . . and applies to the subset of the electric power industry where "generation of electricity is the predominant source of revenue or principal reason for operation, and whose generation of electricity results primarily from a process utilizing fossil-type fuel . . . [11]

Just as the 2015 ELG Rule applies to the Companies' facilities at Brown, Ghent, Trimble County and Mill Creek Generating Stations, the proposed revisions apply as well.

Q. What needs to be built to achieve the allowable levels of arsenic, mercury, selenium and nitrates/nitrites?

A. In the direct testimony of R. Scott Straight in these cases, he describes the details of what the Companies propose to construct and how they will operate those facilities once constructed. However, I will explain the basics of the Companies' plans. The 2015 ELG Rule requires the Companies to use the Best Available Technology Economically Achievable ("BAT")[12] to control arsenic, mercury, selenium, and nitrate/nitrites. Current BAT technology is chemical precipitation *plus* biological treatment. As discussed above, the Companies already have the chemical precipitation facilities in place (i.e., process

[11] 84 Fed. Reg. 65621.
[12] 84 Fed. Reg. 64624.

water treatment systems) to comply with the 2015 ELG Rule. However, for the stricter mercury limits in the proposed revisions to the ELG Rule and for selenium and nitrates/nitrites, the Companies must construct biological treatment facilities to achieve full compliance. Those biological treatment facilities will allow compliance with the proposed nitrates/nitrites levels as well as compliance with the new mercury and selenium levels.

Q. Do the proposed revisions to the ELG Rule affect compliance dates, and, if so, what are the compliance dates?

A. Yes, they do. The revisions require compliance as soon as possible on or after November 1, 2020, but no later than December 31, 2023 for BATW wastewater and December 31, 2025 for FGD wastewater.[13]

Q. What does "as soon as possible after November 1, 2020" mean?

A. Under the proposed ELG Rule, the state permitting authority (in this case, the Kentucky Division of Water), is afforded discretion as to how soon after November 1, 2020 a discharger must comply. The state permitting authority may consider: (a) time to expeditiously plan, design, procure, and install equipment; (b) changes being made or planned at the facility in response to greenhouse gas regulations under the CAA or the CCR Rule; (c) for FGD wastewater requirements only, an initial commissioning period to optimize the installed equipment; and (d) other factors as appropriate.[14] So, at this time, we cannot say for sure how soon our regulatory compliance date(s) will be.

Q. Would it be prudent to wait until the proposed revisions to the 2015 ELG Rule are final before seeking approval from this Commission?

[13] 84 Fed. Reg. 64664.
[14] 84 Fed. Reg. 64665.

A. No. In fact, it would be imprudent to wait. Our understanding is that the revisions will likely become final during the summer of 2020. But beyond that, even if the revisions *never* become final, as I said above, the Companies cannot achieve compliance with the currently effective 2015 version of the ELG Rule for selenium and nitrates/nitrites without adding ELG water treatment systems. So, even if nothing happens to the ELG Rule, we still need to construct the proposed ELG water treatment systems to comply with existing law.

Q. Are there penalties for not complying with the ELG Rule?

A. Certainly. Each KPDES permit issued to the Companies incorporates the penalty provisions set forth in KRS 224.99.010. Those penalties include up to a $25,000 per day civil penalty for violations of the permit.[15] For those who commit knowing violations, they can be charged with a Class D felony and fined $25,000, imprisoned for one to five years, or both.[16] Further, each day upon which a violation occurs constitutes a separate violation.

Q. Please describe the construction projects the Companies are proposing.

A. The Companies propose constructing ELG water treatment systems at the Ghent, Trimble County, and Mill Creek Generating Stations. The projects are identified as Project 43 for Ghent (KU), Projects 44 and 32 for Trimble County (Project 44 is for KU at Trimble County and Project 32 is for LG&E at Trimble County since it is owned by both Companies), and Project 31 for Mill Creek (LG&E). Each project is similar in that each consists of the construction of an ELG water treatment system along with a "diffuser" at Mill Creek and Ghent that will extend into the Ohio River to help diffuse the pollutants at their point of entry into the river. The Trimble County Station already has a diffuser

[15] KRS 224.99-010(1).
[16] KRS 224.99-010(4).

associated with its wastewater discharge. The diffuser is needed to ensure compliance with the existing KPDES permit requirements. The Ghent project also includes a BATW recirculation system to comply with the BATW discharge limitations in the proposed revisions to the ELG Rule.

The facilities will be located downstream of the recently commissioned process water treatment systems and will treat the effluent in a biological manner to reduce selenium and nitrates/nitrites to allowable levels under the ELG Rule. Biological organisms chemically alter the pollutants causing the pollutants to change into solids which are then able to be removed and disposed of properly.

For KU's Brown Generating Station, the Companies are not proposing anything at this time. Brown does not have the same water usage needs as at Ghent, Trimble County, and Mill Creek. In fact, at Brown, the FGD process is designed to be water negative under normal operating conditions, which means there is no need for ELG water treatment systems. If the bottom ash transport system needs modifications, the steps that would have to be taken at Brown to comply with the ELG Rule are minor compared to the other stations and can be completed much more quickly. Thus, the Companies are delaying a decision at Brown and are not proposing anything for Brown in these cases.

Q. Please describe the sizing for the project at Mill Creek.

A. As explained by Mr. Straight, the proposal includes new ELG water treatment systems for the generating units at Mill Creek. Current designs are to treat only 600 gallons per minute (gpm) of effluent from the process water systems with the design allowing the ELG water treatment systems to be expanded to treat the full 750 gpm should all of the generating units at Mill Creek need to be covered. The Companies have time to assess that possibility since the decision is impacted by the regulatory requirements associated with the 2015 National Ambient Air Quality Standards ("NAAQS") for ozone. Mill Creek is located in Jefferson County which is currently in a marginal non-attainment for ozone levels. As a result, the Kentucky Energy and Environment Cabinet and the Louisville Metro Air Pollution Control District are considering limiting NOx emissions at the Mill Creek station for the months of April through October. Further limitations on NOx emissions could effectively eliminate the ability to simultaneously operate Mill Creek 1 and Mill Creek 2 during these months. Although that situation is evolving, we believe it makes sense to size the Mill Creek proposal at 600 gpm for now.

Q. Do any of your current permits needs to be revised based on the proposed ELG Rule?

A. Yes. Our current KPDES permits reflect the 2015 ELG Rule, but when the proposed revisions to that rule become final, we must seek a modification of our current KPDES permits to reflect those revisions within 90 days.[17] The process for revising the permits is not expected to be complicated, lengthy or controversial.

Q. Will the Companies need any other permits in connection with the construction projects described above?

A. Yes. The proposed installation of the diffusers that extend out into the Ohio River at the Ghent and Mill Creek Generating Stations will require the Companies to obtain a permit(s) from the United States Army Corps of Engineers under Section 404 of the CWA. The Companies plan on requesting those permits four to six weeks after finalizing the design for the diffusers.

[17] See 401 KAR 5:050, Section 7 which references 40 CFR 122.62.

Q. Are there any other environmental regulations that impact the Companies' proposals in this case to comply with the ELG Rule?

A. Not directly. However, in previous cases before this Commission, I have provided extensive testimony regarding the numerous environmental regulations that apply to the Companies' generation facilities. Those include: the MATS Rule (Mercury and Air Toxics Standards); the CCR Rule; and NAAQS which, as discussed above, could have an effect on the Mill Creek proposal. While these and other regulations present a complex challenge for the Companies, they are not directly related to the facilities proposed in this case with the possible exception of NAAQS at Mill Creek. Having said that, it is important to understand that all of the regulations I have discussed, when taken together, result in an increasingly complex, stringent, and expensive environmental compliance situation for the Companies and their customers. The Companies' environmental compliance efforts require prudent business planning, diligence, and expertise on a daily basis. The projects proposed in this case are a result of that planning, diligence, and expertise.

Q. Do you have a recommendation for the Commission?

A. Yes. I recommend approval of all projects the Companies propose in this case.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Gary H. Revlett**, being duly sworn, deposes and says he is the Director, Environmental Affairs for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Gary H. Revlett

Gary H. Revlett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 18th day of March 2020.

Judy Schooler

Notary Public

Notary Public, ID No. 603967

My Commission Expires:

7/11/2022

APPENDIX A

Gary H. Revlett

Director, Environmental Affairs
LG&E and KU Services Company
220 West Main Street
Louisville, Kentucky 40202

Education

University of Louisville, Ph.D. Analytical/Environmental Chemistry - May 1976
Murray State University, B.S. Chemistry - June 1971
OSHA Hazardous Waste Worker Training and 8-hour Refresher Courses

Previous Positions

E.ON U.S. Services Inc.
2006-2010 - Air Manager - Environmental Affairs

Tetra Tech EMI, Louisville, Kentucky
2005-2006 - Senior Air Quality Manager

Kenvirons, Inc., Frankfort, Kentucky
1994-2005 - Vice President and Treasurer
(Director of Air Services and Laboratory Services)
1985-1994 - Associate
(Manager of Testing and Air Services)
1978- 1984 - Senior Environmental Scientist
(Manager of Emission Testing and Air Modeling)

Kentucky Division of Pollution Control, Frankfort, KY
1976-1977 - Principal Chemist - Air Modeling Team

Board/Committee Memberships

Edison Electrical Environmental – Board of Directors and Environmental Subcommittee
EPRI Environmental Council – Voting Council Member
Utility Information Exchange of Kentucky – Board of Directors

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR APPROVAL OF ITS 2020 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	**)))))**	**CASE NO. 2020-00060**
ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR APPROVAL OF ITS 2020 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	**)))))**	**CASE NO. 2020-00061**

DIRECT TESTIMONY OF
R. SCOTT STRAIGHT
VICE PRESIDENT, PROJECT ENGINEERING
KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: March 31, 2020

TABLE OF CONTENTS

Background

Q. Please state your name, position, and business address.

A. My name is R. Scott Straight. I am the Vice President of Project Engineering for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") and an employee of LG&E and KU Services Company, which provides services to KU and LG&E (collectively "Companies"). Before being promoted to my current position in April 2017, I served as Director for Project Engineering for 15 years. I have been with the Companies since 1984. My business address is 220 West Main Street, Louisville, Kentucky, 40202. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. What are your job responsibilities?

A. As Vice President of Project Engineering for the Companies, I am responsible for development, procurement, construction, commissioning and execution of all major generation capital projects for the Companies. This includes not only the construction of new generating units and technologies, but also engineering and construction of projects needed to facilitate generation activity and ensure that new and existing power generation complies with all federal, state and local environmental regulations.

Environmental projects completed or being completed under my supervision include retrofit construction of wet flue gas desulfurization ("FGD") technologies, selective catalytic reduction ("SCR") technologies, particulate control technologies utilizing pulse jet fabric filters ("PJFF") also known as baghouses, construction of dry landfills for coal combustion residuals ("CCR"), construction and implementation of the Companies' CCR handling systems from wet-to-dry conversions, closure of CCR impoundments to comply with the federal CCR Rule, the construction of process water treatment systems to treat FGD wastewater ("process water treatment systems"), and modifications to other station process water systems to comply with state water discharge permits due to the closing of CCR impoundments.

Q. Have you previously testified before this Commission?

A. Yes. I previously testified before this Commission in the last two environmental cost recovery ("ECR") compliance plan proceedings.[1]

Q. What are the purposes of your testimony?

A. My testimony summarizes the 2020 Environmental Compliance Plans ("2020 Plans") for both KU and LG&E and describes the need for the projects contained in the plans. I also describe in general terms how water is used, processed, and discharged in the Companies' generating stations. I will discuss more specifically the need for FGD wastewater treatment facilities and technologies, both recently commissioned and proposed, to comply with various environmental permits and regulations. I will also describe the proposed construction of biological water treatment systems at the Ghent, Trimble County, and Mill Creek generating stations to comply with amendments to the United States Environmental Protection Agency's ("EPA") Effluent Limitations Guidelines Rule ("ELG Rule") (I will refer to these systems as "ELG water treatment systems" throughout my testimony). I will also describe the Companies' plan to install diffusers in the Ohio River at the Ghent and Mill Creek generating stations and how those diffusers will assist the Companies in achieving compliance with the anticipated amendments to the ELG Rule. And, I will describe the need for a Bottom Ash Transport Water ("BATW") recirculation system at

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[1] The last two ECR compliance plan proceedings include 2018 (Case No. 2017-00483 (KU)) and 2016 (Case Nos. 2016-00026 (KU) and 2016-00027 (LG&E)).

Ghent to comply with the bottom ash transport water discharge limitations in the amended ELG Rule.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring eight exhibits. Attached to my testimony are the following four exhibits:

Exhibit RSS-1	ELG Process Water Flow Diagrams for Mill Creek, Trimble County and Ghent Generating Stations
Exhibit RSS-2	EPC Summary Report for ELG Rule Compliance (Water Treatment) (Burns & McDonnell Project Report)
Exhibit RSS-3	EPC Summary Report for ELG Rule Compliance (Ghent Bottom Ash) (Burns & McDonnell Project Report)
Exhibit RSS-4	Project Capital Cost Estimates

I am also sponsoring Application Exhibits 1 and 3 to both the KU and LG&E applications. Application Exhibit 1 to each Company's application contains that Company's 2020 Environmental Compliance Plan. Application Exhibit 3 to each Company's Application contains the maps and drawings for the projects proposed in the applications.

<u>**The Companies' 2020 ECR Plans**</u>

Q. Please Summarize KU's 2020 ECR Plan.

A. Application Exhibit 1, attached to KU's application herein, sets forth KU's 2020 Environmental Compliance Plan ("KU's 2020 Plan"). The plan consists of two projects. The first, Project 43, is for construction of an ELG water treatment system, a BATW recirculation system, and a wastewater outfall diffuser at the Ghent generating station. These facilities are designed to process and lawfully discharge wastewater from Ghent in accordance with the EPA's existing and proposed amendments to the ELG Rule and the existing Kentucky Pollutant Discharge Elimination System ("KPDES") Permit for Ghent.

The estimated capital cost to implement these facilities is $216.5 million, with construction planned for completion in November 2021 for the diffuser, December 2023 for the BATW recirculation system, and November 2024 for the ELG water treatment system.

The second project, Project 44, is for construction of an ELG water treatment system at the Trimble County generating station. The reason for construction of this system at Trimble County is the same as that for Ghent – compliance with existing and proposed EPA regulations pertaining to the ELG Rule and, concurrently, the ELG limitations contained in the KPDES permit for Trimble County. The total project cost is projected to be $99.6 million ($74.7 million net) being split between KU and LG&E.[2] KU's 48 percent share of the net capital cost for the ELG water treatment system is $35.9 million, with construction planned for completion in June 2023. The maps and drawings for both projects are contained in KU Application Exhibit 3.

Q. Please Summarize LG&E's 2020 ECR Plan.

A. Application Exhibit 1, attached to LG&E's application herein, sets forth LG&E's 2020 Environmental Compliance Plan ("LG&E's 2020 Plan"). Like KU's 2020 Plan, LG&E's 2020 Plan consists of two projects. The first, Project 31, is for construction of an ELG water treatment system and wastewater diffuser at the Mill Creek generating station. The facilities are estimated to cost $113.9 million in capital, with construction planned for completion in November 2021 for the diffuser and June 2024 for the ELG water treatment system.

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[2] The net capital figure for Trimble County represents the capital investment corresponding to the Companies' total relative ownership (75 percent) of Trimble County Units 1 and 2. Illinois Municipal Electric Agency and Indiana Municipal Power Association collectively own 25 percent of the capacity of both units, and the costs attributable to that portion of units are reflected in the gross total project cost. The partners' share is excluded from recovery in KU's and LG&E's ECR Plans.

The second project, Project 32, is for LG&E's 52 percent portion of the construction of an ELG water treatment system at the Trimble County generating station, described above. LG&E's share of the capital cost for the ELG water treatment system is $38.8 million, with construction planned for completion in June 2023. The maps and drawings for both projects are contained in LG&E Application Exhibit 3.

Q. Why are the projects included the 2020 ECR Plans needed?

A. The direct testimony of Gary H. Revlett describes in detail the regulatory changes that precipitated the need for construction of the ELG water treatment systems at Ghent, Trimble County, and Mill Creek; as well as the BATW recirculation system at Ghent. In brief, the Companies are working toward compliance with the EPA's 2015 ELG Rule and the EPA's proposed amendments to that rule, which are expected to be finalized in the summer of 2020. The proposed amendments to the ELG Rule still include daily maximum and monthly average limits for the concentration of mercury, nitrates/nitrites, selenium and arsenic allowed in FGD wastewater effluent. In order to meet the proposed limits for these constituents, the Companies will need to install the ELG water treatment systems to treat the effluent from the physical/chemical FGD process water treatment systems recently placed into service. Without the proposed ECR projects at Ghent, Trimble County and Mill Creek stations, the Companies would not be able to continue steam generating operations at these generating stations and simultaneously comply with the ELG Rule, as enforced by KPDES permits at each generating station. This would significantly impair the Companies' ability to fulfill their mandate to provide adequate, efficient, and reasonable service to their ratepayers as these generating stations are the three largest generating stations within the KU and LG&E generating fleet.

The proposed amendments to the ELG Rule also include a 10% volumetric discharge limit (on a 30-day rolling average) for BATW, which must be complied with "as soon as possible" but in no event later than December 31, 2023. This proposed discharge limit will require KU to construct a BATW recirculation system on the existing bottom ash transport system at Ghent. The recirculation system will collect the transport water currently discharged from the remote bottom ash drying facility and reroute it through tanks and piping systems back to the four generating units for reuse. Mill Creek and Trimble County do not require a BATW recirculation system due to their bottom ash transport systems being a dry transport instead of a wet sluicing system like Ghent's.

Q. Why are these projects being proposed now?

A. As Mr. Revlett describes in his testimony, the proposed amendments to the ELG Rule require compliance as soon as possible on or after November 1, 2020, but no later than December 31, 2025 for FGD wastewater and December 31, 2023 for bottom ash transport water.[3] Mr. Revlett further explains that it would be imprudent to wait until the amended ELG rule becomes final because even if the amendment never comes out, the systems proposed in the 2020 ECR Plans are required to comply with the 2015 ELG Rule for limits on selenium and nitrates/nitrites.

In addition to the 2015 ELG Rule, there are other practical reasons to pursue these projects now. With regard to the ELG water treatment systems proposed in these cases, the technology is relatively new for the electrical generation industry and there are only two vendors in the United States that have built full-scale biological ELG water treatment systems of this type. If the Companies wait until the ELG Rule amendment is posted final

[3] 84 Fed. Reg. 64664.

to seek approval for these projects, there is likely to be a significant backlog for the two technology vendors that could jeopardize completion of the projects in time for the last compliance date of December 31, 2025. In addition to the risks associated with vendor availability, the Companies have proven in the past that getting to the market for the Engineering, Procurement and Construction ("EPC") contract(s) in the initial nationwide wave of bidding and executing contracts reduces implementation risks. Securing a qualified and experienced EPC contractor that has the scale and experience to design, procure, construct and commission these water treatment projects greatly reduces the overall implementation risk, as well as overall project cost risk. Leaders to the market for an EPC contractor are able to take advantage of an EPC contractor's best project management talent while also allowing the EPC contractor to secure other materials and subcontractors ahead of their competitors that will be executing similar treatment projects throughout the United States. Being a leader to market results in the Companies' securing better execution teams, better schedule certainty, reduced risks of technology and subcontractor availability, and other benefits as identified above, all of which lower execution risks and ultimately total project costs.

Q. Why is the E.W. Brown generating station excluded from KU's 2020 ECR Plan?

A. Given that E.W. Brown generating station has only one coal-fired generating unit in operation (Unit 3), KU currently expects to be able to operate the FGD in such a way to eliminate the wastewater discharge under normal operating conditions by converting the FGD and CCR treatment processes to a water-negative operation. This means that the expected water balance from evaporation from the FGD up through the chimney, combined with the residual water leaving the process on gypsum and bottom ash, results in the need to *add* water to the FGD instead of having to *discharge* water from the process. During operational upset conditions wastewater can be discharged to the recently installed FGD maintenance tank and later used as FGD makeup when FGD conditions return to normal.

<u>Overview of Water Flow and Discharge at a Generating Station</u>

Q. Explain how wastewater is created in power generation.

In order to explain how FGD wastewater is used and discharged, it may be helpful to give an overview of water flow at a generating station. To assist in that endeavor, we have created the illustrations attached as Exhibit RSS-1, which are high-level flow diagrams of process waters at the Mill Creek, Trimble County, and Ghent generating stations.

These illustrations depict the numerous ways in which water is critical to power production. For a generating station with steam (coal-fired) generating units, water is used in the steam production process, as well as for cooling, cleaning, and transportation, treatment and discharge of the byproducts of power generation, including CCRs.

Water usage can be further subdivided into two types: CCR contact water and non-CCR contact water. The primary use of non-contact water is steam production and cooling. As seen in Exhibit RSS-1, raw water is pumped in from a natural source (the Ohio River in this case) through a dedicated pump and piping system. Water is then diverted to various piping systems within the generating station, one of which is the steam circuit. In this circuit the water is treated to an ultra-high quality and used in the steam circuit where it is heated to very high temperature, creating high pressure steam in the boiler and then run through the steam turbine to drive the electric generator. The steam leaving the turbine is then condensed back into liquid water by running it through a condenser (a large heat exchanger) where cooling water is run through the condenser. The cooled steam circuit water is then pumped back to the boiler where the cycle repeats itself. The cooling water flowing through the condenser picks up the heat from the steam circuit and then is pumped to the large cooling towers where it is cooled through the ambient air that is circulated through the cooling tower. Once cooled, the cooling water is then recirculated back to the condenser to cool the steam leaving the steam turbine, and the process is repeated over again.

CCR contact water consists of most all other uses of water in power generation where water contacts CCR through operational processes (i.e., FGD process), or through the transport of CCR to dewatering facilities. The major area of contact water is in the FGD process where the wastewater is required to be treated to meet the ELG Rule. At Ghent, water transports bottom ash to the bottom ash dewatering facility. Water also contacts CCR through the wash-downs of CCR treatment facilities.

Q. Are there other sources of discharged water not directly related to power production?

A. Yes, as Exhibit RSS-1 shows, discharged water from a generating station includes not only water used in power generation and environmental controls but also stormwater runoff and landfill leachate created by stormwater. Landfill leachate is rainwater that falls on the landfilled CCR, passed through solids in a landfill, collected in the leachate system under the stored CCR, and then collected in the leachate pond. Just like generation process waters, stormwater and leachate waters are collected, monitored and regulated to ensure compliance with environmental regulations.

Q. How is the discharge of water by a generating station regulated?

A. As Mr. Revlett describes in detail in his testimony, pollutants in water discharged from the stations have been regulated by the federal Clean Water Act ("CWA") or its predecessors since the late 1940s. To comply with federal regulations, the Companies must obtain and comply with permits issued by the Kentucky Department for Environmental Protection, Division of Water under the KPDES. Each generating station has its own permit, which specifically regulates the levels of pollutants permitted to be discharged by the station.

Source of Wastewater and Process Water Systems

Q. What is the source of the water that is proposed to be treated by the projects in the 2020 ECR Plan?

A. The ELG Rule's limitations for arsenic, mercury, selenium and nitrates/nitrites apply to FGD wastewater. This includes blowdown (drained water) from the FGD system to control chlorides in the FGD, gypsum dewatering filtrate, and gypsum wash water. The ELG water treatment projects will treat the effluent from the physical/chemical FGD process water treatment systems recently placed into service that control particulate and metals in the FGD wastewater. Effluent water from the ELG water treatment systems will discharge to process water ponds that combine contact and non-contact station process waters and eventually discharge to the original source (the Ohio River in this case).

Q. How is FGD wastewater created?

A. FGD is a scrubbing technology used to remove sulfur dioxide (SO_2) from flue gas emissions created in the combustion process. Limestone is pulverized into fine particles and combined with water to make a limestone slurry. The limestone slurry is pumped to the FGD reaction tank where it is then pumped to the spray headers located up in the FGD module. The slurry captures the SO_2 particles and falls back into the FGD reaction tank where the calcium in the limestone, combined with the sulfur dioxide forms into gypsum particles. The gypsum is then pumped off to the gypsum dewatering system where vacuum belts extract the water from the gypsum, thus allowing the gypsum to fall off the vacuum belt as a solid material and serve as a potential beneficial reuse material. The water is captured from the gypsum drying process and returned to the FGD for reuse; however, the water has residual chlorides and other constituents that need to be purged from the FGD process. A purge stream is bled off the FGD process and sent to the recently constructed process water treatment systems where particulate and metals are removed through chemical and physical treatment. The effluent from this treatment still has selenium and nitrate/nitrites in it as the process water treatment systems were not designed to remove these constituents. The effluent also has residual levels of mercury that must be removed to comply with concentration limits required by the amended ELG Rule.

Q. How is FGD wastewater treated at the Companies' generating stations now?

A. The EPA's Disposal of Coal Combustion Residuals from Electric Utilities final rule ("CCR Rule"), which was a subject to the Companies' last ECR amendment filings, dramatically changed how the Companies stored and processed wastewater to comply with permitting requirements. As the Commission recognized in its final order in those cases, the CCR Rule imposed more stringent requirements on the design, monitoring, operating, corrective action, closure and post closure requirements for surface impoundments associated with disposal and storage of CCR.[4] As a result, the Companies sought and received from the Commission approval for plans to close surface impoundments at a number of generating stations, including Ghent, Trimble County, and Mill Creek.

Closure of these CCR surface impoundments left the Companies with a difficult problem to solve: how to handle process water from pond closures and ongoing operations without storing it in impoundments and impeding the closure process, while

[4] *Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2016 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2016-00026, Final Order, at 4 (Aug. 8, 2016).

simultaneously maintaining compliance with the KPDES discharge permits at each generating station. The solution, as described in detail in the Companies' 2016 Plan filings, was construction of physical/chemical process water treatment systems. These systems are now treating FGD wastewater for particulate and metals at the Trimble County, Mill Creek and Ghent generating stations.

Q. Describe the process water treatment systems built as a result of the Companies' 2016 Plan cases.

A. These systems are designed to chemically and physically treat FGD process wastewater. In general, they include elevated tanks, concrete basins, or a combination of both, pumps, chemical storage, and a building and office to house this equipment and to facilitate sampling of wastewater as it moves through the system. At Trimble County, for example, FGD wastewater is transferred to one of two large equalization tanks, which store wastewater and equalize the flow, temperature, and pollutant concentration of wastewater prior to feeding the downstream treatment process. The equalization tanks then feed into a series of reaction tanks, where chemicals are pumped into the wastewater to capture particulate and metals. From there, the water flows into clarifier tanks where the captured particles fall into a sludge at the bottom of the tank. The sludge is then pumped to filter presses where the water is removed from the solids. Clean water from the clarifier tanks overflows through gravity sand filters into effluent transfer tanks prior to being discharged to the process water ponds.

Q. How big are the process water treatment systems?

A. They are quite large. The primary driver for their size is the high volume of water to be treated from the generating operations. The pictures below show the completed process water treatment system at Trimble County generating station that went into commercial operation in October 2019:

Trimble County Process Water Treatment System – External View

Trimble County Process Water Treatment System – Internal View

The process water treatment system at Ghent is designed to treat a continuous flow of 1,000 gallons per minute (gpm), while the Trimble County and Mill Creek systems are designed to treat up to 750 gpm.

Q. What is the status of the process water treatment systems at Ghent, Trimble County and Mill Creek?

A. The process water treatment system at Trimble County and Mill Creek became operational in October 2019.[5] At Ghent, the Companies' EPC contractor has completed construction and commissioning of the process water treatment system, and recently passed

[5] *Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2016 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2016-00026, 2016 ECR Plan Status Update Report, Quarterly Report – Update #14 (Jan. 30, 2020).

performance testing in March 2020. KU expects to grant the contractor commercial operation in April 2020 and take the system into commercial operation. It is important to note that while not presently being operated by KU, Ghent's process water treatment system is in full operation and being operated by the contractor until reaching the contractual commercial operation milestone.

Q. Do the process water treatment systems help to satisfy the requirements of the 2015 ELG Rule or the proposed amendments?

A. Yes, although the process water treatment systems were not constructed for the purpose of achieving full compliance with the 2015 ELG Rule. The primary purpose of the process water treatment systems installed as part of the CCR impoundment closure programs was to allow the Companies to treat the FGD wastewaters to comply with each Station's KPDES permits. However, as discussed in Mr. Revlett's testimony, the Companies anticipated in their 2016 Plan filing that further projects would be required to achieve compliance with the amended ELG Rule. The 2015 ELG Rule was published in final form in November 2015, and the Companies filed their applications for the 2016 amendments to their ECR Plans just two months later, at the end of January 2016. In direct testimony in that case, John Voyles, former Vice President of Transmission and Generation Services, stated the Companies were evaluating the impact of the new discharge limitations in the 2015 ELG Rule, and that further engineering would be required to evaluate wastewater streams and determine the lowest reasonable cost compliance plan.[6]

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[6] Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2016 Compliance Plan for Recovery by Environmental Surcharge, Case No. 2016-00026, Direct Testimony of John N. Voyles, Jr., Vice President, Transmission and Generation Services, Kentucky Utilities Company, at 10 (Jan. 29, 2016).

Nevertheless, the Companies recognized that process water treatment systems would be an integral part of the overall FGD wastewater treatment required by the ELG regulations and greatly considered those regulations in designing the process water treatment systems that exist today. The Companies were able to take advantage of the interrelatedness between the CCR Rule and the 2015 ELG Rule to create efficiencies that would assist with compliance with both rules. Some examples of this include designing the layouts of the process water treatment systems and future ELG water treatment systems in concert with each other during design of the process water treatment systems to improve the effectiveness of each, reduce operational expenses of each, and to minimize cost impacts in the eventual design of the ELG water treatment systems. Offices, laboratories, primary storage areas, control areas, site traffic and chemical delivery patterns were considered and included in the process water treatment system designs, thus eliminating or greatly reducing the need to consider such in the design of the ELG water treatment systems.

Q. Can the process water treatment systems alone achieve compliance with the proposed amendments to the ELG Rule?

A. No. As explained in Mr. Revlett's testimony, the proposed amendments to the ELG Rule requires the Companies to use the Best Available Technology Economically Achievable ("BAT")[7] to control particulate, metals, arsenic, mercury, selenium, and nitrates/nitrites. Current BAT technology is physical/chemical treatment *plus* biological treatment. The process water systems are physical/chemical systems designed to capture particulate and most metals; however, they are not designed to capture nitrates/nitrites and selenium. The

[7] 84 Fed. Reg. 64624.

levels of nitrate/nitrite and selenium capture required by the ELG Rule requires the use of biological control of the process water treatment system's effluent.

Proposed ELG Water Treatment Systems

Q. How do the ELG water treatment systems work?

A. The first step in the biological treatment process is denitrification. Denitrification is the reduction in concentration of nitrates/nitrites through a biological process utilizing denitrification equipment. Effluent from the denitrification equipment is discharged to the first stage reactor, which is comprised of coated concrete and/or fiberglass vessels and internal reactor surfaces. The reactor contains living microorganisms, which are fed nutrients and convert the nitrates/nitrites and selenium molecules in an aerobic atmosphere, to an elemental form. Effluent from the first stage reactor flows into a second stage reactor, where additional biological processes reduce remaining selenium. The elemental form of selenium is transferred, via a backwash phase of the process, to the equalization tanks at the beginning of the process water treatment system for particulate removal. The second stage reactor feeds to an ultrafiltration ("UF") system where remaining particulate metals are filtered out. The UF tank is then discharged to a series of clean water tanks, which can be used to backwash the biological and UF systems or be discharged.

Exhibit RSS-2 to my testimony is Engineering, Procurement and Construction ("EPC") Summary Report for construction of the ELG water treatment systems at the Ghent, Trimble County, and Mill Creek generating stations. Appendix A to that exhibit contains a process flow diagram encompassing the system just described.

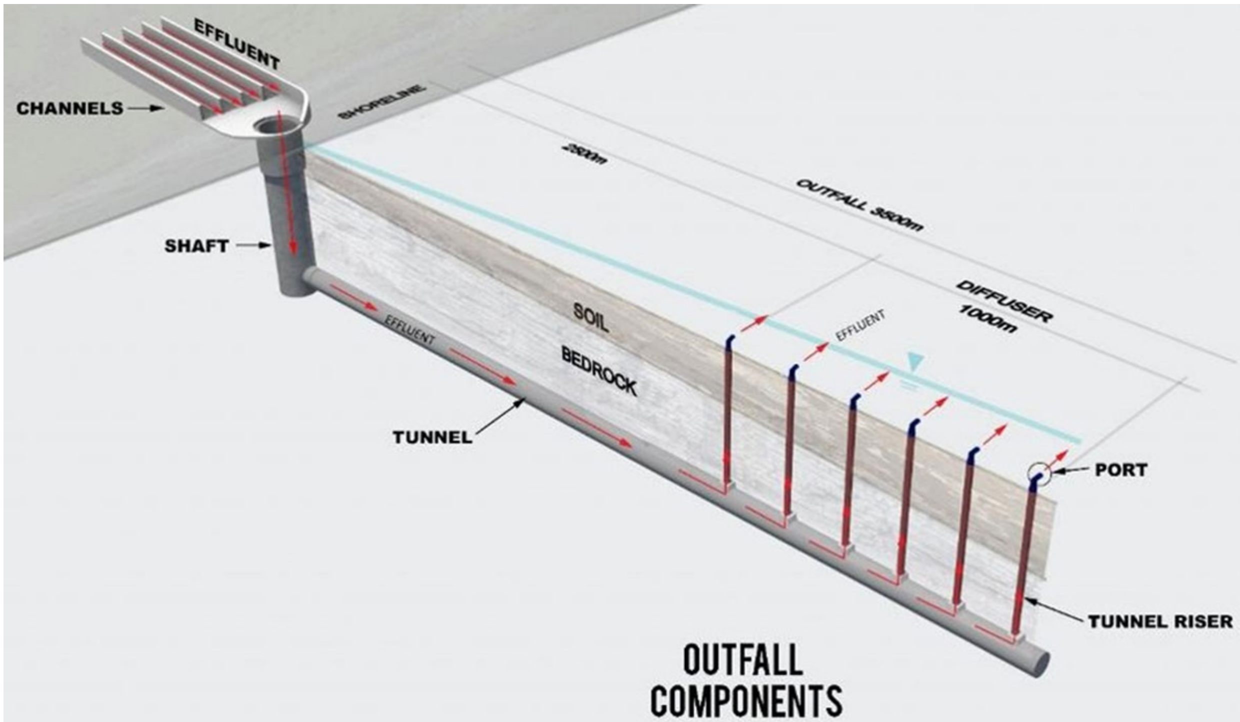
Q. What physical infrastructure is required to build ELG water treatment systems?

A. A system of this type is required to be constructed in a building or under canopy to resist the elements and maintain a stable environment for the biological components of the system to perform. The building houses the denitrification equipment, UF systems, effluent tanks, various pumps and support subsystems. The system also requires cleaning and chemical feed equipment, pumps, piping, valves, and electrical equipment. Separate rooms must be constructed inside the treatment building to house battery systems and electrical equipment. A control room is also required, along with restrooms. The reactor area, including the vessels housing the microorganisms, will be constructed outside the building under a weather canopy. All of the tanks and reactors in the system must be large enough to handle the immense volume of water flowing through the effluent treatment process. In other words, the system must be sized commensurate with the process water treatment system to enable the downstream treatment and handling of flow from the process water treatment systems.

<u>Diffusers at Ghent and Mill Creek</u>

Q. What is a diffuser?

A. The diffusers proposed to be installed at Ghent and Mill Creek are large multi-port pipes that connect to the stations' wastewater outfall pipe and are placed into the bottom of the Ohio River with the discharge ports above the riverbed and facing downstream. The picture below is a schematic showing a representative diffuser similar to the proposed Ghent and Mill Creek diffusers. As this graphic representatively shows, the diffuser is a single large discharge pipe that is installed in the riverbed. The diffuser ports face downstream to disperse the water outfall out of multiple discharge ports instead of a single, larger point of discharge.



Source: Baird.com – Ashbridges Bay Treatment Plant Outfall

Q. What is the purpose of a diffuser?

A. A diffuser does just what its name indicates – it diffuses the discharge of a certain volume of water in the main header pipe into smaller volumes at different port locations. By discharging the outfall into multiple smaller ports instead of a single large port, the concentrations of constituents in the outfall are dispersed into a wider area of the massive river flow, thus significantly reducing the concentration impact to aquatic life the river.

Q. Why are diffusers required at Ghent and Mill Creek?

A. Installation of diffusers at Ghent and Mill Creek will give the Companies operational headroom for compliance with the ELG Rule and the associated KPDES permit requirements to account for events that approach the permitted discharge limits. Certain variables outside the control of the Companies can impact the effectiveness of wastewater treatment, including process water treatment systems and ELG water treatment systems.

These variables include, but are not limited to, dramatic changes in ambient temperature, transient periods during start/stop cycling of generating units whether planned or not, and periods of equipment malfunctions in the water treatment systems. Through the application of a mathematical formula when diffusers are designed, the Companies can achieve compliance with KPDES permit requirements for pollutants, including mercury, arsenic, selenium, and nitrates/nitrites even when unexpected temporary events negatively impact treatment processes.

Project 43: ELG Water Treatment System, Bottom Ash Transport Water Recirculation System, and Diffuser (Ghent)

Q. Please describe the ELG water treatment system at Ghent.

A. The Ghent ELG water treatment system is described in detail in Exhibit RSS-2 to my testimony. It has the same characteristics as the system I described in general terms above. The system will be constructed in close proximity to the recently completed process water treatment system, on the site as shown in Appendices D1 and D2 to Exhibit RSS-2. All facilities will be installed on land currently owned by KU at the generating station. The general layout of the building is depicted on Appendix D3 to Exhibit RSS-2. The list of required mechanical and electrical equipment is contained in Appendices D4 and D5 to Exhibit RSS-2. The system will be designed to handle water flow capacity up to 1,000 gallons per minute. KU expects to award a competitively bid contract by the end of 2020. While the bidders may bid different completion dates, KU is expecting the ELG water treatment system to be constructed and commissioned by November 2024.

Q. Please describe the Bottom Ash Transport Water Recirculation System at Ghent.

A. The BATW recirculation system at Ghent is described in more detail in Exhibit RSS-3 to my testimony. It will consist of transfer tanks, low pressure pumps, high pressure pumps, piping, foundations, controls, and related equipment. This system will collect the bottom ash sluice water after being dewatered from the bottom ash solids in the remote bottom ash dewatering facility, pump the water to collection tanks, where the water will then be pumped back to the bottom ash removal systems underneath the four Unit boilers to be used again for sluicing bottom ash to the remote dewatering facility. The water will be recirculated as necessary, with fresh water being added to replace evaporated water. A 10% purge system, to meet the ELG Rule volume discharge limit, will be included to control pH and other constituent buildup in the recirculation system. The BATW recirculation system will be constructed and commissioned by the end of 2023 to meet compliance deadlines in the proposed ELG Rule amendments.

Q. Why is the BATW recirculation system needed?

A. The ELG Rule requires that BATW be recirculated instead of used once to transport bottom ash and then discharged. The ELG Rule amendment limits the allowable purge to 10% of the system volume on a daily basis. The Rule as currently proposed requires this to be in operation by the end of 2023. As previously stated, Mill Creek and Trimble County utilize dry handling systems for their bottom ash systems and therefore already comply with this provision of the amended ELG Rule.

Q. Please describe the diffuser at Ghent.

A. The diffuser at Ghent will be a multiport diffuser designed to distribute the overflow from the process pond into the Ohio River. The diffuser will consist of piping, fittings, and concrete and steel anchors. Dredging of the riverbed will be required to bury the piping below the riverbed. The multiple ports of the diffuser will protrude above the riverbed and will be directed downstream. Filter cloth and rip rap will be used to prevent scouring of the riverbed in the vicinity of the piping and ports. The diffuser will be installed in the fall of 2021 if river conditions are conducive for construction, with completion in November 2021.

Q. What are the expected capital and O&M costs associated with construction?

A. The total capital cost of Project 43 is expected to be $216.5 million, with the ELG water treatment system comprising $136.5 million, the BATW recirculation system comprising $63.9 million and the diffuser $16.1 million. Exhibit RSS-4 contains a summary of the expected capital costs to build these facilities. Furthermore, the ELG water treatment system is estimated to cost $4.2 million (in 2020 dollars) annually in operations and maintenance expense, most of which is attributable to the chemicals used in treatment, operations personnel, and equipment maintenance. Annual operation and maintenance costs for the BATW recirculation system is estimated to be $0.6 million. The diffuser does not have any annual expected operational or maintenance costs. Appendix D7 to Exhibit RSS-2 and Appendix F to Exhibit RSS-3, respectively, contain a summary of the expected O&M costs for the ELG water treatment system and BATW recirculation system.

Q. Is this project economical?

A. Yes, as described in detail in the direct testimony of Stuart A. Wilson, construction of this project is the least cost means of complying with the amendments to the ELG Rule and the corresponding requirements of the KPDES permit for the Ghent generating station.

<u>Project 44 (KU) and 32 (LG&E): ELG Water Treatment System (Trimble County)</u>

Q. Please describe the proposed ELG water treatment system at Trimble County.

A. The Trimble County ELG water treatment system is described in detail in Exhibit RSS-2 to my testimony. It has the same characteristics as the system I described in general terms above. The system will be constructed in close proximity to the recently completed process water treatment system, on the site as shown in Appendices B1 and B2 to Exhibit RSS-2. All facilities will be constructed on land currently owned by the Companies at the generating station. The general layout of the building is described in Appendix B3 to Exhibit RSS-2. A list of the required mechanical and electrical equipment for the project is contained in Appendices B4 and B5 to Exhibit RSS-2. The system will be constructed to handle water flow capacity up to 600 gallons per minute. The Companies expect to award a bid contract by the end of 2020, with commercial operation expected to commence by June 2023.

Q. What are the expected capital and O&M costs associated with construction?

A. The total net[8] capital cost of the Project 44 is estimated to be $74.7 million, 48 percent of which will be incurred by KU and 52 percent of which will be incurred by LG&E, according to each company's relative ownership of total generating capacity at Trimble County. Exhibit RSS-4 contains a summary of the expected capital costs to build the facilities. Furthermore, the treatment facilities are estimated to cost $3.1 million (in 2020 dollars) annually in operations and maintenance expense, most of which is attributable to the chemicals used in treatment, operations personnel, and equipment maintenance. Appendix B7 to Exhibit RSS-2 contains a summary of the expected O&M costs, which likewise will be split between KU and LG&E according to each company's relative ownership of total generating capacity at Trimble County.

Q. Is this project economical?

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[8] The reference to "net" is for KU's and LG&E's portion of the total cost. While Exhibit RSS-4 reflects the total estimated cost of $99.6 million for the project, the Companies are responsible for only 75 percent of that cost for the reasons stated in footnote 2 above.

A. Yes, as described in detail in Mr. Wilson's testimony, construction of this project is the least cost means of complying with the amendments to the ELG Rule and the corresponding requirements of the KPDES permit for the Trimble County generating station.

Project 31: ELG Water Treatment System and Diffuser (Mill Creek)

Q. Please describe the ELG water treatment system at Mill Creek.

A. The Mill Creek ELG water treatment system is described in detail in Exhibit RSS-2 to my testimony. It has the same characteristics as the system I described in general terms above. The system will be constructed in close proximity to the recently completed process water treatment system, on the site indicated on Appendices C1 and C2 to Exhibit RSS-2. All facilities will be constructed on land currently owned by LG&E at the generating station. The general layout of the building is described in Appendix C3 to Exhibit RSS-2. A list of the required mechanical and electrical equipment for the project is contained in Appendices C4 and C5 to Exhibit RSS-2. The system will be designed and constructed to handle water flow capacity up to 600 gallons per minute, with a conceptual design reserving the area necessary to increase the flow capacity to 750 gallons per minute should it be necessary. LG&E expects to award a bid contract by the end of 2020, with commercial operation expected for the ELG water treatment system in June 2024.

Q. Please describe the proposed diffuser at Mill Creek.

A. Similar to Ghent diffuser, the diffuser at Mill Creek will be a multiport diffuser designed to distribute the overflow from the Mill Creek process pond into the Ohio River. The diffuser will consist of piping, fittings, and concrete and steel anchors. Dredging of the riverbed will be required to bury the piping below the riverbed. The multiple ports of the diffuser will protrude above the riverbed and will be directed downstream. Filter cloth and rip rap will be used to prevent scouring of the riverbed in the vicinity of the piping and ports. The diffuser will be installed in the fall of 2021 if river conditions are conducive to construction, with completion in November 2021.

Q. What are the expected capital and O&M costs associated with construction?

A. The total capital cost of Project 31 is estimated to be $113.9 million, with the ELG water treatment system comprising $102.1 million and the diffuser $11.9 million. Exhibit RSS-4 contains a summary of the expected capital costs to build these facilities. Furthermore, the ELG water treatment system is expected to cost an estimated $3.1 million (in 2020 dollars) annually in operations and maintenance expense, most of which is attributable to the chemicals used in treatment, operations personnel, and equipment maintenance. Appendix C7 to Exhibit RSS-2 contains a summary of the expected O&M costs. The diffuser is not expected to have annual operating and maintenance costs.

Q. Is this project economical?

A. Yes, as described in detail in Mr. Wilson's testimony, construction of this project is the least cost means of complying with the amendments to the ELG Rule and the corresponding requirements of the KPDES permit for the Mill Creek generating station.

Conclusion and Recommendation

Q. What is your conclusion and recommendation to the Commission?

A. I recommend that the Commission approve the proposed projects contained in the Companies' 2020 ECR Plans.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **R. Scott Straight**, being duly sworn, deposes and says that he is Vice President, Project Engineering for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

R. Scott Straight

R. Scott Straight

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 17 day of March 2020.

Kimberly C Bruck

Notary Public

Notary Public, ID No. 566158

My Commission Expires:

10-16-2020

APPENDIX A

R. Scott Straight

Vice President, Project Engineering
LG&E and KU Services Company
220 West Main Street
Louisville, KY 40202

History of Positions:

Director, Project Engineering (2004-2017)
Manager, NO_X Compliance Program Manager (2001-2004)
Manager, Generation Services (1998-2001)
Manager, Technical Services (1995-1998)
Sr. Engineer, Environmental Affairs (focused on Clean Air Act) (1990-1995)
Mechanical Engineer, Special Construction Department (1984-1990)
Design Engineer, Boeing Military Airplane Company (1983-1984)

Recent Responsibilities (Project Engineering):

ECR Projects

2016 LG&E and KU including:
- CCR Rule Compliance (Closures) at Brown, Ghent, Mill Creek, and Trimble County
- Impoundment Closures at Green River, Pineville, and Tyrone
- Process Water Systems at E.W. Brown, Ghent, Mill Creek and Trimble County

2011 ECR Program (LG&E and KU) including:
- PJFFs on Ghent 1-4, E.W. Brown 3, Mill Creek 1-4 and Trimble County 1
- FGDs on Mill Creek 1-4

2009 ECR Program (LG&E and KU)
- Dry CCR Landfills at E.W. Brown, Trimble County and Ghent Landfills; Brown 3's SCR

2004 ECR Program (LG&E and KU)
- Ghent 1, 3 and 4 FGD, Brown Station FGD

2002 ECR Program
- Ghent 1, 3 and 4 SCRs, Mill Creek 3 and 4 SCRs, Trimble County 1 SCR

Non-ECR Projects

2016 E.W. Brown 10 MWe Solar Station
2015 Cane Run 640 MW Natural Gas Combined Cycle Unit #7
2010 Trimble County 810 MW Supercritical Coal Unit #2
2012-2018 Ohio Falls Hydro-Station Units 1-8 Rehabilitation Program

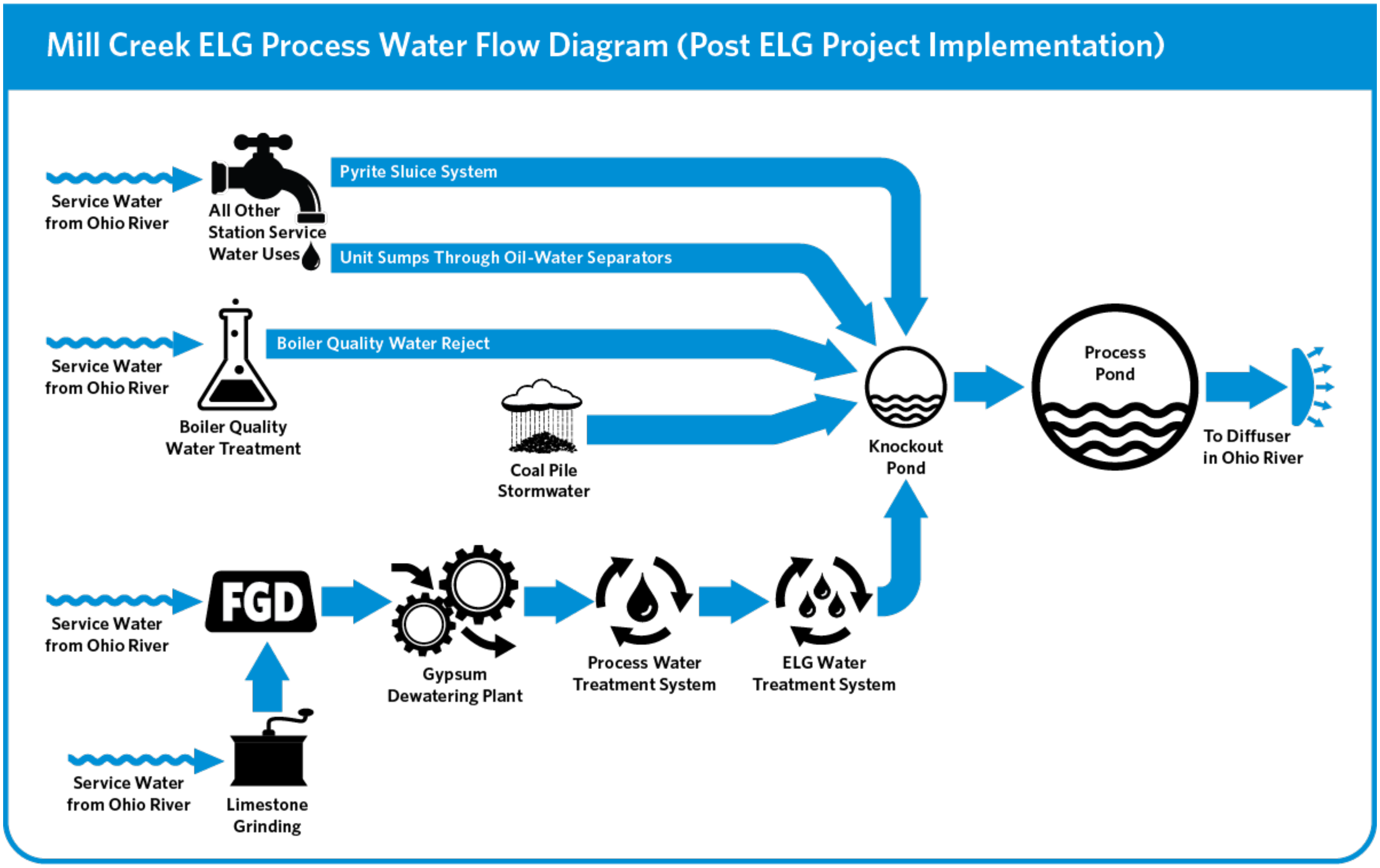
Professional Membership, Boards, Civic Activities & Achievements:

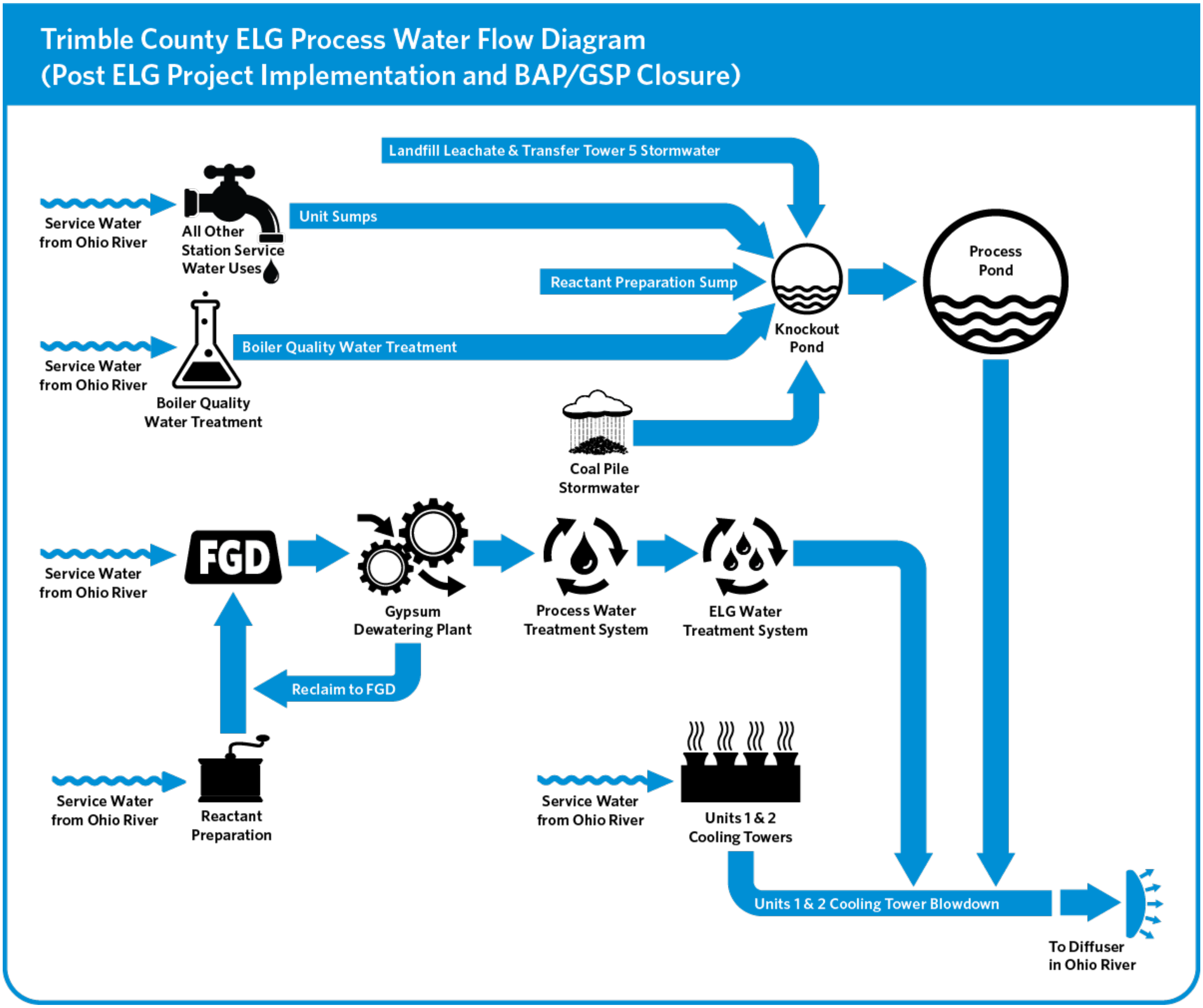
KY Professional Engineer
IN Professional Engineer
Pinnacle Honor Society for Masters Degrees

Beta Sigma Gamma (National Honor Society for Business Graduates)
Member of SCOAR (Southeastern Construction Owners & Assoc. Roundtable)
    SCOAR Board Vice President, Chair of Owner's Forum
EPRI RAC Committee Representative for PPL
University of Kentucky Center for Applied Research Board Member

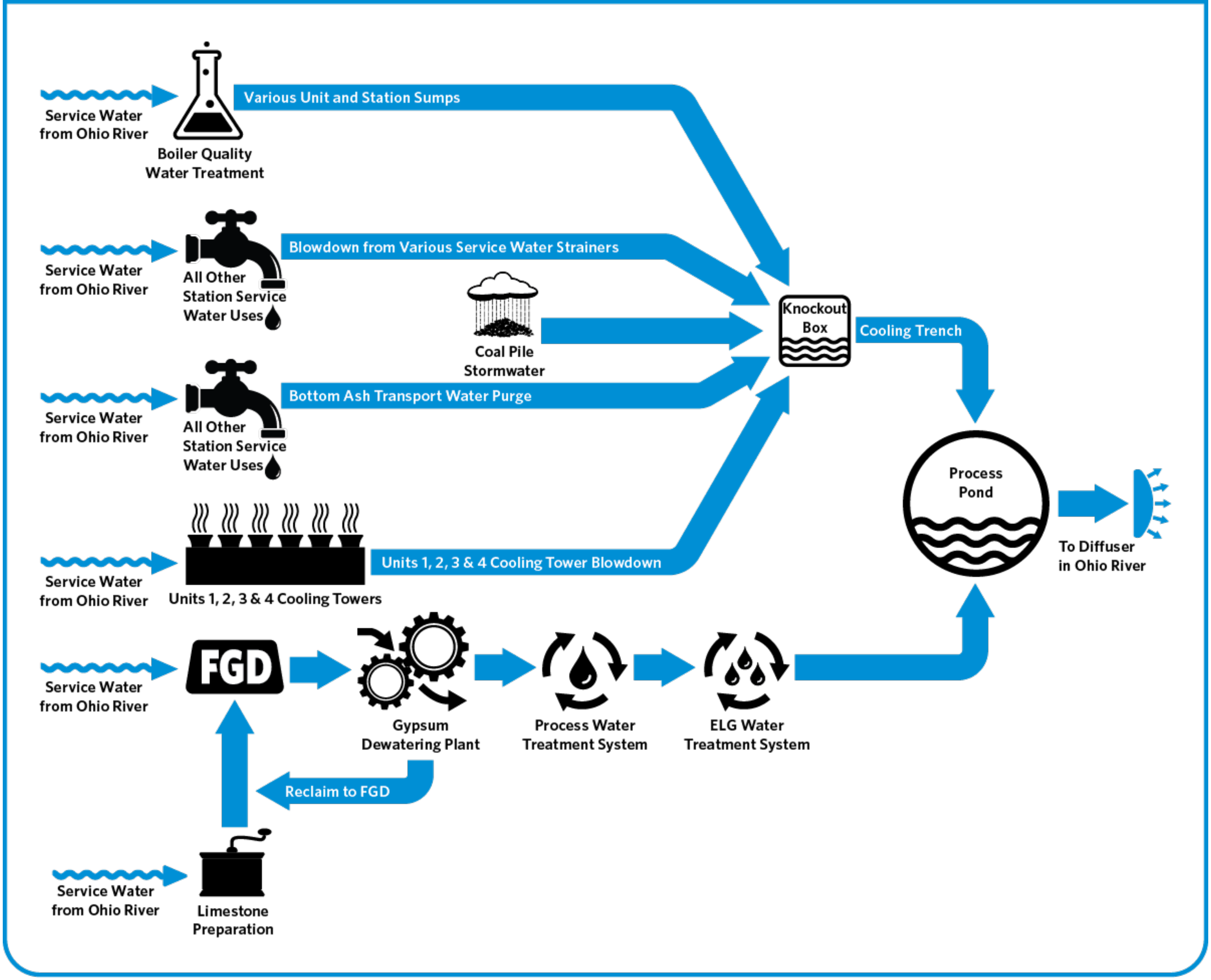
Education:

Bachelor of Science in Mechanical Engineering – Purdue University (1983)
Master of Business Administration – Indiana University (*with honors* 1993)
Steven Covey's Lessons in Leadership (1996)


Mill Creek ELG Process Water Flow Diagram (Post ELG Project Implementation)
Service Water from Ohio River
All Other Station Service Water Uses
Pyrite Sluice System
Unit Sumps Through Oil-Water Separators
Service Water from Ohio River
Boiler Quality Water Treatment
Boiler Quality Water Reject
Coal Pile Stormwater
Knockout Pond
Process Pond
To Diffuser in Ohio River
Service Water from Ohio River
FGD
Gypsum Dewatering Plant
Process Water Treatment System
ELG Water Treatment System
Service Water from Ohio River
Limestone Grinding


Trimble County ELG Process Water Flow Diagram
(Post ELG Project Implementation and BAP/GSP Closure)
Landfill Leachate & Transfer Tower 5 Stormwater
Service Water from Ohio River
All Other Station Service Water Uses
Unit Sumps
Reactant Preparation Sump
Knockout Pond
Process Pond
Service Water from Ohio River
Boiler Quality Water Treatment
Boiler Quality Water Treatment
Coal Pile Stormwater
Service Water from Ohio River
FGD
Gypsum Dewatering Plant
Process Water Treatment System
ELG Water Treatment System
Reclaim to FGD
Service Water from Ohio River
Reactant Preparation
Service Water from Ohio River
Units 1 & 2 Cooling Towers
Units 1 & 2 Cooling Tower Blowdown
To Diffuser in Ohio River

ELG Process Water Flow Diagram (Post ELG Project Implementation)



INDEX AND CERTIFICATION

LG&E and KU Services Company
Trimble County, Mill Creek and Ghent Generating Stations
Engineering, Procurement and Construction (EPC) Summary Report for ELG Rule Compliance (Water Treatment)
Project No. 117966, 117977, 117978

Report Index

Certification

I hereby certify, as a Professional Engineer in the state of Kentucky, the information in this document was assembled under my direct personal charge. This report is not intended or represented to be suitable for revision by the LG&E and KU Services Company or others without specific verification or adaptation by the Engineer.

Mar 26 2020

DocuSign

ENGINEERING, PROCUREMENT AND CONSTRUCTION (EPC) SUMMARY REPORT FOR ELG RULE COMPLIANCE (WATER TREATMENT)

Burns & McDonnell has prepared conceptual design documents for the installation of a new biological treatment system at the Trimble County, Mill Creek and Ghent Generating Stations. The recently commissioned physical/chemical treatment system with the addition of a new biological treatment system is necessary to treat Flue Gas Desulfurization (FGD) wastewater to meet the new EPA Effluent Limitations Guidelines and Standards (ELG rule); particularly to meet selenium, nitrates/nitrites and the more stringent arsenic and mercury limits. The conceptual design documents contained within this report have been utilized in the development of budgetary capital costs estimates and operating and maintenance cost estimates.

ELG RULE BACKGROUND

On August 11, 2017, the EPA announced that it was reconsidering portions of the recent revisions to the ELG rule specifically related to bottom ash transport and flue gas desulfurization (FGD) wastewaters. The postponement of the ELG rule was officially published in the Federal Register on Monday, September 18, 2017, in Volume 82, Number 179.

EPA indicated that it would propose and finalize a new rule, sometime by the fall of 2019. As a result of the ELG rule reconsideration, EPA has also postponed the earliest compliance dates for bottom ash transport water and FGD wastewater to November 1, 2020. In the ELG rule reconsideration, the EPA did not postpone the latest allowable compliance date which is still currently set for December 31, 2023 as it applies to the bottom ash transport section of the rule.

The proposed revised rule was officially published on November 22, 2019. The Best Available Technology Economically Achievable (BAT) technology remains chemical precipitation plus biological treatment. However, for the regulated pollutants (arsenic, mercury, selenium and nitrates/nitrites) the emission limits were revised. Significant other changes include compliance with limits to be as soon as possible but not later than December 31, 2025.

The ELG rule classifies FGD wastewater as blowdown from the FGD system, dewatering filtrate, and gypsum wash water. The ELG rule excluded the following from the FGD wastewater classification: water released from drains, water collected in washdown sumps, and water used for scrubber / equipment washdown or cleaning. EPA has established BAT for existing sources. These limits apply to the Mill Creek, Trimble County and Ghent Generating Stations. The ELG BAT technology basis for existing FGD wastewater is physical/chemical precipitation followed by biological treatment. Physical/Chemical Treatment systems have previously been installed at the Trimble County, Mill Creek and Ghent stations. Biological Treatment systems will need to be added.

The existing physical/chemical system was designed to reduce concentrations of arsenic and mercury to levels compliant with the 2015 ELG rule, as that was the current regulation at time of project development. The new biological treatment system will be used to reduce the concentrations of selenium and nitrates/nitrites as well as provide additional mercury reduction.

CONCEPTUAL DESIGN

The new biological treatment system will receive effluent from the physical/chemical water treatment system and will have capacities of 600 gallons per minute (gpm) for Trimble County and Mill Creek stations and 1,000 gpm for Ghent station. The following documents have been prepared to summarize the conceptual design:

- Process Flow Diagram (Appendix A)
- Trimble County General Arrangements (Appendices B1, B2 and B3)
- Trimble County Mechanical Equipment List (Appendix B4)
- Trimble County Electrical Equipment List (Appendix B5)
- Trimble County Capital Cost Estimate (Appendix B6)
- Trimble County Operating and Maintenance Cost Estimate (Appendix B7)
- Trimble County Project Schedule (Appendix B8)
- Mill Creek General Arrangements (Appendices C1, C2, and C3)
- Mill Creek Mechanical Equipment List (Appendix C4)
- Mill Creek Electrical Equipment List (Appendix C5)
- Mill Creek Capital Cost Estimate (Appendix C6)
- Mill Creek Operating and Maintenance Cost Estimate (Appendix C7)
- Mill Creek Project Schedule (Appendix C8)
- Ghent General Arrangements (Appendices D1, D2 and D3)
- Ghent Mechanical Equipment List (Appendix D4)
- Ghent Electrical Equipment List (Appendix D5)
- Ghent Capital Cost Estimate (Appendix D6)
- Ghent Operating and Maintenance Cost Estimate (Appendix D7)
- Ghent Project Schedule (Appendix D8)

Biological System Configuration

The proposed biological system design is based on Burns & McDonnell's recent experience with similar biological systems installed at other generating stations as well as the existing physical/chemical treatment systems at LG&E and KU. Burns & McDonnell reviewed and incorporated site-specific conditions and requirements into the conceptual designs. The biological equipment will be located adjacent to the existing physical/chemical treatment buildings (see Appendices B, C and D).

A process flow diagram is available in Appendix A. The ELG limits are achieved through the controlled reduction of nitrates/nitrites to nitrogen gas and selenate/selenite to elemental selenium. The dissolved nitrates/nitrites and selenium are removed via biological processes that involves biological organisms removing electrons from the pollutants causing the dissolved pollutants to change into elemental states/forms. The precipitated selenium and other solid metals are then filtered in the Ultrafiltration System (UF) and returned back into the existing physical/chemical treatment system where they are collected and removed with the sludge from the existing physical/chemical treatment system.

The major equipment required for a biological treatment system includes:

- Denitrification vessels
- Stage 1 biological reactors
- Stage 2 biological reactors

- Ultrafiltration (UF) systems
- Effluent tanks
- Associated cleaning and chemical feed equipment.
- Pumps, piping, valves, instrumentation
- Electrical Equipment
- Building and Canopy

The first step in the process is to treat the physical/chemical effluent to reduce the concentration of nitrates/nitrites. This is accomplished through a biological process utilizing new denitrification equipment.

In the second step, the remaining nitrates/nitrites are carried over into the first stage reactors of the biological treatment system as a source of 'food' for the biological system. The first stage reactor is comprised of coated concrete or fiberglass (FRP) vessels with spares. In the first stage the oxidation reduction potential (ORP) is lowered resulting in the remaining nitrates/nitrites to be removed via anaerobic respiration where the bacteria utilize the oxygen in the nitrates/nitrites and release nitrogen gas. A portion of the dissolved selenium is also reduced/captured. The effluent from the first stage is fed to the second stage.

The second stage is comprised of coated concrete vessels with spares that utilize downward flow in the vessel. In the second stage the ORP is further lowered to reduce/capture the remaining selenium in a process similar to that described above for the first stage. The effluent of the second stage is pumped through the UF system where any remaining particulate metals in the effluent are filtered out.

The UF system is comprised of UF membrane trains with spares. The resulting UF effluent feeds a series of effluent tanks that serve as clean water for backwashing the biological and UF systems and a head tank for the effluent pumps.

The biological systems and the UF systems must be periodically backwashed to remove solids collected in the systems. These solids include metals and biological waste from the organisms. These waste streams (and solids) are recycled to the existing physical/chemical system and will be removed in the underflow of the clarifier.

The biological reactors are located under a canopy. The canopy is provided for year-round operation. All other equipment is enclosed in a building.

The following chemical feed systems will be installed to support operation of the biological treatment system:

<u>UF cleaning chemicals for the chemical enhanced backwash (CEB) and clean in place (CIP) systems</u>
- Citric acid
- Sodium hypochlorite (bleach)
- Sodium hydroxide (caustic)
- Hydrochloric acid

<u>Biological related chemicals</u>
- Nutrient feed

- Hydrogen peroxide

CAPITAL COST ESTIMATE

Burns & McDonnell has prepared capital cost estimates for the design, purchase, and installation of a complete operating biological treatment system. Major equipment budgetary price estimates were received from Biological Treatment system suppliers. Balance of plant equipment costs and installation were estimated based on Burns & McDonnell's experience and internal databases. An equipment list for each site summarizing major mechanical equipment, tanks, and skids is included in Appendices B4, C4 and D4. An equipment list for each site summarizing major electrical equipment is included in Appendices B5, C5 and D5.

Generating Station	EPC Capital Cost Estimate
Trimble County Generating Station	\$66.7M
Mill Creek Generating Station	\$66.4M
Ghent Generating Station	\$94.1M

Summaries of the capital cost estimate for each site are provided in Appendices B6, C6 and D6.

Trimble County and Ghent estimates are based on treatment rates reflective of maximum process inlet conditions for all units at full load operation. The cost estimate for Mill Creek is based on a treatment rate (600 gpm) reflective of maximum process inlet conditions for three units in operation at full load. Should the capacity for Mill Creek need to be increased (to 750 gpm) to accommodate maximum inlet conditions with all four units at full load operation the resulting increased capacity would increase the estimated EPC cost by \$7M. The design layout for Mill Creek equipment will allow for this expansion should it be required.

These estimates are based on Burns & McDonnell's professional experience, qualifications, and judgment. These estimates do not include contingencies for weather; availability of labor, material, and equipment; labor productivity; energy or commodity pricing; demand or usage; population demographics; market conditions; changes in technology; and other economic or political factors affecting such estimates, analysis, and recommendations.

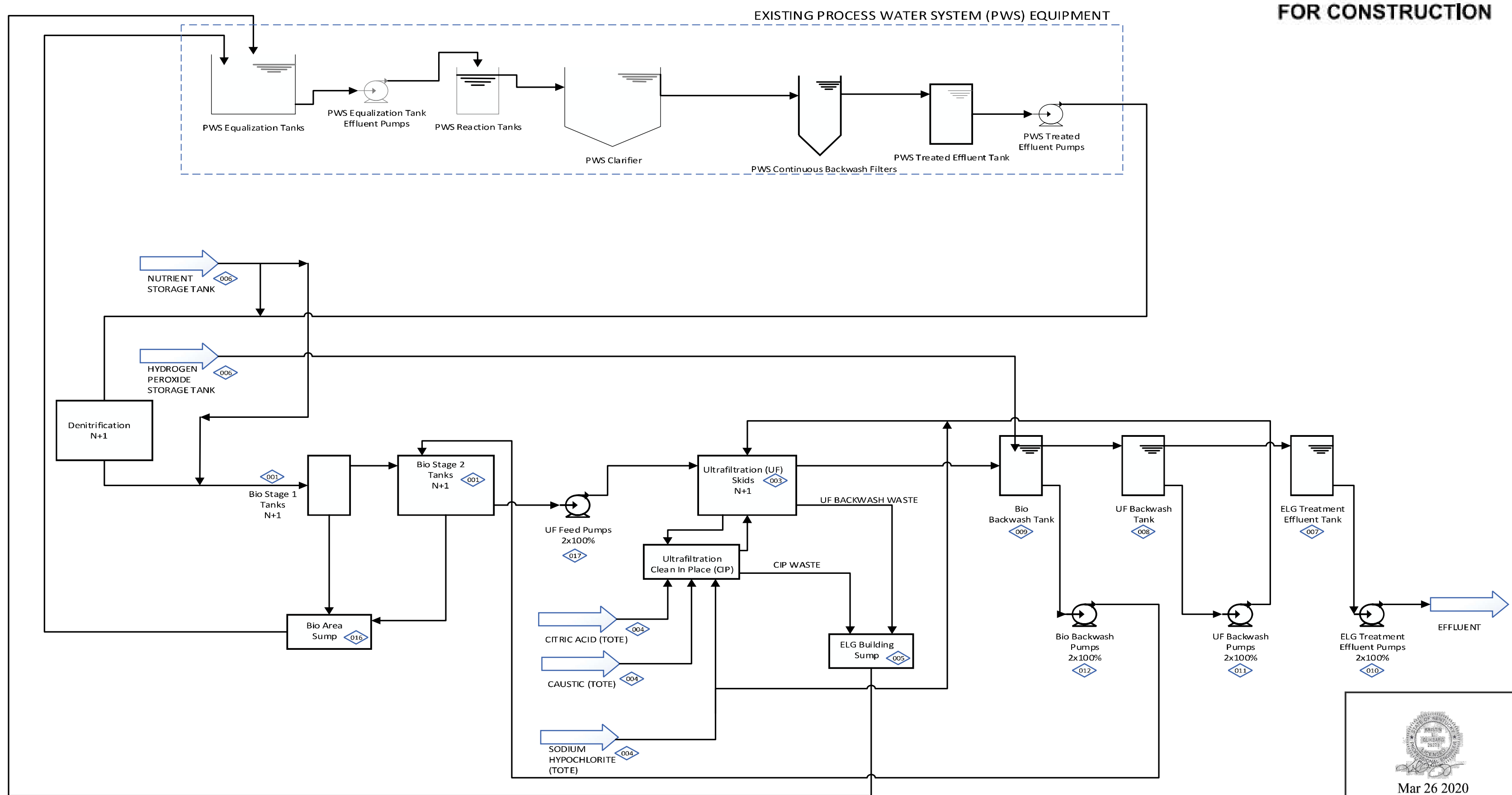
OPERATING AND MAINTENANCE COSTS

Projected operating and maintenance costs are summarized for each site in Appendices B7, C7 and D7.

SCHEDULE

The anticipated schedules to design, procure, and install a new biological treatment system at each site are provided in Appendices B8, C8 and D8.

Appendix A: Process Flow Diagram



PRELIMINARY - NOT FOR CONSTRUCTION

No.	Date	By	Checked	Description

Notes:

BURNS McDONNELL

Date: Detailed: K. Glikbarg

Designed: K. Glikbarg Checked:

LG&E KU PPL companies

Mar 26 2020

Mill Creek, Trimble County & Ghent Generating Stations
Process Flow Diagram
ELG Treatment

Project: Contract:

Drawing PFD-01A Rev.

Sheet 1 of 1 sheets

Exhibit RSS-2
Page 7 of 71

Appendix B: Trimble County Generating Station Conceptual Design Documents

B1: Trimble County Generating Station Site Overview
B2: ELG Location on Trimble County Generating Station Site
B3: ELG Equipment General Arrangement
B4: Trimble County Generating Station Mechanical Equipment List
B5: Trimble County Generating Station Electrical Equipment List
B6: Trimble County Generating Station Capital Cost Estimate
B7: Trimble County Generating Station Operating and Maintenance Cost Estimate
B8: Trimble County Generating Station Schedule

Mar 26 2020

PRELIMINARY - NOT FOR CONSTRUCTION

no.	date	by	ckd	description	no.	date	by	ckd	description

GENERAL ARRANGEMENT

0 32' 64' 128'
SCALE IN FEET

NORTH

BURNS McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: K. GLIKBARG
detailed: N. NITCHALS

LG&E KU
PPL companies

TRIMBLE CO., KY

APPENDIX B1
TRIMBLE COUNTY GENERATING STATION
SITE OVERVIEW

project: 117966 | contract: -

drawing: GA1002A | rev.: -

sheet 1 of 1 sheets

file 117966GA1002A.dwg

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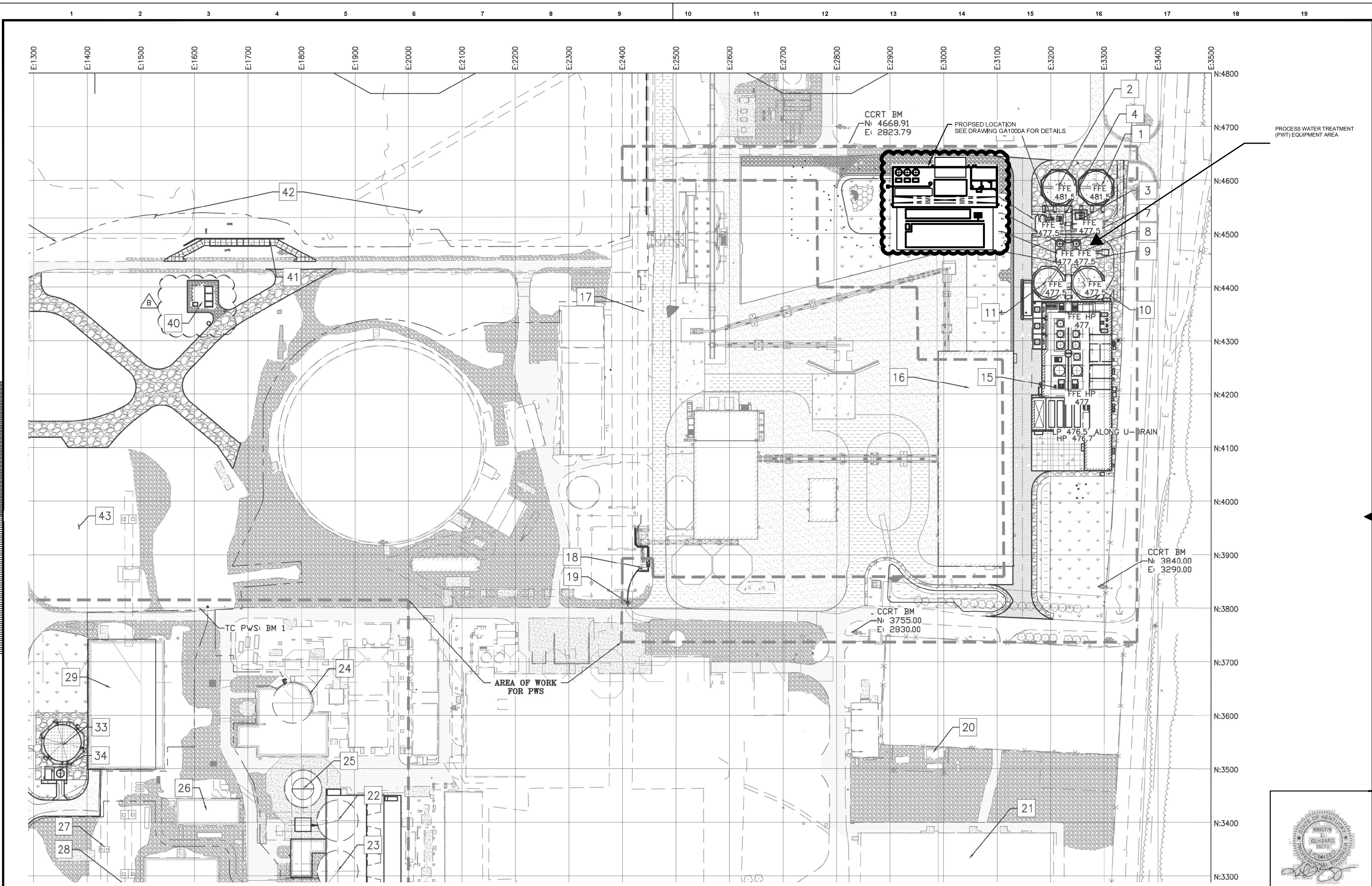

PRELIMINARY - NOT FOR CONSTRUCTION

Mar 26 2020

no.	date	by	ckd	description	no.	date	by	ckd	description

GENERAL ARRANGEMENT

SCALE IN FEET

NORTH

BURNS & McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed K. GLIKBARG
detailed N. NITCHALS

LG&E KU PPL companies

TRIMBLE CO., KY

APPENDIX B2
ELG LOCATION ON TRIMBLE COUNTY GENERATING STATION SITE

project 117966
contract -
drawing GA1001A
rev. -
sheet 1 of 1 sheets
file 117966GA1001A.dwg

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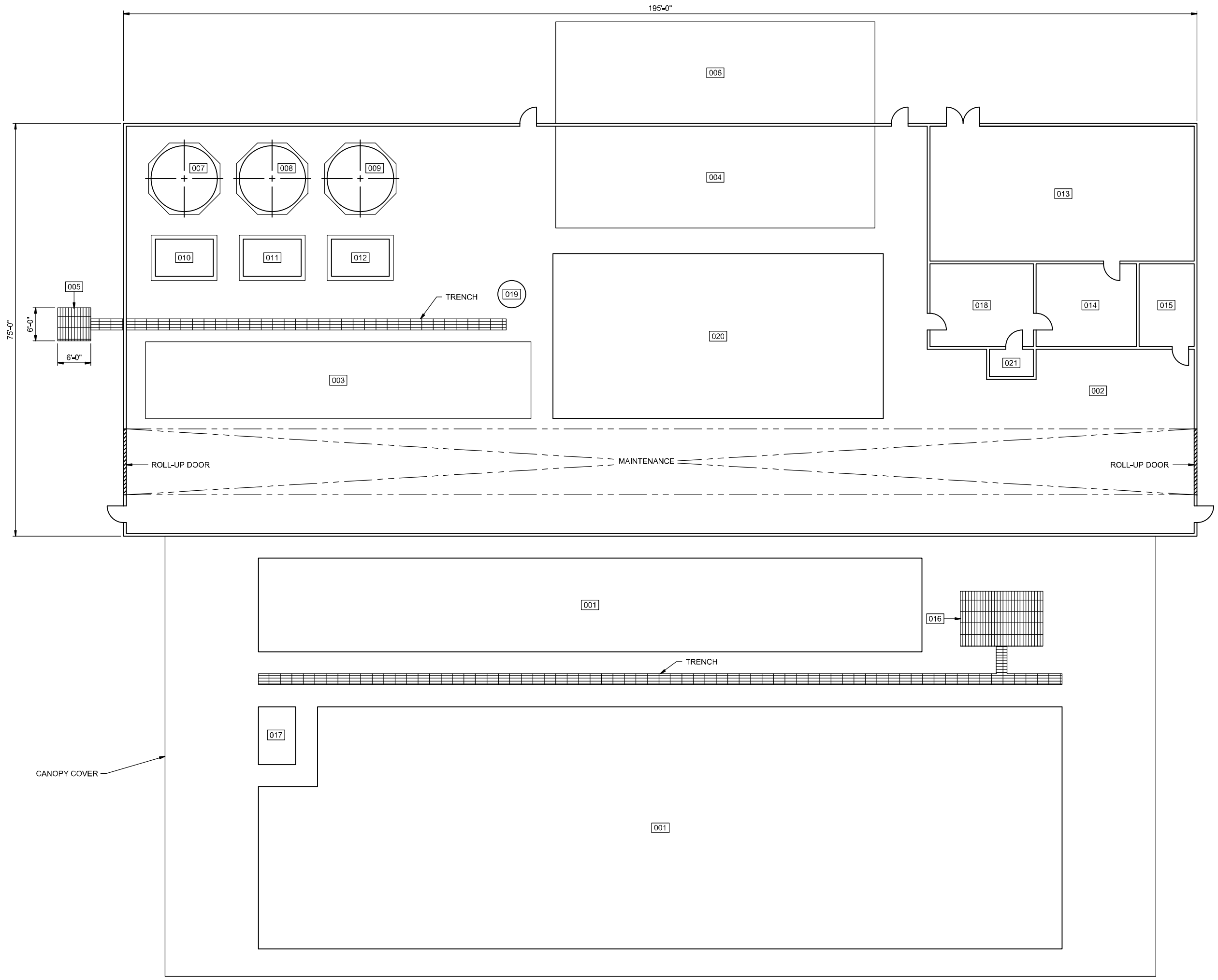

EQUIPMENT IDENTIFICATION AND LOCATION LIST

DWG REF	DESCRIPTION NEW SITE EQUIPMENT
001	BIOLOGICAL REACTOR AREA (CONCRETE VESSELS)
002	EFFLUENT LIMITATION GUIDELINES TREATMENT BUILDING
003	MF/UF AREA
004	CHEMICAL STORAGE ROOM
005	ELG BUILDING SUMP
006	BULK CHEMICAL STORAGE TANK AREA
007	EFFLUENT TANK
008	MF/UF BACKWASH TANK
009	BIO BACKWASH TANK
010	EFFLUENT PUMP SKID
011	UF BACKWASH PUMP SKID
012	BIO BACKWASH PUMP SKID
013	ELECTRICAL ROOM
014	DCS ROOM
015	BATTERY ROOM
016	BIOLOGICAL REACTOR AREA SUMP
017	MF/UF FEED PUMP SKID
018	CONTROL ROOM/LAB
019	AIR RECEIVER
020	DENITRIFICATION EQUIPMENT AREA
021	UNISEX BATHROOM

GENERAL ARRANGEMENT
0 4' 8' 16'
SCALE IN FEET
NORTH

PRELIMINARY - NOT FOR CONSTRUCTION

Mar 26 2020

BURNS McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: K. GLIKBARG
detailed: N. NITCHALS

LG&E KU
PPL companies
TRIMBLE CO., KY

APPENDIX B3
TRIMBLE COUNTY GENERATING STATION ELG
EQUIPMENT GENERAL ARRANGEMENT

project: 117966
contract: -
drawing: GA1000A
rev.: -
sheet 1 of 1 sheets
file 117966GA1000A.dwg

no.	date	by	ckd	description

no.	date	by	ckd	description

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Louisville Gas and Electric & Kentucky Utilities
Trimble County ELG Treatment
600GPM System - Mechanical Equipment List

SYSTEM DESCRIPTION	EQUIPMENT NAME / DESCRIPTION	OPERATING	Supplier	INDOOR/OUTDOOR	Capacity
DENITRIFICATION	NEW DENITRIFICATION SYSTEM	1 x 100%	BIO OEM	INDOOR	10'D X 15'H
BIO	BIOLOGICAL TREATMENT SYSTEM	1 x 100%	BIO OEM	OUTDOOR	
BIO	A BIOREACTOR STAGE 1 FEED PUMP STRAINER	1 x 100%	EPC - BOP	OUTDOOR	
BIO	B BIOREACTOR STAGE 1 FEED PUMP STRAINER	1 x 100%	EPC - BOP	OUTDOOR	
BIO	A BIOREACTOR STAGE 1 TANK	1 x 12.5%	BIO OEM	OUTDOOR	
BIO	B BIOREACTOR STAGE 1 TANK	1 x 12.5%	BIO OEM	OUTDOOR	
BIO	C BIOREACTOR STAGE 1 TANK	1 x 12.5%	BIO OEM	OUTDOOR	
BIO	D BIOREACTOR STAGE 1 TANK	1 x 12.5%	BIO OEM	OUTDOOR	
BIO	E BIOREACTOR STAGE 1 TANK	1 x 12.5%	BIO OEM	OUTDOOR	
BIO	F BIOREACTOR STAGE 1 TANK	1 x 12.5%	BIO OEM	OUTDOOR	
BIO	G BIOREACTOR STAGE 1 TANK	1 x 12.5%	BIO OEM	OUTDOOR	
BIO	A/B BIOREACTOR STAGE 1 TANK FLOW CONTROL SKID	2 x 12.5%	BIO OEM	OUTDOOR	
BIO	C/D BIOREACTOR STAGE 1 TANK FLOW CONTROL SKID	2 x 12.5%	BIO OEM	OUTDOOR	
BIO	E/F BIOREACTOR STAGE 1 TANK FLOW CONTROL SKID	2 x 12.5%	BIO OEM	OUTDOOR	
BIO	G BIOREACTOR STAGE 1 TANK FLOW CONTROL SKID	2 x 12.5%	BIO OEM	OUTDOOR	
BIO	A BIOREACTOR STAGE 2 TANK	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	B BIOREACTOR STAGE 2 TANK	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	C BIOREACTOR STAGE 2 TANK	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	D BIOREACTOR STAGE 2 TANK	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	E BIOREACTOR STAGE 2 TANK	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	F BIOREACTOR STAGE 2 TANK	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	G BIOREACTOR STAGE 2 TANK	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	H BIOREACTOR STAGE 2 TANK	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	J BIOREACTOR STAGE 2 TANK	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	K BIOREACTOR STAGE 2 TANK	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	L BIOREACTOR STAGE 2 TANK	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	M BIOREACTOR STAGE 2 TANK	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	N BIOREACTOR STAGE 2 TANK	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	O BIOREACTOR STAGE 2 TANK	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	A BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	B BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	C BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	D BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	E BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	F BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	G BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	H BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	J BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	K BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	L BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	M BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	N BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	O BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	1 x 6.25%	BIO OEM	OUTDOOR	
BIO	BIOREACTOR BACKWASH TANK	1 x 100%	EPC - BOP	OUTDOOR	20,000 gallons - 14'D x 18'H (FRP Construction)
BIO	BIOREACTOR BACKWASH PUMP SKID	1 x 100%	BIO OEM	OUTDOOR	
BIO	A BIOREACTOR BACKWASH PUMP	1 x 100%	BIO OEM	OUTDOOR	2100
BIO	B BIOREACTOR BACKWASH PUMP	1 x 100%	BIO OEM	OUTDOOR	2100
BIO	WWT EFFLUENT TANK	1 x 100%	EPC - BOP	OUTDOOR	20,000 gallons - 14'D x 18'H (FRP Construction)
BIO	A WWT EFFLUENT PUMP	1 x 100%	BIO OEM	OUTDOOR	800
BIO	B WWT EFFLUENT PUMP	1 x 100%	BIO OEM	OUTDOOR	800
BIO	BIO AREA SUMP	1 x 100%	EPC - BOP	OUTDOOR	15'W x 20' L x 15' D (~30,000 gallons)
BIO	A BIO AREA SUMP PUMP	1 x 100%	EPC - BOP	OUTDOOR	450
BIO	B BIO AREA SUMP PUMP	1 x 100%	EPC - BOP	OUTDOOR	450
BIO- CHEMICAL FEED	NUTRIENT STORAGE TANK	1 x 100%	EPC - BOP	OUTDOOR	20,000 gallons - 14'D x 18'H (FRP Construction)
BIO- CHEMICAL FEED	DENITRIFICATION NUTRIENT FEED SKID	1 x 100%	BIO OEM	INDOOR	
BIO- CHEMICAL FEED	A DENITRIFICATION NUTRIENT FEED PUMP	1 x 100%	BIO OEM	INDOOR	12.3
BIO- CHEMICAL FEED	B DENITRIFICATION NUTRIENT FEED PUMP	1 x 100%	BIO OEM	INDOOR	12.3
BIO- CHEMICAL FEED	BIOREACTOR NUTRIENT FEED SKID	1 x 100%	BIO OEM	INDOOR	
BIO- CHEMICAL FEED	A BIOREACTOR NUTRIENT PUMP	1 x 100%	BIO OEM	INDOOR	8.1
BIO- CHEMICAL FEED	B BIOREACTOR NUTRIENT PUMP	1 x 100%	BIO OEM	INDOOR	8.1
UF	UF FEED PUMP SKID	1 x 100%	BIO OEM	OUTDOOR	
UF	A UF FEED PUMP	1 x 100%	BIO OEM	OUTDOOR	800
UF	B UF FEED PUMP	1 x 100%	BIO OEM	OUTDOOR	800
UF	UF CIP PUMP SKID	1 x 100%	BIO OEM	INDOOR	
UF	UF CIP TANK	1 x 100%	BIO OEM	INDOOR	
UF	A UF CIP PUMP	1 x 100%	BIO OEM	INDOOR	140
UF	B UF CIP PUMP	1 x 100%	BIO OEM	INDOOR	140
UF	A UF MEMBRANE SKID	1 x 50%	BIO OEM	INDOOR	
UF	B UF MEMBRANE SKID	1 x 50%	BIO OEM	INDOOR	
UF	C UF MEMBRANE SKID	1 x 50%	BIO OEM	INDOOR	
UF	D UF MEMBRANE SKID	1 x 50%	BIO OEM	INDOOR	
UF	E UF MEMBRANE SKID	1 x 50%	BIO OEM	INDOOR	
UF	UF BACKWASH TANK	1 x 100%	EPC - BOP	OUTDOOR	20,000 gallons - 14'D x 18'H (FRP Construction)
UF	UF BACKWASH PUMP SKID	1 x 100%	BIO OEM	OUTDOOR	
UF	A UF BACKWASH PUMP	1 x 100%	BIO OEM	OUTDOOR	250
UF	B UF BACKWASH PUMP	1 x 100%	BIO OEM	OUTDOOR	250
UF	UF AREA SUMP	1 x 100%	EPC - BOP	OUTDOOR	~5,000 gallons (8'W x 8'L x 10'D)
UF	A UF AREA SUMP PUMP	1 x 100%	EPC - BOP	OUTDOOR	300
UF	B UF AREA SUMP PUMP	1 x 100%	EPC - BOP	OUTDOOR	300
UF - CHEMICAL FEED	UF CITRIC ACID FEED SKID	1 x 100%	BIO OEM	INDOOR	
UF - CHEMICAL FEED	A UF CITRIC ACID FEED PUMP	1 x 100%	BIO OEM	INDOOR	40
UF - CHEMICAL FEED	B UF CITRIC ACID FEED PUMP	1 x 100%	BIO OEM	INDOOR	40
UF - CHEMICAL FEED	UF SODIUM HYPOCHLORITE FEED SKID	1 x 100%	BIO OEM	INDOOR	
UF - CHEMICAL FEED	A UF SODIUM HYPOCHLORITE FEED PUMP	1 x 100%	BIO OEM	INDOOR	84

Louisville Gas and Electric & Kentucky Utilities
Trimble County ELG Treatment
600GPM System - Mechanical Equipment List

SYSTEM DESCRIPTION	EQUIPMENT NAME / DESCRIPTION	OPERATING	Supplier	INDOOR/OUTDOOR	Capacity
UF - CHEMICAL FEED	B UF SODIUM HYPOCHLORITE FEED PUMP	1 x 100%	BIO OEM	INDOOR	84
UF - CHEMICAL FEED	UF CAUSTIC FEED SKID	1 x 100%	BIO OEM	INDOOR	
UF - CHEMICAL FEED	A UF CAUSTIC FEED PUMP	1 x 100%	BIO OEM	INDOOR	9.4
UF - CHEMICAL FEED	B UF CAUSTIC FEED PUMP	1 x 100%	BIO OEM	INDOOR	9.4
UF - CHEMICAL FEED	UF HYDROGEN PEROXIDE FEED SKID	1 x 100%	BIO OEM	INDOOR	
UF - CHEMICAL FEED	A UF HYDROGEN PEROXIDE FEED PUMP	1 x 100%	BIO OEM	INDOOR	4.4
UF - CHEMICAL FEED	B UF HYDROGEN PEROXIDE FEED PUMP	1 x 100%	BIO OEM	INDOOR	4.4
SERVICE WATER	SERVICE WATER AUTO STRAINER A	1 x 100%	EPC - BOP	INDOOR	
SERVICE WATER	SERVICE WATER AUTO STRAINER B	1 x 100%	EPC - BOP	INDOOR	
COOLING WATER	COOLING WATER PUMP A	1 x 100%	EPC - BOP	INDOOR	
COOLING WATER	COOLING WATER PUMP B	1 x 100%	EPC - BOP	INDOOR	
POTABLE WATER	WWT Building Potable Water Tempering Skid	1 x 100%	EPC - BOP	INDOOR	
POTABLE WATER	WWT Building Potable Water Tempering Skid Tank Heater	1 x 100%	EPC - BOP	INDOOR	
POTABLE WATER	WWT Building Potable Water Tempering Skid Booster Pump	1 x 100%	EPC - BOP	INDOOR	30
POTABLE WATER	WWT Building Potable Water Tempering Skid Recirculation Pump	1 x 100%	EPC - BOP	INDOOR	30
POTABLE WATER	WWT Building Potable Water Tempering Skid Tank	1 x 100%	EPC - BOP	INDOOR	
SEWAGE DRAINS SYSTEM	WWT BUILDING SANITARY LIFT STATION	1 x 100%	EPC - BOP	OUTDOOR	
SEWAGE DRAINS SYSTEM	A WWT SANITARY LIFT STATION PUMP	1 x 100%	EPC - BOP	OUTDOOR	50
SEWAGE DRAINS SYSTEM	B WWT SANITARY LIFT STATION PUMP	1 x 100%	EPC - BOP	OUTDOOR	50
HVAC	Bldg HVAC - Heating	1 x 100%	EPC - BOP		
HVAC	Bldg HVAC - Exhaust Fans	1 x 100%	EPC - BOP		
HVAC	Bldg HVAC - Exhaust Fans	1 x 100%	EPC - BOP		
HVAC	Bldg HVAC - Exhaust Fans	1 x 100%	EPC - BOP		
HVAC	Bldg HVAC - Exhaust Fans	1 x 100%	EPC - BOP		
HVAC	Bldg HVAC - Chemical Room Exhaust Fan	1 x 100%	EPC - BOP		

Louisville Gas and Electric & Kentucky Utilities
Trimble County ELG Treatment
600GPM System - Electrical Equipment List

SYSTEM DESCRIPTION	EQUIPMENT NAME / DESCRIPTION	QUANTITY	Supplier	INDOOR/OUTDOOR
ELECTRICAL EQUIPMENT	13.8 kV-480V TRANSFORMERS	2 EACH	EPC - BOP	INDOOR
ELECTRICAL EQUIPMENT	480V SWITCHGEAR (MAIN-TIE-MAIN)	1 SWITCHGEAR	EPC - BOP	INDOOR
ELECTRICAL EQUIPMENT	480 MCCs (4 LINEUPS)	16 SECTIONS	EPC - BOP	INDOOR
ELECTRICAL EQUIPMENT	480V-208V TRANSFORMER	2 EACH	EPC - BOP	INDOOR
ELECTRICAL EQUIPMENT	208/120V LIGHTING AND POWER PANELS	2 EACH	EPC - BOP	INDOOR
ELECTRICAL EQUIPMENT	125 VDC POWER PANEL	1 EACH	EPC - BOP	INDOOR

FEL-2 CAPITAL COST ESTIMATE SUMMARY SHEET
LGE/KU ELG Treatment
Trimble County Generating Station
600 GPM Water Treatment
Bedford, KY
BMcD #117966

Acct	Area / Discipline	Direct MHRS	Labor Cost	Material Cost	Engr Equip/ Subcontract Cost	Const. Equipment Cost	Total Cost
01	Engineered Equipment	3,370	$518,960	$1,155,225	$7,391,876		$9,066,061
02	Civil	4,438	$537,058	$348,524	$88,125	$86,266	$1,059,973
03	Deep Foundations	2,234	$270,370	$307,266	$1,654,244	$25,187	$2,257,066
04	Concrete	7,498	$906,422	$874,329	$237,493	$41,648	$2,059,893
05	Structural Steel	4,380	$647,890	$589,123			$1,237,013
06	Architectural				$2,256,660		$2,256,660
07	Piping	24,813	$3,635,799	$1,318,799	$351,595		$5,306,192
08	Electrical	41,314	$5,704,676	$2,746,813	$285,950		$8,737,439
09	Instrument & Control	1,459	$202,452	$29,342	$1,078,250		$1,310,044
10	Insulation				$5,242,757		$5,242,757
11	Coatings				$636,400		$636,400
12	Specialty						
13	Demolition						
14	Misc Directs						
	Total Direct Cost	**89,506**	**$12,423,627**	**$7,369,420**	**$19,223,350**	**$153,101**	**$39,169,497**

Rev.	Revision Date
0	03/06/20
1	03/16/20
2	03/25/20

Construction Mgmt & Indirects		$2,983,540
Engineering		$3,916,950
Start-Up		$1,175,085
Commercial		$518,500
Total Indirect Cost		**$8,594,074**
Total Direct and Indirect Costs		**$47,763,572**
Minor Scope Items	20%	$9,552,714
EPC Execution Contingency	10%	$4,776,357
EPC Fee	8%	$4,585,303
Total EPC Contract Costt Cost		**$66,677,946**

Notes:

1) Minor Scope Items is intended to capture costs for scope and small procurements (<$10,000) that may have been unaccounted for within the estimate basis.
2) EPC Execution Contingency is intended to capture costs associated with events outside the Contractor's control (i.e equipment mis-fabrication, and excessive crane rental duration, etc.) that could increase overall cost and.or schedule of the project.

BURNS McDONNELL V3.6

PROJECT CLIENT: **LGE/KU ELG Treatment**

PROJECT DESC: **Trimble County Generating Station - 600 GPM Water Treatment**

PROJECT # : **117966**

SUMMARY
ENGINEERED EQUIPMENT

EST LEVEL: **FEL-2**

ESTIMATE DUE DATE: **1/30/2020**

ESTIMATOR:

DESCRIPTION		LABOR		MATERIAL	EQUIPMENT	EQUIPMENT	**TOTAL**
		MH	COST	COST	COST	RENT / STS	**COST**
P 2	DENITRIFICATION	450	69,297		680,001		**749,297**
P 3	BIOLOGICAL TREATMENT SYSTEM	1,860	286,429	1,155,225	4,850,875		**6,292,529**
P 4	BIO- CHEMICAL FEED	120	18,479		153,000		**171,479**
P 5	UF	390	60,058		1,462,000		**1,522,058**
P 6	UF - CHEMICAL FEED	140	21,559		51,000		**72,559**
P 7	SERVICE WATER	40	6,160		70,000		**76,160**
P 8	COOLING WATER	160	24,639		70,000		**94,639**
P 9	COMPRESSED AIR	30	4,620		5,000		**9,620**
P 10	POTABLE WATER	80	12,320		20,000		**32,320**
P 11	SEWAGE DRAINS SYSTEM	40	6,160		15,000		**21,160**
P 12	Eye Wash Station	60	9,240		15,000		**24,240**
	ESTIMATE TOTALS	**3,370**	**$518,960**	**$1,155,225**	**$7,391,876**		**$9,066,060**

Exhibit RSS-2
Page 16 of 71

PROJECT CLIENT: **LGE/KU ELG Treatment**
PROJECT DESC: **Trimble County Generating Station - 600 GPM Water Treatment**
PROJECT # : **117966**

SUMMARY
CIVIL

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **1/30/2020**
ESTIMATOR:

DESCRIPTION	LABOR		MATERIAL	SUBCON	EQUIPMENT	**TOTAL**
	MH	COST	COST	COST	RENT / STS	**COST**
P 2 Earthwork	544	65,873	8,235		31,844	**105,952**
P 3 Site Surfacing	2,081	251,771	270,659		14,588	**537,019**
P 4 Storm Drainage	561	67,872	37,816		13,195	**118,883**
P 5 Underground Utilities	1,072	129,760	23,188	88,125	26,084	**267,156**
P 7 MISC ITEMS	180	21,782	8,625		555	**30,962**
ESTIMATE TOTALS	**4,438**	**$537,058**	**$348,524**	**$88,125**	**$86,266**	**$1,059,973**

Exhibit RSS-2
Page 17 of 71

PROJECT CLIENT: **LGE/KU ELG Treatment**

PROJECT DESC: **Trimble County Generating Station - 600 GPM Water Treatment**

PROJECT # : **117966**

SUMMARY
DEEP FOUNDATIONS

EST LEVEL: **FEL-2**

ESTIMATE DUE DATE: **1/30/2020**

ESTIMATOR:

DESCRIPTION	LABOR		MATERIAL	SUBCON	EQUIPMENT	**TOTAL**
	MH	COST	COST	COST	RENT / STS	**COST**
P 2 Auger Cast Piles	2,234	270,370	307,266	1,654,244	25,187	**2,257,066**
ESTIMATE TOTALS	**2,234**	**$270,370**	**$307,266**	**$1,654,244**	**$25,187**	**$2,257,066**

Exhibit RSS-2
Page 18 of 71

PROJECT CLIENT: **LGE/KU ELG Treatment**
PROJECT DESC: **Trimble County Generating Station - 600 GPM Water Treatment**
PROJECT # : **117966**

SUMMARY
CONCRETE

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **1/30/2020**
ESTIMATOR:

DESCRIPTION		LABOR MH	LABOR COST	MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
P 2 Bldg, Sumps, Equip Pads	2,781.1 CY	7,498	906,422	874,329	237,493	41,648	**2,059,893**
P 3 Tank Walls (OPT 2)							
	ESTIMATE TOTALS	**7,498**	**$906,422**	**$874,329**	**$237,493**	**$41,648**	**$2,059,893**
	2,781.1 CY	2.7	325.92	314.38	85.40	14.98	740.68

Exhibit RSS-2
Page 19 of 71

PROJECT CLIENT: **LGE/KU ELG Treatment**
PROJECT DESC: **Trimble County Generating Station - 600 GPM Water Treatment**
PROJECT # : **117966**

SUMMARY
STRUCTURAL STEEL

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **1/30/2020**
ESTIMATOR:

DESCRIPTION		LABOR MH	LABOR COST	MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
P 2	Pipe Rack Structural Steel	3,951	584,347	363,158			**947,505**
P 3	Misc Steel	338	50,049	204,688			**254,737**
P 4	UF Bldg Access Stairway	91	13,494	21,276			**34,770**
	ESTIMATE TOTALS	**4,380**	**$647,890**	**$589,123**			**$1,237,013**

Exhibit RSS-2
Page 20 of 71

PROJECT CLIENT: **LGE/KU ELG Treatment**
PROJECT DESC: **Trimble County Generating Station - 600 GPM Water Treatment**
PROJECT # : **117966**

SUMMARY
ARCHITECTURAL

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **1/30/2020**
ESTIMATOR:

DESCRIPTION	LABOR		MATERIAL	SUBCON	EQUIPMENT	**TOTAL**
	MH	COST	COST	COST	RENT / STS	**COST**
P 2 WATER TREATMENT BLDG				2,256,660		**2,256,660**
ESTIMATE TOTALS				**$2,256,660**		**$2,256,660**

Exhibit RSS-2
Page 21 of 71

PROJECT CLIENT: **LGE/KU ELG Treatment**

PROJECT DESC: **Trimble County Generating Station - 600 GPM Water Treatment**

PROJECT # : **117966**

SUMMARY
PIPING

EST LEVEL: **FEL-2**

ESTIMATE DUE DATE: **1/30/2020**

ESTIMATOR:

DESCRIPTION				LABOR		MATERIAL	SUBCON	EQUIPMENT	**TOTAL**
				MH	COST	COST	COST	RENT / STS	**COST**
P 2	PIPING - UG	5616 LF	0.70	3,905	436,362	121,943			**558,305**
P 3	PIPING - AG			8,558	1,309,545	272,112			**1,581,657**
P 4	PIPING - AG (cont)			7,931	1,213,591	750,988			**1,964,579**
P 5	PIPING - AG (cont)	6383 LF	3.02	2,818	431,274	33,916	209,045		**674,235**
P 6	VALVES	100 EA	5.50	550	84,162	132,940			**217,102**
P 7	SPECIALS 1	181 EA	4.98	901	137,911		142,550		**280,461**
P 8	TIE-INS	4 EA	37.50	150	22,953	6,900			**29,853**
	ESTIMATE TOTALS			**24,813**	**$3,635,799**	**$1,318,799**	**$351,595**		**$5,306,192**
	TOTAL	11999 LF	2.07						

Exhibit RSS-2
Page 22 of 71

PROJECT CLIENT: **LGE/KU ELG Treatment**

PROJECT DESC: **Trimble County Generating Station - 600 GPM Water Treatment**

PROJECT # : **117966**

SUMMARY
ELECTRICAL

EST LEVEL: **FEL-2**

ESTIMATE DUE DATE: **1/30/2020**

ESTIMATOR:

DESCRIPTION		LABOR		MATERIAL	SUBCON	EQUIPMENT	**TOTAL**
		MH	COST	COST	COST	RENT / STS	**COST**
P 2	GROUNDING	1,252	174,223	31,834			**206,058**
P 3	8.10 CONDUIT	5,314	739,794	319,354			**1,059,148**
P 4	8.11 CABLE TRAY	372	51,782	19,881			**71,664**
P 5	8.12 UG RACEWAY	17,825	2,481,354	848,366			**3,329,719**
P 6	8.20 MED Volt Cable	288	40,033	50,575			**90,608**
P 7	8.21 480V Cable	1,934	269,172	203,976			**473,148**
P 8	8.22 Cable Control & Insturment	3,087	429,687	99,937			**529,624**
P 9	8.23 Cable, Fiber, Ethernet	176	24,439	21,367			**45,806**
P 10	TERMINATIONS	1,861	259,069	20,018			**279,087**
P 11	8.40 Lighting and Recep	4,764	663,196	221,776			**884,972**
P 12	8.31 Elec Equipment Install	1,017	95,098	816,203			**911,301**
P 14	Security	806	112,225	23,487			**135,712**
P 15	COMMUNICATION				76,000		**76,000**
P 16	HEAT TRACE & CATHODIC				209,950		**209,950**
P 17	LIGHTNING PROTECTION	620	86,272	16,947			**103,219**
P 18	TEMPORARY POWER	1,999	278,331	53,092			**331,423**
P 19	25KV O/H LINE						
	ESTIMATE TOTALS	**41,314**	**$5,704,676**	**$2,746,813**	**$285,950**		**$8,737,439**

PROJECT CLIENT: **LGE/KU ELG Treatment**
PROJECT DESC: **Trimble County Generating Station - 600 GPM Water Treatment**
PROJECT # : **117966**

SUMMARY
INSTRUMENT & CONTROL

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **1/30/2020**
ESTIMATOR:

DESCRIPTION		LABOR		MATERIAL	SUBCON	EQUIPMENT	**TOTAL**
		MH	COST	COST	COST	RENT / STS	**COST**
P 2	INSTRUMENT PROCUREMENT				105,850		**105,850**
P 3	DCS				972,400		**972,400**
P 4	INSTRUMENT INSTALL	1,073	148,921	4,140			**153,061**
P 5	TUBING	386	53,531	25,202			**78,733**
	ESTIMATE TOTALS	**1,459**	**$202,452**	**$29,342**	**$1,078,250**		**$1,310,044**

Exhibit RSS-2
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PROJECT CLIENT: **LGE/KU ELG Treatment**
PROJECT DESC: **Trimble County Generating Station - 600 GPM Water Treatment**
PROJECT # : **117966**

SUMMARY
INSULATION

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **1/30/2020**
ESTIMATOR:

DESCRIPTION		LABOR		MATERIAL	SUBCON	EQUIPMENT	**TOTAL**
		MH	COST	COST	COST	RENT / STS	**COST**
P 2	THERMAL INSULATION				181,665		**181,665**
P 3	Equipment Insulation				25,000		**25,000**
P 4	EXISTING TANK INSULATION AND HT				5,036,092		**5,036,092**
	ESTIMATE TOTALS				**$5,242,757**		**$5,242,757**

Exhibit RSS-2
Page 25 of 71

PROJECT CLIENT: **LGE/KU ELG Treatment**

PROJECT DESC: **Trimble County Generating Station - 600 GPM Water Treatment**

PROJECT # : **117966**

SUMMARY
COATINGS

EST LEVEL: **FEL-2**

ESTIMATE DUE DATE: **1/30/2020**

ESTIMATOR:

DESCRIPTION	LABOR		MATERIAL	SUBCON	EQUIPMENT	**TOTAL**
	MH	COST	COST	COST	RENT / STS	**COST**
P 2 Specialty Coatings				636,400		**636,400**
ESTIMATE TOTALS				**$636,400**		**$636,400**

Exhibit RSS-2
Page 26 of 71

O&M COST ESTIMATE SUMMARY
LOUISVILLE GAS & ELECTRIC
TRIMBLE COUNTY GENERATING STATION
ELG TREATMENT - 600 GPM

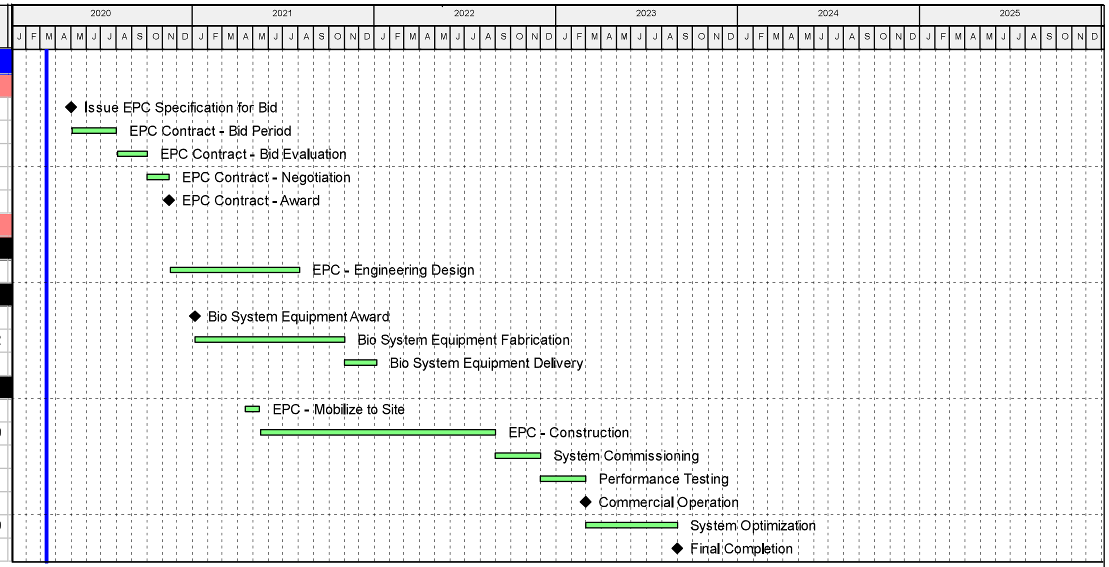
Item	O&M Cost Line Item Description		Cost ($ / Year)
01a	Chemical Consumption - Caustic (17.3 lb/day @ $0.33/lb)		$2,084
01b	Chemical Consumption - Nutrient (189 lb/hr @ $0.68/lb)		$1,123,840
01c	Chemical Consumption - Hydrogen Peroxide (27 lb/hr @ $0.15/lb)		$35,445
01d	Chemical Consumption - Sodium Hypochlorite (145 lb/day @ $0.17/lb)		$9,126
01e	Chemical Consumption - Citric Acid (19 lb/day @ $0.66/lb)		$4,688
01f	Chemical Consumption - Hydrochloric Acid (12 lb/day @ $0.30/lb)		$1,300
02	Operations Personnel (Note 4)		$1,140,000
03	Maintenance (Note 6)		$768,934
04	Chemical Precipitation Waste Disposal		N/A
	Total Annual O&M Cost		**$3,085,416**

Rev.	Revision Date	
	03/25/20	BURNS McDONNELL

Notes:

1 Estimate excludes outage and startup costs.
2 Costs are indicative approximations, from Burns & McDonnell's experience on similar projects.
3 Plant capacity factor is assumed to be 100% for purpose of estimate.
4 Operations personnel on a total of 9.5 FTE. An additional 2 operators per crew (8 FTE - 4 crews) plus 0.5 FTE for maintenance tech, 0.5 FTE for I&C/electrical
5 Annual cost for operating personnel is $120,000/FTE
6 Maintenance is estimated at 4% of the Engineered Equipment/Subcontract Cost from the FEL-2 estimate.

ACTIVITY ID	ACTIVITY DESCRIPTION	START	FINISH	OD
LG&E TRIMBLE COUNTY - ELG Rule Compliance (Bio)				
EPC Contracting				
A1010	Issue EPC Specification for Bid		01-May-20*	0
A1000	EPC Contract - Bid Period	04-May-20	31-Jul-20	63
A1020	EPC Contract - Bid Evaluation	03-Aug-20	01-Oct-20	43
A1030	EPC Contract - Negotiation	01-Oct-20	13-Nov-20	32
A1040	EPC Contract - Award		13-Nov-20	0
EPC Contractor Activities				
Design				
A1050	EPC - Engineering Design	16-Nov-20	03-Aug-21	181
Bio System Package				
A1060	Bio System Equipment Award		04-Jan-21	0
A1090	Bio System Equipment Fabrication	05-Jan-21	01-Nov-21	212
A1100	Bio System Equipment Delivery	02-Nov-21	04-Jan-22	42
Construction / Commissioning				
A1070	EPC - Mobilize to Site	15-Apr-21	14-May-21	22
A1080	EPC - Construction	17-May-21	01-Sep-22	330
A1110	System Commissioning	01-Sep-22	01-Dec-22	64
A1120	Performance Testing	01-Dec-22	01-Mar-23	62
A1130	Commercial Operation		01-Mar-23*	0
A1150	System Optimization	02-Mar-23	31-Aug-23	129
A1140	Final Completion		01-Sep-23	0



Remaining Level of Effort
Actual Level of Effort
Actual Work
Remaining Work
Critical Remaining Work
Milestone

CURRENT PROJECT ID: LG01
PREV PROJECT ID: LG00
TARGET PROJECT ID: N/A

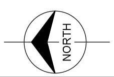
LG&E TRIMBLE COUNTY
Biological Treatment System (EPC)

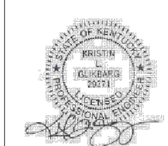
LAYOUT: LT01 - WORKING_2
TASK filter: All Activities

13-Mar-20 DATA DATE
13-Mar-20 @ 04:59 RUN DATE
PAGE 1 OF 1

Appendix C: Mill Creek Generating Station Conceptual Design Documents

C1: Mill Creek Generating Station Site Overview
C2: ELG Location on Mill Creek Generating Station Site
C3: ELG Equipment General Arrangement
C4: Mill Creek Generating Station Mechanical Equipment List
C5: Mill Creek Generating Station Electrical Equipment List
C6: Mill Creek Generating Station Capital Cost Estimate
C7: Mill Creek Generating Station Operating and Maintenance Cost Estimate
C8: Mill Creek Generating Station Schedule





Mar 26 2020

PRELIMINARY - NOT FOR CONSTRUCTION

no.	date	by	ckd	description	no.	date	by	ckd	description

BURNS McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: K. GLIKBARG
detailed: C. LAKEY

LG&E a PPL company
JEFFERSON CO, KY

APPENDIX C1
MILL CREEK GENERATING STATION
SITE OVERVIEW

project 117978 | contract -
drawing GA1002A | rev. –
sheet 1 of 1 sheets
file 117978GA1002A.dwg

Exhibit RSS-2
Page 30 of 71

NORTH

PRELIMINARY - NOT FOR CONSTRUCTION

Mar 26 2020

no.	date	by	ckd	description	no.	date	by	ckd	description

BURNS McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

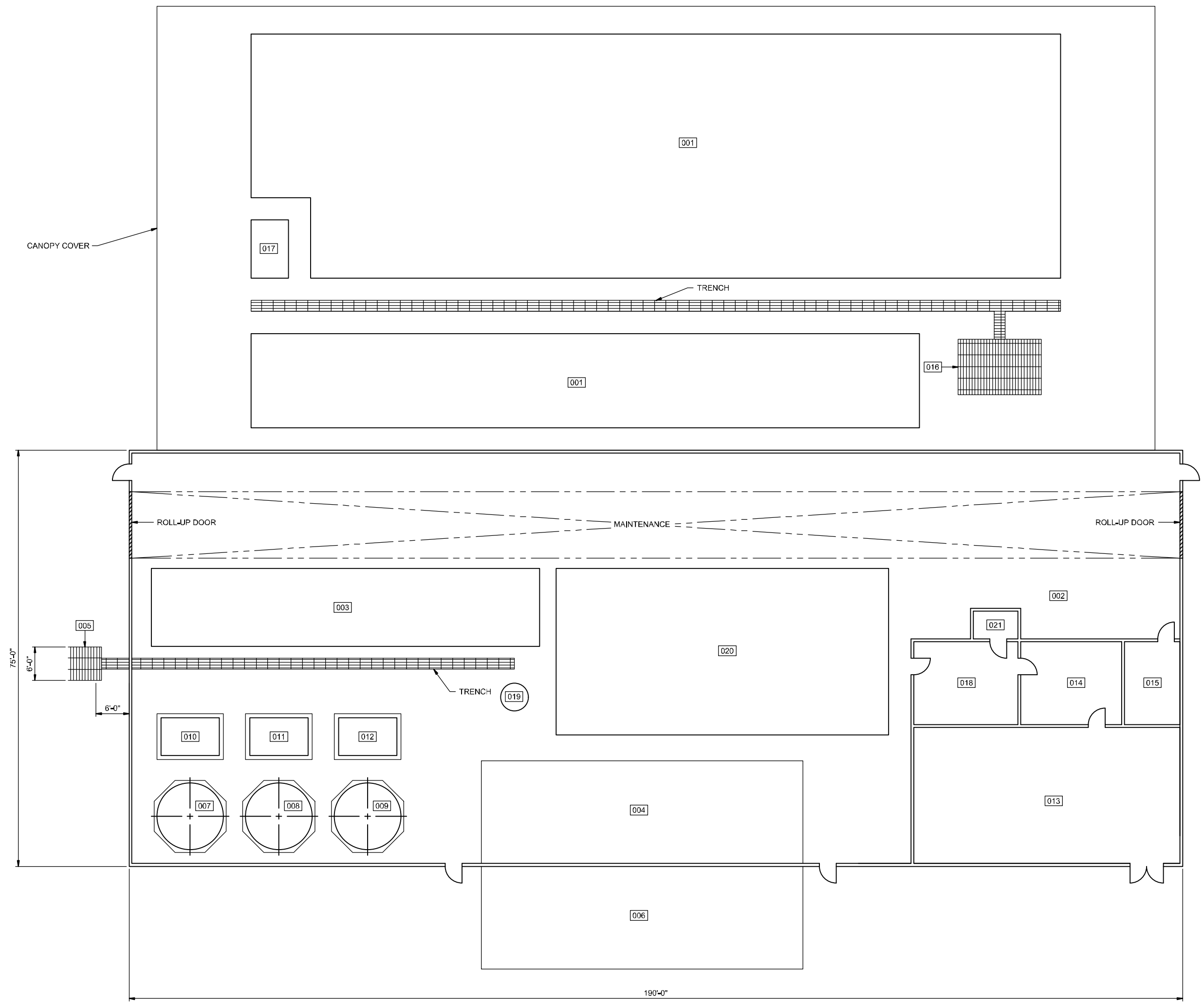
designed: K. GLIKBARG
detailed: C. LAKEY

LG&E
a PPL company
JEFFERSON CO, KY

APPENDIX C2
ELG LOCATION ON MILL CREEK GENERATING STATION SITE

project: 117978
contract: -
drawing: GA1001A
rev.: –
sheet 1 of 1 sheets
file 117978GA1001A.dwg

EQUIPMENT IDENTIFICATION AND LOCATION LIST	
DWG REF	DESCRIPTION NEW SITE EQUIPMENT
001	BIOLOGICAL REACTOR AREA (CONCRETE VESSELS)
002	EFFLUENT LIMITATION GUIDELINES TREATMENT BUILDING
003	MF/UF AREA
004	CHEMICAL STORAGE ROOM
005	ELG BUILDING SUMP
006	BULK CHEMICAL STORAGE TANK AREA
007	EFFLUENT TANK
008	MF/UF BACKWASH TANK
009	BIO BACKWASH TANK
010	EFFLUENT PUMP SKID
011	UF BACKWASH PUMP SKID
012	BIO BACKWASH PUMP SKID
013	ELECTRICAL ROOM
014	DCS ROOM
015	BATTERY ROOM
016	BIOLOGICAL REACTOR AREA SUMP
017	MF/UF FEED PUMP SKID
018	CONTROL ROOM/LAB
019	AIR RECEIVER
020	DENITRIFICATION EQUIPMENT AREA
021	UNISEX BATHROOM



PRELIMINARY - NOT FOR CONSTRUCTION

Mar 26 2020

no.	date	by	ckd	description	no.	date	by	ckd	description

GENERAL ARRANGEMENT
0 4' 8' 16'
SCALE IN FEET

NORTH

BURNS McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed K. GLIKBARG | detailed C. HAYTON

LG&E a PPL company
JEFFERSON CO., KY

APPENDIX C3
MILL CREEK GENERATING STATION ELG
EQUIPMENT GENERAL ARRANGEMENT

project 117978 | contract -
drawing GA1000 | rev. -
sheet 1 of 1 sheets
file 117978GA1000A.dwg

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Louisville Gas and Electric
Mill Creek ELG Treatment
600GPM System - Mechanical Equipment List

SYSTEM DESCRIPTION	EQUIPMENT NAME / DESCRIPTION	Supplier	INDOOR/OUTDOOR	Capacity
DENITRIFICATION	NEW DENITRIFICATION SYSTEM	BIO OEM	INDOOR	
BIO	BIOLOGICAL TREATMENT SYSTEM	BIO OEM	OUTDOOR	
BIO	A BIOREACTOR STAGE 1 FEED PUMP STRAINER	EPC - BOP	OUTDOOR	
BIO	B BIOREACTOR STAGE 1 FEED PUMP STRAINER	EPC - BOP	OUTDOOR	
BIO	A BIOREACTOR STAGE 1 TANK	BIO OEM	OUTDOOR	
BIO	B BIOREACTOR STAGE 1 TANK	BIO OEM	OUTDOOR	
BIO	C BIOREACTOR STAGE 1 TANK	BIO OEM	OUTDOOR	
BIO	D BIOREACTOR STAGE 1 TANK	BIO OEM	OUTDOOR	
BIO	E BIOREACTOR STAGE 1 TANK	BIO OEM	OUTDOOR	
BIO	F BIOREACTOR STAGE 1 TANK	BIO OEM	OUTDOOR	
BIO	G BIOREACTOR STAGE 1 TANK	BIO OEM	OUTDOOR	
BIO	A/B BIOREACTOR STAGE 1 TANK FLOW CONTROL SKID	BIO OEM	OUTDOOR	
BIO	C/D BIOREACTOR STAGE 1 TANK FLOW CONTROL SKID	BIO OEM	OUTDOOR	
BIO	E/F BIOREACTOR STAGE 1 TANK FLOW CONTROL SKID	BIO OEM	OUTDOOR	
BIO	G BIOREACTOR STAGE 1 TANK FLOW CONTROL SKID	BIO OEM	OUTDOOR	
BIO	A BIOREACTOR STAGE 2 TANK	BIO OEM	OUTDOOR	
BIO	B BIOREACTOR STAGE 2 TANK	BIO OEM	OUTDOOR	
BIO	C BIOREACTOR STAGE 2 TANK	BIO OEM	OUTDOOR	
BIO	D BIOREACTOR STAGE 2 TANK	BIO OEM	OUTDOOR	
BIO	E BIOREACTOR STAGE 2 TANK	BIO OEM	OUTDOOR	
BIO	F BIOREACTOR STAGE 2 TANK	BIO OEM	OUTDOOR	
BIO	G BIOREACTOR STAGE 2 TANK	BIO OEM	OUTDOOR	
BIO	H BIOREACTOR STAGE 2 TANK	BIO OEM	OUTDOOR	
BIO	J BIOREACTOR STAGE 2 TANK	BIO OEM	OUTDOOR	
BIO	K BIOREACTOR STAGE 2 TANK	BIO OEM	OUTDOOR	
BIO	L BIOREACTOR STAGE 2 TANK	BIO OEM	OUTDOOR	
BIO	M BIOREACTOR STAGE 2 TANK	BIO OEM	OUTDOOR	
BIO	N BIOREACTOR STAGE 2 TANK	BIO OEM	OUTDOOR	
BIO	O BIOREACTOR STAGE 2 TANK	BIO OEM	OUTDOOR	
BIO	A BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	BIO OEM	OUTDOOR	
BIO	B BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	BIO OEM	OUTDOOR	
BIO	C BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	BIO OEM	OUTDOOR	
BIO	D BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	BIO OEM	OUTDOOR	
BIO	E BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	BIO OEM	OUTDOOR	
BIO	F BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	BIO OEM	OUTDOOR	
BIO	G BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	BIO OEM	OUTDOOR	
BIO	H BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	BIO OEM	OUTDOOR	
BIO	J BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	BIO OEM	OUTDOOR	
BIO	K BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	BIO OEM	OUTDOOR	
BIO	L BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	BIO OEM	OUTDOOR	
BIO	M BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	BIO OEM	OUTDOOR	
BIO	N BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	BIO OEM	OUTDOOR	
BIO	O BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	BIO OEM	OUTDOOR	
BIO	BIOREACTOR BACKWASH TANK	EPC - BOP	OUTDOOR	20,000 gallons - 14'D x 18'H (FRP Construction)
BIO	BIOREACTOR BACKWASH PUMP SKID	BIO OEM	OUTDOOR	
BIO	A BIOREACTOR BACKWASH PUMP	BIO OEM	OUTDOOR	2100
BIO	B BIOREACTOR BACKWASH PUMP	BIO OEM	OUTDOOR	2100
BIO	WWT EFFLUENT TANK	EPC - BOP	OUTDOOR	20,000 gallons - 14'D x 18'H (FRP Construction)
BIO	A WWT EFFLUENT PUMP	BIO OEM	OUTDOOR	800
BIO	B WWT EFFLUENT PUMP	BIO OEM	OUTDOOR	800
BIO	BIO AREA SUMP	EPC - BOP	OUTDOOR	15'W x 20' L x 15' D (~30,000 gallons)
BIO	A BIO AREA SUMP PUMP	EPC - BOP	OUTDOOR	450
BIO	B BIO AREA SUMP PUMP	EPC - BOP	OUTDOOR	450
BIO- CHEMICAL FEED	NUTRIENT STORAGE TANK	EPC - BOP	OUTDOOR	20,000 gallons - 14'D x 18'H (FRP Construction)
BIO- CHEMICAL FEED	DENITRIFICATION NUTRIENT FEED SKID	BIO OEM	INDOOR	
BIO- CHEMICAL FEED	A DENITRIFICATION NUTRIENT FEED PUMP	BIO OEM	INDOOR	12.3
BIO- CHEMICAL FEED	B DENITRIFICATION NUTRIENT FEED PUMP	BIO OEM	INDOOR	12.3
BIO- CHEMICAL FEED	BIOREACTOR NUTRIENT FEED SKID	BIO OEM	INDOOR	
BIO- CHEMICAL FEED	A BIOREACTOR NUTRIENT PUMP	BIO OEM	INDOOR	8.1
BIO- CHEMICAL FEED	B BIOREACTOR NUTRIENT PUMP	BIO OEM	INDOOR	8.1
UF	UF FEED PUMP SKID	BIO OEM	OUTDOOR	
UF	A UF FEED PUMP	BIO OEM	OUTDOOR	800
UF	B UF FEED PUMP	BIO OEM	OUTDOOR	800
UF	UF CIP PUMP SKID	BIO OEM	INDOOR	
UF	UF CIP TANK	BIO OEM	INDOOR	
UF	A UF CIP PUMP	BIO OEM	INDOOR	140
UF	B UF CIP PUMP	BIO OEM	INDOOR	140
UF	A UF MEMBRANE SKID	BIO OEM	INDOOR	
UF	B UF MEMBRANE SKID	BIO OEM	INDOOR	
UF	C UF MEMBRANE SKID	BIO OEM	INDOOR	
UF	D UF MEMBRANE SKID	BIO OEM	INDOOR	
UF	E UF MEMBRANE SKID	BIO OEM	INDOOR	
UF	UF BACKWASH TANK	EPC - BOP	OUTDOOR	20,000 gallons - 14'D x 18'H (FRP Construction)
UF	UF BACKWASH PUMP SKID	BIO OEM	OUTDOOR	
UF	A UF BACKWASH PUMP	BIO OEM	OUTDOOR	250
UF	B UF BACKWASH PUMP	BIO OEM	OUTDOOR	250
UF	UF AREA SUMP	EPC - BOP	OUTDOOR	~5,000 gallons (8'W x 8'L x 10'D)
UF	A UF AREA SUMP PUMP	EPC - BOP	OUTDOOR	300

Louisville Gas and Electric
Mill Creek ELG Treatment
600GPM System - Mechanical Equipment List

SYSTEM DESCRIPTION	EQUIPMENT NAME / DESCRIPTION	Supplier	INDOOR/OUTDOOR	Capacity
UF	B UF AREA SUMP PUMP	EPC - BOP	OUTDOOR	300
UF - CHEMICAL FEED	UF CITRIC ACID FEED SKID	BIO OEM	INDOOR	
UF - CHEMICAL FEED	A UF CITRIC ACID FEED PUMP	BIO OEM	INDOOR	40
UF - CHEMICAL FEED	B UF CITRIC ACID FEED PUMP	BIO OEM	INDOOR	40
UF - CHEMICAL FEED	UF SODIUM HYPOCHLORITE FEED SKID	BIO OEM	INDOOR	
UF - CHEMICAL FEED	A UF SODIUM HYPOCHLORITE FEED PUMP	BIO OEM	INDOOR	84
UF - CHEMICAL FEED	B UF SODIUM HYPOCHLORITE FEED PUMP	BIO OEM	INDOOR	84
UF - CHEMICAL FEED	UF CAUSTIC FEED SKID	BIO OEM	INDOOR	
UF - CHEMICAL FEED	A UF CAUSTIC FEED PUMP	BIO OEM	INDOOR	9.4
UF - CHEMICAL FEED	B UF CAUSTIC FEED PUMP	BIO OEM	INDOOR	9.4
UF - CHEMICAL FEED	UF HYDROGEN PEROXIDE FEED SKID	BIO OEM	INDOOR	
UF - CHEMICAL FEED	A UF HYDROGEN PEROXIDE FEED PUMP	BIO OEM	INDOOR	4.4
UF - CHEMICAL FEED	B UF HYDROGEN PEROXIDE FEED PUMP	BIO OEM	INDOOR	4.4
SERVICE WATER	SERVICE WATER AUTO STRAINER A	EPC - BOP	INDOOR	
SERVICE WATER	SERVICE WATER AUTO STRAINER B	EPC - BOP	INDOOR	
COOLING WATER	COOLING WATER PUMP A	EPC - BOP	INDOOR	
COOLING WATER	COOLING WATER PUMP B	EPC - BOP	INDOOR	
POTABLE WATER	WWT Building Potable Water Tempering Skid	EPC - BOP	INDOOR	
POTABLE WATER	WWT Building Potable Water Tempering Skid Tank Heater	EPC - BOP	INDOOR	
POTABLE WATER	WWT Building Potable Water Tempering Skid Booster Pump	EPC - BOP	INDOOR	30
POTABLE WATER	WWT Building Potable Water Tempering Skid Recirculation Pump	EPC - BOP	INDOOR	30
POTABLE WATER	WWT Building Potable Water Tempering Skid Tank	EPC - BOP	INDOOR	
SEWAGE DRAINS SYSTEM	WWT BUILDING SANITARY LIFT STATION	EPC - BOP	OUTDOOR	
SEWAGE DRAINS SYSTEM	A WWT SANITARY LIFT STATION PUMP	EPC - BOP	OUTDOOR	50
SEWAGE DRAINS SYSTEM	B WWT SANITARY LIFT STATION PUMP	EPC - BOP	OUTDOOR	50
HVAC	Bldg HVAC - Heating	EPC - BOP		
HVAC	Bldg HVAC - Exhaust Fans	EPC - BOP		
HVAC	Bldg HVAC - Exhaust Fans	EPC - BOP		
HVAC	Bldg HVAC - Exhaust Fans	EPC - BOP		
HVAC	Bldg HVAC - Exhaust Fans	EPC - BOP		
HVAC	Bldg HVAC - Chemical Room Exhaust Fan	EPC - BOP		

Louisville Gas and Electric
Mill Creek ELG Treatment
600GPM System - Electrical Equipment List

SYSTEM DESCRIPTION	EQUIPMENT NAME / DESCRIPTION	QUANTITY	Supplier	INDOOR/OUTDOOR
ELECTRICAL EQUIPMENT	4.16 Kv-480V TRANSFORMERS	2 EACH	EPC - BOP	INDOOR
ELECTRICAL EQUIPMENT	480V SWITCHGEAR (MAIN-TIE-MAIN)	1 SWITCHGEAR	EPC - BOP	INDOOR
ELECTRICAL EQUIPMENT	480 MCCs (4 LINEUPS)	16 SECTIONS	EPC - BOP	INDOOR
ELECTRICAL EQUIPMENT	480V-208V TRANSFORMER	2 EACH	EPC - BOP	INDOOR
ELECTRICAL EQUIPMENT	208/120V LIGHTING AND POWER PANELS	2 EACH	EPC - BOP	INDOOR
ELECTRICAL EQUIPMENT	125 VDC POWER PANEL	1 EACH	EPC - BOP	INDOOR

Exhibit RSS-2
Page 35 of 71

01/30/2020

FEL-2 CAPITAL COST ESTIMATE SUMMARY SHEET
LGE/KU ELG Treatment
Mill Creek Generating Station
600 GPM Water Treatment
Louisville, KY
BMcD #117978

Acct	Area / Discipline	Direct MHRS	Labor Cost	Material Cost	Engr Equip/ Subcontract Cost	Const. Equipment Cost	Total Cost
01	Engineered Equipment	3,370	$518,960	$589,615	$7,523,986		$8,632,561
02	Civil	2,959	$358,039	$232,349	$58,750	$57,510	$706,648
03	Deep Foundations	2,310	$279,524	$318,327	$1,706,195	$26,055	$2,330,100
04	Concrete	7,920	$957,348	$888,894	$241,233	$47,530	$2,135,005
05	Structural Steel	4,832	$714,694	$669,234			$1,383,928
06	Architectural				$2,256,660		$2,256,660
07	Piping	28,111	$4,301,603	$1,623,744	$385,295		$6,310,642
08	Electrical	41,647	$5,751,069	$2,529,914	$350,550		$8,631,533
09	Instrument & Control	1,459	$202,452	$29,342	$1,078,250		$1,310,044
10	Insulation				$4,589,682		$4,589,682
11	Coatings				$636,400		$636,400
12	Specialty						
13	Demolition						
14	Misc Directs						
	Total Direct Cost	**92,607**	**$13,083,690**	**$6,881,419**	**$18,827,000**	**$131,095**	**$38,923,204**

Rev.	Revision Date
0	03/06/20
1	03/16/20
2	03/25/20

Construction Mgmt & Indirects		$3,086,890
Engineering		$3,892,320
Start-Up		$1,167,696
Commercial		$484,500
Total Indirect Cost		**$8,631,407**
Total Direct and Indirect Costs		**$47,554,611**
Minor Scope Items	20%	$9,510,922
EPC Execution Contingency	10%	$4,755,461
EPC Fee	8%	$4,565,243
Total EPC Contract Cost		**$66,386,236**

Notes:

1) Minor Scope Items is intended to capture costs for scope and small procurements (<$10,000) that may have been unaccounted for within the estimate basis.
2) EPC Execution Contingency is intended to capture costs associated with events outside the Contractor's control (i.e equipment mis-fabrication, and excessive crane rental duration, etc.) that could increase overall cost and.or schedule of the project.

V 3.6

PROJECT CLIENT: **LGE/KU ELG Treatment**

PROJECT DESC: **Mill Creek Generating Station - 600 GPM Water Treatment**

PROJECT # : **117978**

SUMMARY
ENGINEERED EQUIPMENT

EST LEVEL: **FEL-2**

ESTIMATE DUE DATE: **1/30/2020**

ESTIMATOR:

DESCRIPTION		LABOR		MATERIAL	EQUIPMENT	EQUIPMENT	**TOTAL**
		MH	COST	COST	COST	RENT / STS	**COST**
P 2	DENITRIFICATION	450	69,297		680,001		**749,297**
P 3	BIOLOGICAL TREATMENT SYSTEM	1,860	286,429	589,615	4,982,985		**5,859,029**
P 4	BIO- CHEMICAL FEED	120	18,479		153,000		**171,479**
P 5	UF	390	60,058		1,462,000		**1,522,058**
P 6	UF - CHEMICAL FEED	140	21,559		51,000		**72,559**
P 7	SERVICE WATER	40	6,160		70,000		**76,160**
P 8	COOLING WATER	160	24,639		70,000		**94,639**
P 9	COMPRESSED AIR	30	4,620		5,000		**9,620**
P 10	POTABLE WATER	80	12,320		20,000		**32,320**
P 11	SEWAGE DRAINS SYSTEM	40	6,160		15,000		**21,160**
P 12	Eye Wash Station	60	9,240		15,000		**24,240**
	ESTIMATE TOTALS	**3,370**	**$518,960**	**$589,615**	**$7,523,986**		**$8,632,560**

Exhibit RSS-2
Page 37 of 71

PROJECT CLIENT: **LGE/KU ELG Treatment**
PROJECT DESC: **Mill Creek Generating Station - 600 GPM Water Treatment**
PROJECT # : **117978**

SUMMARY
CIVIL

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **1/30/2020**
ESTIMATOR:

DESCRIPTION		LABOR MH	LABOR COST	MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
P 2	Earthwork	363	43,916	5,490		21,229	**70,635**
P 3	Site Surfacing	1,387	167,848	180,440		9,725	**358,013**
P 4	Storm Drainage	374	45,248	25,211		8,797	**79,255**
P 5	Underground Utilities	715	86,506	15,459	58,750	17,389	**178,104**
P 7	MISC ITEMS	120	14,521	5,750		370	**20,641**
	ESTIMATE TOTALS	**2,959**	**$358,039**	**$232,349**	**$58,750**	**$57,510**	**$706,648**

Exhibit RSS-2
Page 38 of 71

PROJECT CLIENT: **LGE/KU ELG Treatment**
PROJECT DESC: **Mill Creek Generating Station - 600 GPM Water Treatment**
PROJECT # : **117978**

SUMMARY
DEEP FOUNDATIONS

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **1/30/2020**
ESTIMATOR:

DESCRIPTION	LABOR MH	LABOR COST	MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
P 2 Auger Cast Piles	2,310	279,524	318,327	1,706,195	26,055	**2,330,100**
ESTIMATE TOTALS	**2,310**	**$279,524**	**$318,327**	**$1,706,195**	**$26,055**	**$2,330,100**

Exhibit RSS-2
Page 39 of 71

PROJECT CLIENT: **LGE/KU ELG Treatment**

PROJECT DESC: **Mill Creek Generating Station - 600 GPM Water Treatment**

PROJECT # : **117978**

SUMMARY
CONCRETE

EST LEVEL: **FEL-2**

ESTIMATE DUE DATE: **1/30/2020**

ESTIMATOR:

DESCRIPTION			LABOR		MATERIAL	SUBCON	EQUIPMENT	**TOTAL**
			MH	COST	COST	COST	RENT / STS	**COST**
P 2	Bldg, Sumps, Equip Pads	2,781.1 CY	7,498	906,422	874,329	237,493	41,648	**2,059,893**
P 3	Tank Walls (OPT 2)			1	1	1	1	
P 4	Pipe Rack FND	40.9 CY	421	50,925	14,563	3,739	5,880	**75,108**
		ESTIMATE TOTALS	**7,920**	**$957,348**	**$888,894**	**$241,233**	**$47,530**	**$2,135,001**
		2,822.0 CY	2.8	339.24	314.99	85.48	16.84	756.56

Exhibit RSS-2
Page 40 of 71

PROJECT CLIENT: **LGE/KU ELG Treatment**
PROJECT DESC: **Mill Creek Generating Station - 600 GPM Water Treatment**
PROJECT # : **117978**

SUMMARY
STRUCTURAL STEEL

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **1/30/2020**
ESTIMATOR:

DESCRIPTION	LABOR MH	LABOR COST	MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	TOTAL COST
P 2 Pipe Rack Structural Steel	4,494	664,646	464,546			**1,129,191**
P 3 Misc Steel	338	50,049	204,688			**254,737**
ESTIMATE TOTALS	**4,832**	**$714,694**	**$669,234**			**$1,383,928**

Exhibit RSS-2
Page 41 of 71

PROJECT CLIENT:	**LGE/KU ELG Treatment**
PROJECT DESC:	**Mill Creek Generating Station - 600 GPM Water Treatment**
PROJECT # :	**117978**

SUMMARY
ARCHITECTURAL

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **1/30/2020**
ESTIMATOR:

DESCRIPTION	LABOR		MATERIAL	SUBCON	EQUIPMENT	**TOTAL**
	MH	COST	COST	COST	RENT / STS	**COST**
P 2 WATER TREATMENT BLDG				2,256,660		**2,256,660**
ESTIMATE TOTALS				**$2,256,660**		**$2,256,660**

PROJECT CLIENT: **LGE/KU ELG Treatment**
PROJECT DESC: **Mill Creek Generating Station - 600 GPM Water Treatment**
PROJECT # : **117978**

SUMMARY
PIPING

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **1/30/2020**
ESTIMATOR:

DESCRIPTION				LABOR MH	LABOR COST	MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
P 2	PIPING - UG	5501 LF	0.70	3,837	587,118	119,714			**706,832**
P 3	PIPING - AG			9,762	1,493,731	289,145			**1,782,876**
P 4	PIPING - AG (cont)			9,039	1,383,158	1,028,471			**2,411,629**
P 5	PIPING - AG (cont)	7513 LF	3.02	3,872	592,569	46,574	242,745		**881,888**
P 6	VALVES	100 EA	5.50	550	84,162	132,940			**217,102**
P 7	SPECIALS 1	181 EA	4.98	901	137,911		142,550		**280,461**
P 8	TIE-INS	4 EA	37.50	150	22,953	6,900			**29,853**
	ESTIMATE TOTALS			**28,111**	**$4,301,603**	**$1,623,744**	**$385,295**		**$6,310,642**
	TOTAL	13014 LF	2.16						

Exhibit RSS-2
Page 43 of 71

PROJECT CLIENT: **LGE/KU ELG Treatment**
PROJECT DESC: **Mill Creek Generating Station - 600 GPM Water Treatment**
PROJECT # : **117978**

SUMMARY
ELECTRICAL

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **1/30/2020**
ESTIMATOR:

DESCRIPTION		LABOR MH	LABOR COST	MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
P 2	GROUNDING	1,252	174,223	31,834			**206,058**
P 3	8.10 CONDUIT	5,898	821,032				**821,032**
P 4	8.11 CABLE TRAY	1,255	174,655	73,059			**247,713**
P 5	8.12 UG RACEWAY	15,942	2,219,193	734,181			**2,953,374**
P 6	8.20 MED Volt Cable	1,148	159,774	217,367			**377,140**
P 7	8.21 480V Cable	1,934	269,172	203,976			**473,148**
P 8	8.22 Cable Control & Insturment	3,114	433,519	100,507			**534,026**
P 9	8.23 Cable, Fiber, Ethernet	160	22,217	19,425			**41,642**
P 10	TERMINATIONS	1,740	242,163	18,061			**260,223**
P 11	8.40 Lighting and Recep	4,764	663,196	221,776			**884,972**
P 12	8.31 Elec Equipment Install	1,017	95,098	816,203			**911,301**
P 14	Security	806	112,225	23,487			**135,712**
P 15	COMMUNICATION				76,000		**76,000**
P 16	HEAT TRACE & CATHODIC				274,550		**274,550**
P 17	LIGHTNING PROTECTION	620	86,272	16,947			**103,219**
P 18	TEMPORARY POWER	1,999	278,331	53,092			**331,423**
P 19	25KV O/H LINE						
	ESTIMATE TOTALS	**41,647**	**$5,751,069**	**$2,529,914**	**$350,550**		**$8,631,533**

Exhibit RSS-2
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PROJECT CLIENT: **LGE/KU ELG Treatment**
PROJECT DESC: **Mill Creek Generating Station - 600 GPM Water Treatment**
PROJECT # : **117978**

SUMMARY
INSTRUMENT & CONTROL

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **1/30/2020**
ESTIMATOR:

DESCRIPTION		LABOR MH	LABOR COST	MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	TOTAL COST
P 2	INSTRUMENT PROCUREMENT				105,850		**105,850**
P 3	DCS				972,400		**972,400**
P 4	INSTRUMENT INSTALL	1,073	148,921	4,140			**153,061**
P 5	TUBING	386	53,531	25,202			**78,733**
	ESTIMATE TOTALS	**1,459**	**$202,452**	**$29,342**	**$1,078,250**		**$1,310,044**

Exhibit RSS-2
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PROJECT CLIENT: **LGE/KU ELG Treatment**
PROJECT DESC: **Mill Creek Generating Station - 600 GPM Water Treatment**
PROJECT # : **117978**

SUMMARY
INSULATION

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **1/30/2020**
ESTIMATOR:

DESCRIPTION		LABOR MH	LABOR COST	MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
P 2	THERMAL INSULATION				310,190		**310,190**
P 3	Equipment Insulation				25,000		**25,000**
P 4	EXISTING TANK INSULATION AND HEAT TRACE				4,254,492		**4,254,492**
	ESTIMATE TOTALS				**$4,589,682**		**$4,589,682**

Exhibit RSS-2
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PROJECT CLIENT: **LGE/KU ELG Treatment**
PROJECT DESC: **Mill Creek Generating Station - 600 GPM Water Treatment**
PROJECT # : **117978**

SUMMARY
COATINGS

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **1/30/2020**
ESTIMATOR:

DESCRIPTION	LABOR		MATERIAL	SUBCON	EQUIPMENT	**TOTAL**
	MH	COST	COST	COST	RENT / STS	**COST**
P 2 Specialty Coatings				636,400		**636,400**
ESTIMATE TOTALS				**$636,400**		**$636,400**

Exhibit RSS-2
Page 47 of 71

O&M COST ESTIMATE SUMMARY
LOUISVILLE GAS & ELECTRIC
MILL CREEK GENERATING STATION
ELG TREATMENT - 600 GPM

Item	O&M Cost Line Item Description		Cost ($ / Year)
01a	Chemical Consumption - Caustic (17.3 lb/day @ $0.33/lb)		$2,084
01b	Chemical Consumption - Nutrient (189 lb/hr @ $0.68/lb)		$1,123,840
01c	Chemical Consumption - Hydrogen Peroxide (27 lb/hr @ $0.15/lb)		$35,445
01d	Chemical Consumption - Sodium Hypochlorite (145 lb/day @ $0.17/lb)		$9,126
01e	Chemical Consumption - Citric Acid (19 lb/day @ $0.66/lb)		$4,688
01f	Chemical Consumption - Hydrochloric Acid (12 lb/day @ $0.30/lb)		$1,300
02	Operations Personnel (Note 4)		$1,140,000
03	Maintenance (Note 6)		$753,080
04	Chemical Precipitation Waste Disposal		N/A
	Total Annual O&M Cost		**$3,069,562**

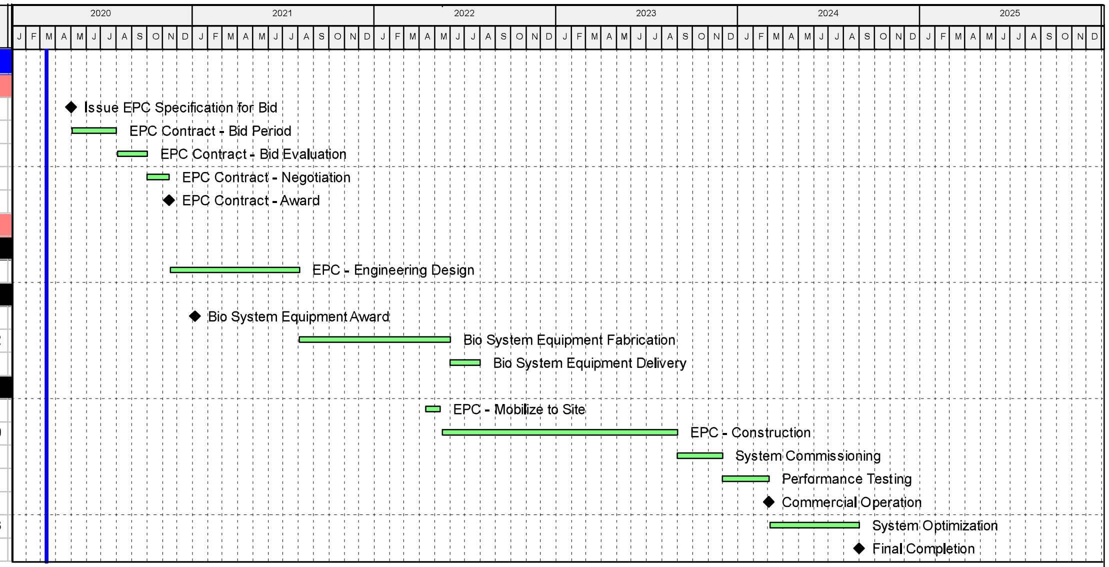
Rev.	Revision Date
	03/25/20

BURNS McDONNELL

Notes:

1 Estimate excludes outage and startup costs.
2 Costs are indicative approximations, from Burns & McDonnell's experience on similar projects.
3 Plant capacity factor is assumed to be 100% for purpose of estimate.
4 Operations personnel on a total of 9.5 FTE. An additional 2 operators per crew (8 FTE - 4 crews) plus 0.5 FTE for maintenance tech, 0.5 FTE for I&C/electrical maintenance tech and 0.5 FTE for a chemist.
5 Annual cost for operating personnel is $120,000/FTE
6 Maintenance is estimated at 4% of the Engineered Equipment/Subcontract Cost from the FEL-2 estimate.

ACTIVITY ID	ACTIVITY DESCRIPTION	START	FINISH	OD
LG&E MILL CREEK - ELG Rule Compliance (Bio)				
EPC Contracting				
A1010	Issue EPC Specification for Bid		01-May-20*	0
A1000	EPC Contract - Bid Period	04-May-20	31-Jul-20	63
A1020	EPC Contract - Bid Evaluation	03-Aug-20	01-Oct-20	43
A1030	EPC Contract - Negotiation	01-Oct-20	13-Nov-20	32
A1040	EPC Contract - Award		13-Nov-20	0
EPC Contractor Activities				
Design				
A1050	EPC - Engineering Design	16-Nov-20	03-Aug-21	181
Bio System Package				
A1060	Bio System Equipment Award		04-Jan-21	0
A1090	Bio System Equipment Fabrication	02-Aug-21*	01-Jun-22	212
A1100	Bio System Equipment Delivery	02-Jun-22	01-Aug-22	42
Construction / Commissioning				
A1070	EPC - Mobilize to Site	14-Apr-22*	13-May-22	22
A1080	EPC - Construction	16-May-22	31-Aug-23	330
A1110	System Commissioning	31-Aug-23	30-Nov-23	64
A1120	Performance Testing	30-Nov-23	01-Mar-24	64
A1130	Commercial Operation		01-Mar-24	0
A1150	System Optimization	04-Mar-24	30-Aug-24	128
A1140	Final Completion		31-Aug-24	0



Remaining Level of Effort
Actual Level of Effort
Actual Work
Remaining Work
Critical Remaining Work
Milestone

CURRENT PROJECT ID: LG01
PREV PROJECT ID: LG00
TARGET PROJECT ID: N/A

LG&E MILL CREEK
Biological Treatment System (EPC)

LAYOUT: LT01 - WORKING_1
TASK filter: All Activities

13-Mar-20 DATA DATE
13-Mar-20 @ 04:50 RUN DATE
PAGE 1 OF 1

Exhibit RSS-2

Appendix D: Ghent Generating Station Conceptual Design Documents

Mar 26 2020

PRELIMINARY - NOT FOR CONSTRUCTION

no.	date	by	ckd	description

no.	date	by	ckd	description

GENERAL ARRANGEMENT

0 16' 32' 64'
SCALE IN FEET

NORTH

BURNS McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed K. GLIKBARG | detailed R. STANDLEY

CARROLL CO., KY

APPENDIX D1
GHENT GENERATING STATION
SITE OVERVIEW

project 117977 | contract -

drawing 117977GA1002A | rev. —

sheet 1 of 1 sheets

file 117977GA1002A.dwg

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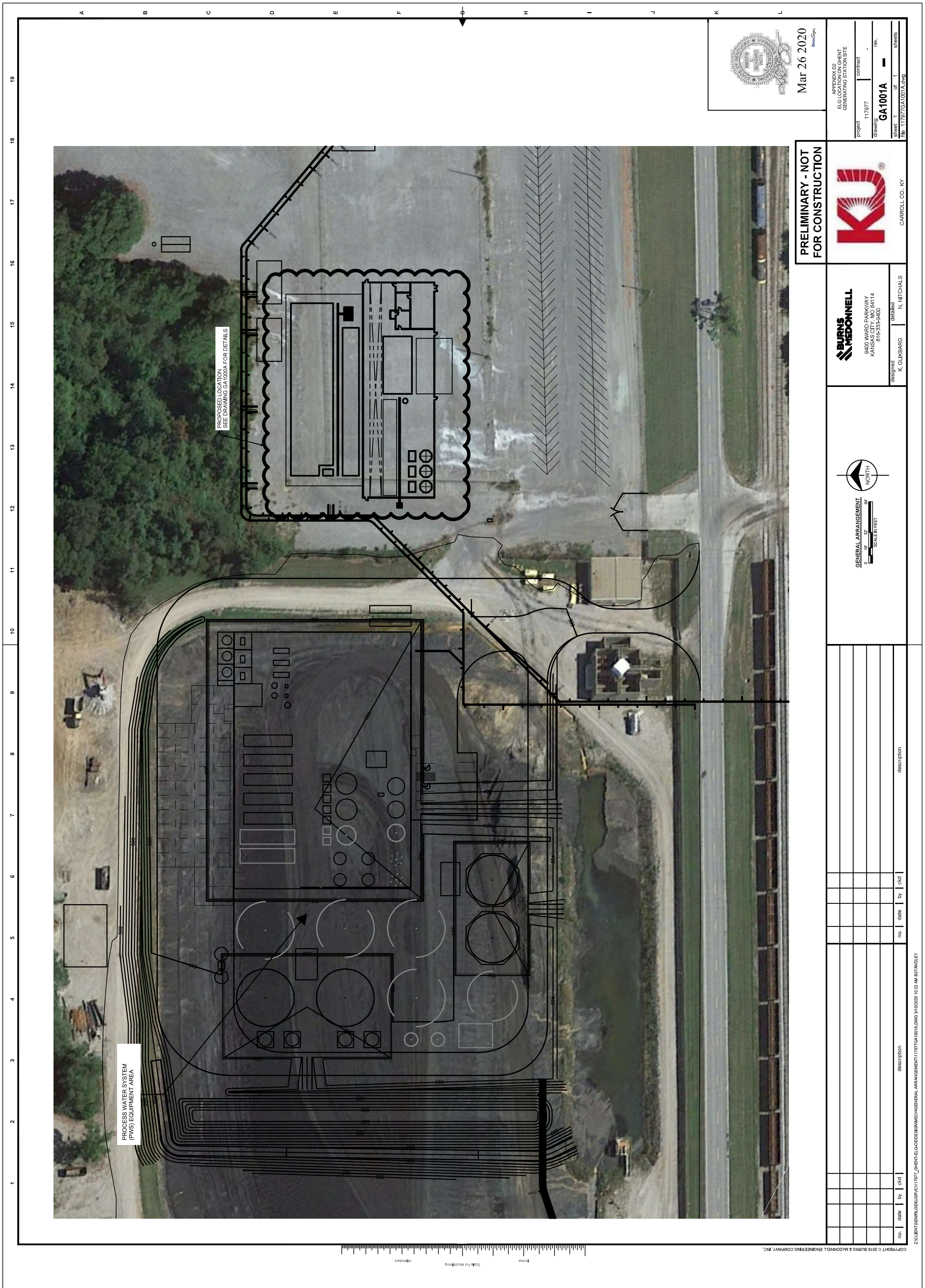
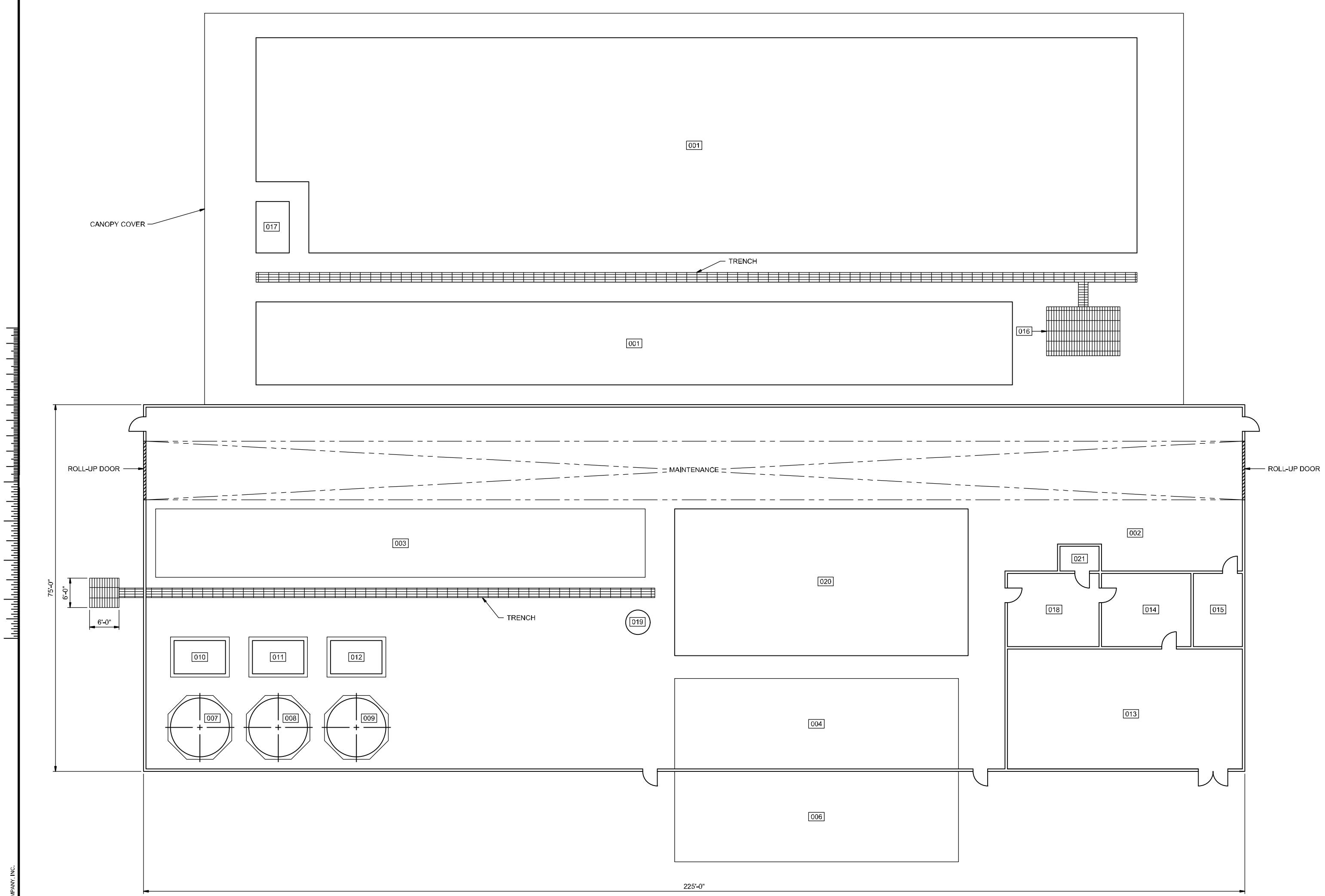

PRELIMINARY - NOT FOR CONSTRUCTION
CARROLL CO., KY
BURNS & McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400
designed K. GLIKBARG
detailed N. NITCHALS
GENERAL ARRANGEMENT
SCALE IN FEET
NORTH
APPENDIX D2
ELG LOCATION ON GHENT GENERATING STATION SITE
project 117977
drawing GA1001A
Mar 26 2020
PROPOSED LOCATION
SEE DRAWING GA1000A FOR DETAILS
PROCESS WATER SYSTEM
(PWS) EQUIPMENT AREA



EQUIPMENT IDENTIFICATION AND LOCATION LIST	
DWG REF	DESCRIPTION NEW SITE EQUIPMENT
001	BIOLOGICAL REACTOR AREA (CONCRETE VESSELS)
002	EFFLUENT LIMITATION GUIDELINES TREATMENT BUILDING
003	MF/UF AREA
004	CHEMICAL STORAGE ROOM
005	ELG BUILDING SUMP
006	BULK CHEMICAL STORAGE TANK AREA
007	EFFLUENT TANK
008	MF/UF BACKWASH TANK
009	BIO BACKWASH TANK
010	EFFLUENT PUMP SKID
011	CITRIC ACID FEED SYSTEM
012	NUTRIENT FEED SKIDS
013	ELECTRICAL ROOM
014	DCS ROOM
015	BATTERY ROOM
016	BIOLOGICAL REACTOR AREA SUMP
017	MF/UF FEED PUMP SKID
018	CONTROL ROOM/LAB
019	AIR RECEIVER
020	DENITRIFICATION EQUIPMENT AREA
021	UNISEX BATHROOM

Mar 26 2020

PRELIMINARY - NOT FOR CONSTRUCTION

no.	date	by	ckd	description	no.	date	by	ckd	description

GENERAL ARRANGEMENT
0 4' 8' 16'
SCALE IN FEET

NORTH

BURNS & McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: K. GLIKBARG
detailed: N. NITCHALS

KU
CARROLL CO., KY

APPENDIX D3
GHENT GENERATING STATION ELG
EQUIPMENT GENERAL ARRANGEMENT

project: 117977
contract: -
drawing: GA1000A
rev.: -
sheet 1 of 1 sheets
file 117977GA1000A.dwg

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Kentucky Utilities
Ghent ELG Treatment
1,000GPM System - Mechanical Equipment List

SYSTEM DESCRIPTION	EQUIPMENT NAME / DESCRIPTION	Supplier	INDOOR/OUTDOOR	Capacity
DENITRIFICATION	NEW DENITRIFICATION SYSTEM	Bio OEM	INDOOR	
BIO	BIOLOGICAL TREATMENT SYSTEM	Bio OEM	OUTDOOR	
BIO	A BIOREACTOR STAGE 1 FEED PUMP STRAINER	EPC BOP	OUTDOOR	
BIO	B BIOREACTOR STAGE 1 FEED PUMP STRAINER	EPC BOP	OUTDOOR	
BIO	A BIOREACTOR STAGE 1 TANK	Bio OEM	OUTDOOR	
BIO	B BIOREACTOR STAGE 1 TANK	Bio OEM	OUTDOOR	
BIO	C BIOREACTOR STAGE 1 TANK	Bio OEM	OUTDOOR	
BIO	D BIOREACTOR STAGE 1 TANK	Bio OEM	OUTDOOR	
BIO	E BIOREACTOR STAGE 1 TANK	Bio OEM	OUTDOOR	
BIO	F BIOREACTOR STAGE 1 TANK	Bio OEM	OUTDOOR	
BIO	G BIOREACTOR STAGE 1 TANK	Bio OEM	OUTDOOR	
BIO	H BIOREACTOR STAGE 1 TANK	Bio OEM	OUTDOOR	
BIO	I BIOREACTOR STAGE 1 TANK	Bio OEM	OUTDOOR	
BIO	J BIOREACTOR STAGE 1 TANK	Bio OEM	OUTDOOR	
BIO	K BIOREACTOR STAGE 1 TANK	Bio OEM	OUTDOOR	
BIO	A/B BIOREACTOR STAGE 1 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	C/D BIOREACTOR STAGE 1 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	E/F BIOREACTOR STAGE 1 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	G/H BIOREACTOR STAGE 1 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	I/J BIOREACTOR STAGE 1 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	K BIOREACTOR STAGE 1 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	A BIOREACTOR STAGE 2 TANK	Bio OEM	OUTDOOR	
BIO	B BIOREACTOR STAGE 2 TANK	Bio OEM	OUTDOOR	
BIO	C BIOREACTOR STAGE 2 TANK	Bio OEM	OUTDOOR	
BIO	D BIOREACTOR STAGE 2 TANK	Bio OEM	OUTDOOR	
BIO	E BIOREACTOR STAGE 2 TANK	Bio OEM	OUTDOOR	
BIO	F BIOREACTOR STAGE 2 TANK	Bio OEM	OUTDOOR	
BIO	G BIOREACTOR STAGE 2 TANK	Bio OEM	OUTDOOR	
BIO	H BIOREACTOR STAGE 2 TANK	Bio OEM	OUTDOOR	
BIO	I BIOREACTOR STAGE 2 TANK	Bio OEM	OUTDOOR	
BIO	J BIOREACTOR STAGE 2 TANK	Bio OEM	OUTDOOR	
BIO	K BIOREACTOR STAGE 2 TANK	Bio OEM	OUTDOOR	
BIO	L BIOREACTOR STAGE 2 TANK	Bio OEM	OUTDOOR	
BIO	M BIOREACTOR STAGE 2 TANK	Bio OEM	OUTDOOR	
BIO	N BIOREACTOR STAGE 2 TANK	Bio OEM	OUTDOOR	
BIO	O BIOREACTOR STAGE 2 TANK	Bio OEM	OUTDOOR	
BIO	P BIOREACTOR STAGE 2 TANK	Bio OEM	OUTDOOR	
BIO	Q BIOREACTOR STAGE 2 TANK	Bio OEM	OUTDOOR	
BIO	R BIOREACTOR STAGE 2 TANK	Bio OEM	OUTDOOR	
BIO	S BIOREACTOR STAGE 2 TANK	Bio OEM	OUTDOOR	
BIO	T BIOREACTOR STAGE 2 TANK	Bio OEM	OUTDOOR	
BIO	U BIOREACTOR STAGE 2 TANK	Bio OEM	OUTDOOR	
BIO	V BIOREACTOR STAGE 2 TANK	Bio OEM	OUTDOOR	
BIO	A BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	B BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	C BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	D BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	E BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	F BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	G BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	H BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	I BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	J BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	K BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	L BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	M BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	N BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	O BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	P BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	Q BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	R BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	S BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	T BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	U BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	V BIOREACTOR STAGE 2 TANK FLOW CONTROL SKID	Bio OEM	OUTDOOR	
BIO	BIOREACTOR BACKWASH TANK	EPC BOP	OUTDOOR	20,000 gallons - 14'D x 18'H (FRP Construction)
BIO	BIOREACTOR BACKWASH PUMP SKID	Bio OEM	OUTDOOR	
BIO	A BIOREACTOR BACKWASH PUMP	Bio OEM	OUTDOOR	2100
BIO	B BIOREACTOR BACKWASH PUMP	Bio OEM	OUTDOOR	2100
BIO	WWT EFFLUENT TANK	EPC BOP	OUTDOOR	20,000 gallons - 14'D x 18'H (FRP Construction)
BIO	A WWT EFFLUENT PUMP	Bio OEM	OUTDOOR	500
BIO	B WWT EFFLUENT PUMP	Bio OEM	OUTDOOR	500
BIO	C WWT EFFLUENT PUMP	Bio OEM	OUTDOOR	500

3/10/2020

Kentucky Utilities
Ghent ELG Treatment
1,000GPM System - Mechanical Equipment List

SYSTEM DESCRIPTION	EQUIPMENT NAME / DESCRIPTION	Supplier	INDOOR/OUTDOOR	Capacity
BIO	BIO AREA SUMP	EPC BOP	OUTDOOR	15'W x 20' L x 15' D (~30,000 gallons)
BIO	A BIO AREA SUMP PUMP	EPC BOP	OUTDOOR	450
BIO	B BIO AREA SUMP PUMP	EPC BOP	OUTDOOR	450
BIO- CHEMICAL FEED	NUTRIENT STORAGE TANK	EPC BOP	OUTDOOR	30,000 gallons - 14'D x 30'H (FRP Construction)
BIO- CHEMICAL FEED	DENITRIFICATION NUTRIENT FEED SKID	Bio OEM	INDOOR	
BIO- CHEMICAL FEED	A DENITRIFICATION NUTRIENT FEED PUMP	Bio OEM	INDOOR	
BIO- CHEMICAL FEED	B DENITRIFICATION NUTRIENT FEED PUMP	Bio OEM	INDOOR	
BIO- CHEMICAL FEED	BIOREACTOR NUTRIENT FEED SKID	Bio OEM	INDOOR	
BIO- CHEMICAL FEED	A BIOREACTOR NUTRIENT PUMP	Bio OEM	INDOOR	
BIO- CHEMICAL FEED	B BIOREACTOR NUTRIENT PUMP	Bio OEM	INDOOR	
UF	UF FEED PUMP SKID	Bio OEM	OUTDOOR	
UF	A UF FEED PUMP	Bio OEM	OUTDOOR	500
UF	B UF FEED PUMP	Bio OEM	OUTDOOR	500
UF	C UF FEED PUMP	Bio OEM	OUTDOOR	500
UF	UF CIP PUMP SKID	Bio OEM	INDOOR	
UF	UF CIP TANK	Bio OEM	INDOOR	
UF	A UF CIP PUMP	Bio OEM	INDOOR	140
UF	B UF CIP PUMP	Bio OEM	INDOOR	140
UF	A UF MEMBRANE SKID	Bio OEM	INDOOR	
UF	B UF MEMBRANE SKID	Bio OEM	INDOOR	
UF	C UF MEMBRANE SKID	Bio OEM	INDOOR	
UF	D UF MEMBRANE SKID	Bio OEM	INDOOR	
UF	E UF MEMBRANE SKID	Bio OEM	INDOOR	
UF	F UF MEMBRANE SKID	Bio OEM	INDOOR	
UF	G UF MEMBRANE SKID	Bio OEM	INDOOR	
UF	H UF MEMBRANE SKID	Bio OEM	INDOOR	
UF	I UF MEMBRANE SKID	Bio OEM	INDOOR	
UF	UF BACKWASH TANK	EPC BOP	OUTDOOR	20,000 gallons - 14'D x 18'H (FRP Construction)
UF	UF BACKWASH PUMP SKID	Bio OEM	OUTDOOR	
UF	A UF BACKWASH PUMP	Bio OEM	OUTDOOR	250
UF	B UF BACKWASH PUMP	Bio OEM	OUTDOOR	250
UF	UF AREA SUMP	EPC BOP	OUTDOOR	~5,000 gallons (8'W x 8'L x 10'D)
UF	A UF AREA SUMP PUMP	EPC BOP	OUTDOOR	300
UF	B UF AREA SUMP PUMP	EPC BOP	OUTDOOR	300
UF - CHEMICAL FEED	UF CITRIC ACID FEED SKID	Bio OEM	INDOOR	
UF - CHEMICAL FEED	A UF CITRIC ACID FEED PUMP	Bio OEM	INDOOR	
UF - CHEMICAL FEED	B UF CITRIC ACID FEED PUMP	Bio OEM	INDOOR	
UF - CHEMICAL FEED	UF SODIUM HYPOCHLORITE FEED SKID	Bio OEM	INDOOR	
UF - CHEMICAL FEED	A UF SODIUM HYPOCHLORITE FEED PUMP	Bio OEM	INDOOR	
UF - CHEMICAL FEED	B UF SODIUM HYPOCHLORITE FEED PUMP	Bio OEM	INDOOR	
UF - CHEMICAL FEED	UF CAUSTIC FEED SKID	Bio OEM	INDOOR	
UF - CHEMICAL FEED	A UF CAUSTIC FEED PUMP	Bio OEM	INDOOR	
UF - CHEMICAL FEED	B UF CAUSTIC FEED PUMP	Bio OEM	INDOOR	
UF - CHEMICAL FEED	UF HYDROGEN PEROXIDE FEED SKID	Bio OEM	INDOOR	
UF - CHEMICAL FEED	A UF HYDROGEN PEROXIDE FEED PUMP	Bio OEM	INDOOR	
UF - CHEMICAL FEED	B UF HYDROGEN PEROXIDE FEED PUMP	Bio OEM	INDOOR	
SERVICE WATER	SERVICE WATER AUTO STRAINER A	EPC BOP	INDOOR	
SERVICE WATER	SERVICE WATER AUTO STRAINER B	EPC BOP	INDOOR	
COOLING WATER	COOLING WATER PUMP A	EPC BOP	INDOOR	
COOLING WATER	COOLING WATER PUMP B	EPC BOP	INDOOR	
COMPRESSED AIR	AIR RECEIVER - ELG BLDG	EPC BOP	INDOOR	500
POTABLE WATER	WWT Building Potable Water Tempering Skid	EPC BOP	INDOOR	
POTABLE WATER	WWT Building Potable Water Tempering Skid Tank Heater	EPC BOP	INDOOR	
POTABLE WATER	WWT Building Potable Water Tempering Skid Booster Pump	EPC BOP	INDOOR	
POTABLE WATER	WWT Building Potable Water Tempering Skid Recirculation Pump	EPC BOP	INDOOR	
POTABLE WATER	WWT Building Potable Water Tempering Skid Tank	EPC BOP	INDOOR	
SEWAGE DRAINS SYSTEM	WWT BUILDING SANITARY LIFT STATION	EPC BOP	OUTDOOR	
SEWAGE DRAINS SYSTEM	A WWT SANITARY LIFT STATION PUMP	EPC BOP	OUTDOOR	
SEWAGE DRAINS SYSTEM	B WWT SANITARY LIFT STATION PUMP	EPC BOP	OUTDOOR	
HVAC	Bldg HVAC - Heating	EPC BOP		
HVAC	Bldg HVAC - Exhaust Fans	EPC BOP		
HVAC	Bldg HVAC - Exhaust Fans	EPC BOP		
HVAC	Bldg HVAC - Exhaust Fans	EPC BOP		
HVAC	Bldg HVAC - Exhaust Fans	EPC BOP		
HVAC	Bldg HVAC - Chemical Room Exhaust Fan	EPC BOP		

Kentucky Utilities
Ghent ELG Treatment
1,000GPM System - Electrical Equipment List

SYSTEM DESCRIPTION	EQUIPMENT NAME / DESCRIPTION	QUANTITY	Supplier	INDOOR/OUTDOOR
ELECTRICAL EQUIPMENT	25 kV PAD MOUNT SWITCHGEAR	2 EACH	EPC - BOP	OUTDOOR
ELECTRICAL EQUIPMENT	25 kV - 480V TRANSFORMERS	2 EACH	EPC - BOP	INDOOR
ELECTRICAL EQUIPMENT	480V SWITCHGEAR (MAIN-TIE-MAIN)	1 SWITCHGEAR	EPC - BOP	INDOOR
ELECTRICAL EQUIPMENT	480 MCCs (4 LINEUPS)	20 SECTIONS	EPC - BOP	INDOOR
ELECTRICAL EQUIPMENT	480V-208V TRANSFORMER	2 EACH	EPC - BOP	INDOOR
ELECTRICAL EQUIPMENT	208/120V LIGHTING AND POWER PANELS	2 EACH	EPC - BOP	INDOOR
ELECTRICAL EQUIPMENT	125 VDC POWER PANEL	1 EACH	EPC - BOP	INDOOR
ELECTRICAL EQUIPMENT	DIESEL GENERATOR CONNECTION BOX	1 EACH	EPC - BOP	OUTDOOR

FEL-2 CAPITAL COST ESTIMATE SUMMARY SHEET
LGE/KU ELG Treatment
Ghent Generating Station
1000 GPM Water Treatment
Ghent, KY
BMcD #117977

Acct	Area / Discipline	Direct MHRS	Labor Cost	Material Cost	Engr Equip/ Subcontract Cost	Const. Equipment Cost	TOTAL COST FRP
01	Engineered Equipment	3,820	$588,258	$270,460	$11,532,022		$12,390,740
02	Civil	4,446	$537,966	$340,877	$88,125	$85,669	$1,052,638
03	Deep Foundations	3,221	$389,808	$443,828	$2,387,714	$36,333	$3,257,682
04	Concrete	10,033	$1,212,860	$1,137,403	$294,251	$64,802	$2,709,316
05	Structural Steel	7,890	$1,167,080	$1,034,707			$2,201,787
06	Architectural				$2,994,950		$2,994,950
07	Piping	41,938	$6,417,408	$5,364,773	$573,940		$12,356,122
08	Electrical	48,057	$6,628,795	$3,274,079	$318,000		$10,220,875
09	Instrument & Control	1,459	$202,452	$29,342	$1,310,300		$1,542,094
10	Insulation				$6,087,498		$6,087,498
11	Coatings				$762,400		$762,400
12	Specialty						
13	Demolition						
14	Misc Directs						
	Total Direct Cost	**120,864**	**$17,144,628**	**$11,895,470**	**$26,349,200**	**$186,803**	**$55,576,101**

Rev.	Revision Date
0	12/20/19
1	01/30/20
2	02/11/20
3	02/18/20
4	02/20/20
4b	02/26/20
4c	03/16/20
5	03/25/20
	f

Construction Mgmt & Indirects		$4,028,815
Engineering		$5,557,610
Start-Up		$1,667,283
Commercial		$569,500
Total Indirect Cost		**$11,823,208**
Total Direct and Indirect Costs		**$67,399,310**
Minor Scope Items	20%	$13,479,862
EPC Execution Contingency	10%	$6,739,931
EPC Fee	8%	$6,470,334
Total EPC Contract Cost		**$94,089,436**

Notes:

1) Minor Scope Items is intended to capture costs for scope and small procurements (<$10,000) that may have been unaccounted for within the estimate basis.
2) EPC Execution Contingency is intended to capture costs associated with events outside the Contractor's control (i.e equipment mis-fabrication, and excessive crane rental duration, etc.) that could increase overall cost and.or schedule of the project.

BURNS McDONNELL

PROJECT CLIENT: **LGE/KU ELG Treatment**

PROJECT DESC: **Ghent Generating Station - 1000 GPM Water Treatment**

PROJECT # : **117977**

SUMMARY
ENGINEERED EQUIPMENT

EST LEVEL: **FEL-2**

ESTIMATE DUE DATE: **1/30/2020**

ESTIMATOR:

DESCRIPTION		LABOR		MATERIAL	EQUIPMENT	EQUIPMENT	**TOTAL**
		MH	COST	COST	COST	RENT / STS	**COST**
P 2	DENITRIFICATION	450	69,297		1,066,667		**1,135,964**
P 3	BIOLOGICAL TREATMENT SYSTEM	2,190	337,247	270,460	8,142,384		**8,750,091**
P 4	BIO- CHEMICAL FEED	120	18,479		210,000		**228,479**
P 5	UF	510	78,537		1,857,971		**1,936,508**
P 6	UF - CHEMICAL FEED	140	21,559		60,000		**81,559**
P 7	SERVICE WATER	40	6,160		70,000		**76,160**
P 8	COOLING WATER	160	24,639		70,000		**94,639**
P 9	COMPRESSED AIR	30	4,620		5,000		**9,620**
P 10	POTABLE WATER	80	12,320		20,000		**32,320**
P 11	SEWAGE DRAINS SYSTEM	40	6,160		15,000		**21,160**
P 12	Eye Wash Station	60	9,240		15,000		**24,240**
	ESTIMATE TOTALS	**3,820**	**$588,258**	**$270,460**	**$11,532,022**		**$12,390,740**

Exhibit RSS-2
Page 58 of 71

PROJECT CLIENT: **LGE/KU ELG Treatment**
PROJECT DESC: **Ghent Generating Station - 1000 GPM Water Treatment**
PROJECT # : **117977**

SUMMARY
CIVIL

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **1/30/2020**
ESTIMATOR:

DESCRIPTION		LABOR MH	LABOR COST	MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
P 2	Earthwork	544	65,873	8,235		31,844	**105,952**
P 3	Site Surfacing	2,088	252,680	263,013		13,992	**529,684**
P 4	Storm Drainage	561	67,872	37,816		13,195	**118,883**
P 5	Underground Utilities	1,072	129,760	23,188	88,125	26,084	**267,156**
P 7	MISC ITEMS	180	21,782	8,625		555	**30,962**
	ESTIMATE TOTALS	**4,446**	**$537,966**	**$340,877**	**$88,125**	**$85,669**	**$1,052,638**

Exhibit RSS-2
Page 59 of 71

PROJECT CLIENT: **LGE/KU ELG Treatment**

PROJECT DESC: **Ghent Generating Station - 1000 GPM Water Treatment**

PROJECT # : **117977**

SUMMARY
DEEP FOUNDATIONS

EST LEVEL: **FEL-2**

ESTIMATE DUE DATE: **1/30/2020**

ESTIMATOR:

DESCRIPTION	LABOR MH	LABOR COST	MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
P 2 Auger Cast Piles	3,221	389,808	443,828	2,387,714	36,333	**3,257,682**
ESTIMATE TOTALS	**3,221**	**$389,808**	**$443,828**	**$2,387,714**	**$36,333**	**$3,257,682**

Exhibit RSS-2
Page 60 of 71

PROJECT CLIENT: **LGE/KU ELG Treatment**
PROJECT DESC: **Ghent Generating Station - 1000 GPM Water Treatment**
PROJECT # : **117977**

SUMMARY
CONCRETE

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **1/30/2020**
ESTIMATOR:

DESCRIPTION		LABOR		MATERIAL	SUBCON	EQUIPMENT	**TOTAL**
		MH	COST	COST	COST	RENT / STS	**COST**
P 2	Bldg, Sumps, Equip Pads	8,762	1,059,214	1,093,809	283,109	47,402	**2,483,534**
P 3	Tank Walls (OPT 2)						
P 4	Pipe Rack FND	1,271	153,646	43,594	11,142	17,400	**225,782**
	ESTIMATE TOTALS	**10,033**	**$1,212,860**	**$1,137,403**	**$294,251**	**$64,802**	**$2,709,316**

Exhibit RSS-2
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PROJECT CLIENT: **LGE/KU ELG Treatment**
PROJECT DESC: **Ghent Generating Station - 1000 GPM Water Treatment**
PROJECT # : **117977**

SUMMARY
STRUCTURAL STEEL

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **1/30/2020**
ESTIMATOR:

DESCRIPTION		LABOR		MATERIAL	SUBCON	EQUIPMENT	**TOTAL**
		MH	COST	COST	COST	RENT / STS	**COST**
P 2	Pipe Rack Structural Steel	7,456	1,102,832	770,955			**1,873,787**
P 3	Misc Steel	434	64,248	263,752			**328,000**
P 4	UF Bldg Access Stairway						
	ESTIMATE TOTALS	**7,890**	**$1,167,080**	**$1,034,707**			**$2,201,787**

Exhibit RSS-2
Page 62 of 71

PROJECT CLIENT: **LGE/KU ELG Treatment**

PROJECT DESC: **Ghent Generating Station - 1000 GPM Water Treatment**

PROJECT # : **117977**

SUMMARY
ARCHITECTURAL

EST LEVEL: **FEL-2**

ESTIMATE DUE DATE: **1/30/2020**

ESTIMATOR:

DESCRIPTION	LABOR MH	LABOR COST	MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
P 2 WATER TREATMENT BLDG				2,994,950		**2,994,950**
ESTIMATE TOTALS				**$2,994,950**		**$2,994,950**

Exhibit RSS-2
Page 63 of 71

PROJECT CLIENT: **LGE/KU ELG Treatment**
PROJECT DESC: **Ghent Generating Station - 1000 GPM Water Treatment**
PROJECT # : **117977**

SUMMARY
PIPING

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **1/30/2020**
ESTIMATOR:

DESCRIPTION			LABOR MH	LABOR COST	MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
P 2	PIPING - UG	8111 LF	4,807	735,647	275,275			**1,010,922**
P 3	PIPING - AG		16,537	2,530,529	1,248,310			**3,778,838**
P 4	PIPING - AG (cont)		15,963	2,442,656	3,654,842			**6,097,498**
P 5	PIPING - AG (cont)	13682 LF	3,350	512,556	46,506	431,390		**990,452**
P 6	VALVES	100 EA	440	67,330	132,940			**200,270**
P 7	SPECIALS 1	181 EA	721	110,329		142,550		**252,879**
P 8	TIE-INS	4 EA	120	18,363	6,900			**25,263**
		ESTIMATE TOTALS	**41,938**	**$6,417,408**	**$5,364,773**	**$573,940**		**$12,356,122**
	TOTAL	21793 LF						

Exhibit RSS-2
Page 64 of 71

PROJECT CLIENT:	**LGE/KU ELG Treatment**	EST LEVEL:	**FEL-2**
PROJECT DESC:	**Ghent Generating Station - 1000 GPM Water Treatment**	ESTIMATE DUE DATE:	**1/30/2020**
PROJECT # :	**117977**	ESTIMATOR:	**RSG**

SUMMARY
ELECTRICAL

DESCRIPTION		LABOR MH	LABOR COST	MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
P 2	GROUNDING	1,539	214,257	39,363			**253,619**
P 3	8.10 CONDUIT	6,479	901,942	406,857			**1,308,798**
P 4	8.11 CABLE TRAY	392	54,625	20,960			**75,585**
P 5	8.12 UG RACEWAY	20,027	2,787,895	983,190			**3,771,085**
P 6	8.20 MED Volt Cable	85	11,894	12,330			**24,224**
P 7	8.21 480V Cable	2,294	319,374	226,555			**545,928**
P 8	8.22 Cable Control & Insturment	3,734	519,760	118,870			**638,629**
P 9	8.23 Cable, Fiber, Ethernet	48	6,682	5,842			**12,524**
P 10	TERMINATIONS	1,957	272,410	17,563			**289,973**
P 11	8.40 Lighting and Recep	5,336	742,853	261,762			**1,004,615**
P 12	8.31 Elec Equipment Install	1,362	128,539	1,020,806			**1,149,345**
P 14	SECURITY	1,186	165,095	37,066			**202,161**
P 15	COMMUNICATION				80,000		**80,000**
P 16	HEAT TRACE & CATHODIC				238,000		**238,000**
P 17	LIGHTNING PROTECTION	1,114	155,128	30,472			**185,600**
P 18	TEMPORARY POWER	2,105	292,980	55,886			**348,867**
P 19	25KV O/H LINE	398	55,362	36,559			**91,921**
	ESTIMATE TOTALS	**48,057**	**$6,628,795**	**$3,274,079**	**$318,000**		**$10,220,875**

Exhibit RSS-2
Page 65 of 71

PROJECT CLIENT: **LGE/KU ELG Treatment**

PROJECT DESC: **Ghent Generating Station - 1000 GPM Water Treatment**

PROJECT # : **117977**

SUMMARY
INSTRUMENT & CONTROL

EST LEVEL: **FEL-2**

ESTIMATE DUE DATE: **1/30/2020**

ESTIMATOR:

DESCRIPTION		LABOR		MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
		MH	COST				
P 2	INSTRUMENT PROCUREMENT				105,850		**105,850**
P 3	DCS				1,204,450		**1,204,450**
P 4	INSTRUMENT INSTALL	1,073	148,921	4,140			**153,061**
P 5	TUBING	386	53,531	25,202			**78,733**
	ESTIMATE TOTALS	**1,459**	**$202,452**	**$29,342**	**$1,310,300**		**$1,542,094**

Exhibit RSS-2
Page 66 of 71

PROJECT CLIENT: **LGE/KU ELG Treatment**

PROJECT DESC: **Ghent Generating Station - 1000 GPM Water Treatment**

PROJECT # : **117977**

SUMMARY
INSULATION

EST LEVEL: **FEL-2**

ESTIMATE DUE DATE: **1/30/2020**

ESTIMATOR:

DESCRIPTION	LABOR MH	LABOR COST	MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
P 2 INSULATION				404,180		**404,180**
P 3 Equipment Insulation				37,000		**37,000**
P 4 EXISTING TANK INSULATION AND HEAT TRACE				5,646,318		**5,646,318**
ESTIMATE TOTALS				**$6,087,498**		**$6,087,498**

Exhibit RSS-2
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PROJECT CLIENT: **LGE/KU ELG Treatment**
PROJECT DESC: **Ghent Generating Station - 1000 GPM Water Treatment**
PROJECT # : **117977**

SUMMARY
COATINGS

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **1/30/2020**
ESTIMATOR:

DESCRIPTION	LABOR		MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
	MH	COST				
P 2 Specialty Coatings				762,400		**762,400**
ESTIMATE TOTALS				**$762,400**		**$762,400**

Exhibit RSS-2
Page 68 of 71

PROJECT CLIENT: **LGE/KU ELG Treatment**
PROJECT DESC: **Ghent Generating Station - 1000 GPM Water Treatment**
PROJECT # : **117977**

SUMMARY
INDIRECTS

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **1/30/2020**
ESTIMATOR:

DESCRIPTION		LABOR MH	LABOR COST	MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
P 2	Construction Mgmt & Indirects	20,144	2,820,170	1,208,644			**4,028,815**
P 3	Engineering				5,557,610		**5,557,610**
P 4	Start-Up				1,667,283		**1,667,283**
P 5	Commercial				569,500		**569,500**
P 6	Escalation				5,731,175		**5,731,175**
	ESTIMATE TOTALS	**20,144**	**$2,820,170**	**$1,208,644**	**$13,525,568**		**$17,554,383**

Exhibit RSS-2
Page 69 of 71

O&M COST ESTIMATE SUMMARY
KENTUCKY UTILITIES
GHENT GENERATING STATION
ELG TREATMENT - 1000 GPM

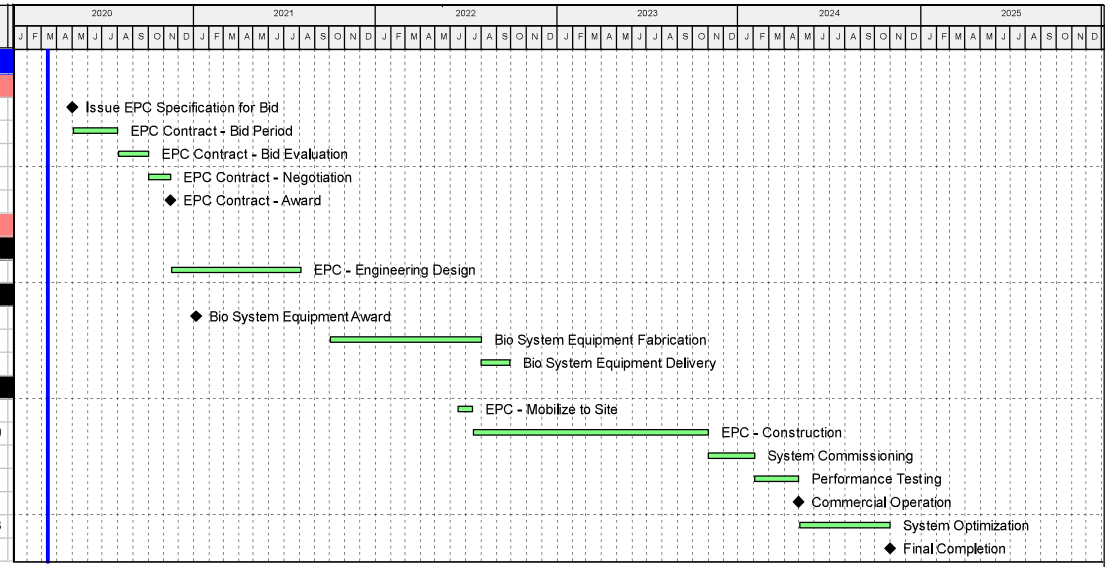
Item	O&M Cost Line Item Description		Cost ($ / Year)
01a	Chemical Consumption - Caustic (33 lb/day @ $0.33/lb)		$3,969
01b	Chemical Consumption - Nutrient (314 lb/hr @ $0.68/lb)		$1,873,067
01c	Chemical Consumption - Hydrogen Peroxide (45 lb/hr @ $0.15/lb)		$58,090
01d	Chemical Consumption - Sodium Hypochlorite (274 lb/day @ $0.17/lb)		$17,324
01e	Chemical Consumption - Citric Acid (28 lb/day @ $0.66/lb)		$6,697
01f	Chemical Consumption - Hydrochloric Acid (23 lb/day @ $0.30/lb)		$2,467
02	Operations Personnel (Note 4)		$1,200,000
03	Maintenance (Note 6)		$1,053,968
04	Chemical Precipitation Waste Disposal		N/A
	Total Annual O&M Cost		**$4,215,581**

Rev.	Revision Date	
	03/25/20	BURNS McDONNELL

Notes:

1 Estimate excludes outage and startup costs.
2 Costs are indicative approximations, from Burns & McDonnell's experience on similar projects.
3 Plant capacity factor is assumed to be 100% for purpose of estimate.
4 Operations personnel on a total of 10 FTE. An additional 2 operators per crew (8 FTE - 4 crews) plus 0.75 FTE for maintenance tech, 0.75 FTE for I&C/electrical maintenance tech and 0.5 FTE for a chemist.
5 Annual cost for operating personnel is $120,000/FTE
6 Maintenance is estimated at 4% of the Engineered Equipment/Subcontract Cost from the FEL-2 estimate.

ACTIVITY ID	ACTIVITY DESCRIPTION	START	FINISH	OD
KU GHENT - ELG Rule Compliance (Bio)				
EPC Contracting				
A1010	Issue EPC Specification for Bid		01-May-20*	0
A1000	EPC Contract - Bid Period	04-May-20	31-Jul-20	63
A1020	EPC Contract - Bid Evaluation	03-Aug-20	01-Oct-20	43
A1030	EPC Contract - Negotiation	01-Oct-20	13-Nov-20	32
A1040	EPC Contract - Award		13-Nov-20	0
EPC Contractor Activities				
Design				
A1050	EPC - Engineering Design	16-Nov-20	03-Aug-21	181
Bio System Package				
A1060	Bio System Equipment Award		04-Jan-21	0
A1090	Bio System Equipment Fabrication	01-Oct-21*	01-Aug-22	211
A1100	Bio System Equipment Delivery	02-Aug-22	27-Sep-22	40
Construction / Commissioning				
A1070	EPC - Mobilize to Site	15-Jun-22	15-Jul-22	22
A1080	EPC - Construction	18-Jul-22	01-Nov-23	330
A1110	System Commissioning	01-Nov-23	02-Feb-24	64
A1120	Performance Testing	02-Feb-24	01-May-24	64
A1130	Commercial Operation		01-May-24*	0
A1150	System Optimization	02-May-24	31-Oct-24	128
A1140	Final Completion		01-Nov-24	0



Remaining Level of Effort
Actual Level of Effort
Actual Work
Remaining Work
Critical Remaining Work
Milestone

CURRENT PROJECT ID: LG01
PREV PROJECT ID: LG00
TARGET PROJECT ID: N/A

KU GHENT
Biological Treatment System (EPC)

LAYOUT: LT01 - WORKING_2
TASK filter: All Activities

13-Mar-20 DATA DATE
13-Mar-20 @ 05:28 RUN DATE
PAGE 1 OF 1

INDEX AND CERTIFICATION

LG&E and KU Services Company
Ghent Generating Station
Engineering, Procurement, and Construction Summary Report for ELG Rule Compliance (Bottom Ash)
Project No. 117977

Report Index

Certification

I hereby certify, as a Professional Engineer in the state of Kentucky, the information in this document was assembled under my direct personal charge. This report is not intended or represented to be suitable for revision by the LG&E and KU Services Company or others without specific verification or adaptation by the Engineer.

STATE OF KENTUCKY
KRISTIN
L.
GLIKBARG
29371
LICENSED
PROFESSIONAL ENGINEER

Mar 25 2020

DocuSign

ENGINEERING, PROCUREMENT AND CONSTRUCTION (EPC) SUMMARY REPORT FOR ELG RULE COMPLIANCE (BOTTOM ASH)

Burns & McDonnell (BMcD) has prepared conceptual design documents for converting the existing Bottom Ash conveying system at the Ghent generating station to a new Bottom Ash High Recycle Rate System. The conversion to a new Bottom Ash High Recycle Rate System is necessary to minimize the release of bottom ash transport wastewater as required by the new Environmental Protection Agency (EPA) Effluent Limitation Guidelines and Standards (ELG rule). The conceptual design documents contained within this report have been utilized in the development of budgetary Engineer, Procurement and Construct (EPC) contractor's Capital Costs estimates and Operating and Maintenance cost estimates to support LG&E.

ELG RULE BACKGROUND

On August 11, 2017, the EPA announced that it was reconsidering portions of the recent revisions to the ELG rule specifically related to bottom ash transport and flue gas desulfurization (FGD) wastewaters. The postponement of the ELG rule was officially published in the Federal Register on Monday, September 18, 2017, in Volume 82, Number 179. EPA provided its rationale for finalizing a postponement of compliance dates for the bottom ash and flue gas desulfurization (FGD) wastewaters.

EPA indicated that it would propose and finalize a new rule, sometime by the fall of 2019. As a result of the ELG rule reconsideration, EPA has also postponed the earliest compliance dates for bottom ash transport water and FGD wastewater to November 1, 2020. In the ELG rule reconsideration, the EPA did not postpone the latest allowable compliance date which is still currently set for December 31, 2023 as it applies to the bottom ash transport water section of the rule.

The proposed revised rule was officially published on November 22, 2019. Bottom ash systems cannot continue to discharge ash transport water, thus conversions to dry handling or High Rate Water Recycle systems are required no later than December 31, 2023. For a High Recycle Rate system (not a completely closed-loop system), blowdown from bottom ash systems shall be reduced or eliminated whenever possible, however is allowed with stipulations of maximum rate and total suspended solids (TSS), oil and grease limits. The maximum allowable blowdown rate is calculated from a 30-day rolling average of 10% of the primary active wetted bottom ash system volume (including piping, hoppers, and primary treatment systems but not maintenance tanks, secondary storage, or other systems that send water to bottom ash). Bottom ash blowdown water can continue to be routed to the plant's FGD system also.

A remote Submerged Flight Conveyor (SFC) system has previously been installed at Ghent station to dewater bottom ash. Return water tanks, pumps, and piping will need to be added to recirculate the ash transport water back to the boiler ash sluice system for conversion to a High Recycle Rate system.

CONCEPTUAL DESIGN

LG&E-KU requested BMcD prepare conceptual design documents and cost estimate for converting the existing Bottom Ash Handling system to a new High Recycle Rate ash handling system at the Ghent generating station. The new bottom ash recycle system equipment will return ash transport water back to the existing bottom ash sluice system. Additionally, the addition of new Lamella separators to the existing SFCs will remove TSS from the recycle water to reduce blowdown as required by the ELG rule. The following documents have been prepared to summarize the conceptual design:

- Process Flow Diagram (Appendix A)
- General Arrangement and Site Layout (Appendix B)
- Major Equipment List (Appendix C)
- Electrical Equipment List (Appendix D)
- Capital Cost Estimate (Appendix E)
- Operating and Maintenance Cost Estimate (Appendix F)
- Project Schedule (Appendix G)

Bottom Ash High Recycle Rate System Configuration

The proposed bottom ash recycle system design is based on Burns & McDonnell recent experience with similar systems installed at other power plants as well as the existing physical layout of the bottom ash dewatering systems at Ghent Station. Burns & McDonnell reviewed and incorporated site-specific conditions and requirements for the Ghent project into the conceptual design. The majority of the bottom ash recycle system equipment will be located east of the existing bottom ash dewatering building (see Appendix B).

Process flow diagrams are available in Appendix A. Ash solids are removed via a mechanical process utilizing the existing remote submerged flight dewatering conveyors, with new lamella plate pack separators to be installed in the conveyors for further TSS reduction in the water recirculated back to the units. The system can blowdown if necessary to a knockout box or as reclaim water to the existing FGD process onsite.

The major new equipment required to convert existing conveying system to a bottom ash recycle system include:

- Lamella Separator addition to existing SFCs
- Variable Frequency Drives added to the existing sump pumps in the dewatering building
- Ash Sluice Water Tanks
- Low Pressure Ash Sluice Pumps
- Blowdown Pumps
- High Pressure Ash Sluice Pumps
- Boiler Hopper Drains Tanks
- Boiler Hopper Overflow Pumps
- Boiler Hopper Ash Forwarding Water Tanks
- Boiler Hopper Ash Forwarding Water Pumps
- Pumps, piping, valves, instrumentation
- Electrical Equipment and Transformers
- Low Pressure Pump/Electrical Building

The first step in the process is to reduce TSS in the system ash transport water for use in a recycle system and for blowdown as necessary in accordance with the ELG. This is accomplished through new lamella separator packs to be installed in the existing submerged flight dewatering conveyors (SFC).

The recycle water from the existing dewatering conveyors is pumped from the existing building sump to new ash sluice water tanks (2x100%) for use in the recycle system. Variable Frequency Drives (VFDs) are to be installed at the existing sump pump to maintain level in the new tanks over variable process conditions. The new sluice tanks will be agitated to prevent freezing in cold conditions and to keep any solids in the system suspended.
The new low pressure (LP) ash sluice forwarding pumps will take suction from the new sluice tanks and pump back to the existing boiler buildings via new cross-tied piping and valving. The pumps are installed in a new building with a new compressed air system, electrical equipment, and drainage sump system. The sump returns water to the forwarding tanks for reuse in the system. New blowdown pumps (2x100%) are also installed in the new pump building with piping to send the limited amount of blowdown water to a knockout box for treatment or to discharge the blowdown water to the existing FGD process water system.

At each pair of the units, (units 1/2 and 3/4), new high pressure (HP) ash sluice pumps (2x100%) take the LP water and boost the pressure for use as ash and pyrite sluice water. The existing high pressure pumps at each of the units are not adequate for recycle service due to entrained solids in the recirculating water and can no longer be used. A side stream of LP water will bypass the HP pumps in order to supply low pressure water users at the boiler hopper. Additionally, cold weather bypass piping will be installed to bypass the high pressure system (and boiler hoppers) directly to the sluice return lines to keep water circulating during non-sluicing cycles in cold weather months to prevent freezing.

The new HP pumps will provide the transport water to sluice the bottom ash and pyrites from the boiler hoppers back to the existing submerged flight conveyors (SFC) where the ash will be dewatered and the effluent (transport water) will return to recirculate within the system.

The existing boiler seal troughs and hopper overflow systems will be modified as required to drain to new hopper drain tanks to be installed near each of the boiler hoppers. Water collected in these tanks will be forwarded to new common (per pair of units) collection tanks to be forwarded back into the system at the existing ash sluice lines via new (2x100%) forwarding pumps.

EPC CONTRACT CAPITAL COST ESTIMATE

Burns & McDonnell has prepared capital cost estimates for the EPC contractor's cost for the design, purchase, and installation of modifications to convert to a bottom ash recirculating water system. Major equipment budgetary price estimates were received from bottom ash handling system suppliers. Balance of plant equipment costs and installation were estimated based on Burns & McDonnell experience and internal data bases. An equipment list summarizing major mechanical and electrical equipment, tanks, and skids are included in Appendix C and D.

EPC Capital Cost Estimate	Estimate Cost
Bottom Ash Closed Loop System	$50.8M

This estimate is considered a conceptual level cost estimate (+/-30%) taking into account major site-specific factors but still utilizing comparable project costs for portions of the estimate. A summary of the capital cost estimate is provided in Appendix E.

Estimates are based on Burns & McDonnell's professional experience, qualifications, and judgment. Burns & McDonnell has no control over weather; cost and availability of labor, material, and equipment; labor productivity; energy or commodity pricing; demand or usage; population demographics; market conditions; changes in technology; and other economic or political factors affecting such estimates, analysis, and recommendations.

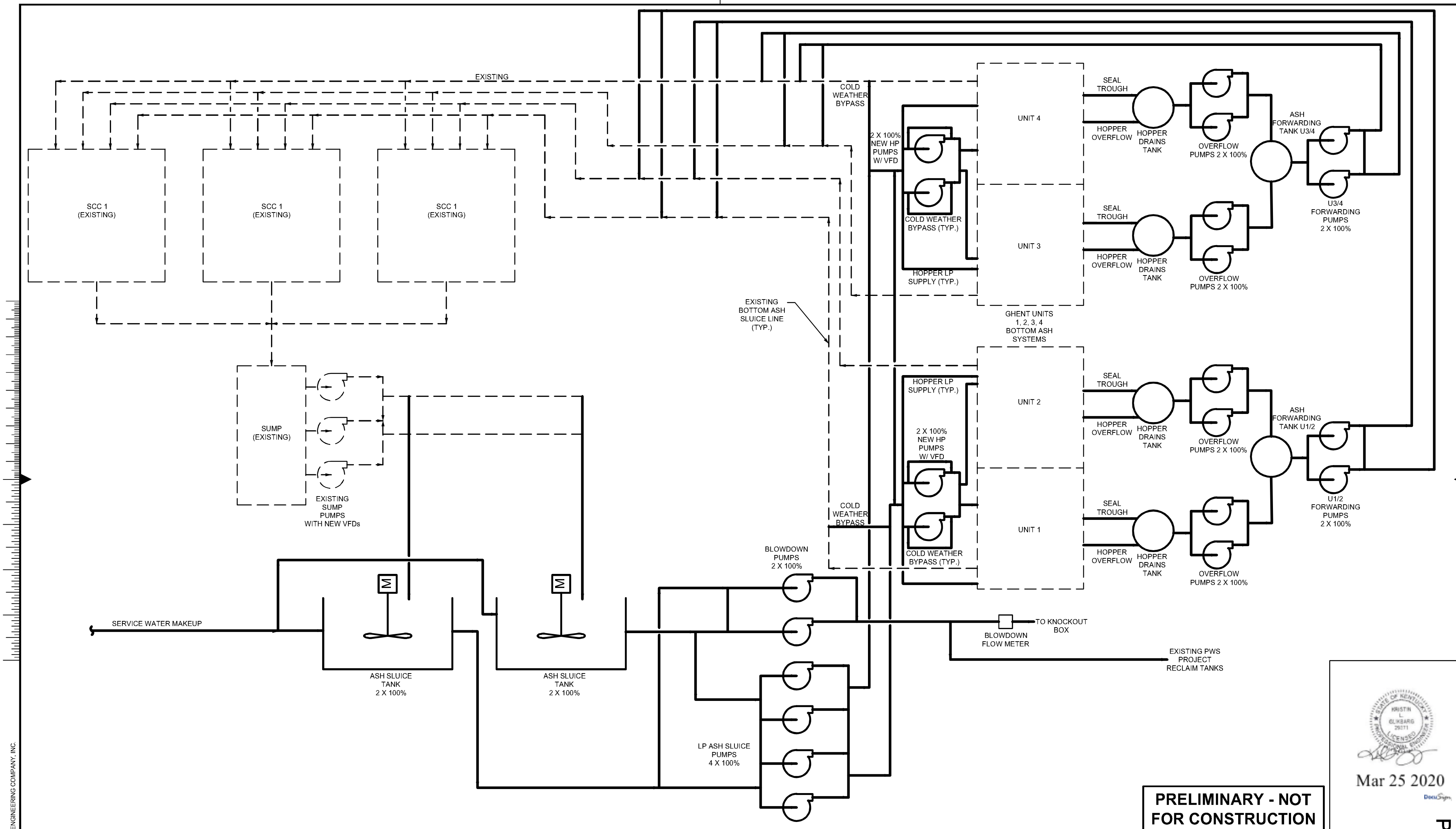
OPERATING AND MAINTENANCE COSTS

Projected Operating and Maintenance cost is summarized in Appendix F.

SCHEDULE

The anticipated schedule to design, procure, and install a new bottom ash recycle system at Ghent is provided in Appendix G.

Appendix A
Process Flow Diagram



PRELIMINARY - NOT FOR CONSTRUCTION

Mar 25 2020

no.	date	by	ckd	description	no.	date	by	ckd	description

BURNS McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400
FIRM LICENSE NO. 43

designed: C. HANSEN
detailed: R. CHANDLER

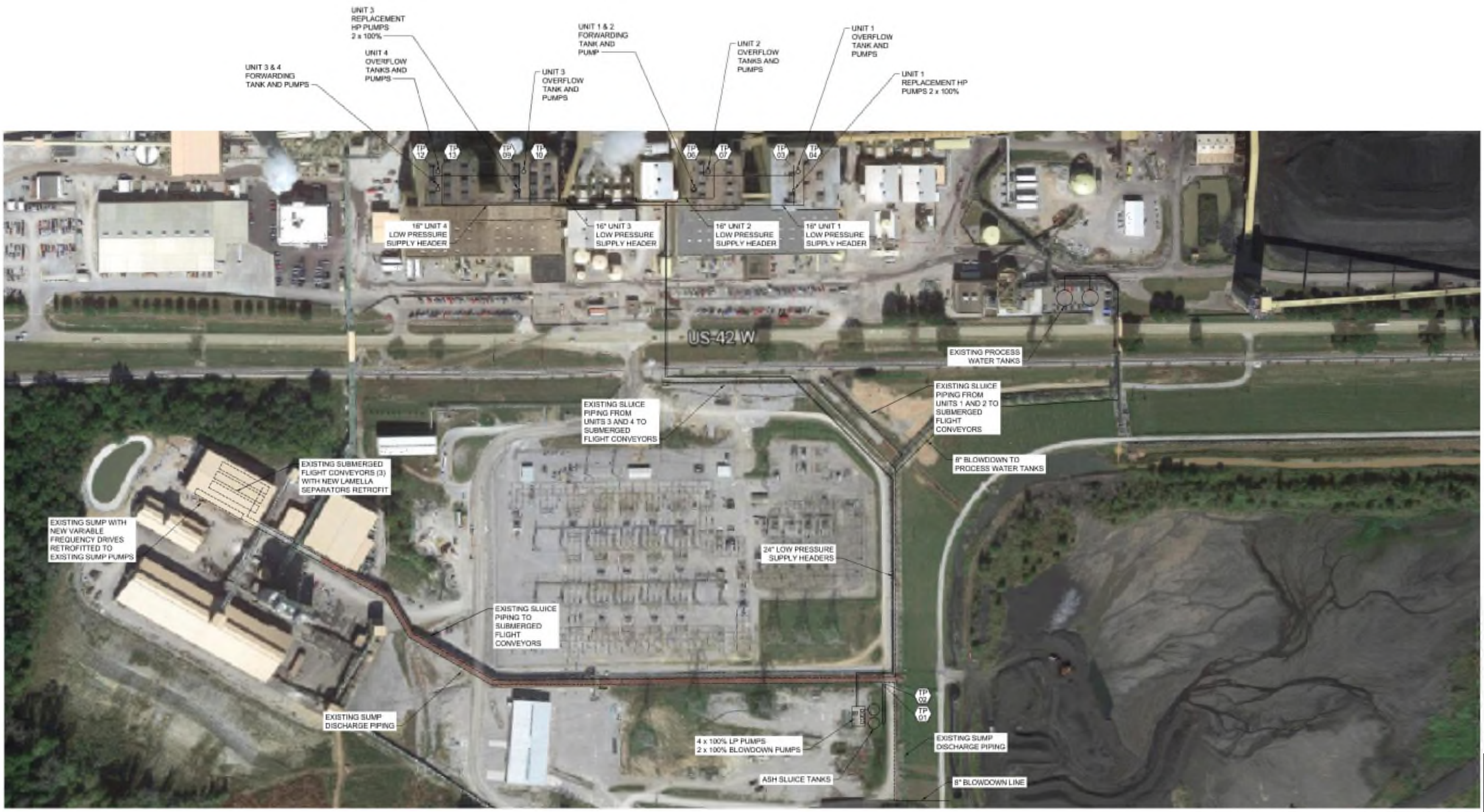
KU Kentucky Utilities Company
CARROLL COUNTY, KY

Ghent Piping & Instrumentation Diagram
ASH SLUICE SYSTEM

project: 117977
contract:
drawing: PFD-AHB05
rev. –
sheet of sheets
file PFD-AHB05.dwg

Appendix B
Site General Arrangement

1 2 3 4 5 6 7 8 9 10 11 12 13 14 15



NORTH

SCALE = NOT TO SCALE

PRELIMINARY - NOT FOR CONSTRUCTION

STATE OF KENTUCKY KRISTIN L. GLIKBARG 29371 LICENSED PROFESSIONAL ENGINEER

Mar 25 2020

no.	date	by	ckd	description	no.	date	by	ckd	description

BURNS McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: C. HANSEN
detailed: C. YODER

KU Kentucky Utilities Company

CARROL CO, KY

GHENT CLOSED LOOP BOTTOM ASH GENERAL ARRANGEMENT

project: 117977
contract: -
drawing: 17977GA2000 —
sheet 1 of 1 sheets
file 117977GA2000_NO_REV.dwg

Exhibit RSS-3
Page 9 of 30

Appendix C
Major Equipment List

Louisville Gas and Electric / Kentucky Utilities
Ghent Generating Stations
Appendix C - Bottom Ash Equipment List

EQUIPMENT NAME / DESCRIPTION	QUANTITY	OPERATING QTY	MOTOR HP ESTIMATE	LOCATION
Ash Sluice (Surge) Tank A	1	1 operating max	n/a	New Pump House Enclosure
Ash Sluice (Surge) Tank B	1	1 operating max	n/a	New Pump House Enclosure
Ash Sluice Tank A Agitator	1	1 operating max	7.5	New Pump House Enclosure
Ash Sluice Tank B Agitator	1	1 operating max	7.5	New Pump House Enclosure
LP Ash Sluice Forwarding Pump	5	4 operating max	400	New Pump House Enclosure
Blowdown Pump	2	1 operating max	150	New Pump House Enclosure
U1/2 HP Pump	2	1 operating max	500	Existing HP pumps to be removed. Install on new pad.
U3/4 HP Pump	2	1 operating max	500	Existing HP pumps to be removed. Install on new pad.
Jet Pumps for Bottom Ash Sluice	8	4 operating max	n/a	Below boiler hoppers (2 each unit)
U1 Hopper Overflow Tank	1	1 operating max	n/a	Near boiler hoppers in existing boiler bldg
U2 Hopper Overflow Tank	1	1 operating max	n/a	Near boiler hoppers in existing boiler bldg
U3 Hopper Overflow Tank	1	1 operating max	n/a	Near boiler hoppers in existing boiler bldg
U4 Hopper Overflow Tank	1	1 operating max	n/a	Near boiler hoppers in existing boiler bldg
U1/2 Forwarding tank	1	1 operating max	n/a	Outside of Unit 1/2 boiler building
U3/4 Forwarding tank	1	1 operating max	n/a	Inside U3 or U4 boiler building
U1/2 Forwarding Pump	2	1 operating max	200	New enclosure outside of Unit 1/2 boiler building
U3/4 Forwarding Pump	2	1 operating max	200	Inside U3 or U4 boiler building
U1 Boiler Overflow Pumps	2	1 operating max	100	Near boiler hoppers in existing boiler bldg
U2 Boiler Overflow Pumps	2	1 operating max	100	Near boiler hoppers in existing boiler bldg
U3 Boiler Overflow Pumps	2	1 operating max	100	Near boiler hoppers in existing boiler bldg
U4 Boiler Overflow Pumps	2	1 operating max	100	Near boiler hoppers in existing boiler bldg
Lamella Packs for Existing SFCs	3	2 operating max	n/a	At SFCs in existing dewatering building
Valves	1 lot	n/a	n/a	Throughout system.
Instrumentation	1 lot	n/a	n/a	Throughout system.
VFDs for existing SFC Building Sump Pumps	3	2 operating max	300 HP	Existing SFC building
Pump House Exhaust Fans	3	3 operating max	3/4 HP	New Pump House Enclosure
Pump House Heater Fans	4	4 operating max	1/3 HP	New Pump House Enclosure
Pump House Intake Louvers	3	3 operating max	n/a	New Pump House Enclosure

Appendix D
Electrical Equipment List

Louisville Gas and Electric / Kentucky Utilities
Ghent Generating Stations
Appendix D - Bottom Ash Electrical Equipment List

EQUIPMENT NAME/ DESCRIPTION	QUANTITY	Units
25kV-4.16kV Transformers	2	each
4.16kV Switchgear (MTM)	14	Breakers
4.16kV-480V Transformers (2000/2667kVA)	2	each
480V Switchgear (MTM)	1	SWGR
480V MCCs	10	Sections
VFD, 100HP including line and load reactors	8	each
VFD, 200HP including line and load reactors	4	each
VFD, 300HP including line and load reactors	3	each
125VDC Battery System & UPS System	1	lot
480V-208V Transformers (45kVA)	2	Each
208/120V Lighting & Power panels	2	Each
MCC section add-on to existing MCC	12	Section

Appendix E
Capital Cost Estimate

FEL-2 CAPITAL COST ESTIMATE SUMMARY SHEET
LGE/KU
GHENT GENERATING STATION
BOTTOM ASH
GHENT, KY
BMcD #117977

Acct	Area / Discipline	Direct MHRS	Labor Cost	Material Cost	Engr Equip/ Subcontract Cost	Const. Equipment Cost	Total Cost
01	Engineered Equipment	13,980	$2,153,000		$7,800,000		$9,953,000
02	Civil						
03	Deep Foundations	472	$57,000	$53,000	$73,000	$15,000	$198,000
04	Concrete	3,830	$463,000	$268,000	$65,000	$71,000	$867,000
05	Structural Steel	1,751	$259,000	$174,000			$433,000
06	Architectural	3,286	$430,000	$472,000	$1,367,000		$2,269,000
07	Piping	48,864	$7,477,000	$1,638,000			$9,115,000
08	Electrical	17,942	$2,498,000	$3,260,000			$5,758,000
09	Instrument & Control	339	$47,000	$146,000	$114,000		$307,000
10	Insulation				$102,000		$102,000
11	Coatings				$25,000		$25,000
12	Specialty						
13	Demolition						
14	Misc Directs	600	$87,000		$10,000		$97,000
	Total Direct Cost	**91,063**	**$13,471,000**	**$6,011,000**	**$9,556,000**	**$86,000**	**$29,124,000**

Rev.	Revision Date
0	12/20/19
1	01/30/20
2	02/18/20

Construction Mgmt & Indirects		$3,035,000
Engineering		$2,912,000
Start-Up		$874,000
Commercial		$431,000
Total Indirect Cost		**$7,252,000**
Total Direct and Indirect Costs		**$36,376,000**
	Cost	
Scope Uncertainty	20%	$7,275,000
EPC Execution Contingency	10%	$3,637,600
EPC Fee	8%	$3,492,000
Total EPC Contract Cost		**$50,780,600**

Notes:

1) Scope uncertainty is intended to capture costs for scope and small procurements (<$10,000) that may have been unaccounted for within the estimate basis.

2) EPC Execution Contingency is intended to capture costs associated with events outside the Contractor's control (i.e equipment mis-fabrication, and excessive crane rental duration, etc.) that could increase overall cost and.or schedule of the project.

BURNS McDONNELL

V 3.6

PROJECT CLIENT: **LGE/KU**
PROJECT DESC: **GHENT GENERATING STATION - BOTTOM ASH**
PROJECT # : **117977**

SUMMARY
ENGINEERED EQUIPMENT

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **12/20/2019**
ESTIMATOR:

DESCRIPTION	LABOR MH	LABOR COST	MATERIAL COST	EQUIPMENT COST	EQUIPMENT RENT / STS	**TOTAL COST**
P 2 ENGINEERED EQUIPMENT	13,980	2,152,838		7,800,000		**9,952,838**
ESTIMATE TOTALS	**13,980**	**$2,152,838**		**$7,800,000**		**$9,952,838**

PROJECT CLIENT: **LGE/KU**
PROJECT DESC: **GHENT GENERATING STATION - BOTTOM ASH**
PROJECT # : **117977**

SUMMARY
DEEP FOUNDATIONS

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **12/20/2019**
ESTIMATOR:

DESCRIPTION	LABOR MH	LABOR COST	MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
P 2 Drilled Piers	472	57,081	52,515	73,320	15,108	**198,023**
ESTIMATE TOTALS	**472**	**$57,081**	**$52,515**	**$73,320**	**$15,108**	**$198,023**

PROJECT CLIENT: **LGE/KU**
PROJECT DESC: **GHENT GENERATING STATION - BOTTOM ASH**
PROJECT # : **117977**

SUMMARY
CONCRETE

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **12/20/2019**
ESTIMATOR:

DESCRIPTION			LABOR MH	LABOR COST	MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	TOTAL COST
P 2	SLUICE PUMP ENCLOSURE	351.0 CY	1,765	213,339	111,701	26,652	35,180	**386,872**
P 3	LP PUMP PADS (5 EA)	10.0 CY	83	9,979	3,959	704	854	**15,495**
P 4	BLOWDOWN PUMP PADS (2 EA)	4.0 CY	26	3,114	1,386	235	285	**5,020**
P 5	HP REPLACEMENT PUMP PADS (10 EA)	19.0 CY	136	16,383	6,996	1,317	1,599	**26,296**
P 6	SLUICE TANKS (2 EA)	295.0 CY	725	87,637	86,125	22,975	13,621	**210,357**
P 7	ELECTRICAL ENCLOSURE	174.0 CY	1,096	132,487	57,729	13,477	19,638	**223,330**
		ESTIMATE TOTALS	**3,830**	**$462,939**	**$267,895**	**$65,360**	**$71,177**	**$867,371**
		853.0 CY	**4.49**	**$543**	**$314**	**$77**	**$83**	**$1,017**

PROJECT CLIENT: **LGE/KU**
PROJECT DESC: **GHENT GENERATING STATION - BOTTOM ASH**
PROJECT # : **117977**

SUMMARY
STRUCTURAL STEEL

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **12/20/2019**
ESTIMATOR:

DESCRIPTION	LABOR		MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
	MH	COST				
P 2 STEEL	1,751	258,964	174,294			**433,258**
ESTIMATE TOTALS	**1,751**	**$258,964**	**$174,294**			**$433,258**

PROJECT CLIENT: **LGE/KU**
PROJECT DESC: **GHENT GENERATING STATION - BOTTOM ASH**
PROJECT # : **117977**

SUMMARY
ARCHITECTURAL

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **12/20/2019**
ESTIMATOR:

DESCRIPTION				LABOR MH	LABOR COST	MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	TOTAL COST
P 2	SLUICING BUILDING	7700 sf	182.66	2,221	290,692	319,370	796,425		**1,406,487**
P 3	ELECTRICAL ENCLOSURE	3456 sf	249.73	1,065	139,458	152,897	570,727		**863,082**
		ESTIMATE TOTALS		**3,286**	**$430,150**	**$472,267**	**$1,367,152**		**$2,269,569**

PROJECT CLIENT: **LGE/KU**
PROJECT DESC: **GHENT GENERATING STATION - BOTTOM ASH**
PROJECT # : **117977**

SUMMARY
PIPING

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **12/20/2019**
ESTIMATOR:

DESCRIPTION				LABOR		MATERIAL	SUBCON	EQUIPMENT	TOTAL
				MH	COST	COST	COST	RENT / STS	COST
P 2	PIPING			17,989	2,752,679	401,428			**3,154,107**
P 3	PIPING (cont)	14250 LF	3.38	30,108	4,607,117	1,236,870			**5,843,987**
P 4	VALVES & SPECIALS	53 EA	14.49	768	117,521				**117,521**
		ESTIMATE TOTALS		**48,864**	**$7,477,317**	**$1,638,298**			**$9,115,615**

PROJECT CLIENT: **LGE/KU**
PROJECT DESC: **GHENT GENERATING STATION - BOTTOM ASH**
PROJECT # : **117977**

SUMMARY
ELECTRICAL

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **12/20/2019**
ESTIMATOR:

DESCRIPTION		LABOR MH	LABOR COST	MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	TOTAL COST
P 2	Electrical Equipment	2,001	278,556	2,387,316			**2,665,872**
P 3	Grounding	677	94,248	12,949			**107,197**
P 4	Conduit	5,273	734,035	275,105			**1,009,140**
P 5	Wire & Cable	5,236	728,907	353,007			**1,081,913**
P 6	Cable Tray	426	59,291	21,869			**81,159**
P 7	Heat Trace	1,014	141,191	54,784			**195,975**
P 8	Fiber	69	9,615	13,079			**22,694**
P 9	RACEWAY ADDS 12/20/19 - JHETER	3,245	451,736	142,247			**593,983**
	ESTIMATE TOTALS	**17,942**	**$2,497,579**	**$3,260,355**			**$5,757,934**

PROJECT CLIENT: **LGE/KU**
PROJECT DESC: **GHENT GENERATING STATION - BOTTOM ASH**
PROJECT # : **117977**

SUMMARY
INSTRUMENT & CONTROL

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **12/20/2019**
ESTIMATOR:

DESCRIPTION	LABOR MH	LABOR COST	MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
P 2 INSTRUMENT & CONTROL	339	46,982	145,590	114,000		**306,572**
ESTIMATE TOTALS	**339**	**$46,982**	**$145,590**	**$114,000**		**$306,572**

PROJECT CLIENT: **LGE/KU**
PROJECT DESC: **GHENT GENERATING STATION - BOTTOM ASH**
PROJECT # : **117977**

SUMMARY
INSULATION

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **12/20/2019**
ESTIMATOR:

DESCRIPTION	LABOR MH	LABOR COST	MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
P 2 INSULATION				102,125		**102,125**
ESTIMATE TOTALS				**$102,125**		**$102,125**

PROJECT CLIENT: **LGE/KU**
PROJECT DESC: **GHENT GENERATING STATION - BOTTOM ASH**
PROJECT # : **117977**

SUMMARY
COATINGS

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **12/20/2019**
ESTIMATOR:

DESCRIPTION	LABOR		MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
	MH	COST				
P 2 COATINGS				25,000		**25,000**
ESTIMATE TOTALS				**$25,000**		**$25,000**

PROJECT CLIENT: **LGE/KU**
PROJECT DESC: **GHENT GENERATING STATION - BOTTOM ASH**
PROJECT # : **117977**

SUMMARY
MISC DIRECTS

EST LEVEL: **FEL-2**
ESTIMATE DUE DATE: **12/20/2019**
ESTIMATOR:

DESCRIPTION		LABOR MH	LABOR COST	MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	TOTAL COST
P 2	LABOR ADD-ONS						
P 3	HEAVY CRANES						
P 4	HEAVY HAUL / FREIGHT / TARRIFS						
P 5	UNDERGROUND WORK						
P 6	CONSTRUCTION TESTING				10,236		**10,236**
P 7	CRAFT START-UP SUPPORT	600	86,789				**86,789**
	ESTIMATE TOTALS	**600**	**$86,789**		**$10,236**		**$97,025**

Appendix F
Operating and Maintenance Cost Estimate

O&M COST ESTIMATE SUMMARY
KENTUCKY UTILITIES
GHENT GENERATING STATION
BOTTOM ASH

Item	O&M Cost Line Item Description		Cost ($ / Year)
02	Operations Personnel (Note 4)		$360,000
03	Maintenance (Note 6)		$286,680
	Total Annual O&M Cost		**$646,680**

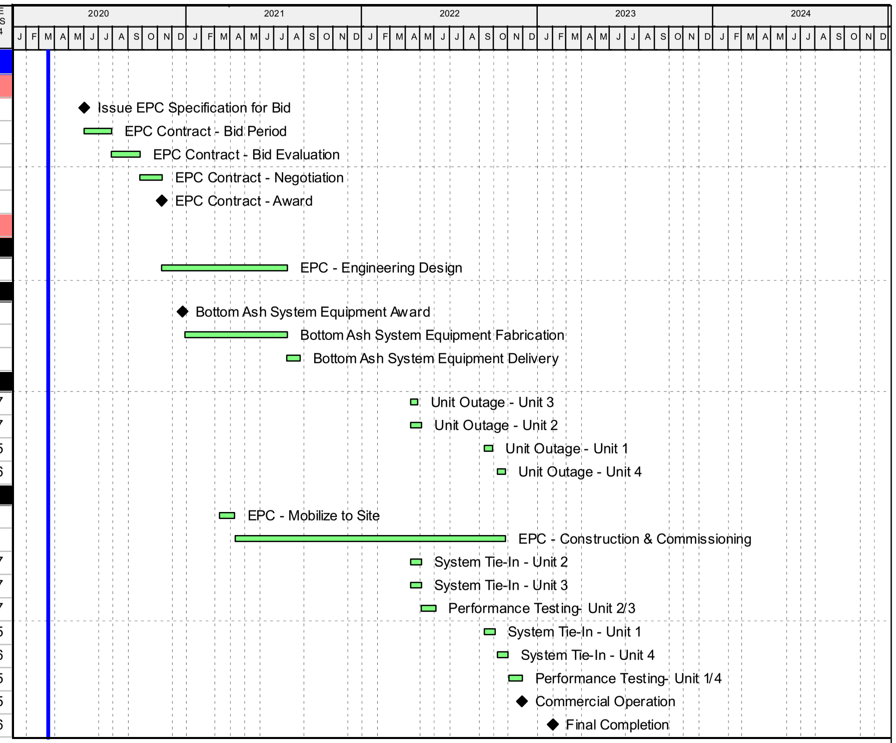
Rev.	Revision Date	
	02/18/20	ISSUED FOR PROJECT SUMMARY REPORT

Notes:

1 Estimate excludes outage and startup costs.
2 Costs are indicative approximations, from Burns & McDonnell's experience on similar projects.
3 Plant capacity factor is assumed to be 100% for purpose of estimate.
4 Operations personnel on a total of 3 FTE. An additional 0.5 operators per crew (2 FTE - 4 crews) plus 0.5 FTE for maintenance tech and 0.5 FTE for I&C/electrical maintenance tech.
5 Annual cost for operating personnel is $120,000/FTE
6 Maintenance is estimated at 3% of the Engineered Equipment/Subcontract Cost from the FEL-2 estimate.

Appendix G
Project Schedule

ACTIVITY ID	ACTIVITY DESCRIPTION	START	FINISH	OD	AD	RD	PREV VAR S	PREV VAR F	BASE VAR S BG14
KU GHENT - ELG Rule Compliance (Bottom Ash)									
EPC Contracting									
A1010	Issue EPC Specification for Bid		01-Jun-20*	0	0	0	0	0	0
A1000	EPC Contract - Bid Period	02-Jun-20	28-Jul-20	40	0	40	0	25	0
A1020	EPC Contract - Bid Evaluation	29-Jul-20	25-Sep-20	42	0	42	25	25	25
A1030	EPC Contract - Negotiation	25-Sep-20	09-Nov-20	32	0	32	25	25	25
A1040	EPC Contract - Award		09-Nov-20	0	0	0	25	25	25
EPC Contractor Activities									
Design									
A1050	EPC - Engineering Design	10-Nov-20	28-Jul-21	181	0	181	25	25	25
Bottom Ash System Package									
A1060	Bottom Ash System Equipment Award		23-Dec-20	0	0	0	25	25	25
A1090	Bottom Ash System Equipment Fabrication	28-Dec-20	28-Jul-21	150	0	150	25	87	25
A1100	Bottom Ash System Equipment Delivery	29-Jul-21	25-Aug-21	20	0	20	87	109	87
Unit Outages									
A1210	Unit Outage - Unit 3	11-Apr-22*	25-Apr-22	11	0	11	127	127	127
A1200	Unit Outage - Unit 2	11-Apr-22*	02-May-22	16	0	16	127	127	127
A1230	Unit Outage - Unit 1	13-Sep-22*	27-Sep-22	11	0	11	125	125	125
A1240	Unit Outage - Unit 4	10-Oct-22*	24-Oct-22	11	0	11	126	126	126
Construction / Commissioning									
A1070	EPC - Mobilize to Site	11-Mar-21	09-Apr-21	22	0	22	25	25	25
A1080	EPC - Construction & Commissioning	12-Apr-21	24-Oct-22*	391	0	391	25	151	25
A1160	System Tie-In - Unit 2	11-Apr-22	02-May-22	16	0	16	127	127	127
A1170	System Tie-In - Unit 3	11-Apr-22	02-May-22	16	0	16	127	127	127
A1120	Performance Testing- Unit 2/3	03-May-22	01-Jun-22	21	0	21	127	128	127
A1110	System Tie-In - Unit 1	13-Sep-22	04-Oct-22	16	0	16	125	125	125
A1180	System Tie-In - Unit 4	10-Oct-22	31-Oct-22	16	0	16	126	126	126
A1190	Performance Testing- Unit 1/4	01-Nov-22*	30-Nov-22	21	0	21	125	125	125
A1130	Commercial Operation		30-Nov-22*	0	0	0	125	125	125
A1140	Final Completion		01-Feb-23*	0	0	0	126	126	126



Remaining Level of Effort Actual Level of Effort Actual Work Remaining Work Critical Remaining Work Milestone	CURRENT PROJECT ID: LG01 PREV PROJECT ID: LG00 TARGET PROJECT ID: N/A	*KU GHENT* *Bottom Ash System*	LAYOUT: LT01 - WORKING_3 TASK filter: All Activities	19-Mar-20 DATA DATE 19-Mar-20 @ 10:04 RUN DATE PAGE 1 OF 1

Summary of 2020 Plans Project Capital Cost Estimates
($,000s)

	KU Project 43 - Ghent	KU Project 44 - Trimble County	Total KU	LG&E Project 31 - Mill Creek	LG&E Project 32 - Trimble County	Total LG&E
Construction Projects						
ELG Water Treatment System	$136,495	$35,853	$172,348	$102,073	$38,841	$140,914
Diffuser	$16,073		$16,073	$11,876		$11,876
BATW Recirculation System	$63,914		$63,914			$0
Total	**$216,482**	**$35,853**	**$252,335**	**$113,949**	**$38,841**	**$152,790**
Allocation of Trimble County Capital Costs						
Trimble County Capital Cost Estimates at Gross	$99,592					
Less: 25% IMEA and IMPA Share	$74,694					
Louisville Gas and Electric Allocation at 52%	$38,841					
Kentucky Utilities Allocation at 48%	$35,853					

Ghent Generating Station ELG Water Treatment System Project Capital Cost Estimate
($,000s)

Item	Pre-2020	2020	2021	2022	2023	2024	Total
Contracts							
ELG EPC		$2,823	$28,227	$33,872	$27,286	$1,882	$94,089
Additional DCS work		$0	$0	$1,000	$0	$0	$1,000
PWS water sampling		$125	$125	$0	$0	$0	$250
Owners Engineer		$210	$140	$140	$140	$70	$700
Well Water System including piping		$120	$1,200	$1,440	$1,160	$80	$4,000
Sub Total	**$0**	**$3,277**	**$29,692**	**$36,452**	**$28,586**	**$2,032**	**$100,039**
Other Direct							
Chemicals through startup ($165k/mo. for 10 mos.)		$0	$0	$0	$825	$825	$1,650
Capital Spare Parts		$0	$0	$0	$400	$0	$400
Plant support		$60	$60	$60	$435	$400	$1,015
Pilot Testing and project spend through the end of 2019	$209						$209
Sub Total	**$209**	**$60**	**$60**	**$60**	**$1,660**	**$1,225**	**$3,274**
Contract and Other Total	**$209**	**$3,337**	**$29,752**	**$36,512**	**$30,246**	**$3,257**	**$103,313**
Project Management & Contingency							
ELG Project Management	$0	$1,026	$2,040	$2,040	$2,040	$2,040	$9,186
Project Contingency	$0	$0	$0	$0	$0	$15,497	$15,497
Escalation	$0	$0	$1,190	$2,979	$3,777	$553	$8,499
Project Management & Contingency Total	**$0**	**$1,026**	**$3,230**	**$5,019**	**$5,817**	**$18,090**	**$33,182**
Project Total	**$209.000**	**$4,363.109**	**$32,981.904**	**$41,531.592**	**$36,062.565**	**$21,346.998**	**$136,495.168**

Revision Notes:

1. Escalation is set at:	4%
2. Contingency is set at:	15%
3. All dollars are in 2020 dollars.	2020

Ghent Generating Station Diffuser Project Capital Cost Estimate
($,000s)

Item	2020	2021	2022	2023	2024	Total
Contracts						
Diffuser for Process Pond Discharge	$1,000	$11,777	$0	$0	$0	$12,777
Owners Engineer	$0	$325	$0	$0	$0	$325
Sub Total	**$1,000**	**$12,102**	**$0**	**$0**	**$0**	**$13,102**
Other Direct						
Plant support	$0	$60	$0	$0	$0	$60
Sub Total	**$0**	**$60**	**$0**	**$0**	**$0**	**$60**
Contract and Other Total	**$1,000**	**$12,162**	**$0**	**$0**	**$0**	**$13,162**
Project Management & Contingency						
Project Management	$90	$360	$0	$0	$0	$450
Project Contingency	$0	$1,974	$0	$0	$0	$1,974
Escalation	$0	$486	$0	$0	$0	$486
Project Management & Contingency Total	**$90**	**$2,821**	**$0**	**$0**	**$0**	**$2,911**
Project Total	**$1,090.000**	**$14,982.780**	**$0.000**	**$0.000**	**$0.000**	**$16,072.780**

Revision Notes:

1. Escalation is set at:	4%
2. Contingency is set at:	15%
3. All dollars are in 2020 dollars.	2020

4. Diffuser value based on MC diffuser Tetratech 2019 contract value + 15% for increased complexity and + 35% for increased capapcity.

Ghent Generating Station Bottom Ash Transport Water Project Capital Cost Estimate
($,000s)

Item	Pre-2020	2020	2021	2022	2023	2024	Total
Contracts							
BATW Recirculation System		$0	$18,281	$28,945	$3,555	$0	$50,781
Owners Engineer		$60	$120	$120	$60	$0	$360
Sub Total	**$0**	**$60**	**$18,401**	**$29,065**	**$3,615**	**$0**	**$51,141**
Other Direct							
Capital Spare Parts		$0	$0	$300	$0	$0	$300
Plant support		$0	$60	$60	$30	$0	$150
Sub Total	**$0**	**$0**	**$60**	**$360**	**$30**	**$0**	**$450**
Contract and Other Total	**$0**	**$60**	**$18,461**	**$29,425**	**$3,645**	**$0**	**$51,591**
Project Management & Contingency							
BATW Project Management		$90	$360	$360	$180	$0	$990
Project Contingency		$0	$0	$0	$7,739	$0	$7,739
Escalation		$0	$738	$2,401	$455	$0	$3,595
Project Management & Contingency Total	**$0**	**$90**	**$1,098**	**$2,761**	**$8,374**	**$0**	**$12,323**
Project Total	**$0.000**	**$150.000**	**$19,559.606**	**$32,186.264**	**$12,018.408**	**$0.000**	**$63,914.278**

Notes:

1. Escalation is set at:	4%
2. Contingency is set at:	15%
3. All dollars are in 2020 dollars.	2020

Trimble County Generating Station ELG Water Treatment System Project Capital Cost Estimate
($,000s)

Item	Pre-2020	2020	2021	2022	2023	2024	Total
Contracts							
ELG EPC		$5,501	$22,004	$22,004	$17,170	$0	$66,678
Additional DCS work		$0	$0	$1,000	$0	$0	$1,000
PWS water sampling		$125	$125	$0	$0	$0	$250
Owners Engineer		$140	$210	$210	$140	$0	$700
Sub Total	**$0**	**$5,766**	**$22,339**	**$23,214**	**$17,310**	**$0**	**$68,628**
Other Direct							
Chemicals through startup ($100k/mo. for 10 mos.)		$0	$0	$700	$300	$0	$1,000
Capital Spare Parts		$0	$0	$0	$250	$0	$250
Plant support		$60	$60	$610	$240	$0	$970
Pilot Testing and project spend through the end of 2019	$5,058						$5,058
Sub Total	**$5,058**	**$60**	**$60**	**$1,310**	**$790**	**$0**	**$7,278**
Contract and Other Total	**$5,058**	**$5,826**	**$22,399**	**$24,524**	**$18,100**	**$0**	**$75,906**
Project Management & Contingency							
ELG Project Management	$0	$1,024	$2,040	$2,040	$2,040	$0	$7,144
Project Contingency	$0	$0	$0	$0	$11,386	$0	$11,386
Escalation	$0	$0	$896	$2,001	$2,260	$0	$5,157
Project Management & Contingency Total	**$0**	**$1,024**	**$2,936**	**$4,041**	**$15,686**	**$0**	**$23,686**
Project Total	**$5,058.000**	**$6,849.431**	**$25,334.671**	**$28,564.858**	**$33,785.448**	**$0.000**	**$99,592.407**

Revision Notes:

1. Escalation is set at:	4%
2. Contingency is set at:	15%
3. All dollars are in 2020 dollars.	2020

Mill Creek Generating Station ELG Water Treatment System Project Capital Cost Estimate
($,000s)

Item	Pre-2020	2020	2021	2022	2023	2024	Total
Contracts							
ELG EPC		$1,992	$19,916	$23,899	$19,252	$1,328	$66,386
Additional DCS work		$0	$0	$1,000	$0	$0	$1,000
PWS water sampling		$125	$125	$0	$0	$0	$250
Owners Engineer		$210	$140	$140	$140	$70	$700
Sub Total	**$0**	**$2,326**	**$20,181**	**$25,039**	**$19,392**	**$1,398**	**$68,336**
Other Direct							
Chemicals through startup ($100k/mo. for 10 mos.)		$0	$0	$0	$700	$300	$1,000
Capital Spare Parts		$0	$0	$0	$250	$0	$250
Plant support		$60	$60	$60	$435	$400	$1,015
Pilot Testing and project spend through the end of 2019	$5,120						$5,120
Sub Total	**$5,120**	**$60**	**$60**	**$60**	**$1,385**	**$700**	**$7,385**
Contract and Other Total	**$5,120**	**$2,386**	**$20,241**	**$25,099**	**$20,777**	**$2,098**	**$75,721**
Project Management & Contingency							
ELG Project Management	$0	$1,026	$2,040	$2,040	$2,040	$2,040	$9,186
Project Contingency	$0	$0	$0	$0	$0	$11,358	$11,358
Escalation	$0	$0	$810	$2,048	$2,594	$356	$5,808
Project Management & Contingency Total	**$0**	**$1,026**	**$2,850**	**$4,088**	**$4,634**	**$13,755**	**$26,352**
Project Total	**$5,120.000**	**$3,412.013**	**$23,090.506**	**$29,187.127**	**$25,411.309**	**$15,852.227**	**$102,073.182**

Revision Notes:

1. Escalation is set at:	4%
2. Contingency is set at:	15%
3. All dollars are in 2020 dollars.	2020

Mill Creek Generating Station Diffuser Project Capital Cost Estimate
($,000s)

Item	2020	2021	2022	2023	2024	Total
Contracts						
Diffuser for Unit 2 cooling tower blowdown and process pond discharge	$0	$9,000	$0	$0	$0	$9,000
Owners Engineer	$250	$325	$0	$0	$0	$575
Sub Total	**$250**	**$9,325**	**$0**	**$0**	**$0**	**$9,575**
Other Direct						
Plant support	$0	$35	$0	$0	$0	$35
Sub Total	**$0**	**$35**	**$0**	**$0**	**$0**	**$35**
Contract and Other Total	**$250**	**$9,360**	**$0**	**$0**	**$0**	**$9,610**
Project Management & Contingency						
Diffuser Project Management	$90	$360	$0	$0	$0	$450
Project Contingency	$0	$1,442	$0	$0	$0	$1,442
Escalation	$0	$374	$0	$0	$0	$374
Project Management & Contingency Total	**$90**	**$2,176**	**$0**	**$0**	**$0**	**$2,266**
Project Total	**$340.000**	**$11,535.900**	**$0.000**	**$0.000**	**$0.000**	**$11,875.900**

Revision Notes:

1. Escalation is set at:	4%
2. Contingency is set at:	15%
3. All dollars are in 2020 dollars.	2020

4. Diffuser value based on MC diffuser Tetratech 2019 contract value + 15% for increased complexity.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR APPROVAL OF ITS 2020 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	**)))))**	**CASE NO. 2020-00060**
ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR APPROVAL OF ITS 2020 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	**)))))**	**CASE NO. 2020-00061**

DIRECT TESTIMONY OF
STUART A. WILSON
DIRECTOR, ENERGY PLANNING/ANALYSIS/FORECASTING
KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: March 31, 2020

Q. Please state your name, position, and business address.

A. My name is Stuart A. Wilson. I am the Director of Energy Planning/Analysis/Forecasting for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") and an employee of LG&E and KU Services Company, which provides services to LG&E and KU (collectively "Companies"). My business address is 220 West Main Street, Louisville, Kentucky, 40202. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes. I previously testified before this Commission in KU's last environmental cost recovery ("ECR") compliance plan proceeding.[1]

Q. Please describe your current job responsibilities.

A. I am responsible for developing the Companies' load forecast, economic analysis, and long-term planning of utility generation. As it pertains to this proceeding, the Generation Planning & Analysis group performed the analyses discussed below under my direction and supervision.

Q. What are the purposes of your testimony?

A. The purposes of my testimony are to explain the methods by which the Companies analyzed the projects included in their 2020 Environmental Compliance Plans ("2020 Plans"), present the analyses, and recommend Commission approval of the 2020 Plans because the projects in the 2020 Plans are the most economical methods of complying with applicable environmental laws and regulations.

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[1] *Application of Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and Approval of Amendment to its 2016 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2017-00483, Direct Testimony of Stuart A. Wilson (Ky. PSC filed Jan. 26, 2018).

Q. What projects are included in the 2020 Plans?

A. KU's and LG&E's 2020 Plans each contain two new capital projects. KU's 2020 Plan contains projects to construct an Effluent Limitations Guidelines ("ELG") water treatment system, wastewater diffuser, and bottom ash transport water ("BATW") recirculation system at Ghent (KU Project 43) and an ELG water treatment system at Trimble County (KU Project 44). LG&E's 2020 Plan contains projects to construct an ELG water treatment system and wastewater diffuser at Mill Creek (LG&E Project 31) and an ELG water treatment system at Trimble County (LG&E Project 32). These projects are described in more detail in the testimony of R. Scott Straight. The testimony of Gary H. Revlett explains the various environmental requirements that necessitate the projects.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring Exhibit SAW-1: Analysis of 2020 Environmental Compliance Plan Projects. This exhibit contains the complete analysis that is the subject of my testimony.

Q. What is the goal of the Companies' resource planning activities?

A. Resource planning starts with reliability as its objective and seeks to ensure reliability at the lowest reasonable cost and risk. The Companies plan their generation portfolio to reliably serve customers in every moment.

Q. What is the timeline for ELG compliance and what alternatives do the Companies have for not complying?

A. As Mr. Revlett explains in his testimony, the 2015 ELG Rule and proposed amendments promulgated by the U.S. Environmental Protection Agency ("EPA") will require additional investment in the projects contained in the 2020 Plans for the Mill Creek, Ghent, and Trimble County generating stations (collectively, the "ELG investment"). As Mr. Revlett indicates, the proposed amendments to the 2015 ELG Rule require compliance as soon as possible on or after November 1, 2020, but no later than December 31, 2023 for BATW and December 31, 2025 for the ELG limits for mercury, arsenic, selenium, and nitrates/nitrites in flue gas desulphurization wastewater. The alternative to making the ELG investment is retiring generating units sooner than they would otherwise be retired and replacing their capacity and energy as required to continue to provide reliable energy at the lowest reasonable cost. Therefore, the Companies evaluated multiple alternatives for each station to determine whether ELG compliance or early retirement is least-cost.

Q. What factors influence the cost of ELG compliance and early retirement?

A. ELG compliance costs depend in large measure on the amount of water flow capacity required at each station to comply with the ELG Rule. The water flow capacity depends on the number of units at each station for which ELG water treatment systems are installed. As discussed in Mr. Straight's testimony, the proposed ELG water treatment systems include denitrification equipment, ultrafiltration systems, effluent tanks, and various pumps and support subsystems. If one generating unit is excluded from a station's compliance plan, the required water flow capacity can be decreased as well as some portion of the capital costs. However, there are economies of scale in constructing the proposed facilities so the cost reduction may not be very large. The cost of not constructing facilities for compliance and instead retiring a generating unit depends primarily on whether the unit's capacity must be replaced in order to maintain system reliability and the relative cost of replacement energy (note that all energy must be "replaced" since hourly energy requirements are unchanged). With the exception of either Mill Creek 1 or Mill Creek 2 (i.e., one unit, not both), all units' capacity would have to be replaced with new generation capacity to avoid the ELG investment and still maintain system reliability.

Q. How do the capital costs for ELG compliance compare to the capital cost of replacement capacity?

A. As I mentioned, the cost of ELG compliance ultimately depends on the number of units for which ELG water treatment systems are installed. Table 1 below lists the capital costs for the ELG compliance alternatives that the Companies evaluated. The Companies compared the cost of ELG compliance and continued coal unit operations to the capital and operating cost of replacement capacity. The cost of natural gas combined cycle ("NGCC") replacement capacity, for example, is more than $1,000/kW. However, all ELG compliance alternatives were developed with the assumption that coal units will be retired by the end of their economic life. Therefore, the ELG investment is assumed to defer the cost of replacement capacity but it does not eliminate it altogether.

Table 1 – ELG Compliance Capital Costs

Station	Water Flow Capacity (gpm)[2]	$Millions	$/kW
Mill Creek (Units 3 and 4)	450	104.9	120.9
Mill Creek (Units 3 and 4 + Either Unit 1 or Unit 2)	600	113.9	97.8
Mill Creek (All Units)	750	122.9	83.9
Ghent (Any 3 Units)	750	200.5	138.8
Ghent (All Units)	1,000	216.5	112.8
Trimble County (All Units; 75% Share)	600	74.7	81.3

Q. What does the analysis assume about the remaining economic operating life of existing coal units?

[2] GPM is gallons per minute.

A. The end of the units' economic life is assumed to be the year on which current depreciation rates are based ("Depreciation Retirement Year"). Table 2 lists the Depreciation Retirement Year for each coal unit evaluated.

Table 2 – Depreciation Retirement Years

Unit	Depreciation Retirement Year
Mill Creek 1	2032
Mill Creek 2	2034
Mill Creek 3	2038
Mill Creek 4	2042
Ghent 1	2034
Ghent 2	2034
Ghent 3	2037
Ghent 4	2038
Trimble County 1	2050
Trimble County 2	2066

Q. Why did the Companies evaluate multiple ELG compliance alternatives for the Mill Creek and Ghent stations?

A. Uncertainty related to future environmental compliance costs is greater for Mill Creek 1, Mill Creek 2, and Ghent 2 because these units are not equipped with selective catalytic reduction ("SCR") to further limit NOx emissions. Therefore, the Companies evaluated multiple alternatives for these stations to evaluate the ELG compliance decision in scenarios where these units are assumed to be retired before their Depreciation Retirement Year. ELG compliance alternatives for the Mill Creek station always include Mill Creek 3 and Mill Creek 4 because these units are equipped with SCR.

Q. Please describe the analytical approach used to evaluate the projects in the Companies' 2020 Plans.

A. The Companies evaluated multiple alternatives for each station over three coal and natural gas price scenarios. In addition, the Companies evaluated a range of replacement generation portfolios comprising various combinations of natural gas and renewable generation. The present value of revenue requirements ("PVRR") for each alternative was initially computed with the assumption that ELG compliance would enable the units to operate until their Depreciation Retirement Year. Then, the Companies evaluated the possibility of the units retiring earlier to determine the earliest year through which the units must operate to justify the ELG investment. A detailed summary of the Companies' analysis is included in Exhibit SAW-1.

Q. How was Exhibit SAW-1 developed?

A. The exhibit was developed to provide a complete discussion of the Companies' analysis. The alternatives evaluated for each station are clearly defined along with all inputs and assumptions. The analysis was performed using PVRR to identify the best decisions from the customers' perspective.

Q. What are the results of the Companies' analysis?

A. Table 2 below compares the PVRR for the least-cost ELG compliance alternative to the PVRR for the least-cost early retirement alternative for each station. The analysis period for Mill Creek and Ghent is based on the assumed operating lives for the units at each station (e.g., for the Mill Creek station, the analysis period ends in 2041 because Mill Creek 4 is assumed to be retired in 2042). The PVRR values in Table 2 are computed as the average of the PVRR for each coal and natural gas price scenario. Sections 5, 6, and 7 in Exhibit SAW-1 contain a detailed summary of each station analysis.

Table 2 – Summary of Results (Average PVRR over Three Fuel Price Scenarios; $M)

Station	Analysis Period	ELG Compliance: Water Treatment Flow Capacity (gpm)	ELG Compliance: Average PVRR over Three Fuel Price Scenarios	Early Retirement: Least-Cost Replacement Generation Portfolio	Early Retirement: Average PVRR over Three Fuel Price Scenarios	PVRR Diff (Early Retirement less ELG Compliance)
Mill Creek	2020-2041	600	15,134	NGCC + 500 MW Solar	15,235	101
Ghent	2020-2037	1,000	13,038	NGCC + 500 MW Solar	13,125	87
Trimble Co.	2020-2050	600	18,803	NGCC + 500 MW Solar	19,166	364

The analysis demonstrates that construction of ELG water treatment systems with water flow capacities of 600 gallons per minute ("gpm") for Mill Creek, 600 gpm for Trimble County, and 1,000 gpm for Ghent is least-cost PVRR over a broad range of possible futures. On average over three fuel price scenarios, the PVRR of the least-cost early retirement alternative for each station is higher than the PVRR of the least-cost ELG compliance alternative. The ELG water treatment systems proposed in the Companies' 2020 Plans are sized so that FGD wastewater from all coal-fired units at Ghent and Trimble County can be processed at full capacity, and FGD wastewater for 3 of the 4 coal-fired units at Mill Creek can be processed at full capacity.

Q. Why are the Companies recommending compliance for only three units at Mill Creek at this time?

A. As discussed in Mr. Revlett's testimony, Jefferson County, the site of the Mill Creek station, is currently in marginal non-attainment with respect to the 2015 National Ambient Air Quality Standards ("NAAQS") for ozone. As a result, the Kentucky Energy and Environment Cabinet and the Louisville Metro Air Pollution Control District are considering limiting NO_x emissions at the Mill Creek station for the months of April through October. Further limitations to NO_x emissions could eliminate LG&E's ability to simultaneously operate Mill Creek 1 and Mill Creek 2 during these months. ELG compliance for the amount of water flow capacity required to operate four generating units at full capacity is not least-cost if the station has this operating constraint. Accordingly, the proposed ELG water treatment system at Mill Creek is sized to handle full FGD wastewater capacity for three generating units or, depending on operating conditions, less than full capacity for all four generating units.

Q. How did the Companies evaluate the uncertainty associated with future regulations to further limit NOx emissions from Mill Creek or Ghent?

A. The analysis does not directly evaluate the possible additional compliance costs for these stations but it does demonstrate that ELG compliance for three units at Mill Creek and all units at Ghent is least-cost even if new regulations are passed that cause Mill Creek 1, Mill Creek 2, and Ghent 2 to be retired. This result is driven by the fact that the incremental cost of ELG compliance for these units is low. For Mill Creek, the incremental cost of ELG compliance for three units versus two is $9 million ($30/kW). For Ghent, the incremental cost of ELG compliance for four units versus three is $16 million ($33/kW).

Q. How did the Companies evaluate the uncertainty associated with future regulations to limit CO_2 emissions?

A. The Companies evaluated the least-cost ELG compliance plan in the context of the Affordable Clean Energy Rule ("ACE Rule"), the now defunct Clean Power Plan, and other potential regulations aimed at more significantly reducing CO_2 emissions from electric generation (see Section 8 of Exhibit SAW-1). Because the ACE Rule requires existing coal-fired electric generating units or boilers to implement cost-effective efficiency projects to lower CO_2 emissions, such projects would have a neutral to favorable impact on the PVRR for the proposed ELG water treatment systems. The Companies' analysis shows that in all fuel price scenarios, CO_2 emissions will be within the limits previously proposed under the Clean Power Plan by 2030, indicating no negative PVRR impact on the proposed ELG projects. Furthermore, as coal units are replaced by a combination of NGCC and renewable generation, CO_2 emissions will decrease significantly beyond 2030. Lastly, the Companies considered the possibility of laws, regulations or both that would result in the replacement of all coal units with either NGCC capacity and limited renewables or significant amounts of renewables and peaking capacity (required to ensure reliability). These hypothetical laws/regulations could take several forms including a CO_2 tax, an aggressive renewable portfolio or clean energy standard, among others. However, provided such regulations do not require the replacement of coal-fired units prior to 2033 or 2034, in some cases well before the end of their depreciable lives, the proposed ELG investment is least-cost.

<u>Conclusion and Recommendation</u>

Q. What is your conclusion about the cost-effectiveness of the projects proposed in the Companies' 2020 Plans?

A. Based on the Companies' analysis, I conclude the projects the Companies propose in their 2020 Plans to comply with the ELG Rule and proposed amendments are the lowest reasonable cost alternatives to reliably serve customers' future energy needs. I therefore recommend that the Commission approve the Companies' proposed projects and cost recovery.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Stuart A. Wilson**, being duly sworn, deposes and says that he is Director, Energy Planning, Analysis & Forecasting for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Stuart A. Wilson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24th day of March 2020.

Notary Public

Notary Public, ID No. 603967

My Commission Expires:

7/11/2022

APPENDIX A

Stuart A. Wilson, CFA
Director, Energy Planning/Analysis/Forecasting
LG&E and KU Services Company
220 West Main Street
Louisville, Kentucky 40202

Previous Positions

Manager, Generation Planning & Analysis	October 2009 – April 2016
Manager, Sales Analysis & Forecasting	May 2008 – October 2009
Supervisor, Sales Analysis & Forecasting	Aug 2006 – April 2008
Economic Analyst	Aug 2000 – July 2006
Compensation Analyst	Aug 1999 – July 2000
Business Analyst	June 1997 – July 1999

Professional Memberships

CFA Society of Louisville

Education/Certifications

E.ON Emerging Leaders Program: 2004-2006

CFA Charterholder: September 2003

LG&E Energy Leadership Development Program: 1997-2002

Master of Business Administration;
Indiana University, May 1997

Master of Engineering in Electrical Engineering;
University of Louisville, December 1995

Bachelor of Science in Electrical Engineering;
University of Louisville, December 1995

Analysis of 2020 Environmental Compliance Plan Projects

PPL companies

Generation Planning & Analysis
March 2020

Table of Contents

1. Executive Summary

Existing and proposed amended Effluent Limit Guidelines ("ELG") promulgated by the U.S. Environmental Protection Agency ("EPA") will require additional investment in water treatment systems to continue operating the Mill Creek, Ghent, and Trimble Count coal units beyond the mandatory compliance date. The alternative to making these investments is retiring the units sooner than they would otherwise be retired and replacing their capacity and energy as required to continue to provide reliable service to customers. Therefore, the Companies evaluated multiple alternatives at each station to determine whether ELG compliance or early retirement is the least-cost.

Table 1 lists the capital cost for ELG compliance at each station. The Companies compared the cost of ELG compliance and continued coal unit operations to the capital and operating costs of replacement capacity. The cost of natural gas combined cycle ("NGCC") replacement capacity, for example, is more than $1,000/kW. However, all ELG compliance alternatives were developed with the assumption that coal units will be retired by the end of their economic life. Therefore, the ELG investment is assumed to defer the cost of replacement capacity but it does not eliminate it altogether.

Table 1 – ELG Compliance Capital Cost

Station	$ Millions	$/kW
Mill Creek	113.9	97.8
Ghent	216.5	112.8
Trimble County (75% Ownership Share)	74.7	81.3

Table 2 compares the present value of revenue requirements ("PVRR") for the least-cost ELG compliance alternative to the PVRR for the least-cost early retirement alternative for each station. The Companies evaluated several replacement generation portfolios comprising various combinations of natural gas and renewable generation. The alternatives were evaluated over three fuel price scenarios; the PVRR values in Table 2 are average PVRR values over the three fuel price scenarios. The analysis period varies for each station based on the assumed operating lives for the units at each station. Based on this analysis, ELG water treatment systems designed for a capacity of 600 gallons per minute (GPM) at Mill Creek and Trimble County, and 1,000 GPM at Ghent, is the least-cost ELG compliance plan.

Table 2 – Summary of Results (Average PVRR over Three Fuel Price Scenarios; $M)

		ELG Compliance		Early Retirement		
Station	Analysis Period	Water Treatment Flow Capacity (GPM)	Average PVRR over Three Fuel Price Scenarios	Least-Cost Replacement Generation Portfolio	Average PVRR over Three Fuel Price Scenarios	PVRR Diff (Early Retirement less ELG Compliance)
Mill Creek	2020-2041	600	15,134	NGCC + 500 MW Solar	15,235	101
Ghent	2020-2037	1,000	13,038	NGCC + 500 MW Solar	13,125	87
Trimble Co.	2020-2050	600	18,803	NGCC + 500 MW Solar	19,166	364

This plan complies with current CO_2 regulations and would comply with potential future CO_2 regulations like those previously included in the Clean Power Plan. Even if regulations were passed causing all coal units to be retired in 2033 or 2034, ELG compliance remains the least-cost plan at this time to reliably meet customers' future energy needs.

2. Introduction

EPA's 2015 ELG Rule and proposed amendments to that rule will require additional investment in water treatment systems at the Mill Creek, Ghent, and Trimble County stations to continue operating the units beyond the ELG compliance date. The 2015 ELG Rule and proposed amendments establish new limits for concentrations of arsenic, mercury, selenium and nitrates/nitrates in flue gas desulphurization ("FGD") wastewater. They also establish new volumetric discharge limits for bottom ash transport water ("BATW"). The ELG Rule and proposed amendment require compliance as soon as possible on or after November 1, 2020, but no later than December 31, 2023 for BATW and December 31, 2025 for the ELG limits for mercury, arsenic, selenium, and nitrates/nitrites.

The systems proposed in the Companies' 2020 ECR Plans to meet the requirements of the ELG Rule and proposed amendments include biological water treatment systems at Ghent, Trimble County and Mill Creek, a BATW recirculation system at Ghent, and wastewater diffusers at Ghent and Mill Creek stations. The alternative to making these investments is retiring units sooner than they would otherwise be retired and replacing their capacity and energy as required to continue to provide reliable service to customers.

At each of the Companies' generating stations, all water is processed in one process-water system. Therefore, if the Companies do not install enough water flow capacity for all units, only a subset of units can be operated beyond the compliance date. If early retirement is least-cost for all units at a station, all units at the station can be operated through December 2028, after which they must be retired.

The Mill Creek station is located in Jefferson County, and Jefferson County is currently in marginal non-attainment with respect to the 2015 National Ambient Air Quality Standards ("NAAQS") for ozone. As a result, the Kentucky Energy and Environment Cabinet and the Louisville Metro Air Pollution Control District are considering limiting NO_x emissions at the Mill Creek station for the months of April through October. Further limitations to NO_x emissions could effectively eliminate the ability to simultaneously operate Mill Creek 1 and Mill Creek 2 during these months. In addition, there is some likelihood that a new cooling tower will be needed for Mill Creek 1 to continue operating the unit and comply with Clean Water Act 316(b) regulations.

3. Analysis Methodology

Given the ELG regulations and the uncertainty surrounding the environmental regulations applicable to Mill Creek, the Companies evaluated multiple alternatives for the Mill Creek, Ghent, and Trimble County stations for the purpose of identifying the least-cost plan for continuing reliable service to customers. The analysis includes ELG compliance alternatives and early retirement alternatives. ELG compliance alternatives include the investment in additional water treatment systems required to comply with ELG regulations ("ELG investment") and continued operation of the coal units beyond the ELG compliance date. The cost of early retirement depends primarily on whether a unit's capacity must be replaced in order to maintain system reliability and the relative cost of replacement energy. With the exception of either Mill Creek 1 or Mill Creek 2 (but not both), the analysis assumes all units' capacity must be replaced to avoid the ELG investment. Given the uncertainty related to Clean Water Act 316(b) regulations for Mill Creek 1 and its shorter book life, the alternatives were developed with the assumption that Mill Creek 1 would be retired first and that it could be retired without replacement.

ELG compliance alternatives were developed with the assumption that all coal units would be retired by the end of their economic life; the end of the units' economic life is assumed to be the year on which current depreciation rates are based ("Depreciation Retirement Year").[1] Therefore, ELG compliance is assumed to defer the cost of replacement generation but it does not eliminate this cost altogether. For Mill Creek, the analysis assumes further restrictions to NO_x limits for the Mill Creek station and that the ELG investment for all four units versus three would simply enable the Companies to operate Mill Creek 1 and 2 simultaneously in the winter months after the ELG compliance date. This assumption was made to simplify the analysis. If the Companies determine that operation of all four units at Mill Creek will not be restricted, the Companies will be able to update the least-cost analysis and – if warranted – install additional water flow capacity prior to the compliance date. The ELG water treatment systems are being designed to allow for expansion of water flow capacity to plan for this contingency.

The Companies evaluated the alternatives for each station over a range of fuel price scenarios. In addition, the Companies evaluated a range of replacement generation portfolios comprising various combinations of natural gas and renewable generation. The Companies initially computed the present value of revenue requirements ("PVRR") for all alternatives with the assumption that ELG compliance would enable the units to operate until their Depreciation Retirement Year. Then, the Companies evaluated the possibility of the units retiring earlier to determine the earliest year through which the units must operate to justify the ELG investment.

In addition to fuel price uncertainty, the analysis considered the risk of future environmental compliance costs related to additional NAAQS limits for ozone, the Affordable Clean Energy Rule ("ACE Rule"), and potentially more stringent regulations to further limit CO_2 emissions. The Companies evaluated alternatives for the Mill Creek station first given the regulatory uncertainty described above. The Ghent station was evaluated second and the Trimble County station was evaluated last.

4. Key Analysis Inputs and Assumptions

4.1. Depreciation Retirement Years

Table 3 lists the Depreciation Retirement Year for each coal unit (i.e., the year on which current depreciation rates are based). All alternatives for this analysis were developed with the assumption that each coal unit will be retired by its Depreciation Retirement Year.

[1] See Exhibits JJS-KU-1 (pp. 36-37) and JJS-LG&E-1 (pp. 36-37) to the testimony of John J. Spanos in the Companies' most recent rate case filings, Case Nos. 2018-00294 (KU) and 2018-00295 (LG&E).

Table 3 – Depreciation Retirement Years

Unit	Depreciation Retirement Year
Mill Creek 1 (“MC1”)	2032
Mill Creek 2 (“MC2”)	2034
Mill Creek 3 (“MC3”)	2038
Mill Creek 4 (“MC4”)	2042
Ghent 1 (“GH1”)	2034
Ghent 2 (“GH2”)	2034
Ghent 3 (“GH3”)	2037
Ghent 4 (“GH4”)	2038
Trimble County 1 (“TC1”)	2050
Trimble County 2 (“TC2”)	2066

4.2. Existing Unit Stay-Open Costs

Stay-open costs for an existing unit include the unit’s ongoing capital and fixed operating and maintenance (“O&M”) costs. These costs are required to continue operating the unit and saved if the unit is retired. Table 4 lists total stay-open costs for the Companies’ coal units assuming no early retirements. Costs that are shared by all units are allocated to units in proportion to how they would be reduced as units retire. Total stay-open costs include costs for regular maintenance and major maintenance; the analysis assumes the additional costs for major maintenance within eight years of retirement can be avoided. Beyond 2030, stay-open costs are assumed to escalate at two percent per year.

Table 4 – Stay-Open Costs ($M, Nominal Dollars)

Total Stay-Open Costs	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
MC1	22.5	10.4	18.1	11.4	18.6	11.7	30.5	12.9	21.1	12.5
MC2	16.2	22.2	17.6	29.7	20.8	36.6	19.6	25.1	20.7	28.3
MC3	37.9	23.4	37.0	22.4	39.0	27.8	60.0	24.0	34.5	26.1
MC4	38.1	66.3	32.5	45.3	35.5	56.1	35.5	48.0	33.5	77.7
GH1	61.2	29.5	28.2	28.6	37.0	33.7	40.0	68.7	33.4	37.4
GH2	24.2	22.2	25.7	30.0	26.0	65.2	33.7	33.1	31.3	30.2
GH3	22.9	22.7	37.1	33.2	72.6	28.0	23.9	27.5	32.4	30.9
GH4	26.1	25.0	28.5	35.5	30.8	33.9	60.8	49.5	36.3	36.6
TC1 (75%)	33.9	16.6	29.8	18.4	51.3	17.3	35.4	17.6	35.5	18.8
TC2 (75%)	33.5	37.2	39.4	38.4	35.4	58.2	29.8	44.6	33.9	43.7

4.3. CCR Revenue Assumptions

Coal combustion residuals (“CCR”) include fly ash, bottom ash, and gypsum. CCR is either used for onsite construction projects, sold to third parties for use in the production of products like cement and wallboard, or stored in an onsite landfill. When sold to a third party, the beneficial use of CCR materials is included in the Environmental Surcharge Mechanism as a credit to offset environmental compliance costs. In 2019, CCR sales revenues totaled $9 million.

In recent years, as coal units have retired in the U.S., the market supply of CCR has decreased and the market price for CCR has increased. Table 5 lists the assumed sales prices for fly ash and gypsum in this analysis. The 2021 values are weighted average prices based on existing contracts. CCR sales prices are expected to approach market prices as existing contracts expire. The current market price for gypsum is approximately $10 per ton at all stations. The market price for fly ash varies based on the station's proximity to local markets. The Mill Creek and Ghent stations have the best access to these markets. After existing contracts expire, CCR sales prices are assumed to escalate at two percent per year.

Table 5 – Sales Price for CCR Sales ($/ton) (Confidential and Proprietary Information)

	Mill Creek		Ghent		Trimble	
Year	Fly Ash	Gypsum	Fly Ash	Gypsum	Fly Ash	Gypsum
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2036	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2037	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2038	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2039	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2040	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2041	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2042	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2043	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2044	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2045	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2046	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2047	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2048	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2049	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2050	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 6 lists the percent of fly ash and gypsum produced at each station that is assumed to be sold to third parties. For Mill Creek, the values reflect current sales levels. For Ghent and Trimble County, the values are the assumed level of sales that will commence after current on-site pond closure projects are completed (no later than October 2025). The Ghent station requires additional loading facilities to increase its fly ash sales after pond closure projects are completed. The Companies will evaluate alternatives for doing this but no costs or revenue impacts associated with these facilities are considered in this analysis.

Table 6 – Percent of CCR Production Sold to Third Parties

Station	Fly Ash	Gypsum
Mill Creek	80%	97%
Ghent	6%	70%
Trimble County	80%	97%

4.4. ELG Compliance Costs

Table 7 contains capital costs for ELG compliance at each station. Uncertainty related to future environmental compliance costs is greater for Mill Creek 1, Mill Creek 2, and Ghent 2 because these units are not equipped with selective catalytic reduction ("SCR"). As a result, the Companies evaluated ELG compliance alternatives that exclude these units. The ELG water treatment systems include denitrification equipment, ultrafiltration systems, effluent tanks, and various pumps and support subsystems. If one unit is excluded, the water flow capacity can be lowered as well as some portion of the capital cost. However, there are economies of scale in constructing the proposed facilities so the incremental cost of ELG compliance for the fourth unit at a station, for example, is less on a dollars per kW basis than the cost for the entire station.

Table 7 – Capital Costs for ELG Compliance ($M, Nominal Dollars)

Station	Water Flow Capacity (GPM)[2]	Pre-2020	2020	2021	2022	2023	2024	Total ($M)	Total ($/kW)
Mill Creek (MC3 & MC4)	450	5.1	3.4	32.5	26.5	23.1	14.4	104.9	120.9
Mill Creek (MC3 & MC4; either MC1 or MC2)	600	5.1	3.8	34.6	29.2	25.4	15.9	113.9	97.8
Mill Creek (All Units)	750	5.1	4.1	36.8	31.9	27.8	17.3	122.9	83.9
Ghent (Any 3 Units)	750	0.2	5.1	63.7	68.8	43.8	18.8	200.5	138.8
Ghent (All Units)	1,000	0.2	5.6	67.5	73.7	48.1	21.3	216.5	112.8
Trimble Co. (All Units; 75% Share)	600	3.8	5.1	19.0	21.4	25.3	0.0	74.7	81.3

[2] GPM is gallons per minute.

Table 8 lists annual operating and maintenance ("O&M") costs that are required at each station to operate the additional water treatment systems. Fixed O&M comprises labor and is assumed to escalate at three percent per year. Consumables primarily comprise water treatment chemicals and are assumed to escalate at four percent per year. These costs commence in the year the systems are placed in service. As coal units are assumed to retire, the volume of consumables required decreases but the number of operators does not.

Table 8 – Annual ELG Compliance O&M Costs ($M, 2020 Dollars)

Unit	Fixed O&M	Consumables	Total
Mill Creek	1.1	2.4	3.6
Ghent	1.6	3.3	4.9
Trimble County (75%)	0.9	1.5	2.3

4.5. Fuel Price Scenarios

Fuel prices in all scenarios are assumed to escalate throughout the analysis period. Table 9 shows undelivered natural gas and coal price forecasts for the low, mid, and high fuel price scenarios, which were developed for the Companies' 2020 Business Plan.

The Henry Hub natural gas price scenarios are based on the following:

- Low: reflects NYMEX forward market prices as of 5/22/2019 for 2020-2030, which were extrapolated through 2050.
- Base: reflects a blend of NYMEX market prices and a smoothed version of the Energy Information Administration's ("EIA's") 2019 Annual Energy Outlook ("AEO") High Oil and Gas Resource and Technology case through 2029, after which the smoothed EIA case was solely used. This case assumes higher resource availability and technological advancement result in lower production costs and continued growth in oil and gas production.
- High: reflects a smoothed version of the EIA's 2019 AEO Reference case.

The Illinois basin, FOB mine coal prices are based on the following:

- Low: reflects the base case prices, adjusted lower by 0.29 times the percentage decrease from the base gas case to the low gas case. The reduction in variance between coal price cases compared to gas price cases is based on the historical relationship between coal and gas prices.
- Base: reflects a blend of coal price bids the Companies received and a long-term price forecast developed by IHS Markit through 2024. In 2025 and beyond, the 2024 price was escalated by the coal escalation rate provided in the EIA's 2019 AEO Reference Case.
- High: reflects the base case prices, adjusted higher by 0.29 times the percentage increase from the base gas case to the high gas case. The reduction in variance between coal price cases compared to gas price cases is based on the historical relationship between coal and gas prices.

Table 9 – Fuel Price Scenarios, Undelivered (Nominal $/mmBtu) (Confidential and Proprietary Information)

	Low		Mid		High	
Year	Natural Gas[3]	Coal[4]	Natural Gas[3]	Coal[4]	Natural Gas[3]	Coal[4]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2036	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2037	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2038	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2039	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2040	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2041	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2042	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2043	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2044	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2045	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2046	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2047	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2048	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2049	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2050	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[3] Henry Hub.
[4] Illinois Basin FOB mine.

4.6. Replacement Generation Portfolios

Table 10 lists forecasted generation for the Mill Creek, Ghent, and Trimble County coal units from 2020 to 2024 as well as their summer and winter net capacities. Because these units are the Companies' lowest-cost coal units, all units have an average capacity factor greater than 50 percent and operate round-the-clock. With the exception of either Mill Creek 1 or Mill Creek 2 (but not both), the analysis assumes all units' capacity must be replaced to avoid the ELG investment.[5] Given the uncertainty related to Clean Water Act 316(b) regulations for Mill Creek 1 and its shorter book life, the alternatives were developed with the assumption that Mill Creek 1 would be retired first and that it could be retired without replacement.

Table 10 – Forecasted Generation and Net Capacity

	Forecasted Generation (GWh)					Average Annual	Net Capacity (MW)	
Unit	**2020**	**2021**	**2022**	**2023**	**2024**	**Energy**	**Summer**	**Winter**
Mill Creek 1	1,873	1,801	1,882	1,834	1,917	1,861	300	300
Mill Creek 2	1,681	1,885	1,756	1,924	1,813	1,812	297	295
Mill Creek 3	2,236	2,190	2,454	2,190	2,387	2,291	391	394
Mill Creek 4	2,488	2,881	2,491	2,945	2,784	2,718	477	486
Ghent 1	2,630	2,193	2,323	2,493	2,637	2,455	475	479
Ghent 2	3,192	2,981	2,853	2,970	2,873	2,974	485	486
Ghent 3	2,118	1,999	1,956	1,932	2,020	2,005	481	476
Ghent 4	2,221	2,388	2,349	2,388	2,409	2,351	478	478
Trimble County 1 (75%)	2,666	2,351	2,552	2,382	2,612	2,513	370	370
Trimble County 2 (75%)	3,347	3,267	3,252	2,948	3,247	3,212	549	570

Table 11 summarizes the replacement generation portfolios evaluated in this analysis. These portfolios were developed to represent the range of portfolios that could replace a coal unit's capacity and energy. Based on current regulations and fuel prices, natural gas combined cycle ("NGCC") units are the most cost-effective resource for replacing dispatchable capacity and energy. The NGCC and NGCC + Renew portfolios were identified in the Companies' 2018 Integrated Resource Plan ("IRP") as likely replacement portfolios for coal generation. While all portfolios reduce system CO_2 emissions, the Peak + Renew portfolio was developed to have the most significant reduction in CO_2 emissions. Peaking capacity could be provided by simple-cycle combustion turbines ("SCCTs") or battery storage. For the purpose of this analysis, peaking capacity is modeled as a SCCT because SCCT costs are currently lower than the cost of battery storage.

[5] Energy from all units must be replaced because hourly energy requirements are unchanged.

Table 11 – Replacement Generation Portfolios

Portfolio Name	NGCC Capacity	Peaking Capacity	Renewables
NGCC	NGCC capacity to replace coal units' contribution to summer peak	N/A	N/A
NGCC + Renew	NGCC capacity to replace coal units' contribution to winter peak	N/A	500 MW of nameplate solar
Peak + Renew	N/A	Peaking capacity required to replace coal units' contributions to summer and winter peak after contributions from renewables	Solar and wind generation required to replace retired coal units' energy on annual basis

Replacement generation portfolios for all alternatives were developed to at least maintain the replaced units' contributions to summer and winter peak demands. In doing this, the Companies are assuming that any reductions to total generating capacity beyond the possible retirement of Mill Creek 1 will be made through changes to their higher-cost marginal resources, such as the small-frame SCCTs ("secondary CTs"). The NGCC replacement portfolio was developed to replace retired coal units' contribution to summer peak on a megawatt-for-megawatt basis, which results in no change to the Companies' summer reserve margin. Because the ratio of winter and summer net capacity ("seasonal capacity ratio") for an NGCC unit is slightly higher than the ratio for the Companies' coal units, this portfolio results in a slightly higher winter reserve margin.

Table 12 lists the assumed contributions to the Companies' summer and winter peak demands for solar and wind as a percent of each resource's nameplate capacity. These values are consistent with the Companies' 2018 IRP and PJM's published class average solar capacity factor and reflect an average contribution during a typical peak hour.[6] From one year to the next, the contributions of wind and solar will vary based on the availability of wind and solar irradiance as well as the timing of the peak hour. Based on these contribution values, 500 MW of solar would contribute an average of 300 megawatts ("MW") to the Companies' summer peak and zero MW to the Companies' winter peak, which occurs at night. For this reason, NGCC capacity in the NGCC + Renew portfolio was sized to replace the retired coal units' contribution to winter peak. As a result, the NGCC + Renew portfolio has slightly less NGCC capacity than the NGCC portfolio.

[6] https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en

Table 12 – Solar and Wind Contribution to Peak (Percent of Nameplate Capacity)

	Contribution to Summer Peak	Contribution to Winter Peak
Solar	60%	0%
Wind	15.2%	32.6%

The Companies evaluated two replacement portfolios for Mill Creek 2 to determine the optimal approach for developing Peak + Renew replacement portfolios for other retirement scenarios (see Table 13). Due to transmission costs and the planned expiration of the production tax credit for wind, the cost of out-of-state wind energy is higher than the cost of in-state solar energy.[7] However, because wind has the potential to contribute more on average to the Companies' winter peak than solar, the inclusion of wind is assumed to reduce the need for peaking capacity in the analysis. The first option in Table 13 minimizes the need for peaking capacity; the second option minimizes the cost of renewable energy. In all fuel price scenarios, the added cost of wind energy exceeds the savings in peaking capacity costs.

Table 13 – Options Considered for "Peak + Renew" Replacement Portfolio

Option	Peaking Capacity	Wind and Solar	Total Renewable Energy
Option 1	177 MW Summer (194 MW Winter)[8]	400 MW Wind 100 MW Solar	1,897 GWh
Option 2	270 MW Summer (295 MW Winter)[9]	0 MW Wind 900 MW Solar	1,940 GWh

The Ghent station, for example, produces approximately 9,785 GWh per year on average. Replacing this amount of energy on an annual basis with solar would require over 4,500 MW of nameplate solar and create significant over-generation issues in the shoulder months and significant energy deficits in the winter months when solar capacity factors are lowest. Therefore, the Peak + Renew replacement portfolios were developed by adding up to 2,500 MW of solar and then wind if necessary to replace the retired coal units' energy on an annual basis.[10] 2,500 MW is close to the Companies' minimum load during daylight hours in March and April. As discussed previously, all Peak + Renew portfolios contain enough peaking capacity to at least maintain the replaced units' contributions to summer and winter

[7] The Companies' 2018 IRP demonstrated that the cost of out-of-state wind including transmission costs is lower than the cost of in-state wind due to more favorable capacity factors for out-of-state wind.
[8] Based on the contribution percentages in Table 12, 400 MW of wind and 100 MW of solar will contribute on average 120 MW to the summer peak and 130 MW to the winter peak. 177 MW is the summer capacity for Mill Creek 2 less 120 MW.
[9] 270 MW is the winter capacity for Mill Creek 2 (295 MW) divided by the seasonal capacity ratio for a SCCT unit (1.09).
[10] Both wind and solar are added in 100 MW nameplate increments.

peak demands. More details regarding the replacement portfolios evaluated for each alternative are included in the station analysis summaries (Section 5, Section 6, and Section 7).

4.7. Replacement Generation Resources

The replacement generation portfolios evaluated in this analysis comprise SCCT, NGCC, solar, and wind generation resources. Table 14 contains the assumed costs for these resources in real 2017 dollars, assuming overnight construction and in-service in 2020.[11] All costs are based on the 2019 Annual Technology Baseline ("2019 ATB") from the National Renewable Energy Laboratory ("NREL") except capital costs, heat rates, seasonal capacity ratios, and firm gas transportation costs for SCCT and NGCC resources. Capital costs, heat rates, and seasonal capacity ratios for SCCT and NGCC resources are based on vendor estimates from projects currently under construction. Furthermore, the capital cost for SCCT capacity ($572/kW) reflects the cost of constructing multiple units as contemplated in the Peak + Renew replacement portfolio and is much lower than the 2019 ATB cost ($903/kW), which reflects the cost of constructing a single unit with fewer economies of scale. The cost for NGCC capacity used in this analysis is 15 percent higher than the 2019 ATB cost for NGCC capacity ($887/kW). Firm gas transportation costs for SCCT and NGCC capacity are based on the cost of firm gas transportation for Cane Run 7 and the Trimble County SCCTs. Consistent with the Companies' 2018 IRP, wind energy is assumed to be sourced from outside Kentucky; the cost of transmission for wind is based on the current MISO drive-out tariff price. The production tax credit ("PTC") for wind is expiring. After 2023, the PTC is assumed to be zero dollars per megawatt-hour ("MWh"). Similarly, the investment tax credit for solar is 30 percent today but is assumed to be ten percent after 2023.[12] As a result, the cost of solar in this analysis is higher than it is today.

[11] As discussed previously, peaking capacity in the "Peak + Renew" replacement portfolio is modeled as a SCCT because SCCT costs are currently lower than the cost of battery storage.
[12] https://atb.nrel.gov/electricity/2019/files/2019-ATB-data.xlsm

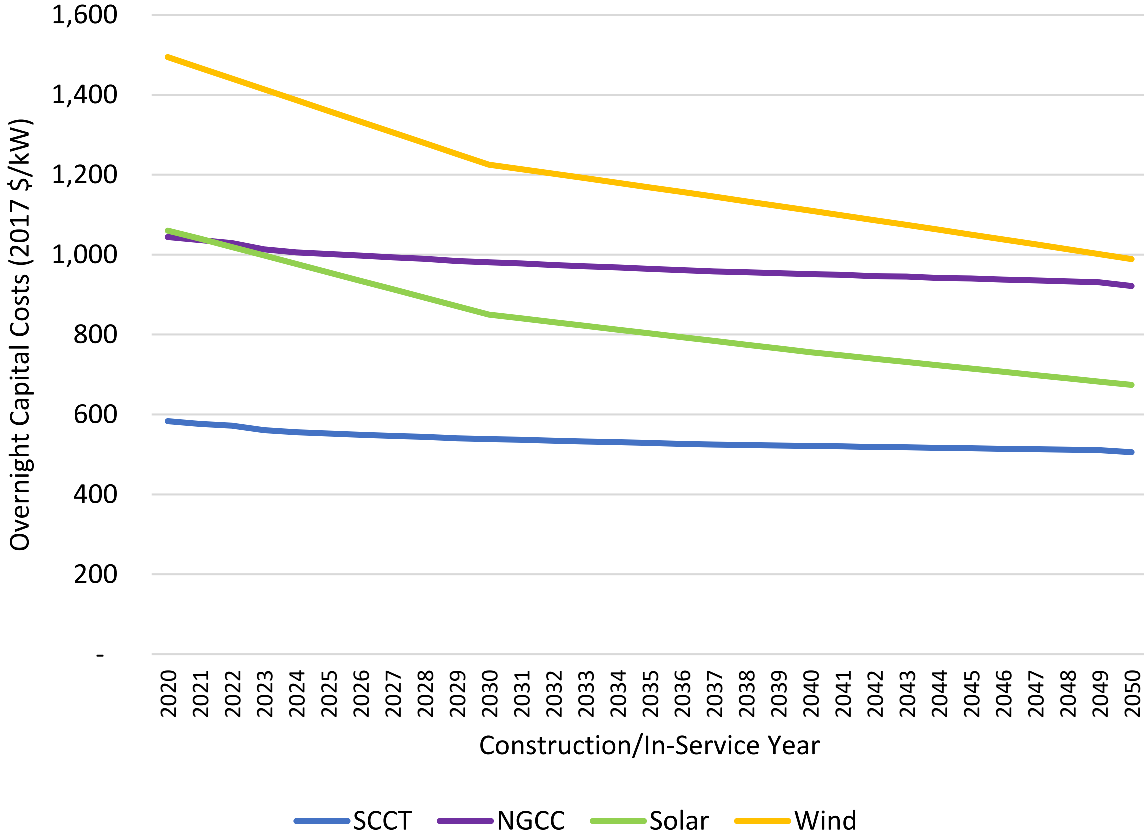
Table 14 – Generation Resources Assumptions (2020 In-Service; 2017 Dollars)

	Peaking Capacity (SCCT)	NGCC	Solar[13]	Wind[14]
Capital Cost ($/kW)	583	1,044	1,060	1,494
Fixed O&M ($/kW-yr)	12	11	13	42
Firm Gas Cost ($/kW-yr)	22	18	N/A	N/A
Variable O&M ($/MWh)	7.14	2.77	N/A	N/A
Heat Rate (MMBtu/MWh)	9.9	6.3	N/A	N/A
Transmission Cost ($/MW-Yr)	N/A	N/A	N/A	44,648
Nominal O&M Cost Escalation	2%	2%	(0.4%)-0.8%[15]	1.2%
Seasonal Capacity Ratio	1.09	1.04	N/A	N/A
Capacity Factor	5-90%	10-90%	25%	48%
Production Tax Credit ($/MWh, After 2023)	N/A	N/A	N/A	0
Investment Tax Credit (After 2023)	N/A	N/A	10%	N/A

Figure 1 contains the capital cost forecast for each resource. All escalation assumptions are taken from the 2019 ATB. According to NREL, real capital costs for both wind and solar are forecast to decline by approximately two percent per year from 2025 to 2030 and approximately one percent per year from 2030 to 2050. Alternatively, real capital costs for NGCC and SCCT capacity are forecast to decline by 0.3 to 0.5 percent over both of these periods. The analysis uses a two percent inflation rate to convert all resource costs from real to nominal dollars.

[13] NREL 2019 ATB, Solar – Utility PV, Kansas City Mid
[14] NREL 2019 ATB, Land-Based Wind, TRG 5 - Mid
[15] NREL's 2019 ATB assumes escalation of -0.4 percent in 2025 through 2030 and +0.8 percent in 2030 through 2050.

Figure 1 – Generation Resource Capital Cost Forecast (Overnight; 2017 Dollars)



4.8. Transmission System Cost Considerations

Table 15 lists the estimated cost of transmission system projects that would be required if all Mill Creek or Ghent units were retired and replaced with generation at another site. The Companies did not estimate a cost for the Trimble County station. These costs at Mill Creek and Ghent could be substantially avoided with the addition of gas pipeline infrastructure to support NGCC generation at the sites. However, they could only be avoided at Mill Creek if the units were retired gradually such that space for new generation could be created with time to construct replacement generation on-site. The Ghent station has more available space to accommodate replacement generation but it is much further from the nearest interstate pipeline (20+ miles). Therefore, the cost of gas pipeline infrastructure for Ghent would be much higher than for Mill Creek. Given the potential to avoid most if not all of these costs in scenarios with gradual, staggered replacements, these costs are excluded from PVRR calculations and considered only qualitatively in the early retirement scenarios will with multiple unit retirements in a single year.

Table 15 – Transmission Costs if All Units are Retired and Replaced with Generation at Another Site

Station	Cost of Transmission System Projects ($M, 2019 Dollars)
Mill Creek	$652.8
Ghent	$923.9

Lastly, some of the Peak + Renew replacement generation portfolios include significant amounts of wind and solar (up to 2,500 MW of solar and more than 4,000 MW of out-of-state wind). The analysis includes the current MISO drive-out cost for transmitting power from out-of-state but no other transmission projects are contemplated even though they will likely be needed.

4.9. Financial Assumptions

Table 16 lists the inputs used to compute capital revenue requirements in this analysis.

Table 16 – Financial Assumptions

	Combined Companies
% Debt	47%
% Equity	53%
Cost of Debt	4.24%
Cost of Equity	9.725%
Tax Rate	24.95%
Property Tax Rate	0.15%
Insurance Rate	0.0217%
WACC (After-Tax)	6.65%

5. Mill Creek Analysis

Given the uncertainty surrounding other potential environmental regulations and thus additional compliance costs at Mill Creek 1 and 2, the Companies evaluated seven alternatives for the Mill Creek station (see Table 17). The alternatives include ELG compliance alternatives with an ELG investment and continued operations beyond the ELG compliance date and early retirement alternatives where the ELG investment is avoided by replacing the units' capacity and energy sooner than it otherwise would be replaced. The naming convention for ELG compliance alternatives includes "ELG," the number of units for which additional water treatment systems are installed, and the assumed retirement years for Mill Creek 1 and Mill Creek 2 (e.g., ELG 3; 2025/2034). The naming convention for the early retirement alternatives includes "Early Ret" and the assumed retirement years for Mill Creek 1 and Mill Creek 2 (e.g., Early Ret; 2025/2029). All alternatives were developed with the assumption that all coal units will be retired by their Depreciation Retirement Year.[16] The compliance date for the ELG compliance alternatives with an ELG investment for all units or three units ("ELG 4; 2032/2034," "ELG 3; 2025/2034," and "ELG 3; 2025/2029") is assumed to be June 2024. The compliance date for the ELG 2; 2025/2025 alternative is assumed to be December 2025 to give the Companies additional time to secure replacement generation for Mill Creek 2.

[16] Table 3 lists the Depreciation Retirement Years for the Mill Creek, Ghent, and Trimble County coal units.

Table 17 – Mill Creek Alternatives

Alternative	Mill Creek Units in Compliance w/ ELG	Water Flow Capacity (GPM)	Assumed Retirement Year				ELG Compliance Date
			MC1	MC2	MC3	MC4	
ELG 4; 2032/2034	All Units	750	2032	2034	2038	2042	June 2024
ELG 3; 2025/2034	MC1 or MC2; MC3-4	600	2025	2034	2038	2042	June 2024
ELG 3; 2025/2029	MC1 or MC2; MC3-4	600	2025	2029	2038	2042	June 2024
ELG 2; 2025/2026	MC3-4	450	2025	2026	2038	2042	Dec 2025
Early Ret; 2029/2029	None	0	2029	2029	2029	2029	N/A
Early Ret; 2025/2029	None	0	2025	2029	2029	2029	N/A
Early Ret; 2025/2026	None	0	2025	2026	2029	2029	N/A

Table 18 contains the capital cost of additional ELG water treatment systems at Mill Creek for each ELG compliance alternative. Costs incurred prior to 2020 are considered sunk. Despite different compliance dates, the capital spend profile is similar for all ELG compliance alternatives. Table 19 contains the cost to operate the new systems. Table 19 contains the Mill Creek station's stay-open costs for each alternative. Stay-open costs for an existing unit include the unit's ongoing capital and fixed O&M costs. The analysis assumes stay-open costs for major maintenance within eight years of retirement can be avoided. Table 4 on page 6 contains stay-open costs for the all coal units assuming no early retirements. All Mill Creek alternatives include the investments required at the Ghent and Trimble County stations to comply with ELG and operate until their Depreciation Retirement Years. Therefore, ELG compliance costs and stay-open costs for the Ghent and Trimble County units are the same in all Mill Creek alternatives.

Table 18 – Mill Creek ELG Capital Costs ($M, Nominal Dollars)

ELG Capital	2020	2021	2022	2023	2024	Total
ELG 4; 2032/2034	4.1	36.8	31.9	27.8	17.3	117.8
ELG 3; 2025/2034	3.8	34.6	29.2	25.4	15.9	108.8
ELG 3; 2025/2029	3.8	34.6	29.2	25.4	15.9	108.8
ELG 2; 2025/2026	3.4	32.5	26.5	23.1	14.4	99.8

Table 19 - Mill Creek ELG Compliance O&M Costs ($M, Nominal Dollars)

	Mill Creek Alternative						
Year	ELG 4; 2032/2034	ELG 3; 2025/2034	ELG 3; 2025/2029	ELG 2; 2025/2026	Early Ret; 2029/2029	Early Ret; 2025/2029	Early Ret; 2025/2026
2021	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2024	3.4	3.0	3.0	2.5	0.0	0.0	0.0
2025	4.3	3.7	3.7	3.1	0.0	0.0	0.0
2026	4.4	3.8	3.8	3.2	0.0	0.0	0.0
2027	4.6	3.9	3.9	3.3	0.0	0.0	0.0
2028	4.8	4.1	4.1	3.4	0.0	0.0	0.0
2029	4.9	4.2	3.5	3.5	0.0	0.0	0.0
2030	5.1	4.4	3.7	3.7	0.0	0.0	0.0
2031	5.3	4.5	3.8	3.8	0.0	0.0	0.0
2032	4.7	4.7	3.9	3.9	0.0	0.0	0.0
2033	4.9	4.9	4.1	4.1	0.0	0.0	0.0
2034	4.2	4.2	4.2	4.2	0.0	0.0	0.0
2035	4.4	4.4	4.4	4.4	0.0	0.0	0.0
2036	4.5	4.5	4.5	4.5	0.0	0.0	0.0
2037	4.7	4.7	4.7	4.7	0.0	0.0	0.0
2038	3.5	3.5	3.5	3.5	0.0	0.0	0.0
2039	3.7	3.7	3.7	3.7	0.0	0.0	0.0
2040	3.8	3.8	3.8	3.8	0.0	0.0	0.0
2041	3.9	3.9	3.9	3.9	0.0	0.0	0.0

Table 20 – Mill Creek Stay-Open Costs ($M, Nominal Dollars)

	Mill Creek Alternative						
Year	ELG 4; 2032/2034	ELG 3; 2025/2034	ELG 3; 2025/2029	ELG 2; 2025/2026	Early Ret; 2029/2029	Early Ret; 2025/2029	Early Ret; 2025/2026
2021	114.7	114.7	114.7	114.7	114.7	114.7	114.7
2022	122.3	122.3	122.3	122.3	101.8	101.8	101.8
2023	105.3	105.3	105.3	105.3	105.3	105.3	105.3
2024	108.8	108.8	108.8	108.8	108.8	108.8	108.8
2025	113.9	95.3	95.3	95.3	113.9	95.3	95.3
2026	121.8	110.1	110.1	83.9	110.1	110.1	83.9
2027	136.2	115.1	115.1	95.5	94.2	94.2	74.6
2028	110.0	97.1	97.1	72.0	97.1	97.1	72.0
2029	109.9	88.8	68.1	68.1	0.0	0.0	0.0
2030	144.7	132.2	103.9	103.9	0.0	0.0	0.0
2031	126.1	103.2	81.9	81.9	0.0	0.0	0.0
2032	112.4	112.4	83.0	83.0	0.0	0.0	0.0
2033	107.4	107.4	85.2	85.2	0.0	0.0	0.0
2034	86.3	86.3	86.3	86.3	0.0	0.0	0.0
2035	88.7	88.7	88.7	88.7	0.0	0.0	0.0
2036	89.8	89.8	89.8	89.8	0.0	0.0	0.0
2037	92.3	92.3	92.3	92.3	0.0	0.0	0.0
2038	62.8	62.8	62.8	62.8	0.0	0.0	0.0
2039	46.4	46.4	46.4	46.4	0.0	0.0	0.0
2040	65.4	65.4	65.4	65.4	0.0	0.0	0.0
2041	48.2	48.2	48.2	48.2	0.0	0.0	0.0

Table 21 lists the replacement generation portfolios for the Mill Creek, Ghent, and Trimble County coal units with retirements tied to Depreciation Retirement Years. The quantity of peaking and NGCC capacity is a function of the peak contribution from wind and solar resources. As a result, the unit-specific values may vary by scenario, but the total volume of replacement capacity is the same across each replacement alternative. As discussed previously, the analysis assumes either Mill Creek 1 or Mill Creek 2 can be retired without replacement and that Mill Creek 1 would be retired first given the uncertainty associated with Clean Water Act 316(b) regulations.

Table 21 – Replacement Generation Portfolios (MW, Summer/Winter Capacity for NGCC and Peaking)

	NGCC Portfolio	NGCC + Renew Portfolio		Peak + Renew Portfolio		
Unit	**NGCC**	**NGCC**	**Solar**	**Peak**	**Solar**	**Wind**
Mill Creek 1	0	0	0	0	0	0
Mill Creek 2	297/308	285/295	500	270/295	900	0
Ghent 1	475/492	462/479	0	438/479	1,100	0
Ghent 2	485/503	469/486	0	295/323	500	500
Ghent 3	481/499	459/476	0	286/313	0	500
Ghent 4	478/495	461/478	0	288/315	0	500
Mill Creek 3	391/405	380/394	0	181/198	0	600
Mill Creek 4	477/494	469/486	0	236/258	0	700
Trimble County 1	370/383	357/370	0	159/174	0	600
Trimble County 2	549/569	550/570	0	312/342	0	700

The Companies initially computed the PVRR for each alternative with the assumption that ELG compliance would enable the units to operate until their Depreciation Retirement Year. Therefore, PVRR values were initially computed over the period from 2020 to 2041, where 2041 is the last year of operation before Mill Creek 4 is assumed to be retired. The PVRR for each alternative was computed as the PVRR of the following cost and revenue items:

1. Generation system production costs
2. Existing unit stay-open costs
3. Existing unit CCR revenues
4. ELG compliance costs and associated O&M
5. Capital and stay-open costs for replacement generation portfolios

Generation production costs for the LG&E and KU system were computed using the PROSYM production cost model from ABB. The PVRR for all alternatives include the full PVRR for capital expenditures, even when a unit is retired before its Depreciation Retirement Year. The analysis summarized in this section assumed no cost for CO_2 emissions; various forms of CO_2 regulations are considered in Section 8.

Table 22 contains the results of this analysis and excludes the cost of transmission system upgrades that would be required if all four Mill Creek units are retired by 2029.[17] The least-cost alternative for each fuel price scenario is highlighted in gray. The NGCC + Renew portfolio is the least-cost replacement portfolio in the mid and high fuel price scenarios; the NGCC portfolio is least-cost in the low fuel price scenario. Excluding transmission system costs, ELG compliance for three units (ELG 3; 2025/2034) is least-cost in the mid and high fuel price scenarios and the third best case in the low fuel price scenario; replacing all four units by 2029 (Early Ret; 2025/2029) is least-cost in the low fuel price scenario, is the fourth best case in the mid fuel price scenario but is significantly more expensive ($262 million in PVRR) in the high fuel price scenario. In all fuel price scenarios, the incremental cost of ELG compliance for

[17] These costs are discussed in Section 4.8.

four Mill Creek units versus three units is not justified (i.e., the PVRR for the ELG 4; 2032/2034 alternative is higher than the PVRR for the ELG 3; 2025/2034 alternative in all fuel price scenarios).

Table 22 – Mill Creek Analysis Results ($M, PVRR 2020-2041, Excluding Transmission System Costs)

Fuel Price	Alternative	Replacement Generation Portfolio			Least-Cost Replacement Generation Portfolio	PVRR Diff from Least-Cost Alternative
		NGCC	NGCC + Renew	Peak + Renew		
Mid	ELG 4; 2032/2034	15,017	15,002	15,508	NGCC + Renew	58
	ELG 3; 2025/2034	14,959	14,944	15,450	NGCC + Renew	0
	ELG 3; 2025/2029	15,001	14,998	15,533	NGCC + Renew	54
	ELG 2; 2025/2026	15,014	15,040	15,615	NGCC	69
	Early Ret; 2029/2029	15,056	15,041	16,059	NGCC + Renew	97
	Early Ret; 2025/2029	15,030	15,014	16,032	NGCC + Renew	70
	Early Ret; 2025/2026	15,054	15,067	16,126	NGCC	109
Low	ELG 4; 2032/2034	14,288	14,290	14,912	NGCC	102
	ELG 3; 2025/2034	14,223	14,226	14,848	NGCC	37
	ELG 3; 2025/2029	14,254	14,277	14,935	NGCC	68
	ELG 2; 2025/2026	14,258	14,315	15,019	NGCC	72
	Early Ret; 2029/2029	14,216	14,228	15,452	NGCC	30
	Early Ret; 2025/2029	14,186	14,198	15,421	NGCC	0
	Early Ret; 2025/2026	14,201	14,247	15,517	NGCC	15
High	ELG 4; 2032/2034	16,322	16,274	16,590	NGCC + Renew	43
	ELG 3; 2025/2034	16,279	16,231	16,547	NGCC + Renew	0
	ELG 3; 2025/2029	16,341	16,290	16,625	NGCC + Renew	59
	ELG 2; 2025/2026	16,367	16,334	16,703	NGCC + Renew	103
	Early Ret; 2029/2029	16,580	16,512	17,184	NGCC + Renew	280
	Early Ret; 2025/2029	16,562	16,493	17,166	NGCC + Renew	262
	Early Ret; 2025/2026	16,600	16,549	17,256	NGCC + Renew	317

Table 23 lists the average PVRR over the three fuel price scenarios for each alternative and for the top two replacement portfolios.[18] Based on the average PVRR, ELG compliance for three Mill Creek units (ELG 3; 2025/2034) is least-cost. The "ELG 3; 2025/2029" alternative was developed to evaluate a scenario where the Companies install ELG systems for three units and Mill Creek 2 is required to be retired in 2029. The PVRR for this alternative is lower than the PVRR of ELG compliance for two units (ELG 2; 2025/2026), demonstrating that ELG compliance for three units is least-cost even if Mill Creek 2

[18] In Table 23, the average PVRR for the "ELG 4; 2032/2034" alternative is $15,209 million for the NGCC replacement portfolio. This value was computed as the average of $15,017 million, $14,288 million, and $16,322 million in Table 22.

is retired in 2029. Compared to the least-cost early retirement alternative (Early Ret; 2025/2029), the PVRR for this alternative is $101 million to $105 million favorable.

Table 23 – Mill Creek Analysis Results ($M, Average PVRR 2020-2041)

	NGCC		NGCC + Renew	
Alternative	**Average PVRR**	**Diff from Least-Cost**	**Average PVRR**	**Diff from Least-Cost**
ELG 4; 2032/2034	15,209	55	15,189	55
ELG 3; 2025/2034	15,154	0	15,134	0
ELG 3; 2025/2029	15,199	45	15,189	55
ELG 2; 2025/2026	15,213	59	15,229	96
Early Ret; 2029/2029	15,284	131	15,260	126
Early Ret; 2025/2029	15,259	105	15,235	101
Early Ret; 2025/2026	15,285	131	15,288	154

The PVRR values in Table 22 and Table 23 were computed over the period from 2020 through 2041 because Mill Creek 2, 3, and 4 are assumed to be replaced with new generation by 2042. To estimate the minimum year through which the Mill Creek units must operate to justify the ELG investment, the Companies computed the PVRR difference between the least-cost early retirement alternative (Early Ret; 2025/2029) and the least-cost ELG compliance alternative (ELG 3; 2025/2034) with the assumption that the Mill Creek units would be replaced sooner. The results of this "breakeven" analysis are summarized in Table 24. In Table 24, the PVRR differences for the 2042 case are the same as in Table 23, where the Mill Creek units in the ELG compliance alternative are assumed to be retired in 2025, 2034, 2038, and 2042. For the 2035 case, for example, the assumed retirement years for Mill Creek 1 and 2 are unchanged but Mill Creek 3 and 4 are assumed to be retired and replaced in 2035. With these assumptions, the generation portfolio for each alternative is the same beginning in the year the last Mill Creek unit is retired.

Table 24 – PVRR Differences: "Early Ret; 2025/2029" less "ELG 3; 2025/2034" ($M)

Year Last Mill Creek Unit Retired in ELG Compliance Alternative	Replacement Portfolio	
	NGCC	NGCC + Renew
2025	(117)	(117)
2026	(119)	(119)
2027	(122)	(122)
2028	(124)	(124)
2029	(127)	(127)
2030	(87)	(86)
2031	(79)	(78)
2032	(46)	(43)
2033	(18)	(15)
2034	11	15
2035	35	35
2036	41	40
2037	62	60
2038	83	80
2039	74	71
2040	87	84
2041	94	89
2042	105	101

The Mill Creek units can be operated through 2028 with no ELG investment. In Table 24, the 2029 retirement year case compares the PVRR of ELG compliance and operations through 2028 to the PVRR of operating through 2028 with no ELG compliance costs. Not surprisingly, the revenue requirements for the early retirement alternative are favorable to the ELG compliance alternative in this case. The Companies would not make the ELG investment if they believed the coal units were going to be retired in 2029; the PVRR of the ELG investment is $127 unfavorable in this case. However, with each year the units operate beyond 2028, the favorability of the early retirement alternative decreases. For example, if all Mill Creek units are retired in 2032, the PVRR difference is reduced from $127 million to $43 million or $46 million, depending on the replacement portfolio. For both the NGCC and NGCC + Renew replacement portfolios, the ELG compliance alternative is least-cost cost provided the Mill Creek units are retired no sooner than 2034.

6. Ghent Analysis

The Companies evaluated four alternatives for the Ghent station (see Table 25). The naming convention for the Ghent alternatives is the same as the Mill Creek alternatives except the retirement year in each name pertains to Ghent 2. The Companies evaluated Ghent 2 separately because Ghent 2 is not equipped with SCR. For all Ghent alternatives, Mill Creek 1 is assumed to be retired in 2025 without replacement and the remaining Mill Creek coal units are assumed to be retired and replaced in their Depreciation Retirement Year. The compliance date for the ELG compliance alternatives with an ELG investment for all units (ELG 4; 2034 and ELG 4; 2029) is assumed to be November 2024. The compliance date for the ELG 3; 2026 alternative is assumed to be December 2025 to give the Companies additional time to secure replacement generation.

Table 25 – Ghent Alternatives

Alternative	Units in Compliance	Water Flow Capacity (GPM)	Assumed Retirement Year				ELG Compliance Date
			GH1	GH2	GH3	GH4	
ELG 4; 2034	All Units	1,000	2034	2034	2037	2038	Nov 2024
ELG 4; 2029	All Units	1,000	2034	2029	2037	2038	Nov 2024
ELG 3; 2026	Any 3 Units	750	2034	2026	2037	2038	Dec 2025
Early Ret; 2029	None	0	2029	2029	2029	2029	N/A

Table 26 and Table 27 contain the capital and operating costs for additional water treatment systems for each ELG compliance alternative. Despite different compliance dates, the capital spend profile is similar for all ELG compliance alternatives. Table 28 contains the Ghent station's stay-open costs for each alternative. The replacement generation portfolios for the Ghent analysis are the same as the Mill Creek analysis (see Table 21).

Table 26 – Ghent ELG Compliance Costs ($M, Nominal Dollars)

ELG Controls	2020	2021	2022	2023	2024	Total
ELG 4; 2034	5.6	67.5	73.7	48.1	21.3	216.3
ELG 4; 2029	5.6	67.5	73.7	48.1	21.3	216.3
ELG 3; 2026	5.1	63.7	68.8	43.8	18.8	200.3

Table 27 – Ghent ELG O&M Costs ($M, Nominal Dollars)

	Ghent Alternative			
Year	**ELG 4; 2034**	**ELG 4; 2029**	**ELG 3; 2026**	**Early Ret; 2029**
2021	0.0	0.0	0.0	0.0
2022	0.0	0.0	0.0	0.0
2023	0.0	0.0	0.0	0.0
2024	3.7	3.7	3.1	0.0
2025	5.8	5.8	4.8	0.0
2026	6.0	6.0	5.0	0.0
2027	6.3	6.3	5.2	0.0
2028	6.5	6.5	5.4	0.0
2029	6.7	5.5	5.5	0.0
2030	7.0	5.7	5.7	0.0
2031	7.2	6.0	6.0	0.0
2032	7.5	6.2	6.2	0.0
2033	7.8	6.4	6.4	0.0
2034	5.2	5.2	5.2	0.0
2035	5.4	5.4	5.4	0.0
2036	5.6	5.6	5.6	0.0
2037	4.2	4.2	4.2	0.0

Table 28 – Ghent Stay-Open Costs ($M, Nominal Dollars)

	Ghent Alternative			
Year	**ELG 4; 2034**	**ELG 4; 2029**	**ELG 3; 2026**	**Early Ret; 2029**
2021	134.4	134.4	134.4	105.1
2022	99.3	99.3	99.3	99.3
2023	119.6	119.6	119.6	119.6
2024	127.3	127.3	127.3	127.3
2025	166.4	166.4	166.4	121.8
2026	123.5	123.5	95.6	123.5
2027	158.4	158.4	124.7	132.1
2028	145.3	145.3	112.2	145.3
2029	133.5	102.1	102.1	0.0
2030	135.1	104.9	104.9	0.0
2031	137.8	107.0	107.0	0.0
2032	140.5	109.1	109.1	0.0
2033	143.3	111.3	111.3	0.0
2034	73.1	73.1	73.1	0.0
2035	74.5	74.5	74.5	0.0
2036	76.0	76.0	76.0	0.0
2037	42.0	42.0	42.0	0.0

Table 29 contains the results of this analysis and excludes the cost of transmission system upgrades that would be required if all four Ghent units are retired by 2029 as well as the cost of natural gas pipeline infrastructure required to support replacement generation at the site.[19] In Table 29, ELG compliance is assumed to enable the units to operate until their Depreciation Retirement Year. The PVRR values include the same cost items as in the Mill Creek analysis and were computed over the period from 2020 to 2037; 2037 is the last year of operation before Ghent 4 is assumed to be retired. The least-cost alternative for each fuel price scenario is highlighted in gray. The "NGCC + Renew" portfolio is the least-cost replacement portfolio in the mid and high fuel price scenarios; the NGCC portfolio is least-cost in the low fuel price scenario. Excluding the cost of transmission system upgrades and gas pipeline infrastructure, ELG compliance for four units (ELG 4; 2034) is least-cost in the mid and high fuel price scenarios and the second best case in the low fuel price scenario; replacing all four units by 2029 (Early Ret; 2029) is least-cost in the low fuel price scenario, second best in the mid fuel price scenario, and significantly more expensive ($269 million in PVRR) in the high fuel price scenario.

Table 29 – Ghent Analysis Results ($M, PVRR 2020-2037, Excluding Transmission System Costs and Gas Pipeline Costs)

Fuel Price	Alternative	Replacement Generation Portfolio			Least-Cost Replacement Generation Portfolio	PVRR Diff from Least-Cost Alternative
		NGCC	NGCC + Renew	Peak + Renew		
Mid	ELG 4; 2034	12,903	12,900	13,092	NGCC + Renew	0
	ELG 4; 2029	12,988	12,994	13,253	NGCC	88
	ELG 3; 2026	13,018	13,053	13,405	NGCC	118
	Early Ret; 2029	12,959	12,950	13,681	NGCC + Renew	50
Low	ELG 4; 2034	12,369	12,375	12,615	NGCC	64
	ELG 4; 2029	12,433	12,456	12,781	NGCC	128
	ELG 3; 2026	12,446	12,505	12,933	NGCC	142
	Early Ret; 2029	12,305	12,318	13,190	NGCC	0
High	ELG 4; 2034	13,858	13,839	13,958	NGCC + Renew	0
	ELG 4; 2029	13,980	13,952	14,112	NGCC + Renew	112
	ELG 3; 2026	14,037	14,027	14,258	NGCC + Renew	187
	Early Ret; 2029	14,152	14,108	14,606	NGCC + Renew	269

Table 30 lists the average PVRR over the three fuel price scenarios for each alternative and the top two replacement portfolios. Based on these results, ELG compliance for four units (ELG 4; 2034) is least-cost even if Ghent 2 is retired in 2029; the PVRR for the ELG 4; 2029 alternative is less than the PVRR for the ELG 3; 2026 alternative. Compared to the early retirement alternative (Early Ret; 2029), the PVRR for this alternative is $87 million to $96 million favorable.

[19] These costs are discussed in Section 4.8.

Table 30 – Ghent Analysis Results ($M, Average PVRR 2020-2037, Excluding Transmission System Costs and Gas Pipeline Costs)

Alternative	NGCC		NGCC + Renew	
	Average PVRR	Diff from Least-Cost	Average PVRR	Diff from Least-Cost
ELG 4; 2034	13,043	0	13,038	0
ELG 4; 2029	13,134	91	13,134	96
ELG 3; 2026	13,167	124	13,195	157
Early Ret; 2029	13,139	96	13,125	87

Table 31 contains the results of a breakeven analysis for Ghent like the one for Mill Creek. The Depreciation Retirement Years for the Ghent units are 2034, 2034, 2037, and 2038. For both the NGCC and NGCC + Renew replacement portfolios, the ELG investment is justified even if the Ghent units are retired as early as 2034.

Table 31 – PVRR Differences: "Early Ret; 2029" less "ELG 4; 2034" ($M)

Year Last Ghent Unit Retired in ELG Compliance Alternative	Replacement Portfolio	
	NGCC	NGCC + Renew
2025	(231)	(231)
2026	(235)	(235)
2027	(239)	(239)
2028	(243)	(243)
2029	(247)	(247)
2030	(211)	(211)
2031	(142)	(142)
2032	(74)	(75)
2033	(11)	(13)
2034	12	9
2035	41	36
2036	53	46
2037	83	74
2038	96	87

7. Trimble County Analysis

The Companies evaluated two alternatives for the Trimble County station (see Table 32). Both Trimble County alternatives assume Mill Creek 1 is retired in 2025 without replacement and the remaining Mill Creek units and the Ghent units are retired and replaced in their Depreciation Retirement Year. The Depreciation Retirement Year for Trimble County 2 is 2066. However, as a conservative assumption for this analysis, the Companies assumed Trimble County 2 would be retired in 2051 immediately after a 30-year analysis period. The compliance date for the ELG compliance alternative is assumed to be June 2023.

Table 32 – Trimble County Alternatives

Alternative	Units in Compliance	Water Flow Capacity (GPM)	Assumed Retirement Year		ELG Compliance Date
			TC1	TC2	
ELG 2	All Units	600	2050	2051[20]	June 2023
Early Ret	None	0	2029	2029	N/A

Table 33 and Table 34 contain the capital and operating costs for additional water treatment systems for each ELG compliance alternative. Table 34 contains the Trimble County station's stay-open costs for each alternative. The replacement generation portfolios for the Trimble County analysis are the same as the Mill Creek and Ghent analyses (see Table 21).

Table 33 – Trimble County ELG Compliance Costs ($M, Nominal Dollars)

ELG Controls	2020	2021	2022	2023	Total
ELG 2	5.1	19.0	21.4	25.3	70.9

[20] As a conservative assumption for this analysis, the Companies assumed Trimble County 2 would be retired in 2051 immediately after a 30-year analysis period.

Table 34 – Trimble County ELG O&M Costs ($M, Nominal Dollars)

Year	Trimble County Alternative	
	ELG 2	Early Ret
2021	0.0	0.0
2022	0.0	0.0
2023	2.1	0.0
2024	2.7	0.0
2025	2.8	0.0
2026	2.9	0.0
2027	3.0	0.0
2028	3.1	0.0
2029	3.2	0.0
2030	3.3	0.0
2031	3.4	0.0
2032	3.6	0.0
2033	3.7	0.0
2034	3.8	0.0
2035	4.0	0.0
2036	4.1	0.0
2037	4.3	0.0
2038	4.4	0.0
2039	4.6	0.0
2040	4.7	0.0
2041	4.9	0.0
2042	5.1	0.0
2043	5.3	0.0
2044	5.5	0.0
2045	5.7	0.0
2046	5.9	0.0
2047	6.1	0.0
2048	6.3	0.0
2049	6.6	0.0
2050	4.9	0.0

Table 35 – Trimble County Stay-Open Costs ($M, Nominal Dollars)

Year	Trimble County Alternative	
	ELG 2	**Early Ret**
2021	67.4	67.4
2022	53.8	53.8
2023	69.2	69.2
2024	56.8	56.8
2025	86.7	69.0
2026	75.5	57.6
2027	65.3	65.3
2028	62.2	62.2
2029	69.4	0.0
2030	62.4	0.0
2031	76.8	0.0
2032	64.9	0.0
2033	100.6	0.0
2034	88.5	0.0
2035	83.1	0.0
2036	70.3	0.0
2037	86.4	0.0
2038	73.1	0.0
2039	89.9	0.0
2040	76.1	0.0
2041	117.8	0.0
2042	103.7	0.0
2043	97.4	0.0
2044	82.4	0.0
2045	101.3	0.0
2046	85.7	0.0
2047	105.4	0.0
2048	89.2	0.0
2049	109.6	0.0
2050	64.9	0.0

Table 36 contains the results of this analysis where ELG compliance is assumed to enable the units to operate until their Depreciation Retirement Year. Even though the Depreciation Retirement Year for Trimble County 2 is 2066, the PVRR values were computed from 2020 to 2050. ELG compliance for both units (ELG 2) is the least-cost alternative in all fuel price scenarios. The NGCC + Renew replacement portfolio is least-cost in all fuel price scenarios.

Table 36 – Trimble County Analysis Results ($M, PVRR 2020-2050)

Fuel Price	Alternative	Replacement Generation Portfolio			Least-Cost Replacement Generation Portfolio	PVRR Diff from Least-Cost Alternative
		NGCC	NGCC + Renew	Peak + Renew		
Mid	ELG 2	18,539	18,496	19,659	NGCC + Renew	0
	Early Ret	18,842	18,806	20,776	NGCC + Renew	310
Low	ELG 2	17,378	17,369	18,780	NGCC + Renew	0
	Early Ret	17,503	17,510	19,861	NGCC	134
High	ELG 2	20,649	20,543	21,267	NGCC + Renew	0
	Early Ret	21,299	21,183	22,462	NGCC + Renew	639

Table 37 lists the average PVRR over the three fuel price scenarios for each alternative and the top two replacement portfolios. Based on these results, ELG compliance for both units (ELG 2) is least-cost. The PVRR for the early retirement alternative (Early Ret) is $360 million to $364 million unfavorable.

Table 37 – Trimble County Analysis Results ($M, Average PVRR 2020-2050)

Alternative	NGCC		NGCC + Renew	
	Average PVRR	Diff from Least-Cost	Average PVRR	Diff from Least-Cost
ELG 2	18,855	0	18,803	0
Early Ret	19,215	360	19,166	364

Table 38 contains the results of a breakeven analysis for Trimble County. The Depreciation Retirement Years for the Trimble County coal units are 2050 and 2066 but this analysis conservatively assumes Trimble County 2 is retired in 2051 after the end of the 30-year analysis period. Based on the result in Table 38, the investment in additional water treatment systems is justified even if the Trimble County units are retired as early as 2032.

Table 38 – PVRR Differences: ELG 2 less Early Ret ($M)

Year Last Trimble County Unit Retired in ELG Compliance Alternative	Replacement Portfolio	
	NGCC	NGCC + Renew
2025	(80)	(80)
2026	(82)	(82)
2027	(84)	(84)
2028	(86)	(86)
2029	(87)	(87)
2030	(60)	(57)
2031	(25)	(19)
2032	(0)	8
2033	32	41
2034	38	49
2035	56	65
2036	82	90
2037	113	121
2038	137	145
2039	166	174
2040	189	196
2041	216	223
2042	225	232
2043	238	245
2044	257	263
2045	280	286
2046	297	302
2047	318	322
2048	334	338
2049	353	357
2050	359	363
2051	360	364

8. CO_2 Considerations

Excluding the risk associated with potential future CO_2 laws and/or regulations, this analysis demonstrates that ELG compliance for three units at Mill Creek and all units at the Ghent and Trimble County stations is least-cost (see Sections 5, 6, and 7). This section evaluates the recommended compliance plan in the context of the ACE Rule, the now defunct Clean Power Plan, and potential CO_2 regulations aimed at more significantly reducing CO_2 emissions from electric generation.

8.1. Affordable Clean Energy ("ACE") Rule

On July 8, 2019, EPA's final ACE Rule was published with an effective date of September 6, 2019. As part of this action EPA repealed the Clean Power Plan. The ACE Rule requires existing coal-fired electric generating units or boilers to implement heat rate improvement ("HRI") / energy efficiency) projects, thus emitting less carbon emissions for an equal amount of energy produced. EPA's proposed changes to New Source Review ("NSR") requirements to avoid triggering NSR and Best Available Control Technology at facilities that undertake HRIs under the ACE rule were not finalized, although EPA still plans to issue the final changes to NSR in late summer 2020. Kentucky must submit a State Implementation Plan ("SIP") for compliance with the ACE Rule by July 8, 2022 and compliance is required within 2 years. The Companies will be working with Kentucky in developing the SIP. It is still too early to fully predict the impact of implementing the ACE Rule and lawsuits have already been filed opposing EPA's actions.

The Companies currently expect to be required to invest in HRI projects that are economically favorable based on operating benefits through the end of each unit's economic life. Therefore, the PVRR based on evaluation through the end of each unit's economic life must be less than or equal to zero for investment in ACE projects to be required. The Companies assume that each unit's Depreciation Retirement Year is a reasonable estimate for the end of a unit's economic life. Because no economically unfavorable projects are expected to be required, the Companies expect that the ACE rule will have no unfavorable PVRR impact on the proposed ELG projects.

8.2. Clean Power Plan

The Clean Power Plan ("CPP") was first proposed by the EPA during the Obama administration in June 2014, with the final version released in August 2015 and published to the Federal Register on October 23, 2015. The CPP sought to reduce CO_2 emissions from electric power generation by 32% from 2005 levels. The CPP was later repealed by the EPA in October 2017 during the Trump administration and replaced with the ACE Rule.

While the CPP never went into effect, its intended framework could be illustrative of how future CO_2 regulations might be structured. Under the CPP, the EPA had intended to provide states with significant latitude to develop their own CO_2 emission reductions plans, but also established default guidelines for states without their own compliance plans. While the Companies do not know precisely how the state would have chosen to design its State Implementation Plan, the default guidelines provide some insight into potential constraints.

First, the CPP allowed states to choose between a rate (lb/MWh) or equivalent mass (total tons) goal. Given flat-to-declining load growth in much of the Commonwealth, coupled with coal unit retirements over the last decade, the mass goal was deemed to have been the most likely outcome. Under either a rate or equivalent mass goal, the CPP established interim and final targets, with the final level to be achieved in 2030. Kentucky's 2030 mass goal for existing units was 63,126,121 short tons, and the CPP allowed for an additional 663,880 short tons to account for generation from new sources.[21, 22] In total, the CPP sought to have Kentucky's CO_2 emissions from electric power generation at or below 63,790,001 short tons by 2030 and beyond. The state would then have had the flexibility to distribute those allowances to the various generating sources.

The CPP's default allocation was in proportion to 2012 electricity generation; however, since the CPP was proposed, many of the states' coal-fired units have retired or announced an upcoming retirement (see Table 39).[23] Adjusting for these retirements and new unit additions since 2015 (Cane Run 7 for the Companies; Paradise NGCC for TVA), along with the assumed retirement of Mill Creek 1 in 2025, a proportional allocation today would assign the Companies roughly 51% of total allowances and limit their CO_2 emissions to 32,729,652 out of 63,790,001 short tons.

Table 39 – Kentucky Coal-Fired Generation Retired or Retiring Since CPP Proposal

Utility	**Unit**
American Electric Power	Big Sandy 1 (converted to gas)[24]
American Electric Power	Big Sandy 2
Big Rivers Electric Cooperative	Kenneth C Coleman 1-3
Big Rivers Electric Cooperative	Robert A Reid 1
Duke Energy	East Bend 2
East Kentucky Power Cooperative	Dale 1-4
Henderson Municipal Power & Light	HMP&L Station Two Henderson 1-2
LG&E and KU Energy	E W Brown 1-2
LG&E and KU Energy	Cane Run 4-6
LG&E and KU Energy	Green River 3-4
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Tennessee Valley Authority	Paradise 1-3

Table 40 compares this CO_2 limit to forecasted CO_2 emissions in 2030 for the units in the least-cost ELG compliance plan that would be subject to the CPP limit. As proposed, the CPP's CO_2 limit did not apply to emissions from SCCT units. The Companies' forecasted CO_2 emissions are below this limit across all

[21] Equivalent mass goals from https://archive.epa.gov/epa/sites/production/files/2015-08/clean-power-plan-state-goal-visualizer_0.xlsm
[22] New Source Complement from Table 9, https://www.epa.gov/sites/production/files/2015-11/documents/tsd-cpp-new-source-complements.pdf.
[23] In addition, the CPP provided guidelines for new known planned sources for which historical generation was unavailable (specifically the Companies' Cane Run 7 and TVA's Paradise NGCC unit), recommending an estimate of generation if these units were operating at a 55% capacity factor.
[24] For purposes of this analysis, Big Sandy's 2012 generation was adjusted by the ratio of CO_2 emissions for the combustion of coal compared to gas, which is assumed to be dividing by 205.2 lb/MMBtu and multiplying by 120 lb/MMBtu.

fuel price scenarios. After 2030, the Companies' forecasted emissions continue to decline as coal units are replaced by a combination of NGCC and renewable generation, which have comparably lower CO_2 emissions than coal-fired generation.[25]

Table 40 - CO_2 Emissions Comparison in 2030 (000s short tons)

Fuel Price Scenario	Estimated CPP CO_2 Limit	Forecasted CO_2 Emissions in 2030	Forecasted Emissions in 2030 less CPP Limit
Low	32,730	29,923	(2,807)
Base	32,730	30,560	(2,170)
High	32,730	31,672	(1,057)

8.3. CO_2 Regulations Aimed at More Significantly Reducing CO_2 Emissions

The previous sections demonstrate that the least-cost ELG compliance plan complies with current CO_2 regulations and would comply with regulations like the Clean Power Plan. This section contemplates a potentially more stringent CO_2 regulation that would result in the immediate replacement of all coal units with either the NGCC + Renew or Peak + Renew replacement portfolios.[26] Compared to a coal unit, CO_2 emissions from a NGCC unit are approximately 60% lower. Replacing coal generation with a combination of peaking capacity and renewables is the most aggressive way to reduce the Companies' CO_2 emissions.

Regulations that would result in the immediate replacement of all coal units could take several forms (e.g., CO_2 tax, aggressive renewable portfolio or clean energy standard, etc.). The Companies evaluated the cost of the replacement portfolios directly to avoid speculation regarding the form of these regulations. The alternatives evaluated for this part of the analysis are listed in Table 41.

[25] The CPP's technical support documents assumed an emission rate of 2,160 lb/MWh for coal ("fossil steam"), and 894 lb/MWh for NGCC. See page 11, https://www.epa.gov/sites/production/files/2015-11/documents/tsd-cpp-emission-performance-rate-goal-computation.pdf

[26] The NGCC + Renew and Peak + Renew replacement generation portfolios are summarized in Table 11 on page 8.

Table 41 – Alternatives for Analysis of More Stringent CO_2 Regulations

Alternative	Description
ELG	Invest in additional water treatment systems for 3 Mill Creek units and all Ghent and Trimble County Units. Except Mill Creek 1, replace units in Depreciation Retirement Year. This is the least-cost compliance plan based on current regulations.
Early Ret MC	Don't invest in additional water treatment systems at Mill Creek. Replace Mill Creek units in 2029. Physically comply with ELG at the Ghent and Trimble County stations.
Early Ret MC/GH	Don't invest in additional water treatment systems at Mill Creek or Ghent. Replace Mill Creek and Ghent units in 2029. Physically comply with ELG at Trimble County.
Early Ret MC/GH/TC	Don't invest in additional water treatment systems. Replace Mill Creek, Ghent, and Trimble County units in 2029.

Table 42 lists the average PVRR over the three fuel price scenarios for each alternative in Table 41 and all replacement portfolios. The PVRR values are computed over the period from 2020 to 2050. As discussed previously, with no additional costs for CO_2 emissions, complying with ELG regulations and replacing coal units in their Depreciation Retirement Year with a combination of NGCC capacity and renewables is least-cost (see gray highlighted cell). Avoiding the ELG investment and replacing coal units sooner with NGCC capacity and renewables increases the PVRR by $101 million to $579 million, depending on which units are retired in 2029. However, with no additional costs for CO_2 emissions, replacing coal units in 2029 with peaking capacity and renewables increases the PVRR by $1,099 million to $4,008 million.

Table 42 – Analysis of More Stringent CO_2 Regulations (Average PVRR 2020-2050, $M)

	Replacement Portfolio			Least-Cost Replacement Generation Portfolio	PVRR Diff versus Least-Cost NGCC + Renew Alternative	
Alternative	**NGCC**	**NGCC + Renew**	**Peak + Renew**		**NGCC + Renew**	**Peak + Renew**
ELG	18,855	18,803	19,902	NGCC + Renew	0	1,099
Early Ret MC	18,960	18,904	20,494	NGCC + Renew	101	1,692
Early Ret MC/GH	19,075	19,003	21,317	NGCC + Renew	200	2,514
Early Ret MC/GH/TC	19,459	19,382	22,811	NGCC + Renew	579	4,008

Table 43 compares the PVRR of the early retirement alternatives to the PVRR of the ELG compliance alternative. In the early retirement alternatives, coal units are replaced with the NGCC + Renew portfolio in 2029; in the ELG compliance alternative, coal units are replaced with the same portfolio in their Depreciation Retirement Year. The results for the 2051 case match the PVRR differences in Table 42 above. In this case, all coal units in the ELG compliance alternative are assumed to be replaced in the earlier of their Depreciation Retirement Year or 2051. In the 2040 case, for example, all coal units in the ELG compliance alternative are assumed to be replaced in the earlier of their Depreciation Retirement Year or 2040, and so on.

Table 43 – PVRR Differences: Replace Coal in 2029 less ELG Compliance ($M)

Year Last Coal Unit Retired in ELG Compliance Alternative	Replacement Portfolios: Early Retirement: NGCC + Renew ELG Compliance: NGCC + Renew		
	Early Retirement Alternative		
	Early Ret MC	Early Ret MC/GH	Early Ret MC/GH/TC
2025	(117)	(348)	(427)
2026	(119)	(354)	(436)
2027	(122)	(361)	(445)
2028	(124)	(368)	(453)
2029	(127)	(374)	(461)
2030	(86)	(296)	(351)
2031	(78)	(216)	(233)
2032	(43)	(112)	(100)
2033	(15)	(21)	29
2034	15	34	95
2035	35	83	162
2036	40	98	203
2037	60	146	282
2038	80	179	339
2039	71	169	358
2040	84	183	394
2041	89	188	426
2042	101	200	447
2043	101	200	460
2044	101	200	479
2045	101	200	501
2046	101	200	517
2047	101	200	537
2048	101	200	553
2049	101	200	572
2050	101	200	579
2051	101	200	579

As discussed previously, coal units can be operated through 2028 with no ELG investment. In Table 43, the 2029 retirement year case compares the PVRR of ELG compliance and operations through 2028 to the PVRR of operating through 2028 with no ELG compliance costs. The PVRR differences in the 2029 retirement year case reflect the maximum level of downside risk or regret in the event the Companies complied with ELG regulations and new regulations were subsequently passed that resulted in the replacement of coal in 2029 with the NGCC + Renew portfolio; the favorability of the early retirement scenarios is greatest (most negative) in the 2029 retirement year case. However, this favorability diminishes with each year the continued operation of coal units is least-cost. For example, if all coal units are retired in 2031 instead of 2029, the favorability of the early retirement scenario decreases from $461 million to $233 million. The ELG compliance alternative is least-cost provided a regulation like this doesn't take effect until 2033 or 2034.

Table 44 contains the same analysis as Table 43 except coal units in the early retirement alternatives are assumed to be replaced by the Peak + Renew portfolio. The maximum level of downside risk is the same but the "breakeven" year is sooner because the Peak + Renew portfolio is much more expensive than the NGCC + Renew portfolio. Provided a regulation requiring the replacement of coal units with renewables and peaking capacity takes effect after 2030, ELG compliance is least-cost. Moreover, when a coal unit is replaced, the Companies cannot undo the capital investment. No basis exists today for replacing coal units in 2029 with peaking capacity and renewables. However, if this decision was made based on concerns regarding future CO_2 regulations and then no regulations were passed, the downside risk associated with that decision would quickly far outweigh the downside risk associated with the ELG compliance decision. For example, if the Mill Creek units were replaced with peaking capacity and renewables in 2029 based on concerns regarding future CO2 regulations and then no such regulations were passed, the level of regret would be $194 million in 2033 and more than $1 billion by 2042.

Table 44 – PVRR Differences: Replace Coal in 2029 less ELG Compliance ($M)

Year Last Coal Unit Retired in ELG Compliance Alternative	Replacement Portfolios: Early Retirement – Peak + Renew ELG Compliance – NGCC + Renew		
	Early Retirement Alternative		
	Early Ret MC	Early Ret MC/GH	Early Ret MC/GH/TC
2025	(117)	(348)	(427)
2026	(119)	(354)	(436)
2027	(122)	(361)	(445)
2028	(124)	(368)	(453)
2029	(127)	(374)	(461)
2030	(29)	(111)	(67)
2031	37	148	325
2032	120	412	701
2033	194	650	1,056
2034	268	842	1,335
2035	366	1,014	1,594
2036	456	1,166	1,832
2037	545	1,329	2,081
2038	657	1,480	2,308
2039	760	1,583	2,491
2040	871	1,694	2,670
2041	969	1,793	2,840
2042	1,072	1,896	2,993
2043	1,156	1,980	3,127
2044	1,230	2,054	3,253
2045	1,297	2,120	3,375
2046	1,372	2,196	3,500
2047	1,444	2,268	3,625
2048	1,507	2,331	3,731
2049	1,567	2,389	3,835
2050	1,628	2,451	3,930
2051	1,692	2,514	4,008

Finally, these alternatives were evaluated on a station-by-station basis to be consistent with earlier analyses. In reality, a more stringent CO_2 regulation would likely only impact the Companies' marginal units and some amount of the ELG investment would still be needed. Earlier analyses demonstrated, for example, that even if Mill Creek 2 and Ghent 2 were retired in 2029, there would be no level of regret associated with the ELG compliance decision.

9. Conclusions

ELG compliance for three Mill Creek units and all Ghent and Trimble County Units is the least-cost ELG compliance plan. Accordingly, the systems proposed in the Companies' 2020 ECR Plans are sized so that FGD wastewater from all coal-fired units at Ghent and Trimble County can be processed at full capacity, and FGD wastewater for 3 of the 4 coal-fired units at Mill Creek can be processed at full capacity. The proposed ELG water treatment system at Mill Creek is sized to handle full FGD wastewater capacity for 3 generating units or, depending on operating conditions, less than full capacity for all 4 generating units.

This plan complies with current CO_2 regulations and would comply with CO_2 regulations like the Clean Power Plan. The analysis initially assumed that ELG compliance would enable coal units to operate until their Depreciation Retirement Year. However, even if regulations are passed, causing all coal units to be retired in 2033 or 2034, ELG compliance remains the least-cost plan to reliably meet customers' future energy needs.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR APPROVAL OF ITS 2020 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	**)))))**	**CASE NO. 2020-00060**
ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR APPROVAL OF ITS 2020 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	**)))))**	**CASE NO. 2020-00061**

DIRECT TESTIMONY OF
ANDREA M. FACKLER
MANAGER, REVENUE REQUIREMENT/COST OF SERVICE
KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: March 31, 2020

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Background

Q. Please state your name, position, and business address.

A. My name is Andrea M. Fackler. I am the Manager, Revenue Requirement/Cost of Service for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") and an employee of LG&E and KU Services Company, which provides services to KU and LG&E (collectively "Companies"). My business address is 220 West Main Street, Louisville, Kentucky, 40202.

Q. Please describe your professional background.

A. I am a Certified Public Accountant with the Chartered Global Management Accountant designation. At the beginning of my career, I spent three years working in public accounting before joining LG&E and KU Services Company in 2010. I have served in a variety of positions at LG&E and KU Services Company and was recently promoted to Manager, Revenue Requirement/Cost of Service. A complete statement of my work experience and education is contained in Appendix A attached to my testimony.

Q. Have you previously submitted testimony or data responses to state regulatory commissions?

A. Yes, I submitted testimony to the Virginia State Corporation Commission regarding KU's 2020 Levelized Fuel Factor filing.[1] I also sponsored data responses in the Companies' most recent fuel adjustment clause six-month review cases[2] and was responsible for

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[1] *Application of Kentucky Utilities Company d/b/a Old Dominion Power Company to Revise Its Fuel Factor*, Case No. PUR-2020-00029, Direct Testimony of Andrea M. Fackler (Va. SCC filed Feb. 14, 2020).

[2] *An Examination of the Application of the Fuel Adjustment Clause of Kentucky Utilities Company from May 1, 2019 to October 31, 2019*, Case No. 2020-00006, Response of Kentucky Utilities Company to Commission Staff's First Request for Information Dated February 11, 2020 (Ky. PSC Feb. 25, 2020); *An Examination of the Application of the Fuel Adjustment Clause of Louisville Gas and Electric Company from May 1, 2019 to October 31, 2019*, Case No. 2020-00007, Response of Louisville Gas and Electric Company to Commission Staff's First Request for Information Dated February 11, 2020 (Ky. PSC Feb. 25, 2020).

preparing the data and information provided to this Commission in the Companies' data responses in a variety of proceedings over the last four years.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring ten exhibits. Attached to my testimony are four exhibits for KU and four exhibits for LG&E. These exhibits are:

Exhibit AMF-1	KU Proposed ECR Tariff – Redline
Exhibit AMF-2	Current KU Environmental Surcharge Monthly Reports
Exhibit AMF-3	Proposed KU Environmental Surcharge Monthly Reports
Exhibit AMF-4	KU 2020 Plan Customer Bill Impact
Exhibit AMF-5	LG&E Proposed ECR Tariff – Redline
Exhibit AMF-6	Current LG&E Environmental Surcharge Monthly Reports
Exhibit AMF-7	Proposed LG&E Environmental Surcharge Monthly Reports
Exhibit AMF-8	LG&E 2020 Plan Customer Bill Impact

I am also sponsoring Application Exhibit 4 to both the KU and LG&E Applications.

Q. What are the purposes of your testimony?

A. My testimony addresses how the environmental surcharge under KU's and LG&E's Environmental Cost Recovery ("ECR") Surcharge tariff provisions will be calculated to include the costs of KU's and LG&E's 2020 Environmental Compliance Plans (collectively the "2020 Plans"), explains that the methodologies for calculating the ECR surcharge remain the same, presents the revisions to the monthly ECR reporting forms ("ES Forms") that KU and LG&E propose and explains why the revisions to the forms are appropriate, details the costs included in base rates, and discusses the bill impact on KU's and LG&E's customers.

ECR Surcharge Tariff Provisions

Q. Are the Companies proposing any changes to their ECR Surcharge tariff sheets?

A. No. KU and LG&E are not proposing to make any changes to their ECR Surcharge tariff sheets other than to change their issue and effective dates to reflect the Applications in these proceedings. KU's proposed ECR Tariff is attached to the KU Application as Exhibit 4, and a redline version comparing the proposed ECR Tariff to the existing tariff is attached to my testimony as Exhibit AMF-1. LG&E's proposed ECR Tariff is attached to the LG&E Application as Exhibit 4, and a redline version comparing the proposed ECR Tariff to the existing tariff is attached to my testimony as Exhibit AMF-5. Both KU's and LG&E's ECR tariffs have an issue date of March 31, 2020 and are proposed to be effective September 30, 2020. Therefore, the revised environmental surcharges will be effective with the expense month of September 2020 for bills issued on and after the first day of the billing cycle for November 2020.[3]

Q. Will the methodologies for calculating the environmental surcharge change if the Commission approves recovery of the 2020 Plans?

A. No. The Companies will continue to use the currently approved methodologies for calculating the environmental surcharge, including the revenue allocation methodology I describe below. The proposed calculation of the monthly Environmental Surcharge billing factor will continue to consolidate the 2009 Plans, the 2011 Plans, and the 2016 Plans, and will also now include the proposed 2020 Plans.

Q. What revenue allocation are the Companies proposing in these cases?

[3] The first day of the billing cycle for November 2020 is October 28, 2020.

A. The Companies propose to continue to use the two-step revenue-allocation methodology approved by the Commission in the Companies' 2011 ECR Plan proceedings, which methodology the Companies have used in calculating their ECR charges since the Commission's approval in those proceedings.[4] Since the 2011 Order, the Commission has reviewed this ECR revenue allocation methodology in four cases each for KU and LG&E and approved the Companies' ECR roll-ins based on the methodology.[5] In the most recent two-year review cases, the Commission again advised KU and LG&E to continue to use the methodology until the Commission directs otherwise.[6]

Revisions to ES Forms

Q. Will the monthly reporting forms used for calculating the environmental surcharge change if the Commission approves recovery of the Companies' 2020 Plans?

A. Yes, the ES forms will change slightly to reflect the recovery of the costs associated with the 2020 Plans. For KU, Exhibit AMF-2 contains KU's current monthly ES Forms and Exhibit AMF-3 contains KU's proposed monthly ES Forms. For LG&E, Exhibit AMF-6 contains LG&E's current monthly ES Forms and Exhibit AMF-7 contains LG&E's proposed monthly ES Forms.

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[4] *Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2011-00161, Order at Appx. A, p. 8-10 (Ky. PSC Dec. 15, 2011); *Application of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2011-00162, Order at Appx. A, p. 8-10 (Ky. PSC Dec. 15, 2011).

[5] For KU, the Commission reviewed the ECR revenue allocation methodology in Case Nos. 2013-00242, 2015-00221, 2017-00266, and 2019-00205. For LG&E, the Commission reviewed the ECR revenue allocation methodology in Case Nos. 2013-00243, 2015-00222, 2017-00267, and 2019-00206.

[6] *Electronic Examination by the Public Service Commission of the Environmental Surcharge Mechanism of Kentucky Utilities Company for the Two-Year Billing Period Ending April 30, 2019*, Case No. 2019-00205, Order (Ky. PSC Oct. 22, 2019); *Electronic Examination by the Public Service Commission of the Environmental Surcharge Mechanism of Louisville Gas and Electric Company for the Two-Year Billing Period Ending April 30, 2019*, Case No. 2019-00206, Order (Ky. PSC Oct. 22, 2019).

Q. Please describe the modifications the Companies are proposing to the ES Forms as a result of the 2020 Plans.

A. As I previously explained, the calculation of the monthly billing factor for recovery of the cost of the 2020 Plans will be consistent with the current methodology approved by the Commission. ES Form 1.10 will continue to show the calculation of the Jurisdictional Environmental Surcharge Billing Factor using the same methodology previously approved by the Commission.

The plant, construction work in progress, and depreciation expenses for each company for the 2009 Plans, the 2011 Plans, and the 2016 Plans are currently reported on ES Form 2.10. This form is being expanded to include the projects for the 2020 Plans for which KU and LG&E are seeking cost recovery.

The pollution control equipment operating and maintenance ("O&M") expenses for the 2009 Plans, the 2011 Plans, and the 2016 Plans are currently reported on ES Form 2.50. This form is being expanded to include the O&M expenses associated with the 2015 Effluent Limitations Guidelines ("ELG") projects in the 2020 Plans. As discussed below and in the direct testimony of Robert M. Conroy, the Companies are proposing to recover the O&M expenses for the ELG projects in the 2020 Plans through the ECR mechanism.

Costs in Base Rates

Q. Are the Companies proposing to recover O&M associated with the projects in their environmental surcharges?

A. Yes. As shown on page 2 of the 2020 Plans, the Companies expect to incur new O&M in the form of chemical reagents associated with the projects and are seeking recovery of those O&M expenses through their ECR mechanisms. The O&M associated with the projects in the 2020 Plans is not included in existing base rates or ECR O&M.

Q. Are any of the capital expenditures for the projects in the 2020 Plans already included in existing base rates?

A. Yes. The total capital expenditures for projects in the 2020 Plans have been reduced for the amounts included in the forecasted test year for the most recent base rate case. The calculations are shown in the following tables.

KU ECR Projects		Number of Projects	Total Estimated Capital	Spend in Base Rates	Estimated ECR Spend
43	Ghent ELG Water Treatment System, Diffuser, and Bottom Ash Transport Water Recirculation System	3	$216.5 M	$0.3 M	$216.2 M
44	Trimble County ELG Water Treatment System	1	$35.9 M	$1.8 M	$34.1 M

LG&E ECR Projects		Number of Projects	Total Estimated Capital	Spend in Base Rates	Estimated ECR Spend
31	Mill Creek ELG Water Treatment System and Diffuser	2	$113.9 M	$4.7 M	$109.2 M
32	Trimble County ELG Water Treatment System	1	$38.8 M	$1.8 M	$37.0 M

Q. How will the Companies treat these costs in future base rates?

A. Upon approval of the 2020 Plans, the Companies will reset future base rates to allow the total costs for these ECR projects to be recovered through the ECR mechanism, thus ensuring no double recovery.

Q. What depreciation rates are the Companies proposing to use for the facilities in their 2020 Plans?

A. Existing book depreciation rates previously approved by the Commission will be used in the calculation of the depreciation expense for the new capital projects until depreciation rates are changed in a future base rate proceeding.

Bill Impact

Q. Have the Companies estimated the impact of the new projects on their Environmental Cost Recovery Surcharges for customers' bills?

A. Yes. The tables below show for each Company the estimated annual impact on Total E(m), Jurisdictional E(m), and the incremental billing factor associated with the projects contained in the 2020 Plans. As shown in Table 1, the estimated impact on a KU Group 1 customer is an increase of 0.04% initially in 2020 and increasing to a maximum of 2.13% in 2025. For a residential customer using an average of 1,139 kWh per month, the initial monthly increase is expected to be $0.05 in 2020, upon approval by the Commission. It is estimated that this amount will increase to a maximum of $2.46 per month in 2025. The estimated impact on a KU Group 2 customer is an increase of 0.06% initially in 2020 and increasing to a maximum of 2.98% in 2025. Exhibit AMF-4 shows the details of the impact on the calculation of the environmental surcharge and a KU residential customer for 2020 through 2029.

Table 1: KU Environmental Cost Recovery Surcharge Summary

	2020	2021	2022	2023	2024	2025
Total E(m) - (in '000s)	$709	$7,458	$15,482	$23,615	$30,556	$37,421
12 Month Average Jurisdictional Ratio	91.65%	91.65%	91.65%	91.65%	91.65%	91.65%
Jurisdictional E(m) - (in '000s)	$650	$6,835	$14,190	$21,644	$28,005	$34,297
Forecasted Jurisdictional R(m) - (in '000s)	$1,580	$1,582	$1,585	$1,592	$1,604	$1,612
Incremental Billing Factor Group 1	0.04%	0.43%	0.90%	1.36%	1.75%	2.13%
Residential Customer Impact Monthly bill (1,139 kWh per month)	$0.05	$0.50	$1.04	$1.57	$2.02	$2.46
Incremental Billing Factor Group 2	0.06%	0.59%	1.24%	1.89%	2.44%	2.98%

As shown in Table 2, the estimated impact on an LG&E Group 1 electric customer is an increase of 0.05% initially in 2020 and increasing to a maximum of 1.90% in 2025. For a residential customer using an average of 917 kWh per month, the initial monthly increase is expected to be $0.05 in 2020, upon approval by the Commission. It is estimated that this amount will increase to a maximum of $1.91 per month in 2025. The estimated impact on an LG&E Group 2 electric customer is an increase of 0.07% initially in 2020 and increasing to a maximum of 2.56% in 2025. Exhibit AMF-8 shows the details of the impact on the calculation of the environmental surcharge and an LG&E residential customer for 2020 through 2029.

Table 2: LG&E Environmental Cost Recovery Surcharge Summary

	2020	2021	2022	2023	2024	2025
Total E(m) - (in '000s)	$605	$4,528	$8,432	$12,891	$18,761	$21,804
12 Month Average Jurisdictional Ratio	96.81%	96.81%	96.81%	96.81%	96.81%	96.81%
Jurisdictional E(m) - (in '000s)	$586	$4,384	$8,163	$12,479	$18,162	$20,778
Forecasted Jurisdictional R(m) - (in '000s)	$1,092	$1,090	$1,095	$1,098	$1,105	$1,113
Incremental Billing Factor Group 1	0.05%	0.40%	0.75%	1.14%	1.64%	1.90%
Residential Customer Impact Monthly bill (917 kWh per month)	$0.05	$0.41	$0.75	$1.15	$1.66	$1.91
Incremental Billing Factor Group 2	0.07%	0.54%	1.00%	1.52%	2.21%	2.56%

Conclusion and Recommendation

Q. What is your conclusion and recommendation to the Commission?

A. I recommend that the Commission approve KU's and LG&E's 2020 Plans and applications for cost recovery of their compliance costs through each of the Companies' Rate Schedule ECR tariffs, as well as the proposed changes to KU's and LG&E's Rate Schedule ECR tariffs and monthly ES Forms to be effective with the expense month of September 2020 for bills issued on and after the first day of the billing cycle for November 2020.[7]

Q. Does this conclude your testimony?

A. Yes, it does.

[7] The first day of the billing cycle for November 2020 is October 28, 2020.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Andrea M. Fackler**, being duly sworn, deposes and says that she is Manager - Revenue Requirement/Cost of Service for LG&E and KU Services Company, and that she has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of her information, knowledge and belief.

Andrea M. Fackler
Andrea M. Fackler

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 17th day of March 2020.

(SEAL)
Notary Public

Notary Public, ID No. 603967

My Commission Expires:

7/11/2022

APPENDIX A

Andrea M. Fackler, CPA, CGMA

Manager, Revenue Requirement/Cost of Service
LG&E and KU Services Company
220 West Main Street
Louisville, Kentucky 40202

Previous Positions

LG&E and KU Services Company

Rate & Regulatory Analyst III & Senior	Jan 2016 – Nov 2019
Accounting Analyst III & Senior	Aug 2012 – Jan 2016
Accounting Analyst II & III	Jul 2010 – Aug 2012

Dean Dorton Ford, PSC

Supervisor in Accounting and Compliance Services	Jan 2007 – May 2010

Professional/Trade Memberships

American Institute of Certified Public Accountants
Kentucky Society of Certified Public Accountants ("KSCPA")
Institute of Management Accountants

Education/Training

LG&E and KU Strategic Business Integration, 2017-2018 Cohort
Bachelor of Science in Accounting, University of Kentucky, Dec 2006
Bachelor of Business Administration, University of Kentucky, Dec 2006

Civic Activities

Baptist Health NICU Family Advisory Council, 2019 – Current
Members in Business and Industry Committee Member, KSCPA, July 2017 – Current
President-Elect, President, and Immediate Past President, LG&E and KU Young Energy Professionals, 2015-2017
Member and Chair of Communications and Marketing Committee, LG&E and KU Young Energy Professionals, 2013-2014

Kentucky Utilities Company

P.S.C. No. 19, First Revision of Original Sheet No. 87
Canceling P.S.C. No. 19, Original Sheet No. 87

Adjustment Clause **ECR**

Environmental Cost Recovery Surcharge

APPLICABLE

In all territory served.

AVAILABILITY

This schedule is mandatory to all rate schedules listed in Section 1 of the General Index except Rate PSA and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and FAC (including OSS) and DSM Adjustment Clauses. Rate schedules subject to this adjustment clause are divided into Group 1 or Group 2 as follows: T T T T T

Group 1: Rates RS; RTOD-Energy; RTOD-Demand; VFD; AES; LS; RLS; LE; and TE. T
Group 2: Rates GS; PS; TODS; TODP; RTS; FLS; EVSE; EVC; and OSL. T
.

RATE

The monthly billing amount under each of the schedules to which this mechanism is applicable, shall be increased or decreased by a percentage factor calculated in accordance with the following formula.

Group Environmental Surcharge Billing Factor = Group E(m) / Group R(m)

As set forth below, Group E(m) is the sum of Jurisdictional E(m) of each approved environmental compliance plan revenue requirement of environmental compliance costs for the current expense month allocated to each of Group 1 and Group 2. Group R(m) for Group 1 is the twelve (12) month average revenue for the current expense month and for Group 2 it is the twelve (12) month average non-fuel revenue for the current expense month. T T

DEFINITIONS

1. For all Plans, E(m) = [(RB/12) (ROR + (ROR – DR) (TR / (1 – TR))] + OE – EAS + BR
   a. RB is the Total Environmental Compliance Rate Base.
   b. ROR is the Rate of Return on Environmental Compliance Rate Base, designated as the overall rate of return [cost of short-term debt, long-term debt, preferred stock, and common equity].
   c. DR is the Debt Rate [cost of short-term debt, and long-term debt].
   d. TR is the Composite Federal and State Income Tax Rate.
   e. OE is the Operating Expenses. OE includes operation and maintenance expense recovery authorized by the K.P.S.C. in all approved ECR Plan proceedings.
   f. EAS is the total proceeds from emission allowance sales.
   g. BR is the operation and maintenance expenses, and/or revenues if applicable, associated with Beneficial Reuse.
   h. Plans are the environmental surcharge compliance plans submitted to and approved by the Kentucky Public Service Commission pursuant to KRS 278.183.

DATE OF ISSUE: ~~May 14, 2019~~March 31, 2020

DATE EFFECTIVE: ~~With Service Rendered~~September 30, 2020
~~On and After May 1, 2019~~

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. ~~2018-00294~~2020-00060 dated ~~April 30, 2019~~XX, 2020

Kentucky Utilities Company

P.S.C. No. 19, First Revision of Original Sheet No. 87.1
Canceling ~~P.S.C. No. 19, Original Sheet No. 87.1~~

Adjustment Clause **ECR**
Environmental Cost Recovery Surcharge

DEFINITIONS (continued)

2. Total E(m) (sum of each approved environmental compliance plan revenue requirement) is multiplied by the Jurisdictional Allocation Factor. Jurisdictional E(m) is adjusted for any (Over)/Under collection or prior period adjustment and by the subtraction of the Revenue Collected through Base Rates for the Current Expense month to arrive at Adjusted Net Jurisdictional E(m). Adjusted Net Jurisdictional E(m) is allocated to Group 1 and Group 2 on the basis of Revenue as a Percentage of Total Revenue for the twelve (12) months ending with the Current Month to arrive at Group 1 E(m) and Group 2 E(m). ~~T~~

3. The Group 1 R(m) is the average of total Group 1 monthly base revenue for the twelve (12) months ending with the current expense month. Base revenue includes Customer, energy, and lighting charges for each rate schedule included in Group 1 to which this mechanism is applicable and automatic adjustment clause revenues for the Fuel Adjustment Clause and the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 1. ~~T~~

4. The Group 2 R(m) is the average of total Group 2 monthly base non-fuel revenue for the twelve (12) months ending with the current expense month. Base non-fuel revenue includes Customer, non-fuel energy, and demand charges for each rate schedule included in Group 2 to which this mechanism is applicable and automatic adjustment clause revenues for the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 2. Non-fuel energy is equal to the tariff energy rate for each rate schedule included in Group 2 less the base fuel factor as defined on Sheet No. 85.1, Paragraph 6. ~~T~~ ~~T~~

5. Current expense month (m) shall be the second month preceding the month in which the Environmental Surcharge is billed.

DATE OF ISSUE: ~~May 14, 2019~~March 31, 2020

DATE EFFECTIVE: September 30, 2020~~With Service Rendered On and After May 1, 2019~~

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. ~~2018-00294~~2020-00060 dated ~~April 30, 2019~~XX, 2020

ES FORM 1.00

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Net Jurisdictional E(m) and
Jurisdictional Environmental Surcharge Billing Factor
For the Expense Month of

GROUP 1 (Total Revenue)

Group 1 E(m) -- ES Form 1.10, line 15	=
Group 1 ES Billing Factor -- ES Form 1.10, line 17	=

GROUP 2 (Net Revenue)

Group 2 E(m) -- ES Form 1.10, line 15	=
Group 2 ES Billing Factor -- ES Form 1.10, line 17	=

Effective Date for Billing:

Submitted by: ______________________________

Title: Manager, Revenue Requirements/Cost of Service

Date Submitted:

ES FORM 1.10

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Calculation of Total E(m) and
Jurisdictional Surcharge Billing Factor

For the Expense Month of

Calculation of Total E(m)

E(m) = [(RB / 12) (ROR+(ROR -DR)(TR/(1-TR)))] + OE - BAS + BR, where

RB	=	Environmental Compliance Rate Base
ROR	=	Rate of Return on the Environmental Compliance Rate Base
DR	=	Debt Rate (both short-term and long-term debt)
TR	=	Composite Federal & State Income Tax Rate
OE	=	Pollution Control Operating Expenses
BAS	=	Total Proceeds from By-Product and Allowance Sales
BR	=	Beneficial Reuse Operating Expenses

				Environmental Compliance Plans
(1)	RB		=	
(2)	RB / 12		=	
(3)	(ROR + (ROR - DR) (TR / (1 - TR)))		=	
(4)	OE		=	
(5)	BAS		=	
(6)	BR		=	
(7)	E(m)	(2) x (3) + (4) - (5) + (6)	=	

Calculation of Adjusted Net Jurisdictional E(m)

(8)	Jurisdictional Allocation Ratio for Expense Month -- ES Form 3.10	=	
(9)	Jurisdictional E(m) = Total E(m) x Jurisdictional Allocation Ratio [(7) x (8)]	=	
(10)	Adjustment for (Over)/Under-collection pursuant to Case No. 2019-00014	=	
(11)	Prior Period Adjustment (if necessary)	=	
(12)	Revenue Collected through Base Rates	=	
(13)	Adjusted Net Jurisdictional E(m) [(9) + (10) + (11) - (12)]	=	

Calculation of Group Environmental Surcharge Billing Factors

			GROUP 1 (Total Revenue)	GROUP 2 (Net Revenue)
(14)	Revenue as a Percentage of 12-month Total Revenue ending with the Current Month -- ES Form 3.00	=		
(15)	Group E(m) [(13) x (14)]	=		
(16)	Group R(m) = Average Monthly Group Revenue for the 12 Months Ending with the Current Expense Month -- ES Form 3.00	=		
(17)	Group Environmental Surcharge Billing Factors [(15) ÷ (16)]	=		

ES FORM 2.00

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Revenue Requirements of Environmental Compliance Costs
For the Expense Month of

Determination of Environmental Compliance Rate Base

	Environmental Compliance Plan	
Eligible Pollution Control Plant		
Eligible Pollution CWIP Excluding AFUDC		
Subtotal		
Additions:		
Inventory - Emission Allowances per ES Form 2.31, 2.32, 2.33 and 2.34		
Less: Allowance Inventory Baseline		
Net Emission Allowance Inventory		
Cash Working Capital Allowance		
Net Unamortized Closure Cost Balance - Active Stations[1]		
Net Unamortized Closure Cost Balance - Retired Stations[1]		
Subtotal		
Deductions:		
Accumulated Depreciation on Eligible Pollution Control Plant		
Pollution Control Deferred Income Taxes		
Pollution Control Deferred Investment Tax Credit		
Subtotal		
Environmental Compliance Rate Base		

Determination of Pollution Control Operating Expenses

	Environmental Compliance Plan	
Monthly Operations & Maintenance Expense		
Monthly Depreciation & Amortization Expense		
Monthly Taxes Other Than Income Taxes - Eligible Plant		
Monthly Taxes Other Than Income Taxes - Closure Costs		
Amortization of Monthly Closure Costs - Active Stations		
Amortization of Monthly Closure Costs - Retired Stations		
Amortization of Excess ADIT with gross-up		
Monthly Emission Allowance Expense from ES Form 2.31, 2.32, 2.33 and 2.34		
Add KU Current Month TC2 Emission Allowance Expense reported on ES Form 2.31, 2.32, 2.33 and 2.34		
Less Monthly Emission Allowance Expense in base rates		
Net Recoverable Emission Allowance Expense		
Monthly Surcharge Consultant Fee		
Construction Monitoring Consultant Fee		
Total Pollution Control Operations Expense		

Determination of Beneficial Reuse Operating Expenses

	Environmental Compliance Plan
Total Monthly Beneficial Reuse Expense	
Adjustment for Beneficial Reuse in Base Rates (from ES Form 2.61)	
Net Beneficial Reuse Operations Expense	

Note 1: The net unamortized closure cost balance is comprised of CCR closure cost expenditures less accumulated amortization, accumulated deferred income taxes and amount in base rates.

ES FORM 2.01

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Amortization of Monthly CCR Closure Costs

For the Month Ended:

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Description	Accumulated CCR Closure Costs	Accumulated Amortization (Prior Month)	Current Month Amortization	Accumulated Amortization (Current Month)	Accumulated Deferred Income Taxes (ADIT)	Unamortized CCR Closure Cost Balance (Net of ADIT)
			[(2)-(3)]/ RemainingAmortMonths	(3)+(4)		(2)-(5)-(6)
2016 Plan:						
Amended Project 36 - Brown Station (Main Pond)						
Project 39 - Green River Station						
Project 39 - Pineville Station						
Project 39 - Tyrone Station						
Project 40 - Ghent Station						
Project 41 - Trimble County Station						
Project 42 - Brown Station (Aux. Pond)						
Net Total - All Projects:						

Note 1: The Accumulated Deferred Income Taxes (ADIT) includes Excess Deferred Taxes resulting from the Tax Cuts and Jobs Act.

ES FORM 2.10

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Plant, CWIP & Depreciation Expense

For the Month Ended:

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Description	Eligible Plant In Service	Eligible Accumulated Depreciation	CWIP Amount Excluding AFUDC	Eligible Net Plant In Service	Unamortized ITC as of Date	Deferred Tax Balance as of Date	Monthly Depreciation Expense	Monthly Property Tax Expense
				(2)-(3)+(4)				
2009 Plan:								
Project 28 - Brown 3 SCR								
Project 29 - ATB Expansion at E.W. Brown Station (Phase II)								
Project 30 - Ghent CCP Storage (Landfill- Phase I)								
Project 31 - Trimble County Ash Treatment Basin (BAP/GSP)								
Project 32 - Trimble County CCP Storage (Landfill - Phase I)								
Project 33 - Beneficial Reuse								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2009 Plan								
Net Total - 2009 Plan:								
2011 Plan:								
Project 29 - Brown Landfill (Phase I)								
Project 34 - E.W. Brown Station Air Compliance								
Project 35 - Ghent Station Air Compliance								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2011 Plan								
Net Total - 2011 Plan:								
2016 Plan:								
Project 36 - Brown Landfill (Phase II)								
Project 37 - Ghent 2 WFGD Improvements								
Project 38 - Supplemental Mercury Control								
Project 40 - Ghent New Process Water Systems								
Project 41 - Trimble County New Process Water Systems								
Project 42 - Brown New Process Water Systems								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2016 Plan								
Net Total - 2016 Plan:								
Net Total - All Plans:								

Note 1: Trimble County projects for the 2009 Plan are proportionately shared by KU at 48% and LG&E at 52%
Note 2: Project 29 as approved in the 2009 ECR Plan recovers costs associated with the Brown Aux Pond (Phase II). In the 2011 Plan, Project 29 was amended to recover costs associated with the conversion of the Brown Main Ash Pond to the Brown Landfill (Phase I)
Note 3: The Deferred Tax Balance includes Excess Deferred Taxes resulting from the Tax Cuts and Jobs Act.

ES FORM 2.30

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances

For the Month Ended:

Vintage Year	Number of Allowances				Total Dollar Value Of Vintage Year				Comments and Explanations
	SO_2 CAIR	SO_2 CSAPR	NOx Ozone Season	NOx Annual	SO_2 CAIR	SO_2 CSAPR	NOx Ozone Season	NOx Annual	
Current Year									
2021									
2022									
2023									
2024									
2025									
2026									
2027									
2028									
2029									
2030									
2031									
2032									
2033									
2034									
2035									
2036									
2037									
2038									
2039									
2040									
2041 - 2050									

In the "Comments and Explanation" Column, describe any allowance inventory adjustment other than the assignment of allowances by EPA. Inventory adjustments include, but are not limited to, purchases, allowances acquired as part of other purchases, and the sale of allowances.

ES FORM 2.31

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of CAIR Emission Allowances (SO_2) - Current Vintage Year

For the Expense Month of

	Beginning Inventory	Allocations/ Purchases	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity							
Dollars							
$/Allowance							
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity							
Dollars							
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity							
Dollars							
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity							
Dollars							
$/Allowance							
From LG&E							
Quantity							
Dollars							
$/Allowance							

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor

ES FORM 2.32

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of CSAPR Emission Allowances (SO_2) - Current Vintage Year

For the Expense Month of

	Beginning Inventory	Allocations/ Purchases	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity							
Dollars							
$/Allowance							
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity							
Dollars							
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity							
Dollars							
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity							
Dollars							
$/Allowance							
From LG&E							
Quantity							
Dollars							
$/Allowance							

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor

ES FORM 2.33

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances (NOx) - Ozone Season Allowance Allocation

For the Expense Month of

	Beginning Inventory	Allocations/ Purchases	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity							
Dollars							
$/Allowance							
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity							
Dollars							
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity							
Dollars							
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity							
Dollars							
$/Allowance							
From LG&E:							
Quantity							
Dollars							
$/Allowance							

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor.

ES FORM 2.34

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Inventory of Emission Allowances (NOx) - Annual Allowance Allocation

For the Expense Month of

	Beginning Inventory	Allocations/ Purchases	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity							
Dollars							
$/Allowance							
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity							
Dollars							
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity							
Dollars							
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity							
Dollars							
$/Allowance							
From LG&E:							
Quantity							
Dollars							
$/Allowance							

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor.

ES FORM 2.40

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
O&M Expenses and Determination of Cash Working Capital Allowance

For the Month Ended:

Environmental Compliance Plan	
O&M Expenses	Environmental Compliance Plans
11th Previous Month	
10th Previous Month	
9th Previous Month	
8th Previous Month	
7th Previous Month	
6th Previous Month	
5th Previous Month	
4th Previous Month	
3rd Previous Month	
2nd Previous Month	
Previous Month	
Current Month	
Total 12 Month O&M	

Determination of Working Capital Allowance	
12 Months O&M Expenses	
One Eighth (1/8) of 12 Month O&M Expenses	1/8
Pollution Control Cash Working Capital Allowance	

ES FORM 2.50

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Pollution Control - Operations & Maintenance Expenses

For the Month Ended:

O&M Expense Account	E. W. Brown	Ghent	Trimble County	Total
2009 Plan				
506154 - ECR NOx Operation -- Consumables				
506155 - ECR NOx Operation -- Labor and Other				
512151 - ECR NOx Maintenance				
506159 - ECR Sorbent Injection Operation				
506152 - ECR Sorbent Reactant - Reagent Only				
512152 - ECR Sorbent Injection Maintenance				
502013 - ECR Landfill Operations				
512107 - ECR Landfill Maintenance				
Adjustment for CCP Disposal in Base Rates (ES Form 2.51)				
Total 2009 Plan O&M Expenses				
2011 Plan				
506159 - ECR Sorbent Injection Operation				
506152 - ECR Sorbent Reactant - Reagent Only				
512152 - ECR Sorbent Injection Maintenance				
506156 - ECR Baghouse Operations				
512156 - ECR Baghouse Maintenance				
506151 - ECR Activated Carbon				
502013 - ECR Landfill Operations				
512107 - ECR Landfill Maintenance				
Total 2011 Plan O&M Expenses				
2016 Plan				
506153 - ECR Liquid Injection - Reagent Only				
Total 2016 Plan O&M Expenses				
Current Month O&M Expense for All Plans				

Note 1: Trimble County projects for the 2009 Plan are proportionately shared by KU at 48% and LG&E at 52%.

ES FORM 2.51

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
CCP Disposal Facilities Expenses
For the Month Ended:

On-Site CCP Disposal O&M Expense	Ghent	Trimble County
Existing CCP Disposal Facilities (Pre 2009 Plan Project)		
(1) 12 Months Ending with Expense Month		
(2) Monthly Amount [(1) / 12]		
2009 Plan Project		
(3) Monthly Expense		
Total Generating Station		
(4) Monthly Expense [(2) + (3)]		
Base Rates		
(5) Annual Expense Amount (12 Mo Ending with Last Test Year)		
(6) Monthly Expense Amount [(5) / 12]		
(7) Total Generating Station Less Base Rates [(4) - (6)]		
(8) Less 2009 Plan Project [(7) - (3)]		
If Line (8) Greater than Zero, No Adjustment		
If Line (8) Less than Zero, Adjustment for Base Rates		
Adjustment for Base Rate Amount (to ES Form 2.50)		

Note 1: Trimble County projects for the 2009 Plan are proportionately shared by KU at 48% and LG&E at 52%.

Note 2: ES Form 2.51 will not be utilized until O&M costs associated with the 2009 Plan are incurred.

ES FORM 2.60

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Beneficial Reuse - Operations & Maintenance Expenses
For the Month Ended:

Third Party	O&M Expense Account	Plant	Total O&M
Total Monthly Beneficial Reuse Expense			
Adjustment for Beneficial Reuse in Base Rates (from ES Form 2.61)			
Net Beneficial Reuse O&M Expense			

ES FORM 2.61

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Beneficial Reuse Opportunities
For the Month Ended:

	On-Site CCP Disposal O&M Expense	E. W. Brown	Ghent	Trimble County	Total
	Existing Beneficial Reuse Opportunities (Pre 2009 Plan Project)				
(1)	12 Months Ending with Expense Month				
(2)	Monthly Amount [(1) / 12]				
	2009 Plan Project 33				
(3)	Monthly Amount (Expense/Revenue)				
	Total Beneficial Reuse - Generating Station				
(4)	Monthly Expense [(2) + (3)]				
	Beneficial Reuse in Base Rates				
(5)	Annual Expense Amount (12 Mo Ending with Last Test Year)				
(6)	Monthly Expense Amount [(5) / 12]				
(7)	Total Generating Station Less Base Rates [(4) - (6)]				
(8)	Less 2009 Plan Project 33 [(7) - (3)]				
	If Line (8) Greater than Zero, No Adjustment				
	If Line (8) Less than Zero, Adjustment for Base Rates				
Adjustment for Base Rate Amount (to ES Form 2.60)					

Note 1: Trimble County projects for the 2009 Plan are proportionately shared by KU at 48% and LG&E at 52%.

ES FORM 3.00

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Monthly Average Revenue Computation of R (m) for GROUP 1 AND GROUP 2

For the Month Ended:

	GROUP 1 (Total Revenues) - Kentucky Jurisdictional Revenues						
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Month	Non-fuel Base Rate Revenues	Base Rate Fuel Component	Fuel Clause Revenues Including Off-System Sales Tracker	DSM Revenues	Environmental Surcharge Revenues	Total (2)+(3)+(4)+(5)+(6)	Total Excluding Environmental Surcharge (7)-(6)
Average Monthly Jurisdictional Revenues, Excluding Environmental Surcharge, for 12 Months Ending Current Expense Month.							
Average Kentucky Jurisdictional Revenues excluding Environmental Surcharge for 12-months ending with Current Month =							
GROUP 1 Revenues as a Percentage of Total Revenues for 12-months ending with the Current Month							

	GROUP 2 (Net Revenues) - Kentucky Jurisdictional Revenues							
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Month	Non-fuel Base Rate Revenues	Base Rate Fuel Component	Fuel Clause Revenues Including Off-System Sales Tracker	DSM Revenues	Environmental Surcharge Revenues	Total (2)+(3)+(4)+(5)+(6)	Total Excluding Environmental Surcharge (7)-(6)	Total Non-Fuel Revenues plus DSM (2)+(5)
Average Monthly Jurisdictional Revenues, Excluding Environmental Surcharge and Fuel, for 12 Months Ending Current Expense Month.								
Average Kentucky Jurisdictional Revenues excluding Environmental Surcharge for 12-months ending with Current Month =								
GROUP 2 Revenues as a Percentage of Total Revenues for 12-months ending with the Current Month								

ES FORM 3.10

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Reconciliation of Reported Revenues

For the Month Ended:

		Revenues per Form 3.00	Revenues per Income Statement
Kentucky Retail Revenues			
(1)	Base Rates (Customer Charge, Energy Charge, Demand Charge)		
(2)	Fuel Adjustment Clause including Off System Sales Tracker		
(3)	DSM		
(4)	Environmental Surcharge		
(5)	CSR Credits		
(6)	EDR Credits		
(7)	Total Kentucky Jurisdictional Revenues for Environmental Surcharge Purposes =		
Non -Jurisdictional Revenues			
(8)	Tennessee Retail		
(9)	Virginia Retail		
(10)	Wholesale		
(11)	InterSystem (Total Less Transmission Portion Booked in Account 447)		
(12)	Total Non-Jurisdictional Revenues for Environmental Surcharge Purposes =		
(13)	Total Company Revenues for Environmental Surcharge Purposes =		
	Jurisdictional Allocation Ratio for Current Month [(7) / (13)] =		
Reconciling Revenues			
(14)	Brokered		
(15)	InterSystem (Transmission Portion Booked in Account 447)		
(16)	Unbilled		
(17)	Provision for Refund		
(18)	Miscellaneous		
(19)	Total Company Revenues per Income Statement =		

NOTE: Base Rates (Line 1) includes the TCJA credit of $0.00 for this month.

ES FORM 1.00

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Net Jurisdictional E(m) and
Jurisdictional Environmental Surcharge Billing Factor
For the Expense Month of

GROUP 1 (Total Revenue)

Group 1 E(m) -- ES Form 1.10, line 15	=
Group 1 ES Billing Factor -- ES Form 1.10, line 17	=

GROUP 2 (Net Revenue)

Group 2 E(m) -- ES Form 1.10, line 15	=
Group 2 ES Billing Factor -- ES Form 1.10, line 17	=

Effective Date for Billing:

Submitted by: ______________________________

Title: Manager, Revenue Requirements/Cost of Service

Date Submitted:

ES FORM 1.10

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Calculation of Total E(m) and
Jurisdictional Surcharge Billing Factor

For the Expense Month of

Calculation of Total E(m)

E(m) = [(RB / 12) (ROR+(ROR -DR)(TR/(1-TR)))] + OE - BAS + BR, where

RB	=	Environmental Compliance Rate Base
ROR	=	Rate of Return on the Environmental Compliance Rate Base
DR	=	Debt Rate (both short-term and long-term debt)
TR	=	Composite Federal & State Income Tax Rate
OE	=	Pollution Control Operating Expenses
BAS	=	Total Proceeds from By-Product and Allowance Sales
BR	=	Beneficial Reuse Operating Expenses

				Environmental Compliance Plans
(1)	RB		=	
(2)	RB / 12		=	
(3)	(ROR + (ROR - DR) (TR / (1 - TR)))		=	
(4)	OE		=	
(5)	BAS		=	
(6)	BR		=	
(7)	E(m)	(2) x (3) + (4) - (5) + (6)	=	

Calculation of Adjusted Net Jurisdictional E(m)

(8)	Jurisdictional Allocation Ratio for Expense Month -- ES Form 3.10	=	
(9)	Jurisdictional E(m) = Total E(m) x Jurisdictional Allocation Ratio [(7) x (8)]	=	
(10)	Adjustment for (Over)/Under-collection pursuant to Case No. 2019-00014	=	
(11)	Prior Period Adjustment (if necessary)	=	
(12)	Revenue Collected through Base Rates	=	
(13)	Adjusted Net Jurisdictional E(m) [(9) + (10) + (11) - (12)]	=	

Calculation of Group Environmental Surcharge Billing Factors

			GROUP 1 (Total Revenue)	**GROUP 2 (Net Revenue)**
(14)	Revenue as a Percentage of 12-month Total Revenue ending with the Current Month -- ES Form 3.00	=		
(15)	Group E(m) [(13) x (14)]	=		
(16)	Group R(m) = Average Monthly Group Revenue for the 12 Months Ending with the Current Expense Month -- ES Form 3.00	=		
(17)	Group Environmental Surcharge Billing Factors [(15) ÷ (16)]	=		

ES FORM 2.00

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Revenue Requirements of Environmental Compliance Costs
For the Expense Month of

Determination of Environmental Compliance Rate Base

	Environmental Compliance Plan	
Eligible Pollution Control Plant		
Eligible Pollution CWIP Excluding AFUDC		
Subtotal		
Additions:		
Inventory - Emission Allowances per ES Form 2.31, 2.32, 2.33 and 2.34		
Less: Allowance Inventory Baseline		
Net Emission Allowance Inventory		
Cash Working Capital Allowance		
Net Unamortized Closure Cost Balance - Active Stations[1]		
Net Unamortized Closure Cost Balance - Retired Stations[1]		
Subtotal		
Deductions:		
Accumulated Depreciation on Eligible Pollution Control Plant		
Pollution Control Deferred Income Taxes		
Pollution Control Deferred Investment Tax Credit		
Subtotal		
Environmental Compliance Rate Base		

Determination of Pollution Control Operating Expenses

	Environmental Compliance Plan	
Monthly Operations & Maintenance Expense		
Monthly Depreciation & Amortization Expense		
Monthly Taxes Other Than Income Taxes - Eligible Plant		
Monthly Taxes Other Than Income Taxes - Closure Costs		
Amortization of Monthly Closure Costs - Active Stations		
Amortization of Monthly Closure Costs - Retired Stations		
Amortization of Excess ADIT with gross-up		
Monthly Emission Allowance Expense from ES Form 2.31, 2.32, 2.33 and 2.34		
Add KU Current Month TC2 Emission Allowance Expense reported on ES Form 2.31, 2.32, 2.33 and 2.34		
Less Monthly Emission Allowance Expense in base rates		
Net Recoverable Emission Allowance Expense		
Monthly Surcharge Consultant Fee		
Construction Monitoring Consultant Fee		
Total Pollution Control Operations Expense		

Determination of Beneficial Reuse Operating Expenses

	Environmental Compliance Plan
Total Monthly Beneficial Reuse Expense	
Adjustment for Beneficial Reuse in Base Rates (from ES Form 2.61)	
Net Beneficial Reuse Operations Expense	

Note 1: The net unamortized closure cost balance is comprised of CCR closure cost expenditures less accumulated amortization, accumulated deferred income taxes and amount in base rates.

ES FORM 2.01

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Amortization of Monthly CCR Closure Costs

For the Month Ended:

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Description	Accumulated CCR Closure Costs	Accumulated Amortization (Prior Month)	Current Month Amortization	Accumulated Amortization (Current Month)	Accumulated Deferred Income Taxes (ADIT)	Unamortized CCR Closure Cost Balance (Net of ADIT)
			[(2)-(3)]/ RemainingAmortMonths	(3)+(4)		(2)-(5)-(6)
2016 Plan:						
Amended Project 36 - Brown Station (Main Pond)						
Project 39 - Green River Station						
Project 39 - Pineville Station						
Project 39 - Tyrone Station						
Project 40 - Ghent Station						
Project 41 - Trimble County Station						
Project 42 - Brown Station (Aux. Pond)						
Net Total - All Projects:						

Note 1: The Accumulated Deferred Income Taxes (ADIT) includes Excess Deferred Taxes resulting from the Tax Cuts and Jobs Act.

ES FORM 2.10

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Plant, CWIP & Depreciation Expense

For the Month Ended:

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Description	Eligible Plant In Service	Eligible Accumulated Depreciation	CWIP Amount Excluding AFUDC	Eligible Net Plant In Service	Unamortized ITC as of Date	Deferred Tax Balance as of Date	Monthly Depreciation Expense	Monthly Property Tax Expense
				(2)-(3)+(4)				
2009 Plan:								
Project 28 - Brown 3 SCR								
Project 29 - ATB Expansion at E.W. Brown Station (Phase II)								
Project 30 - Ghent CCP Storage (Landfill- Phase I)								
Project 31 - Trimble County Ash Treatment Basin (BAP/GSP)								
Project 32 - Trimble County CCP Storage (Landfill - Phase I)								
Project 33 - Beneficial Reuse								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2009 Plan								
Net Total - 2009 Plan:								
2011 Plan:								
Project 29 - Brown Landfill (Phase I)								
Project 34 - E.W. Brown Station Air Compliance								
Project 35 - Ghent Station Air Compliance								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2011 Plan								
Net Total - 2011 Plan:								
2016 Plan:								
Project 36 - Brown Landfill (Phase II)								
Project 37 - Ghent 2 WFGD Improvements								
Project 38 - Supplemental Mercury Control								
Project 40 - Ghent New Process Water Systems								
Project 41 - Trimble County New Process Water Systems								
Project 42 - Brown New Process Water Systems								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2016 Plan								
Net Total - 2016 Plan:								
2020 Plan:								
Project 43 - Ghent ELG Water Treatment System, Diffuser, and BATW Recirculation System								
Project 44 - Trimble County ELG Water Treatment System								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2020 Plan								
Net Total - 2020 Plan:								
Net Total - All Plans:								

Note 1: Trimble County projects for the 2009 Plan and 2020 Plan are proportionately shared by KU at 48% and LG&E at 52%
Note 2: Project 29 as approved in the 2009 ECR Plan recovers costs associated with the Brown Aux Pond (Phase II). In the 2011 Plan, Project 29 was amended to recover costs associated with the conversion of the Brown Main Ash Pond to the Brown Landfill (Phase I)
Note 3: The Deferred Tax Balance includes Excess Deferred Taxes resulting from the Tax Cuts and Jobs Act.

ES FORM 2.30

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances

For the Month Ended:

Vintage Year	Number of Allowances				Total Dollar Value Of Vintage Year				Comments and Explanations
	SO_2 CAIR	SO_2 CSAPR	NOx Ozone Season	NOx Annual	SO_2 CAIR	SO_2 CSAPR	NOx Ozone Season	NOx Annual	
Current Year									
2021									
2022									
2023									
2024									
2025									
2026									
2027									
2028									
2029									
2030									
2031									
2032									
2033									
2034									
2035									
2036									
2037									
2038									
2039									
2040									
2041 - 2050									

In the "Comments and Explanation" Column, describe any allowance inventory adjustment other than the assignment of allowances by EPA. Inventory adjustments include, but are not limited to, purchases, allowances acquired as part of other purchases, and the sale of allowances.

ES FORM 2.31

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of CAIR Emission Allowances (SO_2) - Current Vintage Year

For the Expense Month of

	Beginning Inventory	Allocations/ Purchases	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity							
Dollars							
$/Allowance							
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity							
Dollars							
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity							
Dollars							
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity							
Dollars							
$/Allowance							
From LG&E							
Quantity							
Dollars							
$/Allowance							

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor

ES FORM 2.32

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of CSAPR Emission Allowances (SO_2) - Current Vintage Year

For the Expense Month of

	Beginning Inventory	Allocations/ Purchases	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity							
Dollars							
$/Allowance							
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity							
Dollars							
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity							
Dollars							
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity							
Dollars							
$/Allowance							
From LG&E							
Quantity							
Dollars							
$/Allowance							

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor

ES FORM 2.33

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances (NOx) - Ozone Season Allowance Allocation

For the Expense Month of

	Beginning Inventory	Allocations/ Purchases	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity							
Dollars							
$/Allowance							
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity							
Dollars							
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity							
Dollars							
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity							
Dollars							
$/Allowance							
From LG&E:							
Quantity							
Dollars							
$/Allowance							

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor.

ES FORM 2.34

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Inventory of Emission Allowances (NOx) - Annual Allowance Allocation

For the Expense Month of

	Beginning Inventory	Allocations/ Purchases	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity							
Dollars							
$/Allowance							
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity							
Dollars							
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity							
Dollars							
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity							
Dollars							
$/Allowance							
From LG&E:							
Quantity							
Dollars							
$/Allowance							

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor.

ES FORM 2.40

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
O&M Expenses and Determination of Cash Working Capital Allowance

For the Month Ended:

Environmental Compliance Plan	
O&M Expenses	Environmental Compliance Plans
11th Previous Month	
10th Previous Month	
9th Previous Month	
8th Previous Month	
7th Previous Month	
6th Previous Month	
5th Previous Month	
4th Previous Month	
3rd Previous Month	
2nd Previous Month	
Previous Month	
Current Month	
Total 12 Month O&M	

Determination of Working Capital Allowance	
12 Months O&M Expenses	
One Eighth (1/8) of 12 Month O&M Expenses	1/8
Pollution Control Cash Working Capital Allowance	

ES FORM 2.50

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Pollution Control - Operations & Maintenance Expenses

For the Month Ended:

O&M Expense Account	E. W. Brown	Ghent	Trimble County	Total
2009 Plan				
506154 - ECR NOx Operation -- Consumables				
506155 - ECR NOx Operation -- Labor and Other				
512151 - ECR NOx Maintenance				
506159 - ECR Sorbent Injection Operation				
506152 - ECR Sorbent Reactant - Reagent Only				
512152 - ECR Sorbent Injection Maintenance				
502013 - ECR Landfill Operations				
512107 - ECR Landfill Maintenance				
Adjustment for CCP Disposal in Base Rates (ES Form 2.51)				
Total 2009 Plan O&M Expenses				
2011 Plan				
506159 - ECR Sorbent Injection Operation				
506152 - ECR Sorbent Reactant - Reagent Only				
512152 - ECR Sorbent Injection Maintenance				
506156 - ECR Baghouse Operations				
512156 - ECR Baghouse Maintenance				
506151 - ECR Activated Carbon				
502013 - ECR Landfill Operations				
512107 - ECR Landfill Maintenance				
Total 2011 Plan O&M Expenses				
2016 Plan				
506153 - ECR Liquid Injection - Reagent Only				
Total 2016 Plan O&M Expenses				
2020 Plan				
502015 - ECR Effluent Water Chemicals				
502017 - ECR Effluent Water Operations				
512157 - ECR Effluent Water Maintenance				
Total 2020 Plan O&M Expenses				
Current Month O&M Expense for All Plans				

Note 1: Trimble County projects for the 2009 Plan and 2020 Plan are proportionately shared by KU at 48% and LG&E at 52%.

ES FORM 2.51

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
CCP Disposal Facilities Expenses
For the Month Ended:

	On-Site CCP Disposal O&M Expense	Ghent	Trimble County
	Existing CCP Disposal Facilities (Pre 2009 Plan Project)		
(1)	12 Months Ending with Expense Month		
(2)	Monthly Amount [(1) / 12]		
	2009 Plan Project		
(3)	Monthly Expense		
	Total Generating Station		
(4)	Monthly Expense [(2) + (3)]		
	Base Rates		
(5)	Annual Expense Amount (12 Mo Ending with Last Test Year)		
(6)	Monthly Expense Amount [(5) / 12]		
(7)	Total Generating Station Less Base Rates [(4) - (6)]		
(8)	Less 2009 Plan Project [(7) - (3)]		
	If Line (8) Greater than Zero, No Adjustment		
	If Line (8) Less than Zero, Adjustment for Base Rates		
	Adjustment for Base Rate Amount (to ES Form 2.50)		

Note 1: Trimble County projects for the 2009 Plan are proportionately shared by KU at 48% and LG&E at 52%.

Note 2: ES Form 2.51 will not be utilized until O&M costs associated with the 2009 Plan are incurred.

ES FORM 2.60

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Beneficial Reuse - Operations & Maintenance Expenses
For the Month Ended:

Third Party	O&M Expense Account	Plant	Total O&M
Total Monthly Beneficial Reuse Expense			
Adjustment for Beneficial Reuse in Base Rates (from ES Form 2.61)			
Net Beneficial Reuse O&M Expense			

ES FORM 2.61

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Beneficial Reuse Opportunities
For the Month Ended:

	On-Site CCP Disposal O&M Expense	E. W. Brown	Ghent	Trimble County	Total
	Existing Beneficial Reuse Opportunities (Pre 2009 Plan Project)				
(1)	12 Months Ending with Expense Month				
(2)	Monthly Amount [(1) / 12]				
	2009 Plan Project 33				
(3)	Monthly Amount (Expense/Revenue)				
	Total Beneficial Reuse - Generating Station				
(4)	Monthly Expense [(2) + (3)]				
	Beneficial Reuse in Base Rates				
(5)	Annual Expense Amount (12 Mo Ending with Last Test Year)				
(6)	Monthly Expense Amount [(5) / 12]				
(7)	Total Generating Station Less Base Rates [(4) - (6)]				
(8)	Less 2009 Plan Project 33 [(7) - (3)]				
	If Line (8) Greater than Zero, No Adjustment				
	If Line (8) Less than Zero, Adjustment for Base Rates				
Adjustment for Base Rate Amount (to ES Form 2.60)					

Note 1: Trimble County projects for the 2009 Plan are proportionately shared by KU at 48% and LG&E at 52%.

ES FORM 3.00

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Monthly Average Revenue Computation of R (m) for GROUP 1 AND GROUP 2

For the Month Ended:

	GROUP 1 (Total Revenues) - Kentucky Jurisdictional Revenues						
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Month	Non-fuel Base Rate Revenues	Base Rate Fuel Component	Fuel Clause Revenues Including Off-System Sales Tracker	DSM Revenues	Environmental Surcharge Revenues	Total (2)+(3)+(4)+(5)+(6)	Total Excluding Environmental Surcharge (7)-(6)
Average Monthly Jurisdictional Revenues, Excluding Environmental Surcharge, for 12 Months Ending Current Expense Month.							
Average Kentucky Jurisdictional Revenues excluding Environmental Surcharge for 12-months ending with Current Month =							
GROUP 1 Revenues as a Percentage of Total Revenues for 12-months ending with the Current Month							

	GROUP 2 (Net Revenues) - Kentucky Jurisdictional Revenues							
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Month	Non-fuel Base Rate Revenues	Base Rate Fuel Component	Fuel Clause Revenues Including Off-System Sales Tracker	DSM Revenues	Environmental Surcharge Revenues	Total (2)+(3)+(4)+(5)+(6)	Total Excluding Environmental Surcharge (7)-(6)	Total Non-Fuel Revenues plus DSM (2)+(5)
Average Monthly Jurisdictional Revenues, Excluding Environmental Surcharge and Fuel, for 12 Months Ending Current Expense Month.								
Average Kentucky Jurisdictional Revenues excluding Environmental Surcharge for 12-months ending with Current Month =								
GROUP 2 Revenues as a Percentage of Total Revenues for 12-months ending with the Current Month								

ES FORM 3.10

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Reconciliation of Reported Revenues

For the Month Ended:

		Revenues per Form 3.00	Revenues per Income Statement
Kentucky Retail Revenues			
(1)	Base Rates (Customer Charge, Energy Charge, Demand Charge)		
(2)	Fuel Adjustment Clause including Off System Sales Tracker		
(3)	DSM		
(4)	Environmental Surcharge		
(5)	CSR Credits		
(6)	EDR Credits		
(7)	Total Kentucky Jurisdictional Revenues for Environmental Surcharge Purposes =		
Non -Jurisdictional Revenues			
(8)	Tennessee Retail		
(9)	Virginia Retail		
(10)	Wholesale		
(11)	InterSystem (Total Less Transmission Portion Booked in Account 447)		
(12)	Total Non-Jurisdictional Revenues for Environmental Surcharge Purposes =		
(13)	Total Company Revenues for Environmental Surcharge Purposes =		
	Jurisdictional Allocation Ratio for Current Month [(7) / (13)] =		
Reconciling Revenues			
(14)	Brokered		
(15)	InterSystem (Transmission Portion Booked in Account 447)		
(16)	Unbilled		
(17)	Provision for Refund		
(18)	Miscellaneous		
(19)	Total Company Revenues per Income Statement =		

NOTE: Base Rates (Line 1) includes the TCJA credit of $0.00 for this month.

Kentucky Utilities Company
Environmental Cost Recovery Surcharge Summary

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total E(m) - (in '000s)	$709	$7,458	$15,482	$23,615	$30,556	$37,421	$36,659	$35,933	$35,242	$34,582
12 Month Average Jurisdictional Ratio	91.65%	91.65%	91.65%	91.65%	91.65%	91.65%	91.65%	91.65%	91.65%	91.65%
Jurisdictional E(m) - (in '000s)	$650	$6,835	$14,190	$21,644	$28,005	$34,297	$33,599	$32,934	$32,300	$31,695
Forecasted Jurisdictional R(m) - (in '000s)	$1,580	$1,582	$1,585	$1,592	$1,604	$1,612	$1,631	$1,644	$1,654	$1,639
Incremental Billing Factor Group 1	0.04%	0.43%	0.90%	1.36%	1.75%	2.13%	2.06%	2.00%	1.95%	1.93%
Residential Customer Impact (Group 1)										
Monthly bill (1,139 kWh per month)	$0.05	$0.50	$1.04	$1.57	$2.02	$2.46	$2.39	$2.32	$2.26	$2.24
Bill Impact for Other Group 1 Rate Schedules										
All Electric Schools	$0.75	$7.90	$16.36	$24.85	$31.91	$38.88	$37.67	$36.63	$35.69	$35.35
Lighting Energy	$0.10	$1.04	$2.15	$3.27	$4.20	$5.12	$4.96	$4.82	$4.70	$4.65
Traffic Energy	$0.01	$0.08	$0.16	$0.25	$0.32	$0.39	$0.38	$0.37	$0.36	$0.35
Lighting Service and Restricted Lighting	$0.01	$0.07	$0.14	$0.21	$0.27	$0.33	$0.32	$0.31	$0.31	$0.30
Incremental Billing Factor Group 2	0.06%	0.59%	1.24%	1.89%	2.44%	2.98%	2.92%	2.87%	2.80%	2.76%
Bill Impact for Group 2 Rate Schedules										
General Service	$0.11	$1.11	$2.32	$3.54	$4.57	$5.59	$5.48	$5.37	$5.25	$5.16
Power Service - Secondary	$1.45	$15.33	$31.91	$48.73	$62.97	$77.01	$75.47	$73.95	$72.38	$71.13
Power Service - Primary	$2.46	$26.01	$54.15	$82.68	$106.85	$130.68	$128.05	$125.48	$122.82	$120.68
Time of Day Service - Secondary	$5.80	$61.39	$127.83	$195.20	$252.24	$308.49	$302.30	$296.23	$289.95	$284.91
Time of Day Service - Primary	$29.04	$307.18	$639.61	$976.65	$1,262.07	$1,543.53	$1,512.54	$1,482.18	$1,450.72	$1,425.50
Retail Transmission Service	$94.85	$1,003.25	$2,088.99	$3,189.81	$4,122.00	$5,041.26	$4,940.04	$4,840.88	$4,738.13	$4,655.77
Fluctuating Load Service - Transmission	$859.76	$9,093.82	$18,935.31	$28,913.52	$37,363.27	$45,695.77	$44,778.23	$43,879.43	$42,948.08	$42,201.58
Outdoor Sports Lighting Service - Secondar	$0.44	$4.68	$9.74	$14.87	$19.22	$23.50	$23.03	$22.57	$22.09	$21.70

NOTE: Residential includes Volunteer Fire Department and Residential Time of Day customers.

Revenue Requirements Summary
2020 Plan - KU

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Project 43	**Ghent ELG, Diffuser, and BATW Recirculation**										
	Revenue Requirement										
	Eligible Plant	$5,566,191	$73,090,481	$146,808,337	$194,889,310	$216,236,308	$216,236,308	$216,236,308	$216,236,308	$216,236,308	$216,236,308
	Less: Retired Plant	0	0	0	0	0	0	0	0	0	0
	Less: Accumulated Depreciation	0	(87,396)	(87,396)	(3,223,397)	(7,443,689)	(16,849,969)	(26,256,248)	(35,662,527)	(45,068,807)	(54,475,086)
	Plus: Accumulated Depreciation on retired plant	0	0	0	0	0	0	0	0	0	0
	Less: Deferred Tax Balance	0	(128,576)	(243,627)	(501,393)	(2,122,106)	(3,523,135)	(4,643,019)	(5,503,020)	(6,122,359)	(6,530,489)
	Plus: Deferred Tax Balance on retired plant	0	0	0	0	0	0	0	0	0	0
	Environmental Compliance Rate Base	$5,566,191	$72,874,509	$146,477,314	$191,164,520	$206,670,513	$195,863,204	$185,337,040	$175,070,760	$165,045,142	$155,230,732
	Rate of return	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%
		$484,259	$6,340,082	$12,743,526	$16,631,313	$17,980,335	$17,040,099	$16,124,322	$15,231,156	$14,358,927	$13,505,074
	Operating expenses	$0	$0	$0	$357,929	$3,179,766	$5,826,174	$6,041,136	$6,264,155	$6,495,535	$6,735,595
	Annual Depreciation expense	0	87,396	699,166	2,436,835	4,220,292	9,406,279	9,406,279	9,406,279	9,406,279	9,406,279
	Less depreciation on retired plant	0	0	0	0	0	0	0	0	0	0
	Annual Property Tax expense	0	8,349	109,505	220,081	287,499	313,189	299,080	284,970	270,861	256,751
	Total OE	$0	$95,745	$808,671	$3,014,846	$7,687,557	$15,545,643	$15,746,495	$15,955,404	$16,172,675	$16,398,625
	Total E(m) Project 43	**$484,259**	**$6,435,827**	**$13,552,197**	**$19,646,159**	**$25,667,892**	**$32,585,741**	**$31,870,818**	**$31,186,560**	**$30,531,602**	**$29,903,699**

Revenue Requirements Summary
2020 Plan - KU

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Project 44	**KU Trimble Co ELG**										
	Revenue Requirement										
	Eligible Plant	$2,580,061	$11,700,542	$21,983,891	$34,146,653	$34,146,653	$34,146,653	$34,146,653	$34,146,653	$34,146,653	$34,146,653
	Less: Retired Plant	0	0	0	0	0	0	0	0	0	0
	Less: Accumulated Depreciation	0	0	0	(401,365)	(1,142,348)	(1,883,330)	(2,624,313)	(3,365,295)	(4,106,277)	(4,847,260)
	Plus: Accumulated Depreciation on retired plant	0	0	0	0	0	0	0	0	0	0
	Less: Deferred Tax Balance	0	0	0	(219,344)	(649,498)	(1,033,476)	(1,374,856)	(1,676,705)	(1,942,090)	(2,173,653)
	Plus: Deferred Tax Balance on retired plant	0	0	0	0	0	0	0	0	0	0
	Environmental Compliance Rate Base	$2,580,061	$11,700,542	$21,983,891	$33,525,943	$32,354,807	$31,229,846	$30,147,484	$29,104,653	$28,098,285	$27,125,740
	Rate of return	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%
		$224,465	$1,017,947	$1,912,599	$2,916,757	$2,814,868	$2,716,997	$2,622,831	$2,532,105	$2,444,551	$2,359,939
	Operating expenses	$0	$0	$0	$618,127	$1,281,219	$1,327,849	$1,376,205	$1,426,353	$1,478,359	$1,532,295
	Annual Depreciation expense	0	0	0	401,365	740,982	740,982	740,982	740,982	740,982	740,982
	Less depreciation on retired plant	0	0	0	0	0	0	0	0	0	0
	Annual Property Tax expense	0	3,870	17,551	32,976	50,618	49,506	48,395	47,284	46,172	45,061
	Total OE	$0	$3,870	$17,551	$1,052,468	$2,072,819	$2,118,337	$2,165,582	$2,214,619	$2,265,514	$2,318,338
	Total E(m) Project 44	**$224,465**	**$1,021,817**	**$1,930,149**	**$3,969,225**	**$4,887,687**	**$4,835,334**	**$4,788,413**	**$4,746,723**	**$4,710,065**	**$4,678,277**

Revenue Requirements Summary
2020 Plan - KU

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total E(m) - All KU Projects	$708,724	$7,457,645	$15,482,346	$23,615,384	$30,555,579	$37,421,075	$36,659,231	$35,933,284	$35,241,667	$34,581,976
12 Month Average Jurisdictional Ratio	91.65%	91.65%	91.65%	91.65%	91.65%	91.65%	91.65%	91.65%	91.65%	91.65%
Jurisdictional E(m)	$649,563	$6,835,118	$14,189,957	$21,644,090	$28,004,952	$34,297,351	$33,599,102	$32,933,753	$32,299,869	$31,695,246
Group 1 Avg. % of Total Revenue	41.87%	41.87%	41.87%	41.87%	41.87%	41.87%	41.87%	41.87%	41.87%	41.87%
Group 1 E(m)	$271,956	$2,861,693	$5,940,980	$9,061,839	$11,724,973	$14,359,443	$14,067,104	$13,788,539	$13,523,148	$13,270,007
Group 1 R(m)	$661,551,364	$662,174,409	$663,645,491	$666,484,659	$671,626,776	$675,029,526	$682,650,858	$688,126,599	$692,646,840	$686,258,038
Group 1 Incremental ECR Surcharge	0.04%	0.43%	0.90%	1.36%	1.75%	2.13%	2.06%	2.00%	1.95%	1.93%
Group 2 Avg. % of Total Revenue	58.13%	58.13%	58.13%	58.13%	58.13%	58.13%	58.13%	58.13%	58.13%	58.13%
Group 2 E(m)	$377,607	$3,973,425	$8,248,977	$12,582,250	$16,279,979	$19,937,908	$19,531,998	$19,145,214	$18,776,721	$18,425,239
Group 2 R(m)	$672,573,231	$669,102,485	$667,116,713	$666,394,715	$667,241,556	$668,155,794	$667,965,379	$668,149,114	$669,499,335	$668,588,003
Group 2 Incremental ECR Surcharge	0.06%	0.59%	1.24%	1.89%	2.44%	2.98%	2.92%	2.87%	2.80%	2.76%

Revenue Requirements
Project 43 - KU Ghent

	2020	2021	2022	2023	November 2024	2025	2026	2027	2028	2029
In-Service					1	2	3	4	5	6
Ghent										
Project 43 - Ghent ELG Projects	$4,326,191	$32,981,904	$41,531,592	$36,062,565	$21,346,998	$0	$0	$0	$0	$0
Accumulated Expenditures	$4,326,191	$37,308,095	$78,839,687	$114,902,252	$136,249,250	$136,249,250	$136,249,250	$136,249,250	$136,249,250	$136,249,250
Book Depreciation rate, per year	0.000%	0.000%	0.000%	0.000%	4.350%	4.350%	4.350%	4.350%	4.350%	4.350%
Tax Depreciation rate, per year	0.000%	0.000%	0.000%	0.000%	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%
Income tax rate	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%
Deferred Tax Balance	0	0	0	0	1,089,939	2,065,232	2,856,277	3,477,350	3,940,691	4,258,537
Book Accumulated Depreciation Balance	0	0	0	0	740,855	6,667,698	12,594,540	18,521,382	24,448,225	30,375,067
Unrecovered Investment -- Book	4,326,191	37,308,095	78,839,687	114,902,252	136,249,250	136,249,250	136,249,250	136,249,250	136,249,250	136,249,250
Book Depreciation	0	0	0	0	740,855	5,926,842	5,926,842	5,926,842	5,926,842	5,926,842
Unrecovered Investment -- Tax total	4,326,191	37,308,095	78,839,687	114,902,252	136,249,250	136,249,250	136,249,250	136,249,250	136,249,250	136,249,250
Bonus Tax Depreciation	0									
MACRS Tax Depreciation	0	0	0	0	5,109,347	9,835,833	9,097,362	8,416,116	7,783,920	7,200,773
Allowed Rate of Return	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%
Book Depreciation expense total	0	0	0	0	740,855	5,926,842	5,926,842	5,926,842	5,926,842	5,926,842
Tax Depreciation expense total	0	0	0	0	5,109,347	9,835,833	9,097,362	8,416,116	7,783,920	7,200,773
Annual Property Tax Rate	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%
Deferred Tax Activity	0	0	0	0	1,089,939	975,293	791,045	621,074	463,341	317,846
Revenue Recovery on Capital Expenditure to date										
Eligible Plant, cumulative capital expenditures	4,326,191	37,308,095	78,839,687	114,902,252	136,249,250	136,249,250	136,249,250	136,249,250	136,249,250	136,249,250
Less: Retired Plant	0	0	0	0	0	0	0	0	0	0
Less: Accumulated Depreciation	0	0	0	0	(740,855)	(6,667,698)	(12,594,540)	(18,521,382)	(24,448,225)	(30,375,067)
Plus: Accumulated Depreciation on Retired Plant	0	0	0	0	0	0	0	0	0	0
Less: Deferred Tax Balance	0	0	0	0	(1,089,939)	(2,065,232)	(2,856,277)	(3,477,350)	(3,940,691)	(4,258,537)
Plus: Deferred Tax Balance on Retired Plant	0	0	0	0	0	0	0	0	0	0
Environmental Compliance Rate Base	4,326,191	37,308,095	78,839,687	114,902,252	134,418,456	127,516,320	120,798,433	114,250,517	107,860,334	101,615,646
Rate of return	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%
Return on Environmental Compliance Rate Base	$376,379	$3,245,804	$6,859,053	$9,996,496	$11,694,406	$11,093,920	$10,509,464	$9,939,795	$9,383,849	$8,840,561
Operating Expenses	0	0	0	0	2,439,207	5,060,045	5,248,536	5,444,149	5,647,156	5,857,841
Annual Depreciation expense	0	0	0	0	740,855	5,926,842	5,926,842	5,926,842	5,926,842	5,926,842
Less depreciation on retired plant	0	0	0	0	0	0	0	0	0	0
Annual Property Tax expense	0	6,489	55,962	118,260	172,353	203,263	194,372	185,482	176,592	167,702
Total OE	$0	$6,489	$55,962	$118,260	$3,352,416	$11,190,150	$11,369,751	$11,556,473	$11,750,590	$11,952,385
Total E(m) - Project 43 ELG	**376,379**	**3,252,294**	**6,915,015**	**10,114,755**	**15,046,822**	**22,284,070**	**21,879,214**	**21,496,268**	**21,134,439**	**20,792,946**

Revenue Requirements
Project 43 - KU Ghent

	2020	November 2021	2022	2023	2024	2025	2026	2027	2028	2029
In-Service		1	2	3	4	5	6	7	8	9
Ghent										
Project 43 - Ghent Diffuser Project	$1,090,000	$14,982,780	$0	$0	$0	$0	$0	$0	$0	$0
Accumulated Expenditures	$1,090,000	$16,072,780	$16,072,780	$16,072,780	$16,072,780	$16,072,780	$16,072,780	$16,072,780	$16,072,780	$16,072,780
Book Depreciation rate, per year	0.000%	4.350%	4.350%	4.350%	4.350%	4.350%	4.350%	4.350%	4.350%	4.350%
Tax Depreciation rate, per year	0.000%	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%	4.522%	4.462%
Income tax rate	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%
Deferred Tax Balance	0	128,576	243,627	336,944	410,209	464,868	502,363	523,937	530,835	535,326
Book Accumulated Depreciation Balance	0	87,396	87,396	1,485,728	2,184,894	2,884,059	3,583,225	4,282,391	4,981,557	5,680,723
Unrecovered Investment -- Book	1,090,000	16,072,780	16,072,780	16,072,780	16,072,780	16,072,780	16,072,780	16,072,780	16,072,780	16,072,780
Book Depreciation	0	87,396	699,166	699,166	699,166	699,166	699,166	699,166	699,166	699,166
Unrecovered Investment -- Tax total	1,090,000	16,072,780	16,072,780	16,072,780	16,072,780	16,072,780	16,072,780	16,072,780	16,072,780	16,072,780
Bonus Tax Depreciation	0									
MACRS Tax Depreciation	0	602,729	1,160,294	1,073,180	992,816	918,238	849,446	785,637	726,811	717,167
Allowed Rate of Return	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%
Book Depreciation expense total	0	87,396	699,166	699,166	699,166	699,166	699,166	699,166	699,166	699,166
Tax expense total	0	602,729	1,160,294	1,073,180	992,816	918,238	849,446	785,637	726,811	717,167
Annual Property Tax Rate	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%
Deferred Tax Activity	0	128,576	115,051	93,316	73,266	54,658	37,495	21,575	6,897	4,491
Revenue Recovery on Capital Expenditure to date										
Eligible Plant, cumulative capital expenditures	1,090,000	16,072,780	16,072,780	16,072,780	16,072,780	16,072,780	16,072,780	16,072,780	16,072,780	16,072,780
Less: Retired Plant	0	0	0	0	0	0	0	0	0	0
Less: Accumulated Depreciation	0	(87,396)	(87,396)	(1,485,728)	(2,184,894)	(2,884,059)	(3,583,225)	(4,282,391)	(4,981,557)	(5,680,723)
Plus: Accumulated Depreciation on Retired Plant	0	0	0	0	0	0	0	0	0	0
Less: Deferred Tax Balance	0	(128,576)	(243,627)	(336,944)	(410,209)	(464,868)	(502,363)	(523,937)	(530,835)	(535,326)
Plus: Deferred Tax Balance on Retired Plant	0	0	0	0	0	0	0	0	0	0
Environmental Compliance Rate Base	1,090,000	15,856,809	15,741,757	14,250,109	13,477,677	12,723,853	11,987,192	11,266,451	10,560,388	9,856,731
Rate of return	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%
Return on Environmental Compliance Rate Base	$94,830	$1,379,542	$1,369,533	$1,239,759	$1,172,558	$1,106,975	$1,042,886	$980,181	$918,754	$857,536
Operating Expenses	0	0	0	0	0	0	0	0	0	0
Annual Depreciation expense	0	87,396	699,166	699,166	699,166	699,166	699,166	699,166	699,166	699,166
Less depreciation on retired plant	0	0	0	0	0	0	0	0	0	0
Annual Property Tax expense	0	1,635	23,978	23,978	21,881	20,832	19,783	18,734	17,686	16,637
Total OE	$0	$89,031	$723,144	$723,144	$721,047	$719,998	$718,949	$717,900	$716,852	$715,803
Total E(m) - Project 43 Diffuser	**94,830**	**1,468,573**	**2,092,677**	**1,962,903**	**1,893,604**	**1,826,973**	**1,761,835**	**1,698,082**	**1,635,605**	**1,573,338**

Revenue Requirements
Project 43 - KU Ghent

	2020	2021	2022	May 2023	2024	2025	2026	2027	2028	2029
In-Service				1	2	3	4	5	6	7
Ghent										
Project 43 - Ghent BATW Recirculation System Project	$150,000	$19,559,606	$32,186,264	$12,018,408	$0	$0	$0	$0	$0	$0
Accumulated Expenditures	$150,000	$19,709,606	$51,895,870	$63,914,278	$63,914,278	$63,914,278	$63,914,278	$63,914,278	$63,914,278	$63,914,278
Book Depreciation rate, per year	0.000%	0.000%	0.000%	4.350%	4.350%	4.350%	4.350%	4.350%	4.350%	4.350%
Tax Depreciation rate, per year	0.000%	0.000%	0.000%	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%
Income tax rate	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%
Deferred Tax Balance	0	0	0	164,449	621,958	993,035	1,284,380	1,501,732	1,650,833	1,736,626
Book Accumulated Depreciation Balance	0	0	0	1,737,669	4,517,941	7,298,212	10,078,483	12,858,754	15,639,025	18,419,296
Unrecovered Investment -- Book	150,000	19,709,606	51,895,870	63,914,278	63,914,278	63,914,278	63,914,278	63,914,278	63,914,278	63,914,278
Book Depreciation	0	0	0	1,737,669	2,780,271	2,780,271	2,780,271	2,780,271	2,780,271	2,780,271
Unrecovered Investment -- Tax total	150,000	19,709,606	51,895,870	63,914,278	63,914,278	63,914,278	63,914,278	63,914,278	63,914,278	63,914,278
Bonus Tax Depreciation	0	0	0	0	0	0	0	0	0	0
MACRS Tax Depreciation	0	0	0	2,396,785	4,613,972	4,267,556	3,947,985	3,651,423	3,377,870	3,124,130
Allowed Rate of Return	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%
Book Depreciation expense total	0	0	0	1,737,669	2,780,271	2,780,271	2,780,271	2,780,271	2,780,271	2,780,271
Tax expense total	0	0	0	2,396,785	4,613,972	4,267,556	3,947,985	3,651,423	3,377,870	3,124,130
Annual Property Tax Rate	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%
Deferred Tax Activity	0	0	0	164,449	457,508	371,078	291,345	217,352	149,101	85,793
Revenue Recovery on Capital Expenditure to date										
Eligible Plant, cumulative capital expenditures	150,000	19,709,606	51,895,870	63,914,278	63,914,278	63,914,278	63,914,278	63,914,278	63,914,278	63,914,278
Less: Retired Plant	0	0	0	0	0	0	0	0	0	0
Less: Accumulated Depreciation	0	0	0	(1,737,669)	(4,517,941)	(7,298,212)	(10,078,483)	(12,858,754)	(15,639,025)	(18,419,296)
Plus: Accumulated Depreciation on Retired Plant	0	0	0	0	0	0	0	0	0	0
Less: Deferred Tax Balance	0	0	0	(164,449)	(621,958)	(993,035)	(1,284,380)	(1,501,732)	(1,650,833)	(1,736,626)
Plus: Deferred Tax Balance on Retired Plant	0	0	0	0	0	0	0	0	0	0
Environmental Compliance Rate Base	150,000	19,709,606	51,895,870	62,012,159	58,774,380	55,623,031	52,551,415	49,553,792	46,624,420	43,758,356
Rate of return	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%
Return on Environmental Compliance Rate Base	$13,050	$1,714,736	$4,514,941	$5,395,058	$5,113,371	$4,839,204	$4,571,973	$4,311,180	$4,056,325	$3,806,977
Operating Expenses	0	0	0	357,929	740,558	766,129	792,600	820,006	848,379	877,753
Annual Depreciation expense	0	0	0	1,737,669	2,780,271	2,780,271	2,780,271	2,780,271	2,780,271	2,780,271
Less depreciation on retired plant	0	0	0	0	0	0	0	0	0	0
Annual Property Tax expense	0	225	29,564	77,844	93,265	89,095	84,924	80,754	76,583	72,413
Total OE	$0	$225	$29,564	$2,173,442	$3,614,094	$3,635,494	$3,657,796	$3,681,031	$3,705,233	$3,730,437
Total E(m) - Project 43 BATW Recirculation System	**13,050**	**1,714,961**	**4,544,505**	**7,568,500**	**8,727,465**	**8,474,698**	**8,229,769**	**7,992,211**	**7,761,558**	**7,537,414**
Total E(m) - All Project 43	**484,259**	**6,435,827**	**13,552,197**	**19,646,159**	**25,667,892**	**32,585,741**	**31,870,818**	**31,186,560**	**30,531,602**	**29,903,699**

Revenue Requirements
Project 44 - KU Trimble County

				June						
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
In-Service				1	2	3	4	5	6	7
KU Trimble Co										
Project 44 - Trimble County ELG	$2,580,061	$9,120,482	$10,283,349	$12,162,761	$0	$0	$0	$0	$0	$0
Accumulated Expenditures	$2,580,061	$11,700,542	$21,983,891	$34,146,653	$34,146,653	$34,146,653	$34,146,653	$34,146,653	$34,146,653	$34,146,653
Book Depreciation rate, per year	0.000%	0.000%	0.000%	2.170%	2.170%	2.170%	2.170%	2.170%	2.170%	2.170%
Tax Depreciation rate, per year	0.000%	0.000%	0.000%	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%
Income tax rate	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%
Deferred Tax Balance	0	0	0	219,344	649,498	1,033,476	1,374,856	1,676,705	1,942,090	2,173,653
Book Accumulated Depreciation Balance	0	0	0	401,365	1,142,348	1,883,330	2,624,313	3,365,295	4,106,277	4,847,260
Unrecovered Investment -- Book	2,580,061	11,700,542	21,983,891	34,146,653	34,146,653	34,146,653	34,146,653	34,146,653	34,146,653	34,146,653
Book Depreciation	0	0	0	401,365	740,982	740,982	740,982	740,982	740,982	740,982
Unrecovered Investment -- Tax total	2,580,061	11,700,542	21,983,891	34,146,653	34,146,653	34,146,653	34,146,653	34,146,653	34,146,653	34,146,653
Bonus Tax Depreciation	0									
MACRS Tax Depreciation	0	0	0	1,280,499	2,465,047	2,279,972	2,109,239	1,950,798	1,804,651	1,669,088
Allowed Rate of Return	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%
Book Depreciation expense total	0	0	0	401,365	740,982	740,982	740,982	740,982	740,982	740,982
Tax Depreciation expense total	0	0	0	1,280,499	2,465,047	2,279,972	2,109,239	1,950,798	1,804,651	1,669,088
Annual Property Tax Rate	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%
Deferred Tax Activity	0	0	0	219,344	430,154	383,978	341,380	301,849	265,385	231,562
Revenue Recovery on Capital Expenditure to date										
Eligible Plant, cumulative capital expenditures	2,580,061	11,700,542	21,983,891	34,146,653	34,146,653	34,146,653	34,146,653	34,146,653	34,146,653	34,146,653
Less: Retired Plant	0	0	0	0	0	0	0	0	0	0
Less: Accumulated Depreciation	0	0	0	(401,365)	(1,142,348)	(1,883,330)	(2,624,313)	(3,365,295)	(4,106,277)	(4,847,260)
Plus: Accumulated Depreciation on Retired Plant	0	0	0	0	0	0	0	0	0	0
Less: Deferred Tax Balance	0	0	0	(219,344)	(649,498)	(1,033,476)	(1,374,856)	(1,676,705)	(1,942,090)	(2,173,653)
Plus: Deferred Tax Balance on Retired Plant	0	0	0	0	0	0	0	0	0	0
Environmental Compliance Rate Base	2,580,061	11,700,542	21,983,891	33,525,943	32,354,807	31,229,846	30,147,484	29,104,653	28,098,285	27,125,740
Rate of return	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%
Return on Environmental Compliance Rate Base	$224,465	$1,017,947	$1,912,599	$2,916,757	$2,814,868	$2,716,997	$2,622,831	$2,532,105	$2,444,551	$2,359,939
Operating Expenses	0	0	0	618,127	1,281,219	1,327,849	1,376,205	1,426,353	1,478,359	1,532,295
Annual Depreciation expense	0	0	0	401,365	740,982	740,982	740,982	740,982	740,982	740,982
Less depreciation on retired plant	0	0	0	0	0	0	0	0	0	0
Annual Property Tax expense	0	3,870	17,551	32,976	50,618	49,506	48,395	47,284	46,172	45,061
Total OE	$0	$3,870	$17,551	$1,052,468	$2,072,819	$2,118,337	$2,165,582	$2,214,619	$2,265,514	$2,318,338
Total E(m) - Project 44 ELG	**224,465**	**1,021,817**	**1,930,149**	**3,969,225**	**4,887,687**	**4,835,334**	**4,788,413**	**4,746,723**	**4,710,065**	**4,678,277**

Louisville Gas and Electric Company

P.S.C. Electric No. 12, First Revision of Original Sheet No. 87
Canceling P.S.C. Electric No. 12, Original Sheet No. 87

Adjustment Clause **ECR**
Environmental Cost Recovery Surcharge

APPLICABLE

In all territory served.

AVAILABILITY

This schedule is mandatory to all rate schedules listed in Section 1 of the General Index except Rate PSA and Special Charges, all Pilot Programs listed in Section 3 of the General Index, and the FAC (including OSS) and DSM Adjustment Clauses. Rate schedules subject to this adjustment clause are divided into Group 1 or Group 2 as follows: ~~T~~ ~~T~~ ~~T~~ ~~T~~ ~~T~~

Group 1: Rates RS; RTOD-Energy; RTOD-Demand; VFD; LS; RLS; LE; and TE. ~~T~~
Group 2: Rates GS; PS; TODS; TODP; RTS; FLS; EVSE; EVC; and OSL. ~~T~~

RATE

The monthly billing amount under each of the schedules to which this mechanism is applicable, shall be increased or decreased by a percentage factor calculated in accordance with the following formula.

Group Environmental Surcharge Billing Factor = Group E(m) / Group R(m)

As set forth below, Group E(m) is the sum of Jurisdictional E(m) of each approved environmental compliance plan revenue requirement of environmental compliance costs for the current expense month allocated to each of Group 1 and Group 2. Group R(m) for Group 1 is the twelve (12) month average revenue for the current expense month and for Group 2 it is the twelve (12) month average non-fuel revenue for the current expense month. ~~T~~ ~~T~~

DEFINITIONS

1. For all Plans, E(m) = [(RB/12) (ROR + (ROR – DR) (TR / (1 – TR))] + OE – EAS + BR
   a. RB is the Total Environmental Compliance Rate Base.
   b. ROR is the Rate of Return on Environmental Compliance Rate Base, designated as the overall rate of return [cost of short-term debt, long-term debt, preferred stock, and common equity].
   c. DR is the Debt Rate [cost of short-term debt and long-term debt].
   d. TR is the Composite Federal and State Income Tax Rate.
   e. OE is the Operating Expenses. OE includes operation and maintenance expense recovery authorized by the K.P.S.C. in all approved ECR Plan proceedings.
   f. EAS is the total proceeds from emission allowance sales.
   g. BR is the operation and maintenance expenses, and/or revenues if applicable, associated with Beneficial Reuse.
   h. Plans are the environmental surcharge compliance plans submitted to and approved by the Kentucky Public Service Commission pursuant to KRS 278.183.

DATE OF ISSUE: ~~May 14, 2019~~March 31, 2020

DATE EFFECTIVE: ~~With Service Rendered~~ September 30, 2020
~~On and After May 1, 2019~~

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
~~2018-00295~~2020-00061 dated ~~April 30, 2019~~XX, 2020

DEFINITIONS (continued)

2. Total E(m) (sum of each approved environmental compliance plan revenue requirement) is multiplied by the Jurisdictional Allocation Factor. Jurisdictional E(m) is adjusted for any (Over)/Under collection or prior period adjustment and by the subtraction of the Revenue Collected through Base Rates for the Current Expense month to arrive at Adjusted Net Jurisdictional E(m). Adjusted Net Jurisdictional E(m) is allocated to Group 1 and Group 2 on the basis of Revenue as a Percentage of Total Revenue for the twelve (12) months ending with the Current Month to arrive at Group 1 E(m) and Group 2 E(m). ~~T~~

3. The Group 1 R(m) is the average of total Group 1 monthly base revenue for the twelve (12) ~~T~~ months ending with the current expense month. Base revenue includes Customer, energy, and ~~T~~ lighting charges for each rate schedule included in Group 1 to which this mechanism is applicable and automatic adjustment clause revenues for the Fuel Adjustment Clause and the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 1.

4. The Group 2 R(m) is the average of total Group 2 monthly base non-fuel revenue for the twelve ~~T~~ (12) months ending with the current expense month. Base non-fuel revenue includes ~~T~~ Customer, non-fuel energy, and demand charges for each rate schedule included in Group 2 ~~T~~ to which this mechanism is applicable and automatic adjustment clause revenues for the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule in Group 2. Non-fuel energy is equal to the tariff energy rate for each rate schedule included in Group 2 less the base fuel factor as defined on Sheet No. 85.1, Paragraph 6.

5. Current expense month (m) shall be the second month preceding the month in which the Environmental Surcharge is billed.

DATE OF ISSUE: ~~May 14, 2019~~March 31, 2020

DATE EFFECTIVE: ~~With Service Rendered~~ September 30, 2020
~~On and After May 1, 2019~~

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the
Public Service Commission in Case No.
~~2018-00295~~2020-00061 dated ~~April 30, 2019~~XX, 2020

ES FORM 1.00

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Net Group E(m) and
Group Environmental Surcharge Billing Factors
For the Expense Month of

GROUP 1 (Total Revenue)

Group 1 E(m) -- ES Form 1.10, line 15 =

Group 1 ES Billing Factor -- ES Form 1.10, line 17 =

GROUP 2 (Net Revenue)

Group 2 E(m) -- ES Form 1.10, line 15 =

Group 2 ES Billing Factor -- ES Form 1.10, line 17 =

Effective Date for Billing:

Submitted by: ______________________________

Title: Manager, Revenue Requirement/Cost of Service

Date Submitted:

ES FORM 1.10

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Calculation of Total E(m) and
Group Surcharge Billing Factors

For the Expense Month of

Calculation of Total E(m)

E(m) = [(RB / 12) (ROR+(ROR -DR)(TR/(1-TR)))] + OE - BAS + BR, where

RB	=	Environmental Compliance Rate Base
ROR	=	Rate of Return on the Environmental Compliance Rate Base
DR	=	Debt Rate (both short-term and long-term debt)
TR	=	Composite Federal & State Income Tax Rate
OE	=	Pollution Control Operating Expenses
BAS	=	Total Proceeds from By-Product and Allowance Sales
BR	=	Beneficial Reuse Operating Expenses

				Environmental Compliance Plans
(1)	RB		=	
(2)	RB / 12		=	
(3)	(ROR + (ROR - DR) (TR / (1 - TR)))		=	
(4)	OE		=	
(5)	BAS		=	
(6)	BR		=	
(7)	E(m)	(2) x (3) + (4) - (5) + (6)	=	

Calculation of Adjusted Net Jurisdictional E(m)

(8)	Jurisdictional Allocation Ratio for Expense Month -- ES Form 3.10	=	
(9)	Jurisdictional E(m) = Total E(m) x Jurisdictional Allocation Ratio [(7) x (8)]	=	
(10)	Adjustment for (Over)/Under-collection pursuant to Case No. 2019-00015	=	
(11)	Prior Period Adjustment (if necessary)	=	
(12)	Revenue Collected through Base Rates	=	
(13)	Adjusted Net Jurisdictional E(m) [(9) + (10) + (11) - (12)]	=	

Calculation of Group Environmental Surcharge Billing Factors

			GROUP 1 (Total Revenue)	GROUP 2 (Net Revenue)
(14)	Revenue as a Percentage of 12-month Total Revenue ending with the Current Month -- ES Form 3.00	=		
(15)	Group E(m) [(13) x (14)]	=		
(16)	Group R(m) = Average Monthly Group Revenue for the 12 Months Ending with the Current Expense Month -- ES Form 3.00	=		
(17)	Group Environmental Surcharge Billing Factors [(15) ÷ (16)]	=		

ES FORM 2.00

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Revenue Requirements of Environmental Compliance Costs
For the Expense Month of

Determination of Environmental Compliance Rate Base

	Environmental Compliance Plan	
Eligible Pollution Control Plant		
Eligible Pollution CWIP Excluding AFUDC		
Subtotal		
Additions:		
Inventory - Emission Allowances per ES Form 2.31, 2.32, 2.33, and 2.34		
Cash Working Capital Allowance		
Net Unamortized Closure Cost Balance[1]		
Subtotal		
Deductions:		
Accumulated Depreciation on Eligible Pollution Control Plant		
Pollution Control Deferred Income Taxes		
Subtotal		
Environmental Compliance Rate Base		

Determination of Pollution Control Operating Expenses

			Environmental Compliance Plan
Monthly Operations & Maintenance Expense			
Monthly Depreciation & Amortization Expense			
less investment tax credit amortization			
Monthly Taxes Other Than Income Taxes - Eligible Plant			
Monthly Taxes Other Than Income Taxes - Closure Costs			
Amortization of Monthly Closure Costs			
Amortization of Excess ADIT with gross-up			
Monthly Emission Allowance Expense from ES Form 2.31, 2.32, 2.33, and 2.34			
Monthly Surcharge Consulting Fees			
Construction Monitoring Consultant Fee			
Total Pollution Control Operations Expense			

Determination of Beneficial Reuse Operating Expenses

	Environmental Compliance Plan
Total Monthly Beneficial Reuse Expense	
Adjustment for Beneficial Reuse in Base Rates (from ES Form 2.61)	
Net Beneficial Reuse Operations Expense	

Note 1: The net unamortized closure cost balance is comprised of CCR closure cost expenditures less accumulated amortization, accumulated deferred income taxes and amount in base rates.

ES FORM 2.01

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Amortization of Monthly CCR Closure Costs

For the Month Ended:

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Description	Accumulated CCR Closure Costs	Accumulated Amortization (Prior Month)	Current Month Amortization	Accumulated Amortization (Current Month)	Accumulated Deferred Income Taxes (ADIT)	Unamortized CCR Closure Cost Balance (Net of ADIT)
			[(2)-(3)]/ RemainingAmortMonths	(3)+(4)		(2)-(5)-(6)
2016 Plan: Project 29 - Mill Creek Station Project 30 - Trimble County Station						
Net Total - All Projects:	$ -	$ -	$ -	$ -	$ -	$ -

Note 1: The Accumulated Deferred Income Taxes (ADIT) includes Excess Deferred Taxes resulting from the Tax Cuts and Jobs Act.

ES FORM 2.10

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Plant, CWIP & Depreciation Expense

For the Month Ended:

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Description	Eligible Plant In Service	Eligible Accumulated Depreciation	CWIP Amount Excluding AFUDC	Eligible Net Plant In Service	Deferred Tax Balance as of Date	Monthly ITC Amortization Credit	Monthly Depreciation Expense	Monthly Property Tax Expense
				(2)-(3)+(4)				
2009 Plan:								
Project 22 - Cane Run CCP Storage (Landfill - Phase I) [CANCELLED]								
Project 23 - Trimble County Ash Treatment Basin (BAP/GSP)								
Project 24 - Trimble County CCP Storage (Landfill - Phase 1)								
Project 25 - Beneficial Reuse								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2009 Plan								
Net Total - 2009 Plan:								
2011 Plan:								
Project 26 - Mill Creek Station Air Compliance								
Project 27 - Trimble County Unit 1 Air Compliance								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2011 Plan								
Net Total - 2011 Plan:								
2016 Plan:								
Project 28 - Supplemental Mercury Control								
Project 29 - Mill Creek New Process Water Systems								
Project 30 - Trimble County New Process Water Systems								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2016 Plan								
Net Total - 2016 Plan:								
Net Total - All Plans:								

Note 1: Trimble County projects for the 2009 Plan are proportionately shared by KU at 48% and LG&E at 52%.
Note 2: Effective with the September 2012 expense month, Project 22 is cancelled and the previous CWIP balance is included on ES Form 2.50 as an expense for the September 2012 expense month.
Note 3: The Deferred Tax Balance includes Excess Deferred Taxes resulting from the Tax Cuts and Jobs Act.

ES FORM 2.30

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances

For the Month Ended:

Vintage Year	Number of Allowances				Total Dollar Value Of Vintage Year				Comments and Explanations
	SO_2 CAIR	SO_2 CSAPR	NOx Ozone Season	NOx Annual	SO_2 CAIR	SO_2 CSAPR	NOx Ozone Season	NOx Annual	
Current Year									
2021									
2022									
2023									
2024									
2025									
2026									
2027									
2028									
2029									
2030									
2031									
2032									
2033									
2034									
2035									
2036									
2037									
2038									
2039									
2040									
2041 - 2050									

In the "Comments and Explanation" Column, describe any allowance inventory adjustment other than the assignment of allowances by EPA. Inventory adjustments include, but are not limited to, purchases, allowances acquired as part of other purchases, and the sale of allowances.

ES FORM 2.31

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of CAIR Emission Allowances (SO_2) - Current Vintage Year

For the Expense Month of

	Beginning Inventory	Allocations/ Purchases	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity							
Dollars							
$/Allowance							
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity							
Dollars							
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity							
Dollars							
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity							
Dollars							
$/Allowance							
From KU							
Quantity							
Dollars							
$/Allowance							

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor

ES FORM 2.32

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of CSAPR Emission Allowances (SO_2) - Current Vintage Year

For the Expense Month of

	Beginning Inventory	Allocations/ Purchases	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity							
Dollars							
$/Allowance							
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity							
Dollars							
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity							
Dollars							
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity							
Dollars							
$/Allowance							
From KU							
Quantity							
Dollars							
$/Allowance							

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor

ES FORM 2.33

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Inventory of Emission Allowances (NOx) - Ozone Season Allowance Allocation

For the Expense Month of

	Beginning Inventory	Allocations/ Purchases	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity							
Dollars							
$/Allowance							
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity							
Dollars							
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity							
Dollars							
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity							
Dollars							
$/Allowance							
From KU:							
Quantity							
Dollars							
$/Allowance							

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor.

ES FORM 2.34

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances (NOx) - Annual Allowance Allocation

For the Expense Month of

	Beginning Inventory	Allocations/ Purchases	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity							
Dollars							
$/Allowance							
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity							
Dollars							
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity							
Dollars							
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity							
Dollars							
$/Allowance							
From KU:							
Quantity							
Dollars							
$/Allowance							

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor.

ES FORM 2.40

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
O&M Expenses and Determination of Cash Working Capital Allowance

For the Month Ended:

Environmental Compliance Plan	
O&M Expenses	Environmental Compliance Plans
11th Previous Month	
10th Previous Month	
9th Previous Month	
8th Previous Month	
7th Previous Month	
6th Previous Month	
5th Previous Month	
4th Previous Month	
3rd Previous Month	
2nd Previous Month	
Previous Month	
Current Month	
Total 12 Month O&M	

Determination of Working Capital Allowance	
12 Months O&M Expenses	
One Eighth (1/8) of 12 Month O&M Expenses	1/8
Pollution Control Cash Working Capital Allowance	

ES FORM 2.50

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Pollution Control - Operations & Maintenance Expenses
For the Month Ended:

O&M Expense Account	Mill Creek	Trimble County	Total
2009 Plan			
502013 - ECR Landfill Operations			
512107 - ECR Landfill Maintenance			
Adjustment for CCP Disposal in Base Rates (ES Form 2.51)			
Net 2009 Plan O&M Expenses			
2011 Plan			
502056 - ECR Scrubber Operations			
512055 - ECR Scrubber Maintenance			
506159 - ECR Sorbent Injection Operation			
506152 - ECR Sorbent Reactant - Reagent Only			
512152 - ECR Sorbent Injection Maintenance			
506156 - ECR Baghouse Operations			
512156 - ECR Baghouse Maintenance			
506151 - ECR Activated Carbon			
Adjustment for Base Rates Baseline Amounts			
Total 2011 Plan O&M Expenses			
2016 Plan			
506153 - ECR Liquid Injection - Reagent Only			
Total 2016 Plan O&M Expenses			
Current Month O&M Expense for All Plans			

Note 1: Trimble County projects for the 2009 Plan are proportionately shared by KU at 48% and LG&E at 52%.

ES FORM 2.51

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
CCP Disposal Facilities Expenses
For the Month Ended:

	On-Site CCP Disposal O&M Expense	Trimble County
	Existing CCP Disposal Facilities (Pre 2009 Plan Project)	
(1)	12 Months Ending with Expense Month	
(2)	Monthly Amount [(1) / 12]	
	2009 Plan Project	
(3)	Monthly Expense	
	Total Generating Station	
(4)	Monthly Expense [(2) + (3)]	
	Base Rates	
(5)	Annual Expense Amount (12 Mo Ending with Last Test Year)	
(6)	Monthly Expense Amount [(5) / 12]	
(7)	Total Generating Station Less Base Rates [(4) - (6)]	
(8)	Less 2009 Plan Project [(7) - (3)]	
	If Line (8) Greater than Zero, No Adjustment	
	If Line (8) Less than Zero, Adjustment for Base Rates	
Adjustment for Base Rate Amount (to ES Form 2.50)		

Note 1: Trimble County projects for the 2009 Plan are proportionately shared by KU at 48% and LG&E at 52%.

Note 2: ES Form 2.51 will not be utilized until O&M costs associated with the 2009 Plan are incurred.

ES FORM 2.60

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Beneficial Reuse - Operations & Maintenance Expenses

For the Month Ended:

Third Party	O&M Expense Account	Plant	Total O&M
Total Monthly Beneficial Reuse Expense			
Adjustment for Beneficial Reuse in Base Rates (from ES Form 2.61)			
Net Beneficial Reuse O&M Expense			

ES FORM 2.61

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Beneficial Reuse Opportunities
For the Month Ended:

	On-Site CCP Disposal O&M Expense	Mill Creek	Trimble County	Total
	Existing Beneficial Reuse Opportunities (Pre 2009 Plan Project)			
(1)	12 Months Ending with Expense Month			
(2)	Monthly Amount [(1) / 12]			
	2009 Plan Project 25			
(3)	Monthly Amount (Expense/Revenue)			
	Total Beneficial Reuse - Generating Station			
(4)	Monthly Expense [(2) + (3)]			
	Beneficial Reuse in Base Rates			
(5)	Annual Expense Amount (12 Mo Ending with Last Test Year)			
(6)	Monthly Expense Amount [(5) / 12]			
(7)	Total Generating Station Less Base Rates [(4) - (6)]			
(8)	Less 2009 Plan Project 25 [(7) - (3)]			
	If Line (8) Greater than Zero, No Adjustment			
	If Line (8) Less than Zero, Adjustment for Base Rates			
Adjustment for Base Rate Amount (to ES Form 2.60)				

Note 1: Trimble County projects for the 2009 Plan are proportionately shared by KU at 48% and LG&E at 52%.
Note 2: $0 is included in the Mill Creek beneficial reuse in base rates (Line 5) as filed in Case Number 2018-00295.

ES FORM 3.00

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Monthly Average Revenue Computation of R (m) for GROUP 1 AND GROUP 2

For the Month Ended:

	GROUP 1 (Total Revenues) - Kentucky Jurisdictional Revenues						
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Month	Non-fuel Base Rate Revenues	Base Rate Fuel Component	Fuel Clause Revenues Including Off-System Sales Tracker	DSM Revenues	Environmental Surcharge Revenues	Total (2)+(3)+(4)+(5)+(6)	Total Excluding Environmental Surcharge (7)-(6)
Average Monthly Jurisdictional Revenues, Excluding Environmental Surcharge, for 12 Months Ending Current Expense Month.							
Average Kentucky Jurisdictional Revenues excluding Environmental Surcharge for 12-months ending with Current Month =							
GROUP 1 Revenues as a Percentage of Total Revenues for 12-months ending with the Current Month							

	GROUP 2 (Net Revenues) - Kentucky Jurisdictional Revenues							
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Month	Non-fuel Base Rate Revenues	Base Rate Fuel Component	Fuel Clause Revenues Including Off-System Sales Tracker	DSM Revenues	Environmental Surcharge Revenues	Total (2)+(3)+(4)+(5)+(6)	Total Excluding Environmental Surcharge (7)-(6)	Total Non-Fuel Revenues plus DSM (2)+(5)
Average Monthly Jurisdictional Revenues, Excluding Environmental Surcharge and Fuel, for 12 Months Ending Current Expense Month.								
Average Kentucky Jurisdictional Revenues excluding Environmental Surcharge for 12-months ending with Current Month =								
GROUP 2 Revenues as a Percentage of Total Revenues for 12-months ending with the Current Month								

ES FORM 3.10

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Reconciliation of Reported Revenues

For the Month Ended:

		Revenues per Form 3.00	Revenues per Income Statement
Kentucky Retail Revenues			
(1)	Base Rates (Customer Charge, Energy Charge, Demand Charge)		
(2)	Fuel Adjustment Clause including Off System Sales Tracker		
(3)	DSM		
(4)	Environmental Surcharge		
(5)	CSR Credits		
(6)	EDR Credits		
(7)	Total Kentucky Jurisdictional Revenues for Environmental Surcharge Purposes =		
Non -Jurisdictional Revenues			
(8)	InterSystem (Total Less Transmission Portion Booked in Account 447)		
(9)	Total Non-Jurisdictional Revenues for Environmental Surcharge Purposes =		
(10)	Total Company Revenues for Environmental Surcharge Purposes =		
	Jurisdictional Allocation Ratio for Current Month [(7) / (10)] =		
Reconciling Revenues			
(11)	Brokered		
(12)	InterSystem (Transmission Portion Booked in Account 447)		
(13)	Unbilled		
(14)	Miscellaneous		
(15)	Total Company Revenues per Income Statement =		

NOTE (1): Base Rates (Line 1) includes the TCJA credit of $0.00 for this month.

NOTE (2): Revenues per Form 3.00 do not include solar and therefore will not always reflect Revenues per Income Statement.

ES FORM 1.00

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Net Group E(m) and
Group Environmental Surcharge Billing Factors
For the Expense Month of

GROUP 1 (Total Revenue)

Group 1 E(m) -- ES Form 1.10, line 15	=
Group 1 ES Billing Factor -- ES Form 1.10, line 17	=

GROUP 2 (Net Revenue)

Group 2 E(m) -- ES Form 1.10, line 15	=
Group 2 ES Billing Factor -- ES Form 1.10, line 17	=

Effective Date for Billing:

Submitted by: ____________________________

Title: Manager, Revenue Requirement/Cost of Service

Date Submitted:

ES FORM 1.10

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Calculation of Total E(m) and
Group Surcharge Billing Factors

For the Expense Month of

Calculation of Total E(m)

E(m) = [(RB / 12) (ROR+(ROR -DR)(TR/(1-TR)))] + OE - BAS + BR, where

RB	=	Environmental Compliance Rate Base
ROR	=	Rate of Return on the Environmental Compliance Rate Base
DR	=	Debt Rate (both short-term and long-term debt)
TR	=	Composite Federal & State Income Tax Rate
OE	=	Pollution Control Operating Expenses
BAS	=	Total Proceeds from By-Product and Allowance Sales
BR	=	Beneficial Reuse Operating Expenses

				Environmental Compliance Plans
(1)	RB		=	
(2)	RB / 12		=	
(3)	(ROR + (ROR - DR) (TR / (1 - TR)))		=	
(4)	OE		=	
(5)	BAS		=	
(6)	BR		=	
(7)	E(m)	(2) x (3) + (4) - (5) + (6)	=	

Calculation of Adjusted Net Jurisdictional E(m)

(8)	Jurisdictional Allocation Ratio for Expense Month -- ES Form 3.10	=	
(9)	Jurisdictional E(m) = Total E(m) x Jurisdictional Allocation Ratio [(7) x (8)]	=	
(10)	Adjustment for (Over)/Under-collection pursuant to Case No. 2019-00015	=	
(11)	Prior Period Adjustment (if necessary)	=	
(12)	Revenue Collected through Base Rates	=	
(13)	Adjusted Net Jurisdictional E(m) [(9) + (10) + (11) - (12)]	=	

Calculation of Group Environmental Surcharge Billing Factors

			GROUP 1 (Total Revenue)	GROUP 2 (Net Revenue)
(14)	Revenue as a Percentage of 12-month Total Revenue ending with the Current Month -- ES Form 3.00	=		
(15)	Group E(m) [(13) x (14)]	=		
(16)	Group R(m) = Average Monthly Group Revenue for the 12 Months Ending with the Current Expense Month -- ES Form 3.00	=		
(17)	Group Environmental Surcharge Billing Factors [(15) ÷ (16)]	=		

ES FORM 2.00

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Revenue Requirements of Environmental Compliance Costs
For the Expense Month of

Determination of Environmental Compliance Rate Base

	Environmental Compliance Plan	
Eligible Pollution Control Plant		
Eligible Pollution CWIP Excluding AFUDC		
Subtotal		
Additions:		
Inventory - Emission Allowances per ES Form 2.31, 2.32, 2.33, and 2.34		
Cash Working Capital Allowance		
Net Unamortized Closure Cost Balance[1]		
Subtotal		
Deductions:		
Accumulated Depreciation on Eligible Pollution Control Plant		
Pollution Control Deferred Income Taxes		
Subtotal		
Environmental Compliance Rate Base		

Determination of Pollution Control Operating Expenses

			Environmental Compliance Plan
Monthly Operations & Maintenance Expense			
Monthly Depreciation & Amortization Expense			
less investment tax credit amortization			
Monthly Taxes Other Than Income Taxes - Eligible Plant			
Monthly Taxes Other Than Income Taxes - Closure Costs			
Amortization of Monthly Closure Costs			
Amortization of Excess ADIT with gross-up			
Monthly Emission Allowance Expense from ES Form 2.31, 2.32, 2.33, and 2.34			
Monthly Surcharge Consulting Fees			
Construction Monitoring Consultant Fee			
Total Pollution Control Operations Expense			

Determination of Beneficial Reuse Operating Expenses

	Environmental Compliance Plan
Total Monthly Beneficial Reuse Expense	
Adjustment for Beneficial Reuse in Base Rates (from ES Form 2.61)	
Net Beneficial Reuse Operations Expense	

Note 1: The net unamortized closure cost balance is comprised of CCR closure cost expenditures less accumulated amortization, accumulated deferred income taxes and amount in base rates.

ES FORM 2.01

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Amortization of Monthly CCR Closure Costs

For the Month Ended:

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Description	Accumulated CCR Closure Costs	Accumulated Amortization (Prior Month)	Current Month Amortization	Accumulated Amortization (Current Month)	Accumulated Deferred Income Taxes (ADIT)	Unamortized CCR Closure Cost Balance (Net of ADIT)
			[(2)-(3)]/ RemainingAmortMonths	(3)+(4)		(2)-(5)-(6)
2016 Plan: Project 29 - Mill Creek Station Project 30 - Trimble County Station						
Net Total - All Projects:	$ -	$ -	$ -	$ -	$ -	$ -

Note 1: The Accumulated Deferred Income Taxes (ADIT) includes Excess Deferred Taxes resulting from the Tax Cuts and Jobs Act.

ES FORM 2.10

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Plant, CWIP & Depreciation Expense

For the Month Ended:

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Description	Eligible Plant In Service	Eligible Accumulated Depreciation	CWIP Amount Excluding AFUDC	Eligible Net Plant In Service	Deferred Tax Balance as of Date	Monthly ITC Amortization Credit	Monthly Depreciation Expense	Monthly Property Tax Expense
				(2)-(3)+(4)				
2009 Plan:								
Project 22 - Cane Run CCP Storage (Landfill - Phase I) [CANCELLED]								
Project 23 - Trimble County Ash Treatment Basin (BAP/GSP)								
Project 24 - Trimble County CCP Storage (Landfill - Phase 1)								
Project 25 - Beneficial Reuse								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2009 Plan								
Net Total - 2009 Plan:								
2011 Plan:								
Project 26 - Mill Creek Station Air Compliance								
Project 27 - Trimble County Unit 1 Air Compliance								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2011 Plan								
Net Total - 2011 Plan:								
2016 Plan:								
Project 28 - Supplemental Mercury Control								
Project 29 - Mill Creek New Process Water Systems								
Project 30 - Trimble County New Process Water Systems								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2016 Plan								
Net Total - 2016 Plan:								
2020 Plan								
Project 31 - Mill Creek ELG Water Treatment System and Diffuser								
Project 32 - Trimble County ELG Water Treatment System								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2020 Plan								
Net Total - 2020 Plan:								
Net Total - All Plans:								

Note 1: Trimble County projects for the 2009 Plan and 2020 Plan are proportionately shared by KU at 48% and LG&E at 52%.
Note 2: Effective with the September 2012 expense month, Project 22 is cancelled and the previous CWIP balance is included on ES Form 2.50 as an expense for the September 2012 expense month.
Note 3: The Deferred Tax Balance includes Excess Deferred Taxes resulting from the Tax Cuts and Jobs Act.

ES FORM 2.30

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances

For the Month Ended:

Vintage Year	Number of Allowances				Total Dollar Value Of Vintage Year				Comments and Explanations
	SO_2 CAIR	SO_2 CSAPR	NOx Ozone Season	NOx Annual	SO_2 CAIR	SO_2 CSAPR	NOx Ozone Season	NOx Annual	
Current Year									
2021									
2022									
2023									
2024									
2025									
2026									
2027									
2028									
2029									
2030									
2031									
2032									
2033									
2034									
2035									
2036									
2037									
2038									
2039									
2040									
2041 - 2050									

In the "Comments and Explanation" Column, describe any allowance inventory adjustment other than the assignment of allowances by EPA. Inventory adjustments include, but are not limited to, purchases, allowances acquired as part of other purchases, and the sale of allowances.

ES FORM 2.31

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of CAIR Emission Allowances (SO_2) - Current Vintage Year

For the Expense Month of

	Beginning Inventory	Allocations/ Purchases	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity							
Dollars							
$/Allowance							
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity							
Dollars							
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity							
Dollars							
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity							
Dollars							
$/Allowance							
From KU							
Quantity							
Dollars							
$/Allowance							

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor

ES FORM 2.32

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of CSAPR Emission Allowances (SO_2) - Current Vintage Year

For the Expense Month of

	Beginning Inventory	Allocations/ Purchases	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity							
Dollars							
$/Allowance							
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity							
Dollars							
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity							
Dollars							
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity							
Dollars							
$/Allowance							
From KU							
Quantity							
Dollars							
$/Allowance							

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor

ES FORM 2.33

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Inventory of Emission Allowances (NOx) - Ozone Season Allowance Allocation

For the Expense Month of

	Beginning Inventory	Allocations/ Purchases	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity							
Dollars							
$/Allowance							
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity							
Dollars							
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity							
Dollars							
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity							
Dollars							
$/Allowance							
From KU:							
Quantity							
Dollars							
$/Allowance							

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor.

ES FORM 2.34

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances (NOx) - Annual Allowance Allocation

For the Expense Month of

	Beginning Inventory	Allocations/ Purchases	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity							
Dollars							
$/Allowance							
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity							
Dollars							
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity							
Dollars							
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity							
Dollars							
$/Allowance							
From KU:							
Quantity							
Dollars							
$/Allowance							

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor.

ES FORM 2.40

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
O&M Expenses and Determination of Cash Working Capital Allowance

For the Month Ended:

Environmental Compliance Plan	
O&M Expenses	Environmental Compliance Plans
11th Previous Month	
10th Previous Month	
9th Previous Month	
8th Previous Month	
7th Previous Month	
6th Previous Month	
5th Previous Month	
4th Previous Month	
3rd Previous Month	
2nd Previous Month	
Previous Month	
Current Month	
Total 12 Month O&M	

Determination of Working Capital Allowance	
12 Months O&M Expenses	
One Eighth (1/8) of 12 Month O&M Expenses	1/8
Pollution Control Cash Working Capital Allowance	

ES FORM 2.50

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Pollution Control - Operations & Maintenance Expenses
For the Month Ended:

O&M Expense Account	Mill Creek	Trimble County	Total
2009 Plan			
502013 - ECR Landfill Operations	[redacted]		
512107 - ECR Landfill Maintenance	[redacted]		
Adjustment for CCP Disposal in Base Rates (ES Form 2.51)	[redacted]		
Net 2009 Plan O&M Expenses	[redacted]		
2011 Plan			
502056 - ECR Scrubber Operations		[redacted]	
512055 - ECR Scrubber Maintenance		[redacted]	
506159 - ECR Sorbent Injection Operation			
506152 - ECR Sorbent Reactant - Reagent Only			
512152 - ECR Sorbent Injection Maintenance			
506156 - ECR Baghouse Operations			
512156 - ECR Baghouse Maintenance			
506151 - ECR Activated Carbon			
Adjustment for Base Rates Baseline Amounts		[redacted]	
Total 2011 Plan O&M Expenses			
2016 Plan			
506153 - ECR Liquid Injection - Reagent Only			
Total 2016 Plan O&M Expenses			
2020 Plan			
502015 - ECR Effluent Water Chemicals			
502017 - ECR Effluent Water Operations			
512157 - ECR Effluent Water Maintenance			
Total 2020 Plan O&M Expenses			
Current Month O&M Expense for All Plans			

Note 1: Trimble County projects for the 2009 Plan and 2020 Plan are proportionately shared by KU at 48% and LG&E at 52%.

ES FORM 2.51

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
CCP Disposal Facilities Expenses
For the Month Ended:

	On-Site CCP Disposal O&M Expense	Trimble County
	Existing CCP Disposal Facilities (Pre 2009 Plan Project)	
(1)	12 Months Ending with Expense Month	
(2)	Monthly Amount [(1) / 12]	
	2009 Plan Project	
(3)	Monthly Expense	
	Total Generating Station	
(4)	Monthly Expense [(2) + (3)]	
	Base Rates	
(5)	Annual Expense Amount (12 Mo Ending with Last Test Year)	
(6)	Monthly Expense Amount [(5) / 12]	
(7)	Total Generating Station Less Base Rates [(4) - (6)]	
(8)	Less 2009 Plan Project [(7) - (3)]	
	If Line (8) Greater than Zero, No Adjustment	
	If Line (8) Less than Zero, Adjustment for Base Rates	
Adjustment for Base Rate Amount (to ES Form 2.50)		

Note 1: Trimble County projects for the 2009 Plan are proportionately shared by KU at 48% and LG&E at 52%.

Note 2: ES Form 2.51 will not be utilized until O&M costs associated with the 2009 Plan are incurred.

ES FORM 2.60

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Beneficial Reuse - Operations & Maintenance Expenses
For the Month Ended:

Third Party	O&M Expense Account	Plant	Total O&M
Total Monthly Beneficial Reuse Expense			
Adjustment for Beneficial Reuse in Base Rates (from ES Form 2.61)			
Net Beneficial Reuse O&M Expense			

ES FORM 2.61

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Beneficial Reuse Opportunities
For the Month Ended:

	On-Site CCP Disposal O&M Expense	Mill Creek	Trimble County	Total
	Existing Beneficial Reuse Opportunities (Pre 2009 Plan Project)			
(1)	12 Months Ending with Expense Month			
(2)	Monthly Amount [(1) / 12]			
	2009 Plan Project 25			
(3)	Monthly Amount (Expense/Revenue)			
	Total Beneficial Reuse - Generating Station			
(4)	Monthly Expense [(2) + (3)]			
	Beneficial Reuse in Base Rates			
(5)	Annual Expense Amount (12 Mo Ending with Last Test Year)			
(6)	Monthly Expense Amount [(5) / 12]			
(7)	Total Generating Station Less Base Rates [(4) - (6)]			
(8)	Less 2009 Plan Project 25 [(7) - (3)]			
	If Line (8) Greater than Zero, No Adjustment			
	If Line (8) Less than Zero, Adjustment for Base Rates			
Adjustment for Base Rate Amount (to ES Form 2.60)				

Note 1: Trimble County projects for the 2009 Plan are proportionately shared by KU at 48% and LG&E at 52%.
Note 2: $0 is included in the Mill Creek beneficial reuse in base rates (Line 5) as filed in Case Number 2018-00295.

ES FORM 3.00

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Monthly Average Revenue Computation of R (m) for GROUP 1 AND GROUP 2

For the Month Ended:

	GROUP 1 (Total Revenues) - Kentucky Jurisdictional Revenues						
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Month	Non-fuel Base Rate Revenues	Base Rate Fuel Component	Fuel Clause Revenues Including Off-System Sales Tracker	DSM Revenues	Environmental Surcharge Revenues	Total (2)+(3)+(4)+(5)+(6)	Total Excluding Environmental Surcharge (7)-(6)
Average Monthly Jurisdictional Revenues, Excluding Environmental Surcharge, for 12 Months Ending Current Expense Month.							
Average Kentucky Jurisdictional Revenues excluding Environmental Surcharge for 12-months ending with Current Month =							
GROUP 1 Revenues as a Percentage of Total Revenues for 12-months ending with the Current Month							

	GROUP 2 (Net Revenues) - Kentucky Jurisdictional Revenues							
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Month	Non-fuel Base Rate Revenues	Base Rate Fuel Component	Fuel Clause Revenues Including Off-System Sales Tracker	DSM Revenues	Environmental Surcharge Revenues	Total (2)+(3)+(4)+(5)+(6)	Total Excluding Environmental Surcharge (7)-(6)	Total Non-Fuel Revenues plus DSM (2)+(5)
Average Monthly Jurisdictional Revenues, Excluding Environmental Surcharge and Fuel, for 12 Months Ending Current Expense Month.								
Average Kentucky Jurisdictional Revenues excluding Environmental Surcharge for 12-months ending with Current Month =								
GROUP 2 Revenues as a Percentage of Total Revenues for 12-months ending with the Current Month								

ES FORM 3.10

LOUISVILLE GAS AND ELECTRIC COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Reconciliation of Reported Revenues

For the Month Ended:

		Revenues per Form 3.00	Revenues per Income Statement
Kentucky Retail Revenues			
(1)	Base Rates (Customer Charge, Energy Charge, Demand Charge)		
(2)	Fuel Adjustment Clause including Off System Sales Tracker		
(3)	DSM		
(4)	Environmental Surcharge		
(5)	CSR Credits		
(6)	EDR Credits		
(7)	Total Kentucky Jurisdictional Revenues for Environmental Surcharge Purposes =		
Non -Jurisdictional Revenues			
(8)	InterSystem (Total Less Transmission Portion Booked in Account 447)		
(9)	Total Non-Jurisdictional Revenues for Environmental Surcharge Purposes =		
(10)	Total Company Revenues for Environmental Surcharge Purposes =		
	Jurisdictional Allocation Ratio for Current Month [(7) / (10)] =		
Reconciling Revenues			
(11)	Brokered		
(12)	InterSystem (Transmission Portion Booked in Account 447)		
(13)	Unbilled		
(14)	Miscellaneous		
(15)	Total Company Revenues per Income Statement =		

NOTE (1): Base Rates (Line 1) includes the TCJA credit of $0.00 for this month.

NOTE (2): Revenues per Form 3.00 do not include solar and therefore will not always reflect Revenues per Income Statement.

Louisville Gas and Electric Company

Environmental Cost Recovery Surcharge Summary

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total E(m) - (in '000s)	$605	$4,528	$8,432	$12,891	$18,761	$21,804	$21,463	$21,145	$20,847	$20,570
12 Month Average Jurisdictional Ratio	96.81%	96.81%	96.81%	96.81%	96.81%	96.81%	96.81%	96.81%	96.81%	96.81%
Jurisdictional E(m) - (in '000s)	$586	$4,384	$8,163	$12,479	$18,162	$21,108	$20,778	$20,470	$20,182	$19,913
Forecasted Jurisdictional R(m) - (in '000s)	$1,092	$1,090	$1,095	$1,098	$1,105	$1,113	$1,122	$1,133	$1,138	$1,131
Incremental Billing Factor Group 1	0.05%	0.40%	0.75%	1.14%	1.64%	1.90%	1.85%	1.81%	1.77%	1.76%
Residential Customer Impact (Group 1)										
Monthly bill (917 kWh per month)	$0.05	$0.41	$0.75	$1.15	$1.66	$1.91	$1.87	$1.82	$1.79	$1.78
Bill Impact for Other Group 1 Rate Schedules										
Lighting Energy	$0.07	$0.56	$1.03	$1.58	$2.28	$2.63	$2.57	$2.51	$2.46	$2.44
Traffic Energy	$0.02	$0.11	$0.21	$0.32	$0.46	$0.53	$0.52	$0.51	$0.50	$0.49
Lighting Service and Restricted Lighting	$0.01	$0.09	$0.17	$0.25	$0.37	$0.42	$0.41	$0.40	$0.39	$0.39
Incremental Billing Factor Group 2	0.07%	0.54%	1.00%	1.52%	2.21%	2.56%	2.52%	2.48%	2.44%	2.41%
Bill Impact for Group 2 Rate Schedules										
General Service	$0.16	$1.23	$2.28	$3.49	$5.06	$5.87	$5.77	$5.68	$5.58	$5.51
Power Service - Secondary	$2.67	$20.07	$37.36	$57.09	$82.88	$96.05	$94.43	$92.91	$91.35	$90.18
Power Service - Primary	$6.48	$48.62	$90.52	$138.31	$200.80	$232.70	$228.77	$225.10	$221.31	$218.48
Time of Day Service - Secondary	$8.81	$66.11	$123.08	$188.06	$273.03	$316.39	$311.06	$306.06	$300.91	$297.06
Time of Day Service - Primary	$42.92	$322.06	$599.58	$916.14	$1,330.08	$1,541.35	$1,515.35	$1,490.99	$1,465.94	$1,447.17
Retail Transmission Service	$181.03	$1,358.49	$2,529.09	$3,864.38	$5,610.42	$6,501.58	$6,391.89	$6,289.15	$6,183.46	$6,104.29
Fluctuating Load Service	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Outdoor Sports Lighting Service - Secondar	$0.49	$3.64	$6.78	$10.36	$15.04	$17.42	$17.13	$16.85	$16.57	$16.36

NOTES: Residential includes Volunteer Fire Department and Residential Time of Day customers.
There are currently no customers served under Rate Schedule FLS.

Revenue Requirements Summary
2020 Plan - LG&E

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Project 31	**Mill Creek ELG System and Diffuser**										
	Revenue Requirement										
	Eligible Plant	4,158,105	38,784,511	67,971,638	93,382,947	109,235,174	109,235,174	109,235,174	109,235,174	109,235,174	109,235,174
	Less: Retired Plant	0	0	0	0	0	0	0	0	0	0
	Less: Accumulated Depreciation	0	(53,590)	(482,310)	(911,030)	(3,243,529)	(7,186,919)	(11,130,309)	(15,073,699)	(19,017,088)	(22,960,478)
	Plus: Accumulated Depreciation on retired plant	0	0	0	0	0	0	0	0	0	0
	Less: Deferred Tax Balance	0	(97,743)	(204,679)	(295,556)	(807,541)	(1,746,521)	(2,541,161)	(3,202,583)	(3,740,448)	(4,172,570)
	Plus: Deferred Tax Balance on retired plant	0	0	0	0	0	0	0	0	0	0
	Environmental Compliance Rate Base	4,158,105	38,633,177	67,284,648	92,176,361	105,184,103	100,301,733	95,563,703	90,958,892	86,477,637	82,102,126
	Rate of return	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%
		$361,755	$3,361,086	$5,853,764	$8,019,343	$9,151,017	$8,726,251	$8,314,042	$7,913,424	$7,523,554	$7,142,885
	Operating expenses	0	0	0	0	1,770,197	3,669,180	3,802,731	3,941,228	4,084,857	4,233,810
	Annual Depreciation expense	0	53,590	428,720	428,720	2,332,499	3,943,390	3,943,390	3,943,390	3,943,390	3,943,390
	Less depreciation on retired plant	0	0	0	0	0	0	0	0	0	0
	Annual Property Tax expense	0	6,237	58,096	101,234	138,708	158,987	153,072	147,157	141,242	135,327
	Total OE	$0	$59,827	$486,816	$529,954	$4,241,405	$7,771,557	$7,899,193	$8,031,775	$8,169,489	$8,312,527
	Total E(m) Project 31	**361,755**	**3,420,914**	**6,340,581**	**8,549,297**	**13,392,422**	**16,497,808**	**16,213,235**	**15,945,199**	**15,693,043**	**15,455,412**

Revenue Requirements Summary
2020 Plan - LG&E

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Project 32	**Trimble County ELG**										
	Revenue Requirement										
	Eligible Plant	2,797,924	12,678,446	23,818,740	36,995,065	36,995,065	36,995,065	36,995,065	36,995,065	36,995,065	36,995,065
	Less: Retired Plant	0	0	0	0	0	0	0	0	0	0
	Less: Accumulated Depreciation	0	0	0	(478,932)	(1,363,114)	(2,247,296)	(3,131,478)	(4,015,660)	(4,899,842)	(5,784,024)
	Plus: Accumulated Depreciation on retired plant	0	0	0	0	0	0	0	0	0	0
	Less: Deferred Tax Balance	0	0	0	(226,642)	(672,371)	(1,068,073)	(1,417,623)	(1,724,345)	(1,991,561)	(2,222,133)
	Plus: Deferred Tax Balance on retired plant	0	0	0	0	0	0	0	0	0	0
	Environmental Compliance Rate Base	2,797,924	12,678,446	23,818,740	36,289,492	34,959,580	33,679,696	32,445,964	31,255,060	30,103,662	28,988,907
	Rate of return	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%
		$243,419	$1,103,025	$2,072,230	$3,157,186	$3,041,483	$2,930,134	$2,822,799	$2,719,190	$2,619,019	$2,522,035
	Operating expenses	0	0	0	669,637	1,387,987	1,438,503	1,490,889	1,545,215	1,601,556	1,659,986
	Annual Depreciation expense	0	0	0	478,932	884,182	884,182	884,182	884,182	884,182	884,182
	Less depreciation on retired plant	0	0	0	0	0	0	0	0	0	0
	Annual Property Tax expense	0	4,197	19,018	35,728	54,774	53,448	52,122	50,795	49,469	48,143
	Total OE	$0	$4,197	$19,018	$1,184,297	$2,326,943	$2,376,133	$2,427,192	$2,480,193	$2,535,207	$2,592,311
	Total E(m) Project 32	**243,419**	**1,107,222**	**2,091,248**	**4,341,483**	**5,368,427**	**5,306,266**	**5,249,991**	**5,199,383**	**5,154,226**	**5,114,346**

Revenue Requirements Summary
2020 Plan - LG&E

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total E(m) - All LG&E Projects	605,174	4,528,135	8,431,829	12,890,780	18,760,849	21,804,074	21,463,227	21,144,582	20,847,269	20,569,758
12 Month Average Jurisdictional Ratio	96.81%	96.81%	96.81%	96.81%	96.81%	96.81%	96.81%	96.81%	96.81%	96.81%
Jurisdictional E(m)	585,859	4,383,612	8,162,713	12,479,350	18,162,065	21,108,161	20,778,192	20,469,717	20,181,894	19,913,240
Group 1 Avg. % of Total Revenue	42.90%	42.90%	42.90%	42.90%	42.90%	42.90%	42.90%	42.90%	42.90%	42.90%
Group 1 E(m)	$ 251,334	$ 1,880,570	$ 3,501,804	$ 5,353,641	$ 7,791,526	$ 9,055,401	$ 8,913,844	$ 8,781,509	$ 8,658,032	$ 8,542,780
Group 1 R(m)	$ 468,298,575	$ 467,683,308	$ 469,606,889	$ 471,003,228	$ 474,008,217	$ 477,575,871	$ 481,493,551	$ 486,149,595	$ 488,374,702	$ 485,259,797
	0.05%	0.40%	0.75%	1.14%	1.64%	1.90%	1.85%	1.81%	1.77%	1.76%
Group 2 Avg. % of Total Revenue	57.10%	57.10%	57.10%	57.10%	57.10%	57.10%	57.10%	57.10%	57.10%	57.10%
Group 2 E(m)	$ 334,526	$ 2,503,043	$ 4,660,909	$ 7,125,709	$ 10,370,539	$ 12,052,760	$ 11,864,348	$ 11,688,209	$ 11,523,861	$ 11,370,460
Group 2 R(m)	$ 468,748,564	$ 467,370,148	$ 467,472,191	$ 467,732,952	$ 468,873,091	$ 470,237,544	$ 470,830,162	$ 471,417,502	$ 472,733,090	$ 472,490,139
	0.07%	0.54%	1.00%	1.52%	2.21%	2.56%	2.52%	2.48%	2.44%	2.41%

Revenue Requirements
Project 31 - LG&E Mill Creek

	2020	2021	2022	2023	June 2024	2025	2026	2027	2028	2029
In-Service					1	2	3	4	5	6
Mill Creek										
Project 31 - ELG (Mill Creek)	$3,818,105	$23,090,506	$29,187,127	$25,411,309	$15,852,227	$0	$0	$0	$0	$0
Accumulated Expenditures	$3,818,105	$26,908,611	$56,095,738	$81,507,047	$97,359,274	$97,359,274	$97,359,274	$97,359,274	$97,359,274	$97,359,274
Book Depreciation rate, per year	0.000%	0.000%	0.000%	0.000%	3.610%	3.610%	3.610%	3.610%	3.610%	3.610%
Tax Depreciation rate, per year	0.000%	0.000%	0.000%	0.000%	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%
Income tax rate	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%
Deferred Tax Balance	0	0	0	0	435,925	1,312,592	2,057,601	2,681,155	3,191,997	3,598,874
Book Accumulated Depreciation Balance	0	0	0	0	1,903,779	5,418,449	8,933,119	12,447,789	15,962,459	19,477,128
Unrecovered Investment -- Book	3,818,105	26,908,611	56,095,738	81,507,047	97,359,274	97,359,274	97,359,274	97,359,274	97,359,274	97,359,274
Book Depreciation	0	0	0	0	1,903,779	3,514,670	3,514,670	3,514,670	3,514,670	3,514,670
Unrecovered Investment -- Tax total	3,818,105	26,908,611	56,095,738	81,507,047	97,359,274	97,359,274	97,359,274	97,359,274	97,359,274	97,359,274
Bonus Tax Depreciation	0	0	0	0	0	0	0	0	0	0
MACRS Tax Depreciation	0	0	0	0	3,650,973	7,028,366	6,500,679	6,013,882	5,562,135	5,145,438
Allowed Rate of Return	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%
Book Depreciation expense total	0	0	0	0	1,903,779	3,514,670	3,514,670	3,514,670	3,514,670	3,514,670
Tax expense total	0	0	0	0	3,650,973	7,028,366	6,500,679	6,013,882	5,562,135	5,145,438
Annual Property Tax Rate	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%
Deferred Tax Activity	0	0	0	0	435,925	876,667	745,009	623,554	510,843	406,877
Revenue Recovery on Capital Expenditure to date										
Eligible Plant, cumulative capital expenditures	3,818,105	26,908,611	56,095,738	81,507,047	97,359,274	97,359,274	97,359,274	97,359,274	97,359,274	97,359,274
Less: Retired Plant	0	0	0	0	0	0	0	0	0	0
Less: Accumulated Depreciation	0	0	0	0	(1,903,779)	(5,418,449)	(8,933,119)	(12,447,789)	(15,962,459)	(19,477,128)
Plus: Accumulated Depreciation on Retired Plant	0	0	0	0	0	0	0	0	0	0
Less: Deferred Tax Balance	0	0	0	0	(435,925)	(1,312,592)	(2,057,601)	(2,681,155)	(3,191,997)	(3,598,874)
Plus: Deferred Tax Balance on Retired Plant	0	0	0	0	0	0	0	0	0	0
Environmental Compliance Rate Base	3,818,105	26,908,611	56,095,738	81,507,047	95,019,569	90,628,232	86,368,553	82,230,330	78,204,818	74,283,271
Rate of return	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%
Return on Environmental Compliance Rate Base	$332,175	$2,341,049	$4,880,329	$7,091,113	$8,266,703	$7,884,656	$7,514,064	$7,154,039	$6,803,819	$6,462,645
Operating Expenses	0	0	0	0	1,770,197	3,669,180	3,802,731	3,941,228	4,084,857	4,233,810
Annual Depreciation expense	0	0	0	0	1,903,779	3,514,670	3,514,670	3,514,670	3,514,670	3,514,670
Less depreciation on retired plant	0	0	0	0	0	0	0	0	0	0
Annual Property Tax expense	0	5,727	40,363	84,144	122,261	143,183	137,911	132,639	127,367	122,095
Total OE	$0	$5,727	$40,363	$84,144	$3,796,237	$7,327,033	$7,455,312	$7,588,537	$7,726,894	$7,870,575
Total E(m) - ELG Project	332,175	2,346,776	4,920,692	7,175,257	12,062,940	15,211,689	14,969,376	14,742,576	14,530,713	14,333,219

Revenue Requirements
Project 31 - LG&E Mill Creek

	2020	November 2021	2022	2023	2024	2025	2026	2027	2028	2029
In-Service		1	2	3	4	5	6	7	8	9
Mill Creek										
Project 31 - Diffuser (Mill Creek)	$340,000	$11,535,900	$0	$0	$0	$0	$0	$0	$0	$0
Accumulated Expenditures	$340,000	$11,875,900	$11,875,900	$11,875,900	$11,875,900	$11,875,900	$11,875,900	$11,875,900	$11,875,900	$11,875,900
Book Depreciation rate, per year	0.000%	3.610%	3.610%	3.610%	3.610%	3.610%	3.610%	3.610%	3.610%	3.610%
Tax Depreciation rate, per year	0.000%	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%	4.522%	4.462%
Income tax rate	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%
Deferred Tax Balance	0	97,743	204,679	295,556	371,617	433,929	483,560	521,428	548,451	573,696
Book Accumulated Depreciation Balance	0	53,590	482,310	911,030	1,339,750	1,768,470	2,197,190	2,625,910	3,054,630	3,483,350
Unrecovered Investment -- Book	340,000	11,875,900	11,875,900	11,875,900	11,875,900	11,875,900	11,875,900	11,875,900	11,875,900	11,875,900
Book Depreciation	0	53,590	428,720	428,720	428,720	428,720	428,720	428,720	428,720	428,720
Unrecovered Investment -- Tax total	340,000	11,875,900	11,875,900	11,875,900	11,875,900	11,875,900	11,875,900	11,875,900	11,875,900	11,875,900
Bonus Tax Depreciation	0	0	0	0	0	0	0	0	0	0
MACRS Tax Depreciation	0	445,346	857,321	792,954	733,574	678,470	627,641	580,494	537,028	529,903
Allowed Rate of Return	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%
Book Depreciation expense total	0	53,590	428,720	428,720	428,720	428,720	428,720	428,720	428,720	428,720
Tax expense total	0	445,346	857,321	792,954	733,574	678,470	627,641	580,494	537,028	529,903
Annual Property Tax Rate	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%
Deferred Tax Activity	0	97,743	106,936	90,876	76,061	62,313	49,631	37,868	27,023	25,245
Revenue Recovery on Capital Expenditure to date										
Eligible Plant, cumulative capital expenditures	340,000	11,875,900	11,875,900	11,875,900	11,875,900	11,875,900	11,875,900	11,875,900	11,875,900	11,875,900
Less: Retired Plant	0	0	0	0	0	0	0	0	0	0
Less: Accumulated Depreciation	0	(53,590)	(482,310)	(911,030)	(1,339,750)	(1,768,470)	(2,197,190)	(2,625,910)	(3,054,630)	(3,483,350)
Plus: Accumulated Depreciation on Retired Plant	0	0	0	0	0	0	0	0	0	0
Less: Deferred Tax Balance	0	(97,743)	(204,679)	(295,556)	(371,617)	(433,929)	(483,560)	(521,428)	(548,451)	(573,696)
Plus: Deferred Tax Balance on Retired Plant	0	0	0	0	0	0	0	0	0	0
Environmental Compliance Rate Base	340,000	11,724,567	11,188,911	10,669,314	10,164,533	9,673,501	9,195,150	8,728,562	8,272,819	7,818,854
Rate of return	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%
Return on Environmental Compliance Rate Base	$29,580	$1,020,037	$973,435	$928,230	$884,314	$841,595	$799,978	$759,385	$719,735	$680,240
Operating Expenses	0	0	0	0	0	0	0	0	0	0
Annual Depreciation expense	0	53,590	428,720	428,720	428,720	428,720	428,720	428,720	428,720	428,720
Less depreciation on retired plant	0	0	0	0	0	0	0	0	0	0
Annual Property Tax expense	0	510	17,733	17,090	16,447	15,804	15,161	14,518	13,875	13,232
Total OE	$0	$54,100	$446,453	$445,810	$445,167	$444,524	$443,881	$443,238	$442,595	$441,952
Total E(m) - Diffuser Project	29,580	1,074,137	1,419,889	1,374,041	1,329,482	1,286,119	1,243,859	1,202,623	1,162,330	1,122,192
Combined Total E(m) Project 31	**361,755**	**3,420,914**	**6,340,581**	**8,549,297**	**13,392,422**	**16,497,808**	**16,213,235**	**15,945,199**	**15,693,043**	**15,455,412**

Revenue Requirements
Project 32 - LG&E Trimble Co

	2020	2021	2022	June 2023	2024	2025	2026	2027	2028	2029
In-Service				1	2	3	4	5	6	7
LGE Trimble Co										
Project 32 - Trimble County ELG	$2,797,924	$9,880,522	$11,140,295	$13,176,325	$0	$0	$0	$0	$0	$0
Accumulated Expenditures	$2,797,924	$12,678,446	$23,818,740	$36,995,065	$36,995,065	$36,995,065	$36,995,065	$36,995,065	$36,995,065	$36,995,065
Book Depreciation rate, per year	0.000%	0.000%	0.000%	2.390%	2.390%	2.390%	2.390%	2.390%	2.390%	2.390%
Tax Depreciation rate, per year	0.000%	0.000%	0.000%	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%
Income tax rate	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%	24.95%
Deferred Tax Balance	0	0	0	226,642	672,371	1,068,073	1,417,623	1,724,345	1,991,561	2,222,133
Book Accumulated Depreciation Balance	0	0	0	478,932	1,363,114	2,247,296	3,131,478	4,015,660	4,899,842	5,784,024
Unrecovered Investment -- Book	2,797,924	12,678,446	23,818,740	36,995,065	36,995,065	36,995,065	36,995,065	36,995,065	36,995,065	36,995,065
Book Depreciation	0	0	0	478,932	884,182	884,182	884,182	884,182	884,182	884,182
Unrecovered Investment -- Tax total	2,797,924	12,678,446	23,818,740	36,995,065	36,995,065	36,995,065	36,995,065	36,995,065	36,995,065	36,995,065
Bonus Tax Depreciation	0	0	0	0	0	0	0	0	0	0
MACRS Tax Depreciation	0	0	0	1,387,315	2,670,674	2,470,160	2,285,185	2,113,528	1,955,189	1,808,319
Allowed Rate of Return	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%
Book Depreciation expense total	0	0	0	478,932	884,182	884,182	884,182	884,182	884,182	884,182
Tax expense total	0	0	0	1,387,315	2,670,674	2,470,160	2,285,185	2,113,528	1,955,189	1,808,319
Annual Property Tax Rate	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%
Deferred Tax Activity	0	0	0	226,642	445,730	395,702	349,550	306,722	267,216	230,572
Revenue Recovery on Capital Expenditure to date										
Eligible Plant, cumulative capital expenditures	2,797,924	12,678,446	23,818,740	36,995,065	36,995,065	36,995,065	36,995,065	36,995,065	36,995,065	36,995,065
Less: Retired Plant	0	0	0	0	0	0	0	0	0	0
Less: Accumulated Depreciation	0	0	0	(478,932)	(1,363,114)	(2,247,296)	(3,131,478)	(4,015,660)	(4,899,842)	(5,784,024)
Plus: Accumulated Depreciation on Retired Plant	0	0	0	0	0	0	0	0	0	0
Less: Deferred Tax Balance	0	0	0	(226,642)	(672,371)	(1,068,073)	(1,417,623)	(1,724,345)	(1,991,561)	(2,222,133)
Plus: Deferred Tax Balance on Retired Plant	0	0	0	0	0	0	0	0	0	0
Environmental Compliance Rate Base	2,797,924	12,678,446	23,818,740	36,289,492	34,959,580	33,679,696	32,445,964	31,255,060	30,103,662	28,988,907
Rate of return	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%	8.70%
	$243,419	$1,103,025	$2,072,230	$3,157,186	$3,041,483	$2,930,134	$2,822,799	$2,719,190	$2,619,019	$2,522,035
Operating Expenses	0	0	0	669,637	1,387,987	1,438,503	1,490,889	1,545,215	1,601,556	1,659,986
Annual Depreciation expense	0	0	0	478,932	884,182	884,182	884,182	884,182	884,182	884,182
Less depreciation on retired plant	0	0	0	0	0	0	0	0	0	0
Annual Property Tax expense	0	4,197	19,018	35,728	54,774	53,448	52,122	50,795	49,469	48,143
Total OE	$0	$4,197	$19,018	$1,184,297	$2,326,943	$2,376,133	$2,427,192	$2,480,193	$2,535,207	$2,592,311
Total E(m) - Project	**243,419**	**1,107,222**	**2,091,248**	**4,341,483**	**5,368,427**	**5,306,266**	**5,249,991**	**5,199,383**	**5,154,226**	**5,114,346**