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STATE CORPORATION COMMISSION

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APPLICATION OF

KENTUCKY UTILITIES COMPANY d/b/a OLD DOMINION POWER COMPANY **CASE NO. PUR-2024-00052**

For an adjustment of electric base rates

REPORT OF D. MATHIAS ROUSSY, JR., HEARING EXAMINER

December 10, 2024

In this State Corporation Commission ("Commission") case, Kentucky Utilities Company ("KU"), which does business in the Commonwealth as Old Dominion Power Company ("KU-ODP" or "Company"), sought authority to recover from its Virginia jurisdictional customers an additional $9.5 million of revenue annually through a proposed electric base rate increase on and after February 1, 2025.[1] If approved, the Company's Application would increase the monthly bill of a residential customer using 1,000 kilowatt-hours ("kWh") per month by $19.46.[2]

KU-ODP and the Commission's Staff ("Staff") ultimately offered a Stipulation to resolve this proceeding, which the only party that intervened in this case did not oppose. If approved, the Stipulation would, among other things, increase the Company's base rates to recover an additional $8.3 million of revenue annually from Virginia jurisdictional customers, effective February 1, 2025. The Stipulation would increase the monthly bill of a residential customer using 1,000 kWh per month by $15.44.[3]

I find that the evidentiary record can support a finding that the proposed Stipulation is just and reasonable and satisfies the applicable statutory standard for approval provided the costs encompassed by the stipulated revenue requirement exclude charitable contributions, which the Commission determined in 2019 are no longer recoverable from a public utility's ratepayers. Because I do not conclude, based on the record, that KU-ODP demonstrated the stipulated revenue requirement excluded approximately $14,000 of charitable contributions, I do not recommend approval of the Stipulation, as proposed. If the Commission agrees with my analysis, the statutory standard for approval would be satisfied by a revenue requirement that is $14,000 lower than the stipulated revenue requirement.

PROCEDURAL BACKGROUND

On April 30, 2024, KU-ODP filed an application ("Application") with the Commission requesting authority to adjust its electric base rates pursuant to Chapter 10 of Title 56 of the Code of Virginia ("Code") and the Commission's Rules Governing Utility Rate Applications and

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[1] Ex. 4 (Conroy direct) at 24.
[2] *Id.* at 19. Based on average usage of 1,143 kWh per month, the Application would increase a residential customer's monthly bill by $21.82. *Id.*
[3] Ex. 23 (Stipulation) at attached Ex. 3, p. 1.

Annual Informational Filings of Investor-Owned Electric Utilities.[4] On May 1, 2024, KU-ODP filed a Motion for Entry of a Protective Ruling.

On May 30, 2024, the Commission issued an Order for Notice and Hearing ("Procedural Order") in this case. Among other things, the Procedural Order docketed the Application; required the Company to publish notice of the Application; established a procedural schedule, including an evidentiary hearing to convene on November 13, 2024; provided opportunities for interested persons to participate in this case; directed Staff to investigate the Application and file testimony to present the results of Staff's investigation; and appointed a Hearing Examiner to conduct all further proceedings in this matter on behalf of the Commission and to file a report containing the Hearing Examiner's findings and recommendations.

On June 5, 2024, a Hearing Examiner's Protective Ruling was issued.

On July 17, 2024, KU-ODP filed proof of notice and service.[5]

A notice of participation was filed by the Office of Attorney General, Division of Consumer Counsel ("Consumer Counsel") on August 9, 2024.

On November 6, 2024, KU-ODP filed a Stipulation and Recommendation and a Joint Motion to Accept Stipulation and Recommendation. This filing included a Stipulation and Recommendation that KU-ODP and Staff offered to resolve this proceeding.

On November 13, 2024, the evidentiary hearing was convened, as scheduled, in the Commission's courtroom. Kendrick R. Riggs, Esquire, appeared on behalf of the Company. C. Meade Browder, Jr., Esquire, and Carew S. Bartley, Esquire, represented Consumer Counsel. Raymond L. Doggett, Jr., Esquire, and Andrew F. Major, Esquire, represented Staff. At the hearing, the case participants offered their evidence and closing arguments.[6]

PUBLIC COMMENTS

Larry Barton, Dickenson County Administrator, submitted a resolution adopted on May 28, 2024, by the Dickenson County Board of Supervisors. The resolution expresses opposition to the Application's proposed increase, citing, among other things, concern about the financial impact of the proposed increase on Dickenson County citizens.

SUMMARY OF THE RECORD

KU-ODP – Direct

In support of its Application, the Company filed the direct testimonies of **Robert M. Conroy**, Vice President, State Regulation and Rates for KU and Louisville Gas &

[4] 20 VAC 5-204-5 *et seq.* On May 29, 2024, a confidential portion of the Application was filed under seal.
[5] At the hearing, proof of notice and service was admitted as Exhibit 1.
[6] While one member of the public signed up to testify telephonically, he did not answer the Commission's phone calls to provide such testimony at the hearing.

Electric ("LG&E"); **Lonnie E. Bellar**, Senior Vice President, Engineering and Construction, PPL Services Corporation; **Elizabeth J. McFarland**, Vice President, Transmission for KU and LG&E; **Peter W. Waldrab**, Vice President, Electric Distribution for KU and LG&E; **Shannon L. Montgomery**, Vice President, Customer Services for KU and LG&E; **Drew T. McCombs**, Director, Utility Accounting, LG&E and KU Services Company; **Andrea M. Fackler**, Manager, Revenue Requirement/Cost of Service, LG&E and KU Services Company; **Julissa Burgos**, Director, Corporate Finance, PPL Services Corporation; **Adrien M. McKenzie**, President, FINCAP, Inc.; **Chad E. Clements**, Director, Regulated Utility Tax, PPL Services Corporation; **Heather D. Metts**, Director, Financial Planning and Budgeting, LG&E and KU Service Company; **Patrick L. Baryenbruch**, Baryenbruch & Company, LLC; and **Michael E. Hornung**, Manager, Pricing/Tariffs, LG&E and KU Services Company.

Robert Conroy provided an overview of the Application and sponsored Filing Schedule 37.[7] He recommended that the Commission approve the recovery of a $9.5 million revenue deficiency through the Application's proposed rates and charges for service on and after February 1, 2025.[8] To calculate these proposed rates, the Company used a 10.50% rate of return on equity ("ROE"), which is the low end of the 10.50% to 11.50% cost of equity range recommended by Company witness McKenzie.[9] If approved, the Application would increase the monthly bill of a residential customer using 1,000 kWh per month by $19.46.[10]

According to Mr. Conroy, the Application's proposed increase is driven by investments and operating costs that are not yet incorporated into rates, but are associated with providing safe and reliable service to customers.[11] He indicated that KU will have invested, and projects to invest, approximately $1.85 billion of capital into its operations from December 1, 2022, through July 31, 2025.[12] He broke this amount down as follows.[13]

KU Total Company	12/1/22 – 7/31/25
Generation	$794.7 million
Transmission	$339.1 million
Distribution	$447.4 million
Customer Services and Metering	$132.9 million
Other	$136.1 million
Total	$1,850.2 billion

Mr. Conroy emphasized: (i) the Company's investment in the Mill Creek Unit 5 natural gas combined cycle facility; and (ii) the retirement of two coal units (Mill Creek Units 1 and 2) and three gas-fired combustion turbines (Haefling Units 1 and 2, Paddy's Run Unit 12).[14] He indicated these actions were approved in 2023 by the Kentucky Public Service Commission

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[7] Ex. 4 (Conroy direct) at 1. Filing Schedule 37 shows the corporate organization of KU and its parent company, PPL Corporation. *Id.* at 15.
[8] *Id.* at 24.
[9] *Id.* at 13.
[10] *Id.* at 19.
[11] *Id.* at 8.
[12] *Id.* at 10. The Application's rate year is calendar year 2025. *See, e.g.,* Ex. 17 (Morgan) at 1.
[13] Ex. 4 (Conroy direct) at 11.
[14] *Id.*

("Kentucky Commission").[15] According to Mr. Conroy, the Kentucky Commission determined that Mill Creek Unit 5 was the least-cost method of serving load in the most likely scenarios. From December 2022 through July 2025, KU expects to invest approximately $349 million in the construction of this unit.[16]

Mr. Conroy also highlighted an expected $74 million investment for construction of the 120 megawatt ("MW") Mercer Solar Facility over the same period. He testified that the Kentucky Commission approved this facility after determining it would result in savings in certain scenarios without considering the cost of greenhouse gas regulation compliance or income from renewable energy certificate sales.[17]

Mr. Conroy identified KU-ODP's plan to deploy advanced metering infrastructure ("AMI") meters in Virginia, at an estimated investment of $129.2 million, over the same period.[18]

Mr. Conroy asserted that KU-ODP is not earning a reasonable rate of return due to changes in the Company's debt and equity cost of capital.[19] He summarized the Virginia jurisdictional returns calculated by the Company as follows.[20]

Schedule	2023 Return on Rate Base	2023 Return on Common Equity	2022 Return on Rate Base	2022 Return on Common Equity
Schedule 9: Rate of Return Statement – Earnings Test – Per Books	6.04%	7.44%	4.62%	5.11%
Schedule 11 Rate of Return Statement – Earnings Test – Adjusted to a Regulatory Accounting Basis	6.04%	7.49%	4.87%	5.64%
Schedule 19 Rate of Return Statement – Per Books	6.03%	7.50%	4.56%	5.16%
Schedule 21 Rate of Return Statement – Reflecting Ratemaking Adjustments	5.53%	6.50%	5.80%	7.31%

Mr. Conroy indicated that the Company considered customer impact before filing the Application, but he asserted that delaying the filing would have exacerbated the rate impact in the future. According to Mr. Conroy, Company witness Baryenbruch's direct testimony

[15] *Id.*
[16] *Id.* at 11-12. Mr. Conroy testified that Mill Creek Unit 5, like other units jointly or individually owned by KU or LG&E, will be jointly and economically dispatched to serve their loads, including the load served by KU, doing business in Virginia as ODP. *Id.*
[17] *Id.* at 12.
[18] *Id.*
[19] *Id.* at 2.
[20] *Id.* at 9.

demonstrates that KU is a top performing utility from an efficiency and cost management perspective. Mr. Conroy indicated that the Company continues to offer programs to assist low-income customers.[21]

For residential customers, Mr. Conroy identified the Application's proposed increases of the basic service charge, from $12.00 to $15.00, and the energy charge, from 10.122¢/kWh to 11.768¢/kWh. He identified the Company's current basic service charge as less than half of the customer-related cost for the residential class shown in the Company's class cost-of-service study. He identified the ratemaking principle of gradualism as the reason the Application did not propose increasing the Company's residential basic service charge to the full amount shown in its cost-of-service study.[22]

Mr. Conroy asserted that increasing the residential basic service charge would reduce bill fluctuations, on a relative basis,[23] and reduce intra-class subsidies between high-usage and low-usage residential customers.[24] He disagreed that recovering more of the increase through the basic service charge (rather than the energy charge) would send the wrong signal for energy conservation. Instead, he believes a more accurate energy pricing signal to customers enables customers to make better energy efficiency behavioral and investment decisions.[25] He also found it significant that the non-customer-specific fixed costs the Company recovers from most other rate classes through demand charges will remain embedded in energy charges for the residential class.[26]

Mr. Conroy highlighted the Application's proposals to add four new optional time-of-day rate schedules and to offer a new optional outdoor sports lighting rate.[27] He also identified, among other things, the Application's proposal to: increase the monthly meter pulse charge, from $21.00 to $22.00; increase the disconnect/reconnect charge, from $37.00 to $53.00; and increase the meter test charge, from $79.00 to $81.00.[28]

Mr. Conroy recognized that KU-ODP is generally exempt from Chapter 23 of Title 56 of the Code.[29]

Mr. Conroy identified the Application's request for an extension of the time to complete the rebuild of a transmission line approved in Case No. PUR-2020-00110. The requested extension is from December 31, 2024, to June 30, 2026. His testimony recognized that KU-ODP has previously requested and received such an extension in Case No. PUR-2020-00110.[30]

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[21] *Id.* at 14.
[22] *Id.* at 16.
[23] *Id.* at 19.
[24] *Id.* at 17-19. He asserted that customers with above-average energy consumption – including low-income customers – will pay more fixed costs than they should for their service. *Id.* at 18.
[25] *Id.* at 17.
[26] *Id.* at 18.
[27] *Id.* at 20 (identifying proposed Rate RTOD-Energy, Rate RTOD-Demand, Rate GTOD-Energy, Rate GTOD-Demand, in addition to proposed Rate OSL).
[28] *Id.*
[29] *Id.* at 21.
[30] *Id.* at 21-23.

Mr. Conroy discussed the Application's request for a Commission determination that Commission approval under Code § 56-89 is not required for KU-ODP to dispose, at some point in the future, of five properties in Virginia. KU's plan to close all of its business offices, including two in Virginia by the end of 2024, has led the Company to consider disposing of these properties, with appraised values ranging from $1,000 to $470,000.[31]

Mr. Conroy also discussed the Application's request for the Commission to relieve the Company from a reporting obligation imposed in 2010 as a condition of approving the transfer of ownership and control of KU-ODP from E.ON AG to PPL Corporation.[32] He asserted that the annual reporting of information regarding the general corporate objective of the consolidated operations of LG&E and KU Energy LLC and their potential impact on KU-ODP is no longer necessary for the Commission's oversight of KU-ODP's operation.[33]

For the Cane Run Unit 7 carbon capture project identified by Company witness Bellar, Mr. Conroy explained that LG&E and KU's share of costs would be allocated based on ownership of the facility (22% and 78%, respectively). He then discussed how KU total costs are allocated to ODP (approximately 4.5%), and ultimately ODP's Virginia jurisdictional customers (approximately 90%). In the instant case, the Application included no test year costs of the project, but did include projected construction work in progress for approximately $1.1 million of 2025 rate year costs, which is net of a U.S. Department of Energy ("DOE") award, or approximately $41,000 on a Virginia jurisdictional basis. This equates to less than $4,000 in the Application's proposed revenue requirement.[34]

Mr. Conroy indicated that thus far DOE has only allocated funds for the initial phase for the project, the front-end engineering and design study.[35] He expects the decision on whether to move forward with the project after the 18-month study period would be a collaborative decision made by the Company, DOE, and the other project participants.[36]

Mr. Conroy testified that KU-ODP has included 50% of a Virginia jurisdictional amount of charitable contributions in all of its rate cases since 2009, including the instant Application.[37] The Application includes approximately $14,000 of revenue requirement attributable to charitable contributions.[38] He testified that the proposed Stipulation does not explicitly include or exclude charitable contributions in the Stipulation's proposed "black box" revenue requirement.[39] However, he agreed that charitable contribution costs would have been baked into both Staff and KU-ODP's starting points for negotiations.[40] He testified that he is aware of

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[31] *Id.* at 23. He reported a collective book value for these properties of approximately $1.2 million. *Id.*
[32] *Id.* at 24 (citing *Joint Petition of PPL Corporation, E.ON AG, E.ON US Investments Corp., E.ON US LLC, and Kentucky Utilities Company d/b/a Old Dominion Power Company, For approval of transfer of ownership and control*, Case No. PUE-2010-00060, 2010 S.C.C. Ann. Rep. 534, Final Order (Oct. 19, 2010) ("*2010 Transfer Order*")).
[33] Ex. 4 (Conroy direct) at 24. He indicated that Commission Staff is not opposed to this request. *Id.*
[34] Tr. at 48-49 (Conroy).
[35] Tr. at 55 (Conroy).
[36] Tr. at 56 (Conroy).
[37] Tr. at 56-57 (Conroy).
[38] Tr. at 57, 60 (Conroy); Ex. 2 (Application) at Filing Sched. 19, p. 1.
[39] Tr. at 57-58 (Conroy).
[40] Tr. at 58-59 (Conroy).

Commission orders that moved away from including 50% of charitable contributions in rates because Staff referenced such orders in the Company's previous rate case. However, he indicated KU-ODP has not had an order that specifically addressed the issue.[41]

Mr. Bellar discussed the Company's emphasis on safety. He reported, among other things, that KU employees experienced only 14 recordable safety incidents across 1.5 million work hours during 2023.[42]

Mr. Bellar listed the generating plants owned in whole or in part by KU. These plants, which are all located in Kentucky, have an approximate cumulative capacity of 4,755 MW and a net book value of approximately $3.77 billion.[43] According to Mr. Bellar, KU customers benefit from the joint planning and operation of resources in the KU and LG&E generating portfolio.[44]

Mr. Bellar indicated that the average equivalent forced outage rate data in 2023 for coal-fired and combined cycle units owned in whole or in part by KU was 2.2%. Based on this data, he concluded that KU's generating units are performing reliably and cited sound maintenance and operations practices as a contributing factor.[45]

Mr. Bellar identified proposed supply resources and retirements that the Kentucky Commission approved and rejected in a 2022-2023 certificate of public convenience and necessity ("CPCN") proceeding. He indicated that the Kentucky Commission ultimately approved the following:[46]

- Construction of Mill Creek Unit 5, a 645 MW natural gas combined cycle unit, of which KU would own 69%. This unit has an estimated capital cost of $902.2 million and is expected to be operational by June 1, 2027;[47]
- Retirement of coal-fired Mill Creek Units 1 and 2, conditioned on construction of Mill Creek Unit 5;[48]
- Construction of the 120 MW Mercer County Solar Facility, of which KU would own 63%. This facility has an estimated capital cost of $243 million and is expected to be operational by mid-2027;[49]
- Purchase of the 120 MW Marion County Solar Facility. This facility has an estimated capital cost of $220 million and is expected to be purchased in 2027;[50]
- Construction of the 125 MW Marion County Battery Storage Facility, of which LG&E would own 100% but KU would receive power and associated cost allocations through

[41] Tr. at 59-60 (Conroy).
[42] Ex. 5 (Bellar direct) at 3.
[43] *Id.* at 3 and attached Ex. LEB-1. The cumulative capacity is summer net capacity. *Id.*
[44] *Id.* at 4.
[45] *Id.* at 4-5.
[46] *Id.* at 5-6.
[47] *Id.* at 7. The capacity is summer net capacity. *Id.*
[48] *Id.* at 8.
[49] *Id.* at 9.
[50] *Id.* at 10-11.

joint dispatch. This facility has an estimated capital cost of $288 million, but will be eligible for up to a 50% investment tax credit;[51] and

- Solar power purchase agreements.

The Kentucky Commission denied or deferred the proposed construction of additional natural gas combined cycle generation and the proposed retirement of additional coal-fired units.[52]

Mr. Bellar identified the fuel supply arrangement for the approved Mill Creek Unit 5. The new unit will be served by the Texas Gas Transportation interstate pipeline, with which KU has secured a 30-year agreement, beginning November 1, 2026, for 110,000 MMBtu in firm transport capacity through an open season capacity offering. He contended that this agreement will provide KU and LG&E greater flexibility to rebalance gas delivery points for other gas-fired units with less restrictive scheduling requirements, and better optimize the existing transport portfolio for Cane Run Unit 7 and the Trimble County units.[53] KU expects Mill Creek Unit 5 will achieve greater operational efficiency than Cane Run Unit 7.[54]

Mr. Bellar indicated that, after conducting a competitive request for proposals process, KU and LG&E decided that self-building Mill Creek Unit 5, with an owner's engineer, would be the lowest reasonable cost option for serving load and ensuring cost-effective environmental compliance.[55] The engineering, procurement, and construction contract was finalized on February 29, 2024.[56] He asserted that constructing Mill Creek Unit 5 is lower cost than maintaining and upgrading the retiring Mill Creek Units 1 and 2. He added that this new unit improves generation reliability, especially given operational constraints on the retiring coal-fired units based on environmental regulations.[57]

KU and LG&E also plan to self-build the Mercer County Solar Facility using an engineering, procurement, and construction contractor with the assistance of an owners' engineer.[58] Mr. Bellar asserted that solar generation adds balance to KU and LGE's generation portfolio, acts as a hedge against fuel volatility and price increases and potential future carbon constraints, and has relatively low fixed operating and maintenance ("O&M") costs. He indicated that the Kentucky Commission found the proposed solar projects, including this one, showed lower total costs to customers in nearly every economic scenario presented by KU and LGE.[59]

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[51] *Id.* at 11-12. LG&E's storage facility will be built on existing land owned by KU at the Brown Generating Station. *Id.* at 11.
[52] *Id.* at 6.
[53] *Id.* at 7-8. Mechanical completion of the project is expected in December 2026. *Id.* at 9.
[54] *Id.* at 7.
[55] *Id.* at 8.
[56] *Id.* at 9.
[57] *Id.* at 8-9.
[58] *Id.* at 9.
[59] *Id.* at 10.

For the Mercer County Solar Facility, the necessary land has been purchased and an owner's engineer has been retained. Mr. Bellar expects the request for proposals for the engineering, procurement, and construction contractor to be issued later this year.[60]

For the Marion County Solar Facility, Mr. Bellar indicated the purchase of this facility, along with the construction of the Mercer County Solar Facility, are the two best proposals for Company-owned and operated solar generation submitted in response to KU's and LGE's request for proposals. He expected agreements with the third-party builder of this project to be finalized by early summer of 2024, after which the builder will begin construction.[61]

Mr. Bellar provided an update on KU's efforts to comply with the Coal Combustion Rule ("CCR") issued by the U.S. Environmental Protection Agency ("EPA"). Such efforts include:

(1) Construction of Phase II and Phase III of the CCR storage landfill at Brown Generating Station, which have been completed;
(2) Surface impoundment closures at the Green River, Pineville, and Tyrone Generating Stations, which were completed by 2020; and
(3) CCR Rule compliance and construction of process water systems at Brown, Ghent, and Trimble County Generating Stations to enable CCR pond closures. All of these are now completed and operational.[62]

Mr. Bellar indicated that only three impoundment closures remain: Ghent ATB #2 (scheduled December 2024) and Trimble County bottom ash pond and gypsum storage pond (scheduled December 2025). He described the work remaining for these closures.[63]

Mr. Bellar provided an update on KU's efforts to comply with EPA's Effluent Limitations Guidelines ("ELG"). The ELG system at Ghent is scheduled for final completion in December 2024. Mechanical completion of the Trimble County ELG water treatment system was achieved in October 2023, but performance testing continues and may require additional tuning and optimization prior to commercial operation.[64] According to Mr. Bellar, the KU-allocated ELG projects are under the original projected budget of $252.3 million (net of co-ownership) and are projected to cost $175.8 million in total, with $142.5 million (net) having been incurred through 2023. He attributed these estimated savings to KU and LG&E having gone "early to market."[65] However, he expects new ELG rules will require zero liquid discharge of flue gas desulphurization wastewater and bottom ash transport water from coal-fired generating plants by the end of 2029, in addition to limits on residual leachates. The expected new rules may require the installation of processing and control equipment at the Mill Creek, Trible County, and Ghent Generating Stations.[66]

[60] *Id.*
[61] *Id.* at 11. The builder, BrightNight, has secured all necessary land acquisitions, lease rights, easements, and permitting. *Id.*
[62] *Id.* at 12-13.
[63] *Id.* at 13-14.
[64] *Id.* at 14-15.
[65] *Id.* at 15.
[66] *Id.* at 17-18.

Mr. Bellar identified three other environmental regulations expected in the near future that may affect electric generation operations: (1) EPA's proposed Section 111 greenhouse gas rules ("Section 111 Rules"); (2) national ambient air quality standards ("NAAQs") regulating nitrogen oxide emissions both locally and across states ("Good Neighbor Plan"); and (3) the national emissions standards for hazardous air pollutants, known as the Mercury and Air Toxic Standards Rule ("MATS Rule").

Mr. Bellar indicated that EPA's Section 111 Rules, as proposed, would prohibit or significantly restrict the ability to operate coal-fired generating units beyond 2031 without costly natural gas co-firing or carbon capture and storage modifications. These proposed rules would also impose phased carbon dioxide emission limits on new natural gas units and would require limited operation or either hydrogen co-firing (by 2032) or carbon capture and storage (by 2035) for existing natural gas units. According to Mr. Bellar, performance guarantees for the new Mill Creek Unit 5 would comply with the applicable proposed phase one limit without hydrogen co-firing or carbon capture.[67]

Mr. Bellar recognized that Jefferson County, where the Mill Creek Generating Station is located, is currently in non-attainment for the 2015 NAAQs. He discussed the mechanics of the current Good Neighbor Plan, which he indicated is currently stayed due to pending litigation.[68]

According to Mr. Bellar, the proposed MATS Rule reduces coal-fired electric generating unit particulate matter emissions rates threefold, requires compliance with continuous emissions monitoring systems, and expands and complicates stack testing requirements. While the Company does not anticipate additional controls, due to the operation of bag houses on the entire fleet, the proposed rule, among other things, reduces operational flexibility and will increase testing costs and likely bag house maintenance costs.[69]

Mr. Bellar emphasized that environmental compliance costs and the potential for operational constraints on the current generation fleet are major inputs into the utility resource planning process. He indicated the Company's resource planning must evolve with continuing changes to the regulatory landscape.[70]

Mr. Bellar described other capital investments KU plans to make to its generation facilities. He estimated KU's share of major outage maintenance and a turbine performance upgrade on Cane Run Unit 7 will be approximately $34.4 million. He estimated KU's cost to demolish retired Brown Units 1 and 2 will be approximately $26.9 million. He estimated KU's cost to install a new stack at Trimble County will be $17.2 million. A new stack for use by Trimble County Units 1 and 2 was chosen after the Company concluded it was not feasible to reline Unit 1's delaminated stack liner.[71]

[67] *Id.* at 16.
[68] *Id.* at 17.
[69] *Id.* at 18.
[70] *Id.* at 19.
[71] *Id.* at 19-20.

Of the $794.7 million in generation capital identified by Company witness Conroy, Mr. Bellar provided the following breakdown of KU's actual and projected capital investment in generation projects.[72]

KU Total Company	**12/1/22 – 7/31/25**
New Generation	$423.6 million
Environmental Compliance	
CCR Rule	$51.2 million
ELG	$66 million
Outage Maintenance – Coal Units	$73.4 million
Outage Maintenance – Combustion Turbines	$47.9 million
Generation Reliability	$65.4 million
Other	$67.2 million
Total	**$794.7 million**

Mr. Bellar reported that KU's revenue from beneficial use/reuse of CCRs continues to increase, with revenues of $6.9 million in 2022 and nearly $10.9 million in 2023. He asserted that while some CCRs are being used for surface impoundment closures required by the CCR Rule, reuse of significant quantities of CCRs reduces overall disposal costs, conserves landfill space, and creates revenues offsetting other production costs.[73]

According to Mr. Bellar, KU and LG&E use more than 20 programs designed to minimize cost or improve generation reliability or efficiency. He described a few examples.[74]

Mr. Bellar testified about two technology transfer awards from the Electric Power Research Institute ("EPRI"), one of which recognized an innovative approach to vegetation management for a solar facility at the Brown Generating Station. He also identified a carbon capture research and development project at Cane Run Unit 7 that is expected to cost more than $100 million, and for which a $72 million federal grant has been awarded.[75]

Mr. Bellar explained that in 2014 KU constructed a carbon capture test facility at its coal-fired Brown Generating Station. The planned carbon capture at Cane Run 7 would be for a larger slip stream than at Brown (20 MW versus 0.7 MW).[76] The planned project is to prove that the carbon capture equipment and solvents deployed at Brown can be deployed on a natural gas combined cycle facility.[77] Unlike the Brown project, which captured then released carbon back into the flue gas stream, the Cane Run 7 project has an offtake partner that would purchase the carbon.[78] The Company currently contemplates that carbon capture at Cane Run 7 would require a low-end parasitic load of approximately 10-11%.[79]

[72] *Id.* at 20-21.
[73] *Id.* at 21.
[74] *Id.* at 21-22.
[75] *Id.* at 22-23.
[76] Tr. at 31-32 (Bellar). The Brown Generating Station carbon capture equipment remains, but is not actively operated currently. Mr. Bellar reported that KU found carbon capture at a coal facility challenging due to the amount of carbon and the level of parasitic load. Tr. at 37 (Bellar).
[77] Tr. at 36-37 (Bellar).
[78] Tr. at 37 (Bellar).
[79] Tr. at 38 (Bellar).

According to Mr. Bellar, the Cane Run 7 carbon capture project is currently in the engineering phase, which will last until approximately the late Spring of 2026. At that time, if engineering indicates the project would be successful according to its design parameters, the Company, DOE, and other project participants would make a joint decision on whether to move forward. If the project moves forward, the current estimated construction timeline contemplates completion around June 2029. Mr. Bellar testified that the project would operate for 18 months to capture data and information. After this 18-month period, DOE's relationship with the project would cease and the Company could either deconstruct the project or, if economically feasible, continue to operate.[80]

According to Mr. Bellar, the DOE grant that has been awarded would cover 70% of the project's costs. DOE has released funding for the first phase, which is an approximately $7 million front-end engineering and design study.[81] After work has been completed and costs have been incurred, DOE will be billed on a monthly basis for 70% of such costs.[82]

The project partners that would cover the remaining 30% of project costs by financial or in kind contributions include the University of Kentucky, EPRI, Siemens, and Vogt Power.[83] The Company currently contemplates LG&E and KU contributing a total of $15 million in funding to construct the project.[84]

Mr. Bellar explained the compliance options for natural gas combined cycle facilities under the EPA's most recent Section 111 Rules. These rules suggest a significant shift from coal-fired generation to natural gas generation.[85]

Mr. Bellar recognized that the Section 111 Rules are on appeal at the D.C. Circuit Court of Appeals. He also acknowledged that the incoming Trump administration could take a much different view of these rules than the outgoing administration that promulgated the rules.[86] The status of the rules in approximately 18 months, when engineering has been completed, will factor into the decision on whether to move forward with actual construction of the Cane Run 7 carbon capture project.[87] He indicated that the Company must play "the long game" and consider how durable its decisions will be under different administrations.[88]

Mr. Bellar testified that cost will also be a consideration when determining whether to move forward with the project. He indicated that the current target for the project is to have operating and maintenance costs lower than the offtake provider revenue stream.[89]

[80] Tr. at 32 (Bellar).
[81] Tr. at 34 (Bellar). The transcript's references to a "fee study" should be to a "FEED study" (front-end engineering and design study).
[82] Tr. at 44 (Bellar).
[83] Tr. at 35 (sic), 42-43 (Bellar).
[84] Tr. at 42 (Bellar).
[85] Tr. at 35-36, 38-39 (Bellar).
[86] Tr. at 39 (Bellar).
[87] Tr. at 39-40 (Bellar).
[88] Tr. at 40 (Bellar).
[89] Tr. at 40-41 (Bellar).

Ms. McFarland described KU's transmission system, which includes 5,400 circuit miles used to serve approximately 566,000 customers across its system in Kentucky and Virginia. KU's total Company transmission plant has a net book value of approximately $1.25 billion.[90] She also emphasized the safety performance of KU and LG&E's transmission operations (employees and contractors). In 2023, for example, KU and LG&E had no OSHA-recordable injuries during more than 300,000 work hours.[91]

Ms. McFarland asserted that KU's transmission reliability continues to improve. She cited average SAIDIs, excluding major events, of 14.77 minutes, for the five-year period ending in 2018, and of 6.67 minutes for the five-year period ending in 2023. She also cited average SAIFIs of 0.203, for the five-year period ending in 2018, and 0.103 for the five-year period ending in 2023.[92]

Ms. McFarland indicated that KU-ODP has spent and plans to spend more than $25 million in capital on Virginia transmission investments during the period December 1, 2022, to July 31, 2025. Of this amount, she attributed approximately 70% to replacing 276 wooden poles with steel poles and replacing or installing new switching equipment on lines, and the other 30% to substation work.[93] The pole replacement projects during this period include the Dorchester – Pocket North line project approved in Case No. PUR-2020-00110 and replacements planned in 2024 for the Lynch – Imboden line. She also discussed the Company's continued investment in motor operated switching with automatic reclosing schemes and the associated reliability benefits.[94]

Beyond the budgeted amount discussed above, Ms. McFarland reported that KU is seeking significant matching funds from two federal and state grant programs that would be used, in part, for transmission investments.[95] KU has applied for a federal grid resilience grant of $100 million to supplement a proposed $120 million of transmission and distribution investment in Virginia and Kentucky. Of the $220 million total, approximately $25 million is earmarked for transmission investments, including a rebuild project planned in Wise County, Virginia. KU has also applied for approximately $6 million of additional federal funding through the Virginia Grid Resilience and Innovative Partnerships program, which requires an approximately $11 million investment by KU. If awarded, the Company would replace all wood structures with steel on the 69 kV Pocket – Cawood line at the Hamblin tap section and would add two motor operated switches to the line.[96] Ms. McFarland added that these projects would mitigate wildfire risks and indicated that the location of the Wise County project is federally designated as very high risk for wildfires.[97]

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[90] Ex. 6 (McFarland direct) at 3. Approximately 200 circuit miles are in Virginia. *Id.* Ms. McFarland sponsored a map illustrating the Company's transmission infrastructure. *Id.* at attached Ex. BJM-1.
[91] *Id.* at 3-4. "OSHA" is the Occupational Safety and Health Administration.
[92] *Id.* at 4. "SAIDI" is the system average interruption duration index. "SAIFI" is the system average interruption frequency index.
[93] *Id.* at 5, 7. *See also id.* at 8 (showing total company figures for this period).
[94] *Id.* at 6. *See also id.* at 7 (attributing improved reliability to two specific motor operated switching projects).
[95] *Id.* at 8-9. As matching grants for projects not accounted for in the transmission budget discussed above, KU would need to increase its budget if either grant is awarded. *Id.* at 8.
[96] *Id.* at 9. $17 million * .35 = $5.95 million.
[97] *Id.* at 10.

Ms. McFarland discussed the Big Stone Gap transmission reliability project, which initially contemplated a new 1.8 mile 69 kV line but returned to the planning process after the locality did not approve the new line.[98]

Ms. McFarland identified the three rebuild projects approved in Case No. PUR-2020-00110, including the Dorchester – Pocket North rebuild for which KU-ODP's Application requested a further extension of the CPCN sunset date. Like Company witness Conroy, Ms. McFarland recognized that KU-ODP previously sought, and received, an extension of the sunset date in Case No. PUR-2020-00110.[99] She discussed the project's three phases and identified the reason for significant delays in the second phase – which is located in the Jefferson National Forest – due to federal restrictions on tree clearing for access, federal environmental assessments, and Department of Environmental Quality ("DEQ") erosion and sediment control plan and stormwater management plan requirements.[100]

Ms. McFarland testified about the increase to the cost estimate for the Dorchester – Pocket North rebuild due to permitting requirements and construction delays. The estimated cost to rebuild this line has increased from $10.7 million to $27.5 million. She attributed this increased estimate to material cost increases ($2 million), phosphorous credit purchases required by DEQ ($1 million), best management practices ($3.5 million), access road construction requirements imposed by DEQ and the Jefferson National Forest ($4 million), and labor cost increases ($4.3 million). KU-ODP's Application seeks a *pro forma* adjustment for the incremental cost of this project, as detailed by Company witness Metts.[101]

Mr. Waldrab focused on KU-ODP's electric distribution operations. The Company's distribution system in Virginia serves approximately 28,000 customers in Wise, Lee, Russell, Scott, and Dickenson Counties. These facilities include 43 distribution substations, 1,134 circuit miles of overhead lines, and 44 circuit miles of underground lines. From year-end 2020 to year-end 2023, net book value of the Company's Virginia distribution plant increased from approximately $58 million to $70.2 million.[102]

Of the $447.4 million of capital that Company witness Conroy indicated KU will have invested, and projects to invest, into its distribution operations from December 1, 2022, through July 31, 2025, Mr. Waldrab broke this amount down as follows.[103]

KU Total Company	12/1/22 – 7/31/25
Connect New Customers	$191.5 million
Enhance the Network	$74.4 million
Maintain the Network	$111.1 million
Repair the Network	$64.7 million
Miscellaneous	$5.7 million
Total	**$447.4 million**

[98] *Id.* at 11-12.
[99] *Id.* at 12-13.
[100] *Id.* at 12-14.
[101] *Id.* at 15.
[102] Ex. 7 (Waldrab direct) at 2.
[103] *Id.* at 16.

Mr. Waldrab emphasized KU's safety performance on distribution work. He reported, among other things, that during 2021 through 2023 the Company's distribution employees working out of Norton Operations in Virginia had only one OSHA-recordable injury during 109,097 total work hours.[104]

Mr. Waldrab asserted that KU's distribution reliability compares favorably to historical first-quartile performance among peer utilities. He cited a 2023 SAIDI, excluding major events, of 68.22 minutes and a 2023 SAIFI, excluding major events, of 0.609.[105] He detailed KU's storm restoration efforts in March 2023, for which KU and LG&E received an award from the Edison Electric Institute.[106] He also identified KU's investment in a new outage prediction model to help better prepare for severe weather events like the March 2023 storm.[107]

Mr. Waldrab addressed KU-ODP's prediction in its prior base rate case that the benefits of the Company's distribution automation program would be realized upon its completion in 2022. He asserted that this program has resulted in nearly 4,200 avoided customer interruptions and approximately 336,000 avoided customer outage minutes.[108]

Mr. Waldrab summarized KU's pole inspection and treatment program, circuits identified for improvement program, and customers experiencing multiple interruptions program, all initiated in 2010. He asserted that these programs have helped improve KU's SAIDI and SAIFI and helped reduce, by 95% from 2010 to 2023, the number of KU-ODP customers in Virginia who experienced more than five interruptions annually.[109]

Mr. Waldrab reported that the Company currently has 7.5 MW of customer-owned distribution energy resources interconnected behind the meter in Virginia, representing approximately 4% of peak measured load for the Virginia service area. He indicated that most of these are for schools, larger businesses, and data centers. He explained the interconnection process and indicated that requests relating to conversion of abandoned coal mining sites to renewable qualifying facilities have been received, but often are not cost effective due to the distance from substations and interconnection costs.[110]

Mr. Waldrab identified the penetration of distributed resources, expanded transportation electrification, and grid-interactive customer assets as new challenges to the operation and performance of the grid. He identified investments made by KU to increase distribution grid visibility and control, including AMI.[111] He identified a distribution resource integration and value estimation tool for which KU and LG&E received a technology award from EPRI.[112]

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[104] *Id.* at 3.
[105] *Id.* at 3-4. Compared to 2013, Mr. Waldrab indicated that these represent reductions of 17% (SAIDI) and 19% (SAIFI). *Id.* at 6.
[106] *Id.* at 4.
[107] *Id.* at 11.
[108] *Id.* at 5. This program involved the installation of supervisory control and data acquisition ("SCADA") capable electronic reclosers, distributed SCADA software, and the deployment of a distribution management system. *Id.*
[109] *Id.* at 6.
[110] *Id.* at 6-7.
[111] *Id.* at 7-9.
[112] *Id.* at 9-10.

Other distribution capital outlays incurred and projected over December 1, 2022, through July 31, 2025, discussed by Mr. Waldrab include approximately $24.1 million to replace substation equipment, relays, and overhead conductors and $12.6 million for pole inspection, treatment, and replacement. KU also plans to spend $10 million in Virginia in 2025 for wildfire risk mitigation.[113] He also identified a new advanced distribution monitoring system and mobile outage management system that KU expects to implement by the end of 2025, at an estimated cost of $18.5 million.[114]

To mitigate wildfire risk, KU is planning a number of strategies, including (1) identification of the highest risk areas and prioritizing efforts in those areas; (2) development of operational procedures and monitoring strategies; and (3) system hardening, asset investments, and implementation of new technologies specifically designed to combat wildfire risk. Mr. Waldrab recognized that wildfire risk mitigation is a complex issue that does not lend itself to a "one-size" approach.[115] According to Mr. Waldrab, the wildfire risk index maintained by the Federal Emergency Management Agency ("FEMA") considers factors beyond the likelihood of a possible wildfire, such as social vulnerability and resilience to natural disasters. Because of these additional factors, Mr. Waldrab indicated that KU-ODP's Virginia service territory is unique in the southeastern U.S. in that it contains several "very high" and "relatively high" wildfire risk zones.[116] He sponsored maps illustrating KU-ODP's distribution lines in Virginia and showing the levels of wildfire risk where those lines are located.[117]

Some of KU's planned operational and monitoring strategies include: (1) daily monitoring of weather conditions for wildfire favorability; (2) development of an internal dashboard to visually represent wildfire risk daily, by circuit or asset; (3) consideration of deviation from normal processes, such as increased patrols, protection setting changes, and delaying planned work where such deviations could mitigate risk; and (4) having a prepared communication strategy to ensure situational awareness internally and externally.[118]

Mr. Waldrab elaborated that the $10 million KU-ODP plans to invest in Virginia in 2025 to harden its distribution system against wildfire risks will be made on approximately twelve miles of distribution lines in "very high risk" areas identified by FEMA. As proposed, this includes strategic relocation of overhead facilities, replacement of bare overhead conductors with covered conductors, replacement of wood poles supporting primary voltages with either non-flammable ductile iron poles or composite poles, deployment of situational awareness sensors to provide early fault detection, deployment of breakaway overhead service conductors, and deployment of lightning arresters with spark prevention technology.[119] KU-ODP's Application proposed a *pro forma* adjustment for $10 million in wildfire mitigation investment in 2025, as sponsored by Company witness Fackler.[120]

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[113] *Id.* at 10, 14.
[114] *Id.* at 10-11.
[115] *Id.* at 12.
[116] *Id.* at 13 and attached Ex. PWW-2.
[117] *Id.* at attached Exs. PWW-1 and PWW-2.
[118] *Id.* at 13-14.
[119] *Id.* at 14-15. In addition, the federal and state grants discussed above, if awarded, would be used in part to mitigate wildfire risks. *Id.* at 14.
[120] *Id.* at 15-16.

Ms. Montgomery summarized KU's customer service operations. She reported that, from 2020-2023, KU's customer service employees had only three recordable safety incidents and KU's contractors had 16 such incidents across more than 2.3 million work hours.[121] She provided customer experience ratings compiled for KU by a third party. She touted App Store ratings for KU and LG&E's mobile app and an award received for KU and LG&E's interactive voice response system.[122]

Ms. Montgomery explained that KU and LG&E plan to close all their business offices by the end of 2024, due to declining walk-in transactions, staffing challenges, and improvements in the availability and ease of self-service options. She reported that, in Virginia, the Pennington Gas business office closed on March 31, 2023, and the Norton business office closed on April 26, 2024. She discussed how customers were informed in advance of these closures and alternative payment options.[123] She explained that payments can be made online, by mail, or in person. Through a partnership with FiServ, in person payments can be made at various participating locations for a $1.95 transaction fee that has been paid by the customer since third-party cash payments have been accepted.[124]

However, the Application proposes that the convenience fee paid to FiServ be recovered in base rates effective February 1, 2025, rather than charged to each customer using FiServ to make in-person payments. Ms. Montgomery indicated that closure of the Virginia business offices results in certain O&M expense savings to customers, some of which would be offset by including, as proposed, the convenience fee in rates.[125]

Ms. Montgomery indicated that fewer than 25% of comparably sized utilities have walk-in business centers as of 2022. She identified four investor-owned utilities operating in Virginia that have gone to a third-party "authorized payment center" model instead of maintaining business offices or dedicated brick-and-mortar customer service centers.[126]

Ms. Montgomery identified benefits of AMI technology. She cited the *2021 Rate Case Order*'s[127] finding that KU-ODP's plan to deploy AMI in Virginia beginning in 2024 was reasonable and did not require a CPCN.[128] Based on progress deploying AMI in Kentucky, she indicated that KU-ODP now expects network installation to be completed by August 2024, the bulk of approximately 30,000 AMI meters installed in the first quarter of 2025, and full deployment concluded by the end of 2025.[129] Of the $132.9 million KU-ODP has spent and plans to spend over the period December 1, 2022, through July 31, 2025, AMI-related projects account for $129.2 million, according to Ms. Montgomery.[130]

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[121] Ex. 8 (Montgomery direct) at 2.
[122] *Id.* at 2-4.
[123] *Id.* at 4, 6.
[124] *Id.* at 7 (indicating participating locations include, among others, Kroger, Walmart, CVS, Dollar General, Family Dollar, Walgreens, Speedway, and Circle K).
[125] *Id.* at 8.
[126] *Id.* at 4-5.
[127] *Application of Kentucky Utilities Company d/b/a Old Dominion Power Company, For an adjustment of electric base rates*, Case No. PUR-2021-00171, 2022 S.C.C. Ann. Rep. 330, Final Order (May 25, 2022) ("2021 Rate Case" or "*2021 Rate Case Order*", as applicable).
[128] Ex. 8 (Montgomery direct) at 8-10 (citing *2021 Rate Case Order*, 2022 S.C.C. Ann. Rep. at 333).
[129] Ex. 8 (Montgomery direct) at 10.
[130] *Id.* at 11.

Ms. Montgomery identified low-income assistance programs available to qualifying customers, including the WinterShare Energy Assistance Fund and the Virginia Energy Assistance Program that provides funds from the Low-Income Home Energy Assistance Program. Information about these programs is available on KU's website, is included with customer disconnect notices, and is used to train customer service representatives for the programs' promotion when serving past-due and payment-challenged customers. Additionally, when a residential customer receives a pledge for, or notice of, low-income energy assistance from an authorized agency, KU-ODP waives late payment charges for the current month, plus the next 11 months.[131] The Company also grants an automatic 30-day payment extension beyond the disconnect due date when at least 50% of a past-due payment is paid with the involvement of an assistance agency.[132]

Mr. McCombs sponsored or co-sponsored Filing Schedules 6-7, 15-16, 25, 29-31, 34-35, and 38-39.[133] Mr. McCombs identified the following earnings test ("ET") adjustments in Filing Schedule 16 and ratemaking adjustments in Filing Schedule 25 that he supports.[134]

Adjustment	Amount	Type	Description
ET-4	($111,938)	O&M	Remove advertising expense that does not conform to Code § 56-235.2 A
OM-20	($111,633)	O&M	
ET-10	($5,244,764)	Plant	Adjust the effects of FASB Accounting Standards Codification Topic 410 – Asset Retirement and Environmental Obligations, asset retirement obligation accounting, from the cost of service
ET-12	$3,852,620	Plant	
NP-34	($5,392,823)	Plant	
NP-35	$4,068,778	Plant	
ET-11	($182,070)	Plant	Removes from rate base Kentucky land on which KU intended to construct a solar facility, but subsequently sold to a Kentucky locality
OR-5	($612)	Revenue	Remove from the test year out-of-period O&M expense and other operating revenues because they relate to periods outside of the rate year
OM-6	($435,706)	O&M	
OM-16	$18,332	O&M	Adjustments to labor cost, payroll taxes, and KU's 401(k) matching contributions to rate year levels (with Metts)
OT-30	$1,265	Taxes	
OM-21	$160,202	O&M	Normalizes uncollectible expense by multiplying five-year weighted average net write-off rate by jurisdictional adjusted revenues
DE-23	$1,223,485	Deprec. Exp.	Projected increase in depreciation expense, from test year to rate year (with Metts)
IE-33	($43,034)	Interest Exp.	Reflects a pro forma level of interest expense on customer deposits
ORB-51	($41,000)	Rate Base	Removes test year, year-end deferred fuel amounts from the rate year

[131] *Id.* at 11-12.
[132] *Id.* at 13.
[133] Ex. 11 (McCombs direct) at 2-3. He also sponsored workpapers in Filing Schedule 29 corresponding to adjustments he sponsored. *Id.* at 3.
[134] *Id.* at 5-9; Ex. 2 (Application) at Filing Scheds. 16 and 25.

Mr. McCombs testified that while KU-ODP's 2023 Virginia jurisdictional customer service expenses are higher than the comparison utility group evaluated by Company witness Baryenbruch, such affiliate expenses are lower than 2020 levels. Mr. McCombs attributed such higher than average expenses to KU's maintenance of customer service offices that, as discussed by Company witness Montgomery, are now being closed.[135]

Ms. Fackler sponsored and summarized the Application's jurisdictional and class cost-of-service studies in Filing Schedule 40. She also sponsored or co-sponsored Filing Schedules 9, 11, 12, 14, 16-19, 21-22, 24-29, 40, 42-43, and 49.[136]

For the jurisdictional allocation of KU's costs to KU-ODP, Ms. Fackler emphasized the value of methodological continuity and testified that the Application uses the same overall methodology that has been accepted in KU-ODP's last seven general rate cases.[137] The two principal allocators used in the Application's jurisdictional separation studies are: (i) a demand allocator factor based on the monthly average 12 coincident peak demand ("Average 12 CP") to allocate fixed production and transmission fixed costs; and (ii) an energy allocator based on the energy used within each of KU's jurisdictions. Rather than use only actual 2023 data (0.03973) for the Average 12 CP demand allocator factor, Ms. Fackler used the three-year average over 2021-2023 (0.04218).[138] She used a chart to illustrate that KU-ODP's peak contributions during the months of February, April, and October 2023 were significantly lower than the same months in 2022 due to mild weather.[139] She asserted the Application's proposed three-year average would more reasonably match revenues with expenses since the Application includes an adjustment for differences in load between 2023 actual and the rate year.[140]

For class cost-of-service, Ms. Fackler explained the traditional steps of such studies and indicated that KU-ODP's Application uses the same spreadsheet models developed and used in prior base rate cases.[141] She explained how the Company classified production, transmission, and distribution costs in the Application's class cost-of-service study, including the Company's continuing use of the zero-intercept methodology (instead of a minimum system approach) used to classify distribution plant as demand-related or customer-related.[142] She listed and described the primary allocation factors used in the Company's class cost-of-service studies[143] and explained the Company's functional assignment and classification of costs.[144] Ms. Fackler also explained that KU-ODP's Application used an average 12 CP to allocate production and transmission plant.[145]

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[135] Ex. 11 (McCombs direct) at 10.
[136] Ex. 15 (Fackler direct) at 21-22.
[137] *Id.* at 2-3.
[138] *Id.* at 3-4. Transmission-related costs that are currently used solely to provide service to retail customers in Virginia and are not included in KU's open access transmission tariff are directly assigned to Virginia retail customers. *Id.* at 14.
[139] *Id.* at 4 (header omitted).
[140] *Id.* at 5. Ms. Fackler supports the revenue adjustment, OR-1, which assumes normal weather in the rate year. *Id.*
[141] *Id.* at 7-9.
[142] *Id.* at 9-12.
[143] *Id.* at 12-13.
[144] *Id.* at 15-16.
[145] *Id.* at 13-14.

Ms. Fackler summarized the results of the Application's class cost-of-service study,[146] which are shown below in this Report's summary of Staff witness Tufaro's testimony. Based on these results, Ms. Fackler asserted that the current rates of return for residential customers are inadequate. The Application proposes to move residential customers closer to parity but, giving due weight to gradualism, retaining 85% of the inter-class subsidy suggested by the class cost of service study results.[147] She summarized the Application's proposed revenue allocation and the resulting rate class increases as follows.[148]

	Step One	Step Two			Total
Rate Class	Equal %	Current Subsidy Received (Provided) from COS	Subsidy Reduction Percent	Subsidy Reduction	Proposed Revenue Allocation
Rate RS	5,505,651	3,477,435	15%	521,615	6,027,266
Rate GS	1,074,546	(86,504)	15%	(12,976)	1,061,570
Rate PS–Secondary	689,922	(413,285)	15%	(61,993)	627,930
Rate PS–Primary	476,251	(847,424)	15%	(127,114)	349,137
Rate TOD–Secondary	248,627	(126,421)	15%	(18,963)	229,664
Rate TOD–Primary	976,677	(1,513,758)	15%	(227,064)	749,614
Rate RTS	220,962	(448,073)	15%	(67,211)	153,751
Rate P.O.L.T	156,928	(41,970)	15%	(6,295)	150,633

Rate Class	Revenue at Current Rates	Revenue at Proposed Rates	Increase	Percentage Increase
Rate RS	$ 43,472,343	$ 49,501,027	$ 6,028,684	13.9%
Rate GS	$ 8,484,559	$ 9,546,262	$ 1,061,703	12.5%
Rate PS–Secondary	$ 5,447,593	$ 6,075,591	$ 627,998	11.5%
Rate PS–Primary	$ 3,760,454	$ 4,109,527	$ 349,073	9.3%
Rate TOD–Secondary	$ 1,963,147	$ 2,192,878	$ 229,731	11.7%
Rate TOD–Primary	$ 7,711,795	$ 8,460,466	$ 748,671	9.7%
Rate RTS	$ 1,744,702	$ 1,898,206	$ 153,504	8.8%
Rate P.O.L.T	$ 1,239,098	$ 1,389,151	$ 150,053	12.1%

Ms. Fackler identified the following earnings test results from the Company's Filing Schedules 9, 11, 12, and 14.[149]

	Rate Base	Earned Rate of Return	Earned Return on Common Equity
Per Books Thirteen-month average rate base for the period ended December 31, 2023	$292,177,290	6.04%	7.44%
Adjusted to a Regulatory Accounting Basis Thirteen-month average rate base for the period ended December 31, 2023	$289,355,377	6.04%	7.49%

[146] *Id.* at 17.
[147] *Id.* at 17-18.
[148] *Id.* at 19-20 (table headers omitted).
[149] *Id.* at 22-23.

Ms. Fackler identified the following rate of return results from the Company's Filing Schedules 19, 21-22, and 24.[150]

	Rate Base	Earned Rate of Return	Earned Return on Common Equity
Per Books Year-end rate base	$294,017,730	6.03%	7.50%
Adjusted to a Regulatory Accounting Basis Year-end rate base	$327,191,991	5.53%	6.50%

Ms. Fackler summarized average monthly bill impacts based on the Application's proposed cost allocation and $9,411,184 revenue requirement increase using the following table.[151]

Rate Class	Average Usage kWh	Present Average Bill	Proposed Average Bill	Increase
Rate RS	1,143	$157.19	$179.01	$21.82
Rate GS	1,345	$190.12	$213.91	$23.79
Rate PS – Secondary	36,430	$3,880.05	$4,327.34	$447.29
Rate PS – Primary	101,791	$13,314.07	$14,556.33	$1,242.26
Rate TOD – Secondary	189,104	$19,246.53	$21,498.80	$2,252.27
Rate TOD – Primary	436,556	$51,411.97	$56,403.11	$4,991.14
Rate RTS	208,250	$72,695.92	$79,091.92	$6,396.00

Ms. Fackler sponsored some of the calculations in support of the Application's proposed non-residential first time late payment charge waiver, discussed by Company witness Hornung, and differences in revenues from certain miscellaneous charges the Application proposed to change.[152]

Ms. Fackler identified the following earnings test ("ET") adjustments and ratemaking adjustments she supports.[153]

Adjustment	Amount	Type	Description
ET-1	$3,124,569	Revenue	Remove test year per book accrued revenues for fuel factor
OR-2	$3,124,569	Revenue	
ET-2	($3,446,596)	Revenue	Levelize per book fuel factor revenues with fuel expenses
OR-3	($3,446,596)	Revenue	

[150] *Id.* at 24-25.
[151] *Id.* at 26-27 (table header omitted). Filing Schedule 43, sponsored by Ms. Fackler, provides sample billing impacts using various assumed levels of consumption. *Id.* at 27.
[152] *Id.* at 27; Ex. 2 (Application) at Filing Sched. 49-AMF-1 and AMF-2. Filing Schedule 49-AMF-3, also sponsored by Ms. Fackler, shows the unit cost sheet based on the class cost-of-service study. Ex. 15 (Fackler direct) at 27.
[153] Ex. 15 (Fackler direct) at 28-32; Ex. 2 (Application) at Filing Sched. 16 and 25. "OPEB" refers to other post-employment benefits. "FERC" refers to the Federal Energy Regulatory Commission.

Adjustment	Amount	Type	Description
ET-3	($17,685)	Revenue	Remove 25% of off-system sales margins retained pursuant to Code § 56-249.6 D 1
OR-4	($17,685)	Revenue	
ET-5	$15,013	O&M	Expense adjustments for 40-year amortization of OPEB transition obligation
OM-18	$14,941	O&M	
ET-6	($62,006)	Amort. Exp.	Adjustments for annual amortization expense for active generation stations CCR surface impoundment closures
DE-25	$4,422	Amort. Exp.	
ORB-55	$131,046	Rate Base	
ET-13	$8,149	Rate Base	Lead/lag cash working capital adjustments
WC-45	($83,285)	Rate Base	
WC-47	$29,713	Rate Base	
ET-14	$1,673,348	Rate Base	Rate base adjustments for 40-year amortization of OPEB transition obligation
ORB-53	$1,692,942	Rate Base	
OR-1	$3,522,275	Revenue	Adjustment using "expected rate year volumes derived from KU's 2024 Business Plan"
OM-12	$245,091	O&M	Adjustment for the Application's request to establish a regulatory asset for $490,181 out-of-period, FERC-ordered depancaking expenses with two year amortization beginning with base rate change implemented in the instant case (Metts)
OM-15	$42,160	O&M	$42,160 pro form adjustment to incorporate convenience fees for use of FiService for in person cash transactions (Montgomery)
NP-39	$4,378,375	Rate Base	$10 million pro form adjustment for proposed wildfire risk mitigation capital investment in 2025 (Waldrab)

Ms. Fackler presented the overall revenue lag, by lag component, and expense lead days, by expense, from the Company's lead/lag study.[154] Based on the Company's study, which Ms. Fackler asked the Commission to accept, she recommended a Virginia jurisdictional cash working capital requirement of $4.6 million.[155]

[154] Ex. 15 (Fackler direct) at 35-36.
[155] *Id.* at 37-38.

Ms. Burgos testified in support of the Application's proposed cost of debt, capital structure, and certain earnings test and ratemaking adjustments to interest expense.[156] Based on her recommendations and the Application's proposed 10.5% ROE recommended by Company witness McKenzie, the Application's proposed cost of capital is shown below.[157]

	Amount Outstanding ($ Millions)	Percent of Total	Annual Cost Rate	Weighted Cost of Capital
Short Term Debt	48	0.728%	5.259%	0.038%
Long Term Debt	3,060	45.996%	4.409%	2.028%
Common Equity	3,544	53.276%	10.500%	5.594%
Total Capitalization	6,653	100.000%		7.660%

Ms. Burgos explained that her proposed long-term and short-term debt rates are KU's weighted averages as of December 31, 2023.[158] She believes KU's cost of debt is reasonable.[159]

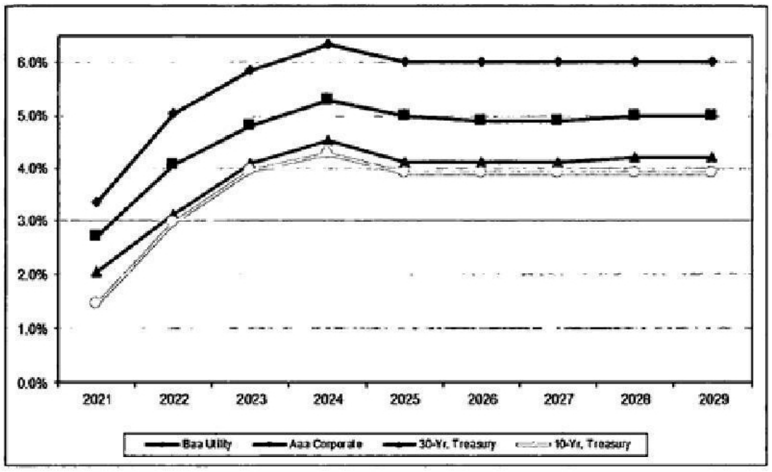
Ms. Burgos discussed the significance of credit ratings, market conditions, and overall investor sentiment at the time of issuance to KU's cost of debt.[160] She reported that KU targets an "A" credit rating from Moody's and S&P, and presently has an A3 rating from Moody's (with first mortgage bonds rated A1) and an A- rating from S& P (with first mortgage bonds rated A). She detailed factors considered by these rating agencies to evaluate a utility's credit quality, and attached to her testimony Moody's and S&P publications discussing their ratings methodologies.[161] Ms. Burgos identified all of the debt issuances and financing arrangements entered by KU since the Company's prior general rate case.[162] She testified that while KU maintains certain credit metrics to access capital markets at attractive prices, other factors could hinder the Company's ability to access capital at lower costs compared to peers, including investors' aversion to entities with coal-fired generation.[163]

Mr. McKenzie testified in support of the Application's proposed ROE. Specifically, he recommended an ROE of 10.50%, the bottom of the 10.50% to 11.50% range he recommended as reasonable. Mr. McKenzie's recommended ROE range includes a 20-basis-point upward risk adjustment.[164]

Mr. McKenzie provided his assessment of current capital conditions. He identified recent inflation expectations and a February 2024 revision by S&P of its outlook for the utility sector to "negative."[165] He highlighted a more than 200-basis-point increase in Treasury bonds and Baa

[156] Ex. 9 (Burgos direct) at 1, 10. Ms. Burgos sponsored Filing Schedules 1-5, 8, 16, and 25. *Id.* at 1-2.
[157] Ex. 2 (Application) at Filing Sched. 8.
[158] Ex. 9 (Burgos direct) at 5.
[159] *Id.* at 7.
[160] *Id.* at 5-6.
[161] *Id.* at 7-9 and attached Exs. JB-1, JB-2, JB-3.
[162] *Id.* at 9-10.
[163] *Id.* at 9.
[164] Ex. 10 (McKenzie direct) at 2-3.
[165] *Id.* at 16-17. He identified statements in 2023 by Fitch Ratings, Inc., and Value Line. *Id.* at 17.

utility bonds as of February 2024, compared to the August 2021 to May 2022 period.[166] He provided the following figure published by Blue Chip Financial Forecasts in December 2023, which he considers evidence showing that long-term capital costs have increased substantially, and that investors expect such higher capital costs to be sustained at least through 2029.[167]



Source: Wolters Kluwer, Blue Chip Financial Forecasts (Dec. 1, 2023); Moody's Investors Service; https://fred.stlouisfed.org/.

The 10.50% ROE recommended by Mr. McKenzie is based on cost of equity estimates that he developed by applying cost of equity models and methods[168] to a proxy group of nine electric utility companies he selected using specified screening criteria.[169] The results of his analysis are summarized in the table below.[170]

Electric Utility Peer Group Analysis

Model or Method	**Description**	**Average**
DCF	Value Line	10.3%
	IBES	10.1%
	Zacks	10.1%
	Internal br + sv	9.1%
CAPM		11.5% - 12.0%
ECAPM		11.6% - 12.1%
Utility Risk Premium		10.8%
Expected Earnings		11.1%
Cost of Equity Range		10.3% - 11.3%

To his range shown above, Mr. McKenzie recommended a 20-basis-point upward risk adjustment due to: (1) the Company's "considerably narrower range of regulatory adjustment mechanisms" compared to his peer group utilities; and (2) the Company's ongoing exposure to

[166] *Id.* at 18-19.
[167] *Id.* at 19 (table header omitted).
[168] *Id.* at 39-57, attached Exs. AMM-5, AMM-6, AMM-7, AMM-8, AMM-9, and AMM-10.
[169] *Id.* at 21-22, attached Ex. AMM-3.
[170] *Id.* at attached Ex. AMM-2. "DCF" refers to the Discounted Cash Flow model. "CAPM" refers to the Capital Asset Pricing Model. "ECAPM" refers to the Empirical Capital Asset Pricing Model.

attrition and environmental risks.[171] Mr. McKenzie listed the type of rate adjustment clauses available to each peer group utility[172] and identified prior Commission proceedings in which risk adjustments were approved.[173] He recognized the Company's historical reliance on coal-fired generation and identified a November 2023 statement by Moody's Investors Service that "[c]arbon transition is a significant risk for KU."[174]

Mr. McKenzie asserted that the Company's 53.28% common equity ratio is reasonable. In support of this assertion, he identified common equity ratios: (1) during the most recent fiscal period for electric utility operating companies owned by the companies in his utility peer group, which ranged between 43.2% to 60.6% with an average of 53.4%; (2) during the five quarters ending December 31, 2023, for the utility peer group companies; and (3) approved during 2022 and 2023 in regulatory proceedings, as reported by Regulatory Research Associates.[175] He added that a stronger balance sheet is warranted to deal with utilities' significant capital investment plans and uncertain environment.[176]

Mr. McKenzie also conducted cost of equity analysis using a non-utility group, the results of which are shown below.[177]

Non-Utility Group Analysis

Model	Description	Average	Midpoint
DCF	Value Line	10.5%	11.2%
	IBES	10.6%	11.3%
	Zacks	10.9%	11.6%

Mr. Clements sponsored Filing Schedule 36 and associated parts of Filing Schedule 49 related to income taxes.[178] He identified the following earnings test ("ET") adjustments and ratemaking adjustments that he supports.[179]

Adjustment	Amount	Type	Description
ET-7	($46,533)	Income Tax	Adjust federal and state income taxes to reflect adjustments
IT-26	$43,077	Income Tax	
ET-8	$33,774	Income Tax	Federal and state income taxes corresponding to annualization and adjustment of interest expense
IT-28	($191,859)	Income Tax	
ET-15	($417,500)	Rate Base	ADIT associated with the adjustment to unfunded OPEB liability
ORB-54	($422,389)	Rate Base	

[171] *Id.* at 8, 25-28.
[172] *Id.* at attached Ex. AMM-3.
[173] *Id.* at 9-12.
[174] *Id.* at 28.
[175] *Id.* at 30-31 and attached Ex. AMM-4.
[176] *Id.* at 32.
[177] *Id.* at 58-61, attached Ex. AMM-11.
[178] Ex. 12 (Clements direct) at 1. He sponsored Filing Schedule 29 workpapers for adjustments he supported. *Id.*
[179] *Id.* at 4-7; Ex. 2 (Application) at Filing Scheds. 16 and 25.

Adjustment	Amount	Type	Description
IT-27	$32,843	Income Tax	Removes 2023 federal and state income tax true-ups and other tax adjustments that apply to other periods; removes unprotected excess ADIT amortization that became fully amortized as of May 31, 2023
IT-29	($56,498)	Income Tax	Increases protected excess ADIT amortization for the rate year
OT-31	$147,303	Tax	Increases property tax levels based on values of plant in service, plant held for future use, construction work in progress, materials and supplies, adjusted "for other known and measurable changes"
ORB-48	($113,360)	Rate Base	Update rate base from the test year to the rate year – adjust the accumulated deferred ITC using a 13-month average for the rate year and adjust the ADIT using a proration for the period ended December 31, 2025
ORB-49	$1,912,197	Rate Base	
ORB-50	$40,106	Rate Base	ADIT adjustment reflecting the rate year adjustments on the transmission pole replacement project discussed by Company witness Metts

Ms. Metts sponsored Filing Schedule 32 in addition to the portions of Filing Schedules 25 and 29 addressing the following ratemaking adjustments she supported.[180]

Adjustment	Amount	Type	Description
OM-7	$292,852	O&M	To normalize outage maintenance expense by using an eight-year blended average of actual amounts and an amount from the Company's 2024 business plan
OM-8	$249,907	O&M	To adjust ELG and bottom ash transport water treatment system expenses to rate year, because the water treatment systems were not in service during the test year but are expected to go in service in 2024
OM-9	$251,856	O&M	To adjust generation reagents and commodities and beneficial reuse to the rate year, to reflect expected price increases as commodity contracts expire and forecasted costs or revenues of expired and expiring reuse contracts
OM-10	$147,064	O&M	To adjust material hauling costs at the Ghent plant to the rate year, because such costs have been primarily capitalized as part of ash pond projects that will be completed in 2024
OM-11	$110,471	O&M	To adjust depancaking expenses to rate year, following FERC Order

[180] Ex. 13 (Metts direct) at 1-3, 5-13; Ex. 2 (Application) at Filing Sched. 25.

Adjustment	Amount	Type	Description
OM-13	($36,434)	O&M	To normalize distribution storm restoration costs, by using a five-year per books average and excluding storm restoration costs reclassified to a regulatory asset in the test year[181]
OM-14	($52,337)	O&M	To adjust business office expenses to rate year, reflecting closure of such offices
OM-16	$18,332	O&M	To adjust labor cost and 401(k) Company match to rate year, based on pro forma forecast and budgeted information
OM-17	$213,017	O&M	To adjust pension and postretirement (benefit)/expense to rate year, based on calculations by KU-ODP's actuarial consultant
OM-19	$123,704	O&M	To adjust other insurance to rate year and remove settlement costs in the test year
OM-22	$243,075	O&M	To reflect amortization of estimated rate case expenses, based on actual expenses incurred in KU-ODP's 2021 Rate Case
DE-23	$1,223,485	Dep. Exp.	To adjust depreciation expense to rate year
DE-24	$162,244	Dep. Exp.	To adjust rate year depreciation expense on transmission pole replacement project
OT-30	$1,265	Tax Exp.	To adjust payroll taxes to rate year
NP-36	$41,814,355	Rate Base	To adjust plant to rate year
NP-37	$134,721	Rate Base	To adjust CWIP to rate year
NP-38	($18,243,267)	Rate Base	To adjust accumulate depreciation reserve to rate year
NP-40	$3,735,238	Rate Base	To adjust rate year CWIP on transmission pole replacement project
NP-41	$5,504,563	Rate Base	To adjust rate year plant in service on transmission pole replacement project
NP-42	$107,436	Rate Base	To adjust rate year accumulated depreciation on transmission pole replacement project
NP-43	($286,106)	Rate Base	To remove Mercer County solar land in the rate year[182]
WC-44	$373,364	Rate Base	To adjust materials and supplies to rate year
WC-46	$98,834	Rate Base	To adjust fuel stock and emission allowances to rate year
ORB-52	($133,907)	Rate Base	To adjust unamortized active pond CCR closure costs to rate year

[181] *See also* Ex. 2 (Application) at Filing Sched. 29, Adjustment OM-13, p. 4 (identifying 2023 storm damage amounts, including a KU total company amount of $10.09 million for a March 2023 storm, that the Company reclassified as a regulatory asset).
[182] *See also* Ex. 2 (Application) at Filing Sched. 29, Adjustment No. NP-43, p. 1 (showing a $7.56 million amount of plant held for future use ($286,106 Virginia jurisdictional) to be sold).

Ms. Metts offered KU-ODP's position that the Company's proposed rate year adjustments can reasonably be predicted to occur during the rate year (calendar year 2025).[183]

Mr. Baryenbruch presented the results of his study evaluating approximately $256 million in charges made in 2023 to KU by its affiliates,[184] and asserted that such costs were necessary and reasonably priced.[185] Based on his evaluation, Mr. Baryenbruch concluded that for 2023:[186]

(1) KU's 2023 cost for administrative and general (A&G) services provided by [PPL Services Corporation] and [LG&E and KU Services Company] [collectively, "Service Companies"] is reasonable compared to the costs for similar utility service companies. In 2023, KU was charged an average of $130 per customer for these services versus a service company comparison group's 2022 average of $120 per customer. KU's $130 annual cost is lower than 10 of the 21 comparison group service companies.

Furthermore, KU's 2023 total A&G expenses and total [O&M] expenses (incurred directly and allocated by [the Service Companies]) are reasonable compared to the same expenses for a comparison group of fully integrated utilities that are subject to traditional rate regulation, are part of a utility holding company and that are provided services by affiliate service companies. KU's 2023 total A&G expenses are $229 per customer versus the comparison group's 2022 average of $272 per customer. KU's 2023 total O&M expenses are $1,605 per customer versus the 2022 average of $2,315 per customer.

(2) [The Service Companies'] services provided to KU during 2023 are priced at the lower of cost or market. On average, the hourly rates for outside service providers are 81% higher than comparable hourly rates charged by [the Service Companies]. If all of the managerial and professional services now provided by [the Service Companies] had been outsourced in 2023, KU and its customers would have incurred approximately $103 million in additional expenses.

Furthermore, services LG&E provided to KU during 2023 were priced at LG&E's cost of service.

(3) During 2023, KU's customer service expenses per customer were $74.10. The comparison group of utilities in Virginia, Kentucky and surrounding states had a 2023 average cost of $53.22. KU's annual cost of $74.10 is lower than 4 of the 30 comparison group utilities.

One factor that accounts for KU's above average cost is the commitments made in connection with its 2010 merger with PPL Corporation. For instance, KU was required to commit that "local customer service offices shall not be closed as a result of the

[183] Ex. 13 (Metts direct) at 4-5.
[184] Ex. 14 (Baryenbruch direct) at 3 (identifying a total of $2.23 billion in 2023 affiliate charges, but identifying non-service transactions and convenience payments not encompassed by his study).
[185] *See, e.g., id.* at summary.
[186] *Id.*

proposed transaction and that, if and when local customer service offices may be closed to achieve world class best practices, PPL, E.ON US, LG&E and KU will take into account the impact of the closures on customer services. In 2023, KU began a program to reduce customer service expenses by closing 26 business offices. By the end of 2025, this is expected to save $6.2 million (in 2020 dollars) in customer service expenses.

Another factor impacting KU's customer service expenses is its widely dispersed service territory. KU provides electric service to customers in 77 counties in central, southeastern, and western Kentucky and to five counties in southwestern Virginia, all covering approximately 4,800 non-contiguous square miles. KU is addressing this issue by implementing [AMI] to automate meter reading and processing of customer read data. Implementation of AMI begins in Virginia in September 2024 and is projected to be completed in February 2025.

(4) The services that [the Service Companies] provide are necessary and would be required even if KU were a stand-alone electric utility. There is no redundancy or overlap in the services provided by [the Service Companies] to KU.

Mr. Hornung sponsored, among other things, the Application's proposed rates and tariffs.[187]

Mr. Hornung addressed the Application's four proposed voluntary time-of-day rate schedules: Residential Time-of-Day Energy Service (Rate RTOD-Energy); Residential Time-of-Day Demand Service (Rate RTOD-Demand); General Time-of-Day Energy Service (Rate GTOD-Energy); and General Time-of-Day Demand Service (Rate GTOD-Demand). He recognized that the *2021 Rate Case Order* directed KU-ODP to propose time-of-day rates for residential and general service customers in its next base rate case application (*i.e.,* the instant Application).[188] He testified that KU has successfully offered these rate schedules in Kentucky for several years and that now is the right time to offer them in Virginia because of the Company's upcoming roll out of AMI, as discussed by Company witness Montgomery, and the potential for increasing electric heating and electric vehicle demand.[189]

As described by Mr. Hornung, proposed Rate RTOD-Energy uses base and peak energy rates, with no demand charge. Proposed Rate RTOD-Energy uses a flat and relatively low energy rate, with base and peak demand rates. To eliminate barriers to participating in Rates RTOD-Energy and RTOD-Demand, KU-ODP proposes the same basic service charge as Rate RS and, like Rate RS, proposes no minimum contract term. While customers could switch between the new RTOD rates as often as they like, such a change would not take effect until the next billing cycle and customers that switch out of RTOD rates cannot return to the same new rate for 12 months.[190] Mr. Hornung identified other similarities between Rate RS and the proposed Rates RTOD-Energy and RTOD-Demand. He testified that KU-ODP designed the

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[187] Ex. 16 (Hornung direct) at 1-2. Filing Schedule 41 includes clean and redline versions of the proposed rates and tariffs. Mr. Hornung also sponsored parts of Filing Schedule 49. *Id.*
[188] *Id.* at 2-3; *2021 Rate Case Order*, 2022 S.C.C. Ann. Rep. at 333.
[189] Ex. 16 (Hornung direct) at 3.
[190] *Id.* at 4.

proposed rates to be revenue-neutral, meaning a residential customer who volunteers to take service under a new time-of-use rate should have the same bill as under Rate RS unless the customer adjusts their demand or energy usage. Both proposed rates have two sets of seasonal base and peak rates, one set for April through October and the other for the remaining months. To preserve the intended impact of price signals, budget billing would not be available to participating customers.[191]

As described by Mr. Hornung, proposed Rates GTOD-Energy and GTOD-Demand have the same basic service charges, among other similarities, as Rate GS. These proposed general service time-of-use rates are structured identical to the proposed residential time-of-use rates, and have the same rate switching provisions and budget billing limitation.[192]

A combined 100-customer participation limit is proposed for Rates RTOD-Energy and RTOD-Demand, and also for Rates GTOD-Energy and GTOD-Demand, because, if successful, these rates will produce a revenue deficit for the Company. According to Mr. Hornung, KU-ODP will gather data from the full deployment of AMI to better understand customers' usage patterns and responses to price signals, which may allow for further refinement of the rates and a broader offering.[193]

Mr. Hornung explained that proposed Rate Schedule OSL would be available for up to ten jurisdictional customers with lighting for outdoor sports fields. The proposed rate consists of a basic service charge, energy charge, and base and peak demand charges that would allow participating customers to avoid costs by avoiding system peaks. KU currently serves six Kentucky customers under this tariff.[194]

Mr. Hornung identified the Application's proposal to expand to all rate schedules the late payment waiver the *2019 Rate Case Order*[195] approved for Rate RS customers. KU-ODP would further make all late payment waivers automatic rather than upon request. KU-ODP would waive a customer's late payment charge automatically if the customer has not incurred a late payment charge in the previous eleven billing cycles.[196]

Mr. Hornung identified the Application's proposed changes to the tariff's Special Charges, including increases to the monthly meter pulse charge (from $21 to $22), the disconnect/reconnect charge (from $37 to $53), and the meter test charge ($79 to $81).[197] He also identified a proposed change to the availability of Rate RTS, which would make it available

[191] *Id.* at 4-6.
[192] *Id.* at 6-8.
[193] *Id.* at 3, n.4, and 7-8.
[194] *Id.* at 8-9.
[195] *Application of Kentucky Utilities Company d/b/a Old Dominion Power Company, For an adjustment of electric base rates*, Case No. PUR-2019-00060, 2020 S.C.C. Ann. Rep. 259, Final Order (Apr. 6, 2020) ("*2019 Rate Case Order*").
[196] Ex. 16 (Hornung direct) at 9. The expanded waiver would also apply to new rate schedules the Application proposes to add in this proceeding. *Id.*
[197] *Id.* at 10. He also identified: (i) proposed changes to various unauthorized reconnect charges; (ii) proposed increase to a rate component of the Excess Facilities Rider, to reflect the Application's proposed weighted average cost of capital; and (iii) various proposed changes to the tariff's text, including changes to reflect that all replacement meters will be AMI meters. *Id.* at 10-11.

to any customer with a 12-month average monthly minimum demand exceeding 250 kVA.[198] He described the Application's proposal to add to the tariff sheet for "Terms and Conditions, Line Extension Plan, Normal Line Extensions" language indicating that a customer is responsible for the cost of any relocation of KU-ODP facilities requested by the customer. Mr. Hornung indicated this proposed language is generally consistent with existing language in the Company's tariff sheet for "Terms and Conditions, Customer Responsibilities, Changes in Service."[199]

Mr. Hornung described the Application's proposal to address the 26 jurisdictional customers that remain grandfathered on Rate GS and Rate PS. He summarized how the issue arose in Case No. PUE-2009-00029 because it was the first KU-ODP rate case in 20 years. He indicated that the *2015 Rate Case Order*[200] directed annual notices to grandfathered customers, which KU-ODP continues to send, and the *2021 Rate Case Order* approved some grandfathering elimination. In the instant case, KU-ODP proposed to: (i) continue mailing annual notices informing grandfathered customers of the possibility of moving to another rate schedule and advising them to contact KU-ODP to discuss options; and (ii) eliminate grandfathered status for all customers who qualify for rates under which they are served as of the effective date of the rates approved in the instant case. Mr. Hornung views this as "the most equitable way to eliminate grandfathering, avoid rate shock, and comport with gradualism." He anticipates this proposal would eliminate grandfathering for two customers.[201]

Staff

Staff presented the results of its investigation through the testimonies of **Justin Morgan**, Manager with the Commission's Division of Utility Accounting and Finance ("UAF"); **Alexander W. Elmes**, a Senior Utility Specialist in UAF; and **Marc A. Tufaro**, Principal Public Utility Regulation ("PUR") Analyst in the Commission's Division of PUR.

Mr. Morgan presented Staff's revenue requirement recommendations. He summarized his recommendations as follows:

- Based on Staff's analysis of the rate year, Staff calculates a 6.37% ROE on a fully adjusted basis. Staff finds that, based on its rate year analysis, an incremental increase in base revenues of $7,956,487 is necessary for KU-ODP to have the opportunity to earn the 9.8% ROE recommended by Staff witness Elmes.
- The Commission should approve Staff's adjustments to the rate year analysis.
- The Commission should reject the Company's regulatory asset request related to out-of-period depancaking expenses.
- The Commission should accept Staff's regulatory liability recommendation related to wildfire mitigation costs.[202]

[198] *Id.* at 10.
[199] *Id.* at 11.
[200] *Application of Kentucky Utilities Company d/b/a Old Dominion Power Company, For an adjustment of electric base rates*, Case No. PUE-2015-00063, 2016 S.C.C. Ann. Rep. 259, Final Order (Feb. 2, 2016) ("*2015 Rate Case Order*").
[201] Ex. 16 (Hornung direct) at 12-16.
[202] Ex. 17 (Morgan) at 3.

Mr. Morgan explained the purpose of a rate year analysis. Based on Staff's recommended ratemaking adjustments, Staff's analysis indicates the Company's current base rates are projected to produce revenue that results in a 6.37% rate year ROE. Because this is below Staff's recommended 9.30% to 10.30% cost of equity range, Staff recommended a $7,956,487 base rate revenue increase based on the 9.80% midpoint of Staff's recommended cost of equity range.[203] He presented the following table to summarize the primary differences between the Application's and Staff's recommended revenue requirements.[204]

Table 1
Revenue Requirement Reconciliation

Company's Revenue Requirement	**$**	**9,411,184**
ROE & Capital Structure Differences	$	(1,537,558)
Revenue Differences	$	628,979
Depancaking Reg Asset	$	(245,939)
Apportioned State Tax Rate	$	(194,440)
Pension/OPEB/Other Benefits	$	108,960
Outage Maitenence Expense	$	(56,959)
Lead/Lag Study	$	(54,432)
Major Storm Expense Correction	$	(52,094)
Payroll, Payroll Taxes, & 401k	$	(21,857)
Rate Case Expense	$	(21,015)
Test Year Jurisdictional Factors	$	(9,585)
Other O&M	$	1,242
Staff's Revenue Requirement	**$**	**7,956,487**

For rate year sales revenue (the second difference listed above), Mr. Morgan explained that KU-ODP's adjustment was based on projections from the Company's business plan. He used the table below to illustrate Staff's differing approach, which increased the revenue requirement by $628,979.[205]

Rate Class	Staff	Company	Difference	Billing Determinant Source
			A + B	
Rate RS	$38,499,381	$38,035,773	$ 463,608	TY WN Avg. Usage x BP Bill Count
Rate GS	$ 6,995,558	$ 6,995,558	$ 0	Company's Business Plan
Rate PS Secondary	$ 4,147,673	$ 4,494,596	$(346,923)	TME 6/30/24 Actuals
Rate PS Primary	$ 2,746,019	$ 2,898,489	$(152,470)	TME 6/30/24 Actuals
Rate RTS	$ 828,727	$ 897,533	$ (68,806)	TME 6/30/24 Actuals
Rate TOD Secondary	$ 1,506,993	$ 1,429,364	$ 77,629	TME 6/30/24 Actuals
Rate TOD Primary	$ 5,978,083	$ 6,580,623	$(602,540)	TME 6/30/24 Actuals
P.O. Lt. & C.O. Lt.	$ 1,168,209	$ 1,167,686	$ 523	Company's Business Plan
Total Base Rate Revenues	**$61,870,643**	**$62,499,622**	**$(628,979)**	

[203] *Id.* at 3-4.
[204] *Id.* at 5.
[205] *Id.* at 5-6.

Mr. Morgan explained why the Company's sales revenue forecasts may be overly optimistic, in Staff's view.[206]

Mr. Morgan addressed the Company's proposed regulatory asset for rate depancaking costs associated with 2021 and 2022. According to Staff, these costs do not meet the requirements for establishing a regulatory asset. Accordingly, Staff excluded the Company's proposed amortization from the rate year and instead included such costs in the 2023 earnings test.[207] Mr. Morgan explained that, to address FERC market power concerns associated with LG&E and KU's exit from the Midwest Independent System Operator ("MISO") in 2006, LG&E and KU are required to pay certain customers for the charges billed to deliver power to the LG&E and KU border.[208] Mr. Morgan explained that in March 2021 FERC accepted a filing that terminated depancaking, but that a federal appellate court reversed FERC's order, requiring depancaking to be reinstated retroactive to March 2021. As a result, the Company recorded depancaking expenses for 2021, 2022, and 2023 related to the under-accrual of depancaking expenses in the test year.[209]

Mr. Morgan identified the three-part test Staff generally uses to evaluate regulatory asset treatment of costs. They must be: (1) material; (2) non-recurring; and (3) beyond the control of the utility. In Staff's view, these costs are recurring because they have been in place since 2006 and are reasonably predicted to be in place during the rate year. Accordingly, Staff's rate year includes a going level of depancaking expense in the amount of $2,111,106.[210] He recommended the Company's regulatory asset request be rejected.[211]

Mr. Morgan addressed Staff's use of an apportioned tax rate, rather than the Company's proposed statutory tax rate.[212] He addressed Staff's use of the most recently available actuarial study to calculate Staff's recommended adjustments to pension and OPEB expense.[213] He explained that Staff's adjustment to outage maintenance expense is a five-year (2021 to 2025) average calculation, while the Company projected rate year expense by blending four historic years and four projected years.[214]

Mr. Morgan attributed the difference between Staff's and the Company's cash working capital adjustments to: (1) Staff using a corrected revenue lag; (2) Staff applying a ratio to accounts payable construction work in progress based on the Company's rate year construction

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[206] *Id.* at 7.

[207] *Id.* at 7-8. Mr. Morgan described rate depancaking as removing the impact of duplicate transmission fees that exist with rate pancaking caused when multiple transmission providers charge for electricity scheduled across transmission providers' borders. *Id.* at 8.

[208] *Id.* at 8-9. Mr. Morgan indicated the intent of depancaking in this circumstance is to hold certain customers harmless from LG&E and KU leaving MISO. *Id.* at 9.

[209] Ex. 17 (Morgan) at 10. *See, e.g., Ky. Mun. Energy Agency v. FERC*, 45 F.4th 162 (D.C. Cir. 2022); *Louisville Gas and Electric Company, Kentucky Utilities Company*, 183 FERC ¶ 61,222, Order on Remand (May 18, 2023), 185 FERC ¶ 61,121, Order Addressing Arguments Raised on Rehearing (Nov. 16, 2023).

[210] Ex. 17 (Morgan) at 10-11.

[211] *Id.* at 24.

[212] *Id.* at 11-12.

[213] *Id.* at 12.

[214] *Id.* at 12-13. Mr. Morgan pointed out that the Company's use of projections out to 2027 incorporates amounts beyond the rate year. *Id.* at 13.

work in progress projections; and (3) Staff's other differing expense adjustments.[215]

Mr. Morgan attributed the difference between Staff's and the Company's payroll adjustments to Staff using the Company's projected headcounts to calculate the change in payroll and Staff using a test year expense percentage (instead of the Company's projected expense percentage).[216] He acknowledged that in the past Staff has not adjusted for projected headcount changes, but indicated that in this case headcount decreases can be reasonably predicted to occur during the rate year.[217]

For regulatory expense, Mr. Morgan testified that Staff used a three-year average of all regulatory expenses incurred by the Company, while the Company used the test year level of regulatory expenses plus a two-year average of the projected costs for the current rate case.[218] Mr. Morgan explained that while the Company used rate year jurisdictional factors, Staff used test year jurisdictional factors, consistent with Staff's historic practice (unless there has been a material change).[219]

Mr. Morgan presented data showing the Company spent 18% more than its projected amounts for capital projects during 2019 through 2023. He indicated that Staff believes this trend is reasonably predicted to occur during the rate year. However, Staff did not make an upward adjustment because Staff views it as unreasonable to predict investment higher than the Company itself contends it will spend.[220]

Mr. Morgan reported that Staff's audit of the Company's projected accumulated deferred income taxes and depreciation expense did not reveal any discrepancies.[221]

For vegetation management expense, Staff's revenue requirement uses the test year level. Mr. Morgan testified that the Company's spending in the test year is expected to remain in effect during the rate year.[222]

Mr. Morgan addressed the Company's revenue requirement including $422,967 associated with wildfire risk mitigation, which he indicated represents only a rate year level of return on rate base.[223] He indicated that the Company does not yet have detailed cost support for this project, with designs and pre-engineering 85% complete for twelve identified circuit miles as the first step of the project. However, because wildfire mitigation capital investments could be necessary for safety and reliability, Staff included the requested amount of capital spending in

[215] *Id.* at 14-15.
[216] *Id.* at 15-17.
[217] *Id.* at 16.
[218] *Id.* at 17-18.
[219] *Id.* at 18.
[220] *Id.* at 19-20.
[221] *Id.* at 20-21.
[222] *Id.* at 21. Mr. Morgan added that in 2022, KU-ODP completed its transition from just-in-time vegetation management to a cycle-based approach. Starting in 2024, KU-ODP initiated a risk-based approach and clearance based triggers to help inform the distribution cycle-based program. *Id.*
[223] *Id.* at 21-22. The Company's revenue requirement does not include any depreciation expense for this project. *Id.* at 22.

Staff's rate base, resulting in a $395,818 revenue requirement impact.[224] Staff further recommended, as a customer safeguard, the Company be directed to track such spending and book a regulatory liability if actual costs fall below the revenue requirement amount included in this proceeding.[225]

Mr. Morgan reported the results of Staff's earning test analysis indicate that during 2023 the Company earned a 7.52% ROE, which is lower than the 9.40% ROE benchmark approved in the 2021 Rate Case.[226]

At the hearing, Mr. Morgan provided Staff's position on the Cane Run 7 carbon capture project and charitable contributions, which were not addressed in Staff's prefiled testimony or the proposed Stipulation. Staff supports the proposed Stipulation. To the extent the Company incurs additional costs for Cane Run 7, the Company will have the burden to prove the reasonableness of those costs in future proceedings.[227]

Regarding charitable contributions, Mr. Morgan acknowledged that Staff's revenue requirement included a Virginia jurisdictional amount of 50% of charitable contributions.[228] He recognized the Commission decided in WGL's 2018 rate case that 100% of such costs should be excluded from rates. He indicated that the Commission has not explicitly made such a finding in a KU-ODP case.[229] Even though both Staff and KU-ODP entered negotiations with 50% of charitable contributions in their competing revenue requirements, Mr. Morgan indicated that the black-box nature of the stipulated revenue requirement does not represent a resolution of any specific cost component not specifically identified by the Stipulation.[230] He indicated that the rebuttal testimony raised revenue requirement issues, but he acknowledged those issues did not include charitable contributions.[231]

Other than the Commission having not addressed charitable contributions specifically in a KU-ODP rate case, Mr. Morgan could not identify a policy reason for treating KU-ODP different from other utilities regulated under Chapