Michael E. Hornung
Manager, Pricing/Tariffs
State Regulation and Rates
T 502-627-4671 | F 502-627-3213
Mike.hornung@lge-ku.com

a PPL company

VIA ELECTRONIC TARIFF FILING SYSTEM

Ms. Linda Bridwell
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601-8294

October 7, 2022

Re: Filing of Special Contract under Kentucky Utilities Company's Economic Development Rider (EDR)
Bitiki-KY, LLC

Dear Ms. Bridwell:

Pursuant to 807 KAR 5:011, Section 13, Kentucky Utilities Company ("KU") P.S.C. No. 20, Original Sheet No. 71, respectfully requests approval of this special contract between KU and Bitiki-KY, LLC. Enclosed for filing are:

- Cover Letter;
- Attachment 1 – Contract for Electric Service;
- Attachment 2 – Special Contract for Economic Development;
- Attachment 3 – State Certification;
- Attachment 4 – Marginal Cost Study; and
- Attachment 5 – Monthly Billing Comparison.

Should you have any questions, please do not hesitate to contact me.

Sincerely,

Michael E. Hornung

KUCES082614

Account Number TBD

CONTRACT FOR ELECTRIC SERVICE

This contract made and entered into this ___31___ day of ___August___, ___2022___ by and between Kentucky Utilities Company ("Company") and ___Bitiki-KY, LLC___ ("Customer").

WITNESSETH:

Beginning When the service is initiated___, or as soon thereafter as connection is made, Company will sell and deliver to Customer at ___1274 State Route 141, Waverly, KY 42462___ all Customer's electric capacity and energy requirements defined as ___3___ phase, 60 cycle, alternating current, nominal voltage at the point of delivery of ___69,000___volts, metered and billed as ___Transmission___ service.

Secondary, Primary, Transmission

Customer requires an estimated Contract Capacity of ___See Comments___ kVa or kW, as is appropriate.

Each month Customer will pay to Company for all capacity provided and energy delivered to Customer in the preceding billing period an amount determined in accordance with the ___RTS___ Rate Schedule and, as may be appropriate, the EDR-effective date to be determined by the Customer and subject to approval by the Public Service Commission (PSC)___ Rider, contract attached if required, and the

COMMENTS:

Customer's estimated contract capacity shall be 2,000 kVA at the effective date of this contract, but shall be adjusted on each of the adjustment dates listed below to the corresponding capacity level and shall remain at that level until the next listed adjustment date.

Adjustment Date	Adjusted Capacity Level
November 2022 Billing Month	4,000 kVa
January 2023 Billing Month	6,000 kVa
March 2023 Billing Month	10,000 kVa
May 2023 Billing Month	13,000 kVa

This contract shall take effect on the stated effective date and remain in effect until one year following the latest adjustment date set forth above. Thereafter, this contract will be automatically renewed for successive periods of one (1) year each, subject to termination at the end of any year upon either party giving written notice of termination to the other party at least 90 days prior to termination date.

KUCES082614

TARIFF PROVISIONS: It is mutually agreed that Company's terms and conditions and applicable rate schedule, as from time to time approved by and on file with the Public Service Commission of Kentucky, are made a part of this contract as fully as if written here.

IN WITNESS WHEREOF, the parties hereto have caused this contract to be executed by their duly authorized representatives the day and year shown above.

KENTUCKY UTILITIES COMPANY	BITIKI-KY, LLC
By	By
Key Account Manager **Official Capacity**	SENIOR VICE PRESIDENT
Attest	**Attest**

Customer Account **350011092664**

SPECIAL CONTRACT
ECONOMIC DEVELOPMENT RIDER

This special contract for Economic Development Rider service ("EDR Contract") is made and entered into this **28th** day of **September**, 2022 by and between Bitiki-KY, LLC ("Customer") and Kentucky Utilities Company ("Company").

WITNESSETH:

WHEREAS, Company is in the business of providing retail electric service in the Commonwealth of Kentucky;

WHEREAS, Customer has applied for and/or is receiving retail electric service from Company pursuant to a Contract for Electric Service dated **8/31/2022** ("Electric Service Contract") under Standard Rate Schedule **Retail Transmission Service (RTS)** ; and

WHEREAS, Customer requests EDR total Demand Charge discounts on the basis that Customer's proposed monthly billing load ("EDR Contracted Load") meets the requirements outlined in Appendix A for (check appropriate space):

________ Brownfield Development load of ________ kVa

X Economic Development new load of **13,000** kVa

________ Economic Development new load of ________ kVa above an Existing Base Load as defined in the aforementioned Appendix A.

The EDR Total Demand Charge discounts shall be incorporated with the bill for electric service issued pursuant to the Electric Service Contract beginning **2/1/2023** and will be subject to the same payment provisions as the Electric Service Contract.

NOW, THEREFORE, in consideration of the mutual agreements made herein, the parties agree as follows:

Company's rates, terms, and conditions for the provision of electric service to Customer, and Customer's obligations, rights and responsibilities to the Company for the supply of electric service, are specified in and determined by the Standard Rate Schedule specified above and other applicable schedules, terms, and conditions of service set forth in the Company's tariffs on file with, and approved by, the Kentucky Public Service Commission ("PSC"), and by the terms of the Electric Service Contract. The Company's Rates, Terms and Conditions for Furnishing Electric Service, as filed with and approved by the PSC, both in effect now and in the future, are incorporated by reference and made a part of this EDR Contract as if fully set forth here in

This EDR Contract is supplemental to, and by agreement made a part of, the Electric Service Contract for the purpose of applying provisions of the Company's Economic Development Rider, Standard Rate Rider EDR ("EDR"), to Customer.

Customer has represented that it anticipates investing **$25,000,000** in its facilities located at **1274 State Route 141 Waverly**, KY (the "EDR Location"), creating approximately **5** new jobs, which economic development will generate the EDR Contracted Load for the Initial Contract Term (as defined below). Therefore, Company hereby agrees to furnish, and Customer agrees to take, EDR service pursuant to the terms and conditions of Standard Rate Rider EDR, as currently approved by the PSC or as may be modified in the future and approved by the PSC.

The initial term of this EDR Contract shall be ten (10) years beginning, at the option of Customer, no later than **12** months following approval of this Special Contract by the PSC (the "Initial Contract Term").

The Total Demand Charge for the twelve (12) consecutive monthly billings and the subsequent four consecutive twelve (12) monthly billing periods, thereafter, shall be reduced by **50%, 40%, 30%, 20%, 10%, respectively** (the "EDR Credits"). All subsequent billing shall be at the full charges stated in the applicable rate schedule after this five (5) year period. Upon termination of the Initial Contract Term, service will continue in accordance with the terms of the Standard Rate Schedule.

In the event that Customer (a) ceases operations at the EDR Location before the Initial Contract Term expires, (b) stops taking service for the EDR Location from Company during the Initial Contract Term, or (c) terminates the EDR Contract before the Initial Contract Term expires (with each of the foregoing being a " Customer Termination Event"), the Customer shall reimburse Company for a portion of the EDR Credits received from the Company by Customer (the "Reimbursement Amount") as set forth hereafter. If a Customer Termination Event occurs during the first two years of the Initial Contract Term, the Customer shall reimburse the Company for 90% of the total EDR Credits received by the Customer. If a Customer Termination Event occurs during the third, fourth or fifth years of the Initial Contract Term, the Customer shall reimburse the Company for 75% of the total EDR Credits received by the Customer. If a Customer Termination Event occurs at any time during the final five years of the Initial Contract Term, the Customer shall reimburse the Company for 50% of the total EDR Credits received by the Customer. The Reimbursement Amount shall be paid to Company by Customer within 30 days of the Customer Termination Event.

Company may terminate this EDR Contract at any time for Customer's failure to comply with the terms and conditions of Standard Rider EDR or this EDR Contract, including but not limited to if Customer ceases operations at the EDR Location, stops taking service during the Initial Contract Term or fails to timely provide the Security (as defined below). Upon termination of the EDR Contract, Company shall be entitled to recover the Reimbursement Amount from Customer and shall be entitled to recover any and all other damages that it may have at law or in equity, from Customer but with the Reimbursement Amount being the exclusive remedy for EDR Credits previously paid or given to Customer by Company. Such termination will only affect the application of, and Customer's service under, the Standard Rider EDR and this EDR Contract, and shall not affect the application of, or Customer's service under, the Electric Service Contract.

Customer agrees to provide all information necessary to satisfy the PSC initial filing requirements and successive annual reports for the duration of this special contract.

The terms and conditions of this EDR Contract shall inure to and be binding upon the parties, together with their respective successors in interest or assigns, except that Customer may not assign or transfer any of its rights, duties, or obligations hereunder without the prior written consent of Company. An assignment by Customer shall not have any effect whatsoever unless approved in writing by Company in advance of such assignment. Nothing herein shall be construed to confer a benefit on any person not a signatory hereto or the successor to a signatory hereto.

All disputes arising between Customer and Company hereunder shall be finally decided by the PSC in accordance with its applicable rules and procedures. This EDR Contract shall be construed and enforced in accordance with the laws of the Commonwealth of Kentucky.

The failure of either party to enforce or insist upon compliance with any of the terms or conditions of this EDR Contract shall not constitute a waiver or relinquishment of any such terms or conditions.

IN WITNESS WHEREOF, Customer and Company have executed this EDR Contract on the day and year first above written.

Kentucky Utilities Company	Customer: **Bitiki-KY, LLC**
By: ES:AMR	By: Kirk D. Sholer
Date: October 1, 2022	Date: Sept. 30, 2022

Appendix A

The combined Louisville Gas and Electric Company and Kentucky Utilities Company current, **2022**, capacity reserve margin is **1,348** MW which is **290** MW in excess of a reserve margin considered essential for a system reliability of **1,058** MW. For each year in which Customer will receive demand charge discounts under the EDR Contract, the Company's projected reserve margins are expected to be: Year 1 **1,452** MW, Year 2 **1,472** MW, Year 3 **1,418** MW, Year 4 **1,332** MW, and Year 5 **1,340** MW.

Company estimates investing **$0** in new facilities to serve the EDR Contracted Load.

Company estimates Customer's minimum monthly billing under Standard Rate Schedule **KU-RTS** will be **$147,000**.

Customer anticipates investing **$25,000,000** in facilities associated with the EDR Contracted Load.

Customer anticipates creating **5** new jobs associated with the EDR Contracted Load.

Customer estimates the EDR Contracted Load to be **13,000** kW or kVA, as is appropriate, at a **95** % load factor.

If the new load is in addition to an existing load, Company and Customer agree that the Existing base Load, in kW or kVa, as is appropriate, is:

January -		Peak,		Intermediate,		Base;
February -		Peak,		Intermediate,		Base;
March -		Peak,		Intermediate,		Base;
April -		Peak,		Intermediate,		Base;
May -		Peak,		Intermediate,		Base;
June -		Peak,		Intermediate,		Base;
July -		Peak,		Intermediate,		Base;
August -		Peak,		Intermediate,		Base;
September -		Peak,		Intermediate,		Base;
October -		Peak,		Intermediate,		Base;
November -		Peak,		Intermediate,		Base; and
December		Peak,		Intermediate,		Base.

Andy Beshear
Governor

Old Capitol Annex
300 West Broadway
Frankfort, Kentucky 40601

Larry Hayes
Interim Secretary

March 31, 2022

Heath Lovell
Bitiki Blockchain, LLC
1274 State Route141
Waverly, KY 42462

RE: **Bitiki Blockchain, LLC (Union County)**
KEIA-22-23802

Dear Mr. Lovell:

I am pleased to inform you that the Kentucky Economic Development Finance Authority has approved your request for consideration under the Kentucky Enterprise Initiative Act ("KEIA") program on March 31, 2022. Please note that the approval is contingent upon receipt of a fully executed Agreement.

Enclosed are two Agreements to be signed by an official of the company. **Please have both copies signed and returned to our office by April 30, 2022.** Once the agreements are executed by our office, we will return one original to you for your records.

Upon receipt of a fully executed Agreement your company will be eligible for a Kentucky Sales and Use Tax refund, not to exceed $250,000, for eligible construction materials and building fixtures/R&D, electronic processing and/or flight simulation equipment. Additionally, the Agreement contains an expiration date that may receive one or more extensions, if necessary, for the project to be completed up to but no later than seven years from the original date of approval. If the approved company would like to request an extension, please send the request to the Office of Financial Services a minimum of 30 days prior to the expiration date.

Proper documentation of all sales or use tax paid is essential for the company to receive its refund. Prior to starting your project, it is recommended the company contact the Certification Section Supervisor in the Division of Sales and Use Tax at the Department of Revenue, at 502-564-5170 to ensure the proper documentation will be collected from the contractor and all subcontractors involved in the project. A Department of Revenue representative may also attempt to contact you within 30 days of your KEIA approval to ensure your familiarity with the necessary refund forms.

The application for refund, **Form 51A200**, and other required forms must be submitted to the Department of Revenue, Sales Tax Division, within 60 days after project completion or expiration of the Agreement, whichever occurs first. You will receive these documents directly from the Department of Revenue. **Exhibit A** of the enclosed Agreement must be completed and returned to the Office of Financial Services <u>at the same time the application for refund is submitted to the Department of Revenue</u> following completion of the project. Failure to submit the application for refund, as described above, could result in the refund being denied.

If you have any questions or need additional information, please contact me at 502-782-1962.

Sincerely,

Michael P. Elder

Michelle P. Elder
Department for Financial Services

Enclosures

c: Tim Bennett
Danna Ware
Corky Peek

AGREEMENT
THE KENTUCKY ENTERPRISE INITIATIVE ACT (KEIA)

This Agreement is made by and between the **KENTUCKY ECONOMIC DEVELOPMENT FINANCE AUTHORITY**, a public body, corporate and politic, created under Chapter 154 of the Kentucky Revised Statutes, **("KEDFA")** and **BITIKI BLOCKCHAIN, LLC**, a Delaware limited liability company, **(the "Company")**, which operates a service or technology facility qualifying as an Eligible Company, as defined in KRS 154 Subchapter 31 (the "Act").

W I T N E S S E T H:

1. Preliminary Statement. Among the facts and circumstances which have resulted in the execution of this Agreement by and between the parties are the following:

A. The Company plans to acquire, expand, construct, install and equip a service or technology facility located at 1274 State Route 141, Waverly, Union County, Kentucky to mine cryptocurrency ("Project").

B. The Project proposed to be undertaken for use by the Company will constitute an "Economic Development Project" within the meaning of the Act.

C. The Company has initiated the development of plans, specifications and designs for the Project and estimates the aggregate cost of the Project will be Twenty-Five Million Dollars ($25,000,000) and the Eligible Expenses, as defined in the Act, for construction materials and building fixtures will be Two Million Seven Hundred Forty-Seven Thousand Four Hundred Thirty-Five Dollars ($2,747,435) and for research and development equipment and/or electronic processing equipment will be Twenty-Two Million Six Thousand Nine Hundred Eighty Dollars ($22,006,980).

D. KEDFA and the Company have executed this Agreement in order to effectuate the purposes of the Act and, subject to due compliance with all requirements of law and the obtaining of all necessary consents and approvals required by law, and to the happening of all acts, conditions and things required, KEDFA authorizes the reimbursement of sales and use tax up to the negotiated Approved Recovery Amount, as defined in the Act, of up to One Hundred Fifty Thousand Dollars ($150,000) for construction materials and building fixtures and up to One Hundred Thousand Dollars ($100,000) for research and development equipment and/or electronic processing equipment, which does not exceed the six percent Kentucky sales and use tax on Eligible Expenses.

E. The Company understands any purchase made prior to the date of this Agreement will not qualify as an Eligible Expense. Only purchases made on or after the date of this Agreement qualify as an Eligible Expense.

2. Representations and Undertakings on the Part of the Company. The Company represents, undertakes, covenants and agrees as follows:

A. The Project is expected to promote the economic development of the Commonwealth;

B. The Company shall cause contracts to be entered into for, or will otherwise provide for, the undertaking of the Project;

C. The Company shall be the entity operating the facility at the time it submits its request for refund;

D. The Company shall make a minimum investment, including the cost of land but excluding the cost of labor, of $500,000 in the Economic Development Project, as defined in the Act, during the term of this Agreement;

E. The Company shall make a minimum investment of $50,000 in research and development equipment and/or electronic processing equipment, as defined in the Act, during the term of this Agreement;

F. The term of the Project and this Agreement shall be from the date of approval by KEDFA through March 31, 2023. The term may be extended upon written request by the Company and by approval of KEDFA for good cause shown, but the term shall not be extended beyond seven (7) years from the date of approval;

G. The Company shall execute information-sharing agreements prescribed by the Department of Revenue with contractors, vendors and other related parties to verify the costs of and payments of sales and use tax on the tangible personal property eligible for the sale and use tax incentive under the Act;

H. The Company shall complete and submit an application to receive the sales and use tax incentives, and any additional documentation required, to the Department of Revenue within 60 days of the earlier of the completion of the Project or the expiration of the term of this Agreement. For a Project with a term of greater than three (3) years, the Company shall, beginning with the third year of the Project term, file with the Department of Revenue annually an informational return, and any supporting documentation required, within 60 days following the end of the calendar year. The Company shall not be eligible to receive the sales and use tax incentives until the Project is complete and the application for incentives is submitted to the Department of Revenue;

I. The Company shall complete and submit Exhibit A provided with this Agreement to KEDFA at the same time the required documents are submitted to the Department of Revenue. The filing of Exhibit A does not constitute a request for refund, only the filing of the required documents with the Department of Revenue will constitute a request for refund;

J. The Company shall report on Exhibit A the total amount of sales and use tax incentives claimed. Failure to provide this information may result in repayment of sales and use tax incentives previously received at the discretion of KEDFA.

K. Information reported to KEDFA on Exhibit A with regard to the Project after approval of the Project shall be available for public disclosure.

L. The Company shall maintain all records and documentation relating to Eligible Expenditures and the Kentucky sales and use tax paid, and shall provide those records and documentation to KEDFA or the Department of Revenue upon request;

M. The sales and use tax incentives shall not be assignable or transferable without the written notice to and approval by KEDFA;

N. The Company shall take such further action and adopt such further proceedings as may be reasonably required to implement its aforesaid undertakings, or as it and KEDFA may deem appropriate in pursuance thereof, or as may be required by law; and

O. The Company has filed its Cabinet for Economic Development Incentive Disclosure Statement (the "Disclosure Statement") related to the Project with KEDFA. If necessary, the Company agrees to update and amend the Disclosure Statement prior to the date of submitting its request as outlined in 2.H. above if changes affecting the Disclosure Statement have occurred during the period between approval and the term of the Project.

3. Undertakings on the Part of KEDFA. Subject to the fulfillment of the conditions herein stated, KEDFA agrees as follows:

A. That it hereby authorizes the reimbursement of sales and use tax up to the negotiated Approved Recovery Amount of One Hundred Fifty Thousand Dollars ($150,000) for construction materials and building fixtures and One Hundred Thousand Dollars ($100,000) for research and development and/or electronic processing equipment, which does not exceed the six percent Kentucky sales and use tax on Eligible Expenses, as defined in the Act; and

B. That it will take such other acts and adopt such further proceedings as may be required to implement the aforesaid undertakings as KEDFA may deem necessary or advisable, subject to compliance with applicable laws.

4. General Provisions.

A. The Total Maximum Incentives available pursuant to this Agreement may be reduced in the sole, reasonable discretion of KEDFA if, after the date of this Agreement, the Company applies for and obtains additional incentives in the form of tax credits, abatements, subsidies, grants or loans approved by KEDFA for this Project, such that the total benefit received by the Company from the aggregate of all incentives approved by KEDFA related to the Project as defined herein would exceed the Total Maximum Incentives available herein.

B. If any provision of this Agreement is determined to be invalid or unenforceable, that determination shall not affect any other provision, the remaining provisions of which shall be construed and enforced as if the invalid or unenforceable provision were not contained herein.

C. In the event that Company fails to submit any documentation required by this Agreement to KEDFA or to the Department of Revenue within any applicable time limitation, KEDFA may suspend any remaining sales and use tax incentives and require repayment of incentives previously received in its sole discretion.

D. Amendments. If the Company wants to amend this Agreement, the Company must submit a request for amendment to KEDFA in writing. After submission, such amendment will be subject to the express, prior written consent of KEDFA after passage of a resolution approving such requested amendment.

E. Entire Agreement. This Agreement constitutes the entire agreement between the parties and no other writings or communications (oral or otherwise) shall have any legal effect unless made pursuant to the terms of this Agreement.

F. No Waiver. No failure by KEDFA to insist upon the strict performance by the Company of any provision hereof shall constitute a waiver of KEDFA's right to strict performance and no express waiver shall be deemed to apply to any other existing or subsequent right of KEDFA to require the Company to remedy any and all failures by the Company to observe or comply with any provision hereof.

G. Release and Indemnification by Company. The Company releases KEDFA from, holds KEDFA harmless against, agrees that KEDFA shall not be liable for, and fully indemnifies KEDFA against, any and all losses, liabilities, claims, actions, proceedings, costs and expenses imposed upon, incurred by, asserted against or with respect to KEDFA on account of: (i) any loss or damage to property or injury to or death of or loss by any person that may be occasioned by any cause whatsoever pertaining to the maintenance, operation and use of the Project; (ii) any loss or damage alleged by any third-party related to the Act (or successor statutes) and the Project; (iii) any breach or default on the part of the Company in the performance or non-performance of any Covenant arising from any act or failure to act by the Company or its respective agents, contractors, servants, employees, licensees, successors or assigns; and (iv) any action taken or omitted to be taken by KEDFA in accordance with the terms of this Agreement (excepting acts of willful misconduct).

In the event KEDFA seeks indemnity hereunder with respect to any action or proceeding brought against KEDFA, KEDFA shall give notice of such action or proceeding to the Company, and the Company upon receipt of that notice, shall have the obligation to assume the defense of KEDFA in such action or proceeding; provided, however, that failure of KEDFA to give such notice shall not relieve the Company from any of its obligations under this Section to assume such defense unless the failure by KEDFA to give such notice so prejudices the defense of KEDFA in such action or proceeding by the Company that the Company cannot duly conduct such defense. KEDFA may employ separate counsel and participate in the defense.

The indemnification set forth above and all references to KEDFA in this Agreement are intended to and shall include all officials, directors, officers, employees, agents and representatives of KEDFA and the Cabinet for Economic Development (the "Cabinet").

H. Governing Law. This Agreement shall be governed by and construed in accordance with the laws of the Commonwealth.

I. Company Authorization of Release of Information. The Company by execution of this Agreement hereby authorizes and agrees that: (i) KEDFA or any of its agents, employees or employees of the Cabinet are permitted to share with the Department of Revenue information, data, research and other materials (including this Agreement and any attachments hereto) that the Company delivers or provides to, or that is otherwise made available to or discovered by, KEDFA or any of its employees, agents or Cabinet employees; and (ii) the Department of Revenue may provide to KEDFA, as KEDFA may request from time to time, copies of any and all Kentucky tax information, including tax returns, of the Company filed with or otherwise made available to the Department of Revenue (collectively, hereinafter the "Tax Information") (such Tax Information KEDFA shall retain confidentially except as otherwise may be required to be disclosed by law, is disclosed in Exhibit A or is disclosed in order to enforce the terms of this Agreement).

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IN WITNESS WHEREOF, the parties hereto have entered into this Agreement by their officers thereunto duly authorized as of the 31st day of March, 2022.

KENTUCKY ECONOMIC DEVELOPMENT FINANCE AUTHORITY

By: Katie Smith

Katie Smith, Commissioner
Department for Financial Services

BITIKI BLOCKCHAIN, LLC

By: Heath A. Lovell

Printed Name: Heath A. Lovell

Title: Member

The Prime Group LLC

Marginal Cost of Service Study

Kentucky Utilities Company
Louisville Gas and Electric Company

August 12, 2022

Table of Contents

Executive Summary

Louisville Gas & Electric Company ("LG&E) and Kentucky Utilities Company ("KU") (collectively "LG&E/KU" or "the Companies") retained The Prime Group, LLC to prepare an estimate of the Companies' marginal cost of providing electric service.

Marginal cost is defined as the change in total cost with respect to a small change in demand (or "output"). In this study, output refers to the total megawatts of capacity or megawatt hours of energy, so that marginal cost is the change in total system cost relative to a small change in total system capacity or energy.

This report describes the methods for estimating marginal production, transmission, and distribution costs for LG&E/KU. For production, the fixed marginal cost and the variable marginal cost are evaluated independently. Results are tabulated herein and in Table ES-1.

Table ES-1.
Louisville Gas & Electric Company and Kentucky Utilities Company
Summary of Marginal Cost of Service

Function	**Marginal Cost of Service**	
	LG&E	**KU**
Production Demand (per KW of Added NCP Demand)	$2.32	$2.32
Production Energy (per KWH of Added Energy)	$0.03447	$0.03447
Transmission (per KW of Added NCP Demand)	$0.06	$0.01

Marginal production demand cost and its calculation are best looked at from the perspective of the electrical system utility planner. The planner begins by developing a schedule of resource additions which allows the utility to meet its forecasted demand obligations. The planner then must address how any incremental demand will be met. Typically, anticipated additional demand is met by taking the existing plan for generation expansion and accelerating it. Based on information from the Companies' 2021 Integrated Resource Plan filed in Kentucky, which indicated that the Companies' next need for generation capacity is 2028, the marginal production demand costs are associated with advancing a Combined Cycle Gas Combustion Turbine from 2028 to 2027 in-service date. The calculation of an Economic Carrying Charge is used to determine the change in cost of advancing this capital asset by one year.

Marginal production energy costs are derived from the Companies' forecasted marginal variable costs for each hour for the twelve months ended December 2023.

Marginal transmission costs are determined using the 2022 Company Business Plan for transmission capacity additions and developing a revenue requirement for those projected capital investments. This projected investment is then divided by the Companies' 12 monthly Coincident Peak demands to determine a Coincident Peak demand rate which is then converted to a rate on a Non-Coincident Peak demand basis based on the Time-of-Day and Retail Transmission Service rate schedules which represent the most likely customers who would be eligible for an Economic Development Rate from the Companies.

Marginal distribution costs are not calculated because the responsibility for such costs are governed by the Line Extension Plan established by KU and LG&E and approved by the Commission in Case Nos. 2020-00349 and 2020-00350 respectively.

This analysis may be utilized to support the commitment made by the Companies in the proceeding, *In The Matter Of: Application Of Louisville Gas And Electric Company And Kentucky Utilities Company To Modify And Rename The Brownfield Development Rider As The Economic Development Rider* in Case No. 2011-00118. In its Order dated August 11, 2011, the Commission noted if the Companies offer special contracts under their Economic Development rate, the Companies will demonstrate with each special contract filing that the discounted rates exceed the marginal cost associated with serving the customer. (Order, page 7.) The marginal cost study presented herein is applicable for such a demonstration.

Introduction

Louisville Gas & Electric Company ("LG&E) and Kentucky Utilities Company ("KU") (collectively "LG&E/KU" or "the Companies") retained The Prime Group, LLC to prepare an estimate of the Companies' typical marginal costs of delivering electricity.

Marginal cost is defined as the change in total cost with respect to a small change in demand, or output. In this report "output" will be used in place of "demand" to avoid confusion with the standard way that the term "demand" is used in the industry to represent the maximum amount of power utilized during any interval over a specified period of time. Therefore, in this study, output refers to the total megawatts of capacity or megawatt hours of energy, so that marginal cost is the change in total system cost relative to a small change in total system capacity or energy.

This report describes the methods for estimating marginal production, transmission, and distribution costs for LG&E/KU. For production, the fixed marginal cost and the variable marginal cost are evaluated independently. The report includes a summary table of the results.

The marginal production demand costs are determined using the resource planning tools that the Companies rely on for development of their Integrated Resource Plan ("IRP"), which is formally prepared every three years and which was most recently filed with the Kentucky Public Service Commission (“the Commission”) on October 19 2021, in Case No. 2021-00393. The Companies expect to need additional generation capacity in 2028 due to the retirement of Brown 3 and Mill Creek 2 for environmental requirements.

The study is also based on data from the Companies' official books and records as reflected on the Form 1 filings with the Federal Energy Regulatory Commission ("FERC"). Form 1 data utilized includes system peak demand data (in MW) and transmission and distribution cost data (in $) by FERC account. Cost escalation factors were determined using the Consumer Price Index ("CPI") data from the U.S. Department of Labor Bureau of Labor Statistics and/or the Handy-Whitman Index of Public Utility Construction Costs ("Handy-Whitman Index"), as appropriate for the particular type of cost to be escalated.

Marginal costs have several applications. In most jurisdictions in the U.S., the most common application of marginal cost studies by utilities is for designing economic development or other incentive rates. Similarly, the marginal costs are also utilized for analyzing discounted rates provided to certain customers pursuant to special contracts. Another application is for the development of particular components of other rate offerings, e.g. determining rate differentials for use in time-differentiated rates, such as time-of-use or critical-peak-pricing rate schedules.

In particular for LG&E and KU, this analysis may be utilized to support the commitment made by the Companies in *In The Matter Of: Application Of Louisville Gas And Electric Company And Kentucky Utilities Company To Modify And Rename The Brownfield Development Rider As The Economic Development Rider* in Case No. 2011-00118. In its Order dated August 11, 2011, the Commission noted if the Companies offer special contracts under their Economic Development rate, the Companies will demonstrate with each special contract filing that the discounted rates exceed the marginal cost associated with serving the customer. (Order, page 7.) The marginal cost data presented herein, or in subsequent studies, is applicable for such a demonstration.

Marginal Cost Theory

Marginal cost is defined as the change in total cost with respect to a change in output of one unit. Mathematically, marginal cost can be represented as the partial derivative of total cost to output, and can be stated as follows:

$$MC = \frac{\partial C}{\partial q}$$

where

MC	=	Marginal Cost
∂C	=	Change in Total Cost
∂q	=	Change in Output

In the context of discrete cost and output, marginal cost can be *estimated* as follows:

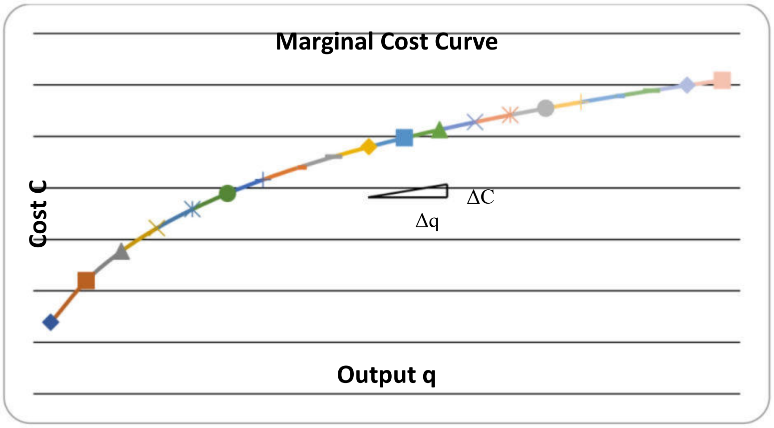
$$MC = \frac{\Delta C}{\Delta q}$$

where

MC	=	Marginal Cost
ΔC	=	Change in Total Cost
Δq	=	Change in Output

Graphically, the marginal cost is the slope of the line resulting from the graph of the total cost C and the total output q, as shown in Figure 1.

Figure 1. Cost vs. Output Curve



In the figure, "output" refers to total megawatts of capacity or megawatt hours of energy required, so that marginal cost is the change in total system cost relative to a small change in total system output.

Marginal Production Demand Cost

The marginal demand costs for production are the changes in capacity costs associated with serving changes in demand on the electric system.

Recall that marginal cost is broadly defined as the change in total cost with respect to a small change in output. In this instance, the "output" refers to total megawatts of generating capacity required, so that marginal cost is the change in total system capacity cost relative to a small change in total system demand.

Marginal production demand cost and its calculation is best looked at from the perspective of the electrical system utility planner. The planner begins by developing a schedule of resource acquisitions which allows the utility to meet its forecasted demand obligations. The planner then must address how any incremental demand will be met. Typically, anticipated additional demand is met by taking the existing plan for generation expansion and accelerating it.[1]

To evaluate the change in capacity costs, a base case is defined that specifies the capacity (and associated capacity cost) required to meet the Companies' base demand forecast for the planning period. Other scenarios are then developed in which the total system demand is increased by set increments, and the capacity acquisitions required to meet those incremental demands are determined. The net present value of the capacity costs in the base case would then be compared to the net present value of the capacity costs for the incremental cases to determine the change in

[1] Charles J. Cicchetti, et al, *The Marginal Cost and Pricing of Electricity: An Applied Approach* (Cambridge, MA: Ballinger Publishing Co., 1977), 8.

capacity cost associated with the change in total system demand. A more detailed description of the computation is shown in Attachment A.

The base case is based on the Companies' 2021 Integrated Resource Plan which indicates that the Companies will need new capacity in 2028 due to the retirement of the Brown 3 and Mill Creek 2 units. In addition, Ford Motor Company recently announced the siting of a 320MW electric vehicle battery facility in the Companies' service territory. Upon announcement, the Companies evaluated this additional load and determined that it did not accelerate the need for generating capacity sooner than 2028. Therefore, this analysis assumes that the next need date for capacity for the Companies remains in 2028 following the announced plant retirements.

The plan includes both supply-side and demand-side resources, but for this assessment only the supply-side resources are considered. To estimate marginal production capacity costs, The Prime Group considered the case wherein new load additions by 2027 would equal 100 MWs, which would require the Companies to build or purchase new capacity to maintain the desired 17% Reserve Margin Requirement (RMR).[2] The Resource Assessment is summarized in Table 1.

Another way to consider this approach is to consider a stable system (the base case). The initial condition is then perturbed (by a small increase in system demand), and equilibrium is re-established (by adjustments to the resource acquisition plan). This process is repeated for several incremental perturbations (i.e. by incremental increases to system demand in blocks of say 25 MW). The cost of the stable base case are then compared to the costs of the stable incremental cases to determine the marginal cost (at whatever increment first requires a change to the resource acquisition plan).

The timing of the generation additions needed to meet demand obligations in each year of the planning period for all of the scenarios are determined by the detailed resource planning models compiled in SAS, R, and Metrix ND with @Risk used to assess the reasonableness of the forecasts which the Companies routinely use in the IRP and in other generation planning and forecast evaluations. The capacity costs associated with the supply resource additions listed are included in the IRP.

[2] Because resource additions are outside the planning horizon, marginal production capacity costs determined based on the assumed addition of 85 MW of load should be considered a maximum anticipated level of marginal costs.

Table 1.
2021 Resource Assessment

Year	Resource
2022	
2023	
2024	Retirement of Mill Creek 1 (300 MW)
2025	Retirement of Haefling 1-2 (24MW) and Paddy's Run 12 (23 MW)
2026	
2027	
2028	Retirement of Mill Creek 2 (297MW) and Brown 3 (412MW)
2029	
2030	
2031	
2032	
2033	
2034	Retirement of Ghent 1 (475MW)/Ghent 2 (485MW)/Brown 9 (121MW)
2035	Retirement of Brown 8 and 10 (121MW x 2)
2036	Retirement of Brown 11 (121MW)

Notes:
- Unit ratings for new units and retirements are summer net ratings.

The cases and the impacts on the resource plan are summarized in Table 2.

Table 2.
Case Summary for Marginal Cost Evaluation

Case	Incremental Demand	Change to Resource Acquisition Plan?
Base	n/a	n/a
Case 1	25 MW	No
Case 2	50 MW	No
Case 3	75 MW	No
Case 4	100 MW	Yes

Increasing the total system demand by 100 MW, requires that the resource acquisition plan in the IRP be revised in order to meet the incremental demand obligations. The acquisition of a Combined Cycle gas combustion turbine must be advanced from 2028 to 2027 in order to meet the incremental 100 MW obligation. This change is highlighted in Table 3. (Other portions of the plan that do not differ, including all of the demand-side options, are not included for the sake of simplicity.)

Table 3.
Change in Resource Plan for Incremental 75 to 100 MW Demand

Year	Base Case	+75 MW Case to +100 MW Case
2027		Combined Cycle Gas Combustion Turbine
2028	Combined Cycle Gas Combustion Turbine	

To determine the change in capacity costs associated with the advancement of Combined Cycle gas combustion turbine from 2028 to 2027, the *Economic Carrying Charge* is calculated. The Economic Carrying Charge is the economic cost of advancing or delaying the present value of revenue requirements associated with capital expenditures. This computation is described in Attachment A.

The marginal production demand cost is the monthly value of the Economic Carrying Charge Rate ("ECRR") applied to the present value revenue requirement ("PVRR") of the capital asset. The computation of both the PVRR of the capital asset and the Economic Carrying Charges are provided in Attachment B. Because the fixed O&M expenses were negligible in comparison to the asset costs, they were not included in the analysis.

Based on the computations included in Attachments A and B, the marginal production demand cost on a Coincident Peak ("CP") basis is $3.84 per month. Using an average coincidence factor from KU and LG&E's large power classes of customers from the last Companies' last retail rate cases, the CP marginal cost value is converted to a Non-Coincident Peak ("NCP") marginal cost value of $2.32 per month. Because the LG&E and KU generating units are jointly operated and dispatched to meet the combined demands of the LG&E and KU systems, a single value is provided for the marginal production demand cost on a joint Company basis. For evaluating an economic development offer, it would be necessary to adjust the NCP marginal cost value to reflect the applicable loss-factor for a prospective customer which could take service at a transmission, primary or secondary voltage.

Marginal Production Energy Cost

The marginal production energy cost is derived from the forecasted twelve months of variable production cost data for the LG&E/KU combined system. Specifically, the Company provided data for the twelve months ended December 2023 pertaining to the marginal costs for fuel, consumables (including scrubber reactants and other reagents), ash and waste disposal, and emission allowances for all 8,760 hours based on each hour's marginal generating unit for the next

MW of capacity needed on the system. The marginal generation unit's variable cost for each hour of the corresponding twelve months was then used to calculate a total average variable cost, for the combined LG&E and KU system. This computation is described in Attachment C. Because the preponderance of LG&E and KU's generating assets are base-load resources, average marginal energy costs will not differ materially from average energy costs on an annual basis.

The marginal production energy cost per kWh of additional energy for both LG&E and KU is $0.03447. In addition, it would be necessary to adjust the marginal energy cost value to reflect the applicable loss-factor for a prospective customer which could take service at a transmission, primary or secondary voltage.

Marginal Transmission Cost

The marginal transmission cost is calculated using the Economic Carrying Charge approach outlined above, but with different source data. The general approach of applying an ECRR to the PVRR of the capital asset is followed; however, in the case of transmission, the capital asset is not a new generating unit but instead represents the value of additional transmission plant.
Recall that marginal costs are defined as the change in total cost with respect to a small change in output. For discrete costs and output, the formula is:

$$MC = \frac{\Delta C}{\Delta q}$$

where

MC	=	Marginal Transmission Cost
ΔC	=	Change in Total Cost of Transmission Plant
Δq	=	Change in system demand

The Prime Group evaluated the capital cost of transmission forecast due to capacity additions based on the Companies' 2022 Business Plan which run from 2023 through 2032. An analysis was performed based on the Companies' current capital structure to determine a PVRR for these forecasted transmission additions. This PVRR was then divided by each of the Companies 12-month Coincident Peak Demands during their most recent rate cases to determine a rate per CP-kW for transmission. This rate was then adjusted using the average coincidence factors of the Companies' large power customers to determine a rate on an NCP basis similar to the Production Demand costs discussed earlier. This computation is shown in Attachment D.

For KU, the marginal transmission cost per KW of additional NCP demand is $0.01. For LG&E, the marginal transmission cost per KW of additional NCP demand is also $0.06. Again, it would be necessary to adjust the marginal transmission cost value to reflect the applicable loss-factor for a prospective customer which could take service at a transmission, primary or secondary voltage.

Marginal Distribution Cost

The marginal distribution cost for KU and LG&E in theory could be calculated using the same approach as the marginal transmission costs. However, from a ratemaking and policy standpoint, distribution and transmission differ. For distribution, the Companies established a Line Extension Plan, most recently approved on June 30, 2021, by the Commission for KU and LG&E in Case Nos. 2020-00349 and 2020-00350 respectively. The Line Extension Plan is applicable in all service territory where the Companies do not have existing facilities to meet the electric service needs of its retail customers. The plan specifies how the costs for normal line extensions and other line extensions will be handled. This practice makes moot the determination of a marginal distribution cost for the system at large because any individual facility addition, and its particular costs, will be considered on an actual-cost and specific-customer basis, pursuant to the Line Extension Plan.

Summary

The marginal costs for KU and LG&E for Production Demand, Production Energy, and Transmission are summarized in Table 4.

Table 4.
Louisville Gas & Electric Company and Kentucky Utilities Company
Summary of Marginal Cost of Service

Function	**Marginal Cost of Service**	
	LG&E	**KU**
Production Demand (per KW of Added NCP Demand)	$2.32	$2.32
Production Energy (per KWH of Added Energy)	$0.03447	$0.03447
Transmission (per KW of Added NCP Demand)	$0.06	$0.01

Attachments

Computation of the
Economic Carrying Charges
Associated With Delaying a Planned Generating Resource
by a Fixed Number of Years

Economic carrying charges are the economic costs of advancing (moving forward) or delaying (moving backwards) the present value revenue requirements associated with a capital expenditure. In other words, an economic carrying charge is a measurement of the effect on a utility's present value revenue requirements (PVRR) of advancing or delaying the installation of a utility resource. For example, if an increase in load causes a generating resource to be moved forward *a* years, the economic carrying charges measures the effect on PVRR of moving the resource forward *m* years. Economic carrying charges are often calculated assuming a=1 (i.e., moving the resource forward one year).

Where:

ECC = Economic Carrying Charges

ECCR = Economic Carrying Charge Rate

PVRR = Present value revenue requirement for the asset in current dollars.

g = Annual Inflation Rate

r = Adjusted Weighted Cost of Capital

L = Life of the asset

i = index factor representing every L years

a = the number of years that the asset is advanced

m = the number of years prior to when the asset is installed after taking into consideration the number of years *a* that the asset is advanced, necessary to reflect the carrying charge rate in current year dollars.

$$ECC = \frac{(1+g)^m}{(1+r)^m}\left[\sum_{i=0}^{\infty} PVRR\ \frac{(1+g)^{Li}}{(1+r)^{Li}} - \frac{(1+g)^a}{(1+r)^a}\sum_{i=0}^{\infty} PVRR\,\frac{(1+g)^{Li}}{(1+r)^{Li}}\right]$$

$$= \frac{(1+g)^m}{(1+r)^m}\left[PVRR\left\{\sum_{i=0}^{\infty}\frac{(1+g)^{Li}}{(1+r)^{Li}} - \frac{(1+g)^a}{(1+r)^a}\sum_{i=0}^{\infty}\frac{(1+g)^{Li}}{(1+r)^{Li}}\right\}\right]$$

$$= \frac{(1+g)^m}{(1+r)^m}\left[PVRR\left\{\left(1-\frac{(1+g)^a}{(1+r)^a}\right)\sum_{i=0}^{\infty}\frac{(1+g)^{Li}}{(1+r)^{Li}}\right\}\right]$$

$$= \frac{(1+g)^m}{(1+r)^m}\left[PVRR\left\{\left(1-\frac{(1+g)^a}{(1+r)^a}\right)\sum_{i=0}^{\infty}\left(\frac{(1+g)^L}{(1+r)^L}\right)^i\right\}\right]$$

$$= PVRR\frac{(1+g)^m}{(1+r)^m}\left[\left(1-\frac{(1+g)^a}{(1+r)^a}\right)\left[\frac{1}{1-\frac{(1+g)^L}{(1+r)^L}}\right]\right]$$

The last step in the above derivation converts a infinite geometric series to a fixed value. Mathematically, a geometric series converges to the following value as long as 0 ≤ x ≤ 1:

$$\sum_{i=0}^{\infty} x^i = \frac{1}{1-x}$$

(See, for example, Walter Rudin, *Principles of Mathematical Analysis* (McGraw-Hill, Inc.; 1976) at 61.) In the context of an economic carrying charge, the infinite series shown in the penultimate line of the above derivation will converge to a known value as long as g < r.

The Economic Carrying Charges (ECC) can also be calculated by multiplying the PVRR by an Economic Carrying Charge Rate (ECCR) (i.e. ECC = PVRR x ECCR), where the ECCR is calculated as follows:

$$ECCR = \frac{(1+g)^m}{(1+r)^m}\left[\left(1-\frac{(1+g)^a}{(1+r)^a}\right)\left[\frac{1}{1-\frac{(1+g)^L}{(1+r)^L}}\right]\right]$$

Louisville Gas & Electric and Kentucky Utilities
Economic Carrying Charge of CCGT Addition

Assumptions	**Values**
Inflation Rate (g)	2.50%
Weighted Cost of Capital (r)	6.41%
Year Scheduled to be Installed	2028
Year Installed After Load Addition	2027
a	1
Current Year	2022
m	5
PVRR	1175.20
Service Life (L)	40
Economic Carrying Charge Rate (ECRR)	3.93%
Coincidence Factor	60.27%

Annual Value (CP) =	**$**	**46.13**
Annual Value (NCP) =	**$**	**27.80**
Monthly Value (CP) =	**$**	**3.84**
Monthly Value (NCP) =	**$**	**2.32**

$$ECCR = \frac{(1+g)^m}{(1+r)^m}\left[\left(1-\frac{(1+g)^a}{(1+r)^a}\right)\left[\frac{1}{1-\frac{(1+g)^L}{(1+r)^L}}\right]\right]$$

Louisville Gas & Electric and Kentucky Utilities
Present Value Revenue Requirement Analysis
New CCGT Addition

Assumptions:

Investment	951.00
Book Life	40
Tax Life	20
Composite Tax Rate	24.8405%
Property Tax Rate	0.74%
Levelized Revenue Requirement Years	40

Results:

Present Value Revenue Requirement	$ 1,175
Levelized Revenue Requirement	$ 87
Levelized Carrying Charge Rate	9.13%

Year	Investment	Book Depreciation	Net Plant	Tax Depreciation	Residual Plant	Deferred Income Tax	Accumulated Deferred Income Tax
0	$ 951						
1		$ 24	$ 927	$ 36	$ 915	$ 3	$ 3
2		24	903	69	847	11	14
3		24	880	63	783	10	24
4		24	856	59	724	9	33
5		24	832	54	670	8	40
6		24	808	50	620	7	47
7		24	785	46	573	6	52
8		24	761	43	530	5	57
9		24	737	42	488	5	62
10		24	713	42	446	5	67
11		24	689	42	403	5	71
12		24	666	42	361	5	76
13		24	642	42	318	5	80
14		24	618	42	276	5	85
15		24	594	42	233	5	90
16		24	571	42	191	5	94
17		24	547	42	148	5	99
18		24	523	42	106	5	104
19		24	499	42	64	5	108
20		24	476	42	21	5	113
21		24	452	21	(0)	(1)	112
22		24	428	-	(0)	(6)	106
23		24	404	-	(0)	(6)	100
24		24	380	-	(0)	(6)	94
25		24	357	-	(0)	(6)	89
26		24	333	-	(0)	(6)	83
27		24	309	-	(0)	(6)	77
28		24	285	-	(0)	(6)	71
29		24	262	-	(0)	(6)	65
30		24	238	-	(0)	(6)	59
31		24	214	-	(0)	(6)	53
32		24	190	-	(0)	(6)	47
33		24	166	-	(0)	(6)	41
34		24	143	-	(0)	(6)	35
35		24	119	-	(0)	(6)	30
36		24	95	-	(0)	(6)	24
37		24	71	-	(0)	(6)	18
38		24	48	-	(0)	(6)	12
39		24	24	-	(0)	(6)	6
40		24	0	-	(0)	(6)	0

Louisville Gas & Electric and Kentucky Utilities
Present Value Revenue Requirement Analysis
New CCGT Addition

Assumptions:

Investment	$	951
Book Life		40
Tax Life		20
Composite Tax Rate		24.8405%
Property Tax Rate		0.74%
Levelized Revenue Requirement Years		40

Results:

Present Value Revenue Requirement	$	1,175
Levelized Revenue Requirement	$	87
Levelized Carrying Charge Rate		9.13%

Year	Rate Base	Interest	Equity	Property Taxes	Income Taxes	Annual Rev Requirement	Present Value Interest Factor	Present Value Revenue Requirement
0							1.000000	$ -
1	$ 924	$ 0	$ 63	$ 7	$ 21	$ 115	0.939758	108
2	889	0	61	7	20	112	0.883146	99
3	856	0	59	6	19	108	0.829944	90
4	823	0	57	6	19	105	0.779947	82
5	792	0	54	6	18	102	0.732961	75
6	762	0	52	6	17	99	0.688807	68
7	732	0	50	6	17	96	0.647312	62
8	704	0	48	6	16	94	0.608317	57
9	675	0	46	5	15	91	0.571671	52
10	647	0	44	5	15	88	0.537233	47
11	618	0	42	5	14	85	0.504869	43
12	590	0	40	5	13	83	0.474455	39
13	562	0	39	5	13	80	0.445873	36
14	533	0	37	5	12	77	0.419013	32
15	505	0	35	4	11	74	0.393771	29
16	476	0	33	4	11	72	0.370049	26
17	448	0	31	4	10	69	0.347757	24
18	419	0	29	4	10	66	0.326808	22
19	391	0	27	4	9	63	0.307120	19
20	363	0	25	4	8	60	0.288619	17
21	340	0	23	3	8	58	0.271232	16
22	322	0	22	3	7	56	0.254893	14
23	304	0	21	3	7	55	0.239537	13
24	286	0	20	3	6	53	0.225107	12
25	268	0	18	3	6	51	0.211546	11
26	250	0	17	2	6	49	0.198803	10
27	232	0	16	2	5	47	0.186826	9
28	214	0	15	2	5	45	0.175572	8
29	197	0	13	2	4	44	0.164995	7
30	179	0	12	2	4	42	0.155055	6
31	214	0	15	2	5	45	0.145715	7
32	190	0	13	1	4	43	0.136937	6
33	166	0	11	1	4	40	0.128687	5
34	143	0	10	1	3	38	0.120935	5
35	119	0	8	1	3	36	0.113650	4
36	95	0	7	1	2	33	0.106803	4
37	71	0	5	1	2	31	0.100369	3
38	48	0	3	0	1	28	0.094323	3
39	24	0	2	0	1	26	0.088641	2
40	0	0	0	0	0	24	0.083301	2

Net Present Value Revenue Requirement $ 1,175

Louisville Gas & Electric and Kentucky Utilities
Present Value Revenue Requirement Analysis
New CCGT Addition

Assumptions:

Investment	$ 951
Book Life	40
Tax Life	20
Composite Tax Rate	24.8405%
Property Tax Rate	0.74%
Levelized Revenue Requirement Years	40

Results:

Present Value Revenue Requirement	$ 1,175
Levelized Revenue Requirement	$ 87
Levelized Carrying Charge Rate	9.13%

Year	Cumulative Present Value Revenue Requirement	Annual Carrying Charge Rate
0	$ -	
1	108	12.10%
2	207	11.75%
3	297	11.41%
4	379	11.08%
5	454	10.76%
6	522	10.45%
7	585	10.14%
8	642	9.85%
9	694	9.56%
10	741	9.27%
11	784	8.98%
12	823	8.69%
13	859	8.39%
14	891	8.10%
15	921	7.81%
16	947	7.52%
17	971	7.23%
18	992	6.94%
19	1,012	6.65%
20	1,029	6.35%
21	1,045	6.11%
22	1,059	5.92%
23	1,073	5.73%
24	1,084	5.54%
25	1,095	5.35%
26	1,105	5.16%
27	1,114	4.97%
28	1,122	4.78%
29	1,129	4.59%
30	1,135	4.40%
31	1,142	4.72%
32	1,148	4.48%
33	1,153	4.23%
34	1,158	3.98%
35	1,162	3.73%
36	1,165	3.49%
37	1,168	3.24%
38	1,171	2.99%
39	1,173	2.75%
40	1,175	2.50%

Louisville Gas and Electric and Kentucky Utilities
Weighted Cost of Capital and MACRS

Capital Structure:

	Percent	Rate	Weighted COC	Tax Rate	Adjusted Rate
Short Term Debt	1.52%	0.46%	0.01%	24.84%	0.01%
Long Term Debt	45.26%	4.08%	1.85%	24.84%	1.39%
Common Equity	53.22%	9.43%	5.02%		5.02%
			6.87%		6.41%

Tax Depreciation Table (MACRS)

	5		15	20
1	20.000%	10.000%	5.000%	3.750%
2	32.000%	18.000%	9.500%	7.219%
3	19.200%	14.400%	8.550%	6.677%
4	11.520%	11.520%	7.700%	6.177%
5	11.520%	9.220%	6.930%	5.713%
6	0.000%	7.370%	6.230%	5.285%
7	0.000%	6.550%	5.900%	4.888%
8	0.000%	6.550%	5.900%	4.522%
9	0.000%	6.560%	5.910%	4.462%
10	0.000%	6.550%	5.900%	4.461%
11	0.000%	0.000%	5.910%	4.462%
12	0.000%	0.000%	5.900%	4.461%
13	0.000%	0.000%	5.910%	4.462%
14	0.000%	0.000%	5.900%	4.461%
15	0.000%	0.000%	5.910%	4.462%
16	0.000%	0.000%	2.950%	4.461%
17	0.000%	0.000%	0.000%	4.462%
18	0.000%	0.000%	0.000%	4.461%
19	0.000%	0.000%	0.000%	4.462%
20	0.000%	0.000%	0.000%	4.461%
21	0.000%	0.000%	0.000%	2.231%
22	0.000%	0.000%	0.000%	0.000%
23	0.000%	0.000%	0.000%	0.000%
24	0.000%	0.000%	0.000%	0.000%
25	0.000%	0.000%	0.000%	0.000%
26	0.000%	0.000%	0.000%	0.000%
27	0.000%	0.000%	0.000%	0.000%
28	0.000%	0.000%	0.000%	0.000%
29	0.000%	0.000%	0.000%	0.000%
30	0.000%	0.000%	0.000%	0.000%

Average Marginal Variable Costs
12 Months ending December 2023 (Forecasted)

Month	Average Marginal Cost ($/MWh)
January	35.83
February	35.54
March	35.43
April	35.78
May	32.74
June	33.45
July	34.03
August	34.09
September	33.59
October	34.67
November	33.90
December	34.64
Average	**34.47**

Capacity-Related Transmission Investment
2022 Business Plan
($ in Thousands)

Year		KU		LG&E	Total
2023		3,552		4,235	7,787
2024		52		867	919
2025		749		1,791	2,540
2026		-		904	904
2027		236		-	236
2028		92		1,229	1,321
2029		995		3,367	4,362
2030		60		3,618	3,678
2031		1,251		-	1,251
2032		-		-	-
10-Year Total		6,987		16,011	22,998
Carrying Cost Percentage		12.65%		13.90%	
Annualized Avoided Costs (in $)		$883,622		$2,224,978	
Forecasted LGE Total System Demand				23,513,673	
Forecasted KU Total System Demand		37,037,501			
Cost per CP kW	$	0.02	$	0.09	
Coincidence Factor		61.26%		59.27%	
Cost per NCP kW	$	0.01	$	0.06	

Comparison of KU Standard Retail Transmission Service Rate with Economic Development Rider to Marginal Cost

		Five Year Average Discount	Discounted Rate		Marginal Cost
KU RTS					
Basic Service Charge	$ 1,499.96		$1,499.96		
Energy Charge	$ 0.02456		$0.02456	Energy	$0.03447
Demand Charge				Demand	
Peak Period	$ 8.95	30%	$6.27	Production	$2.32
Intermediate Period	$ 7.19	30%	$5.03	Transmission	$0.01
Base Period	$ 2.16	30%	$1.51		
	$ 18.30		$12.81		$2.33

5-Year Average Billing Comparison

	Billing Units	Currrent KU RTS	Base Rate Billing	Five Year Average Discount	Base Rate Plus EDR Billing		Marginal Rate	Marginal Rate Billing
Basic Service Charge		$1,499.96						
Energy Charge *	9,015,500	$0.02456	$221,420.68		$221,420.68	Energy	$0.03447	$310,764.29
Demand Charge						Demand		
Peak Period	13,000	$8.95	$116,350.00			Production	$2.32	$30,160.00
Intermediate Period	13,000	$7.19	$93,470.00			Transmission	$0.01	$130.00
Base Period	13,000	$2.16	$28,080.00					
			$237,900.00	30%	$166,530.00			
			$459,320.68		$387,950.68			$341,054.29

* Energy based on an average month with 730 hours and a 95% load factor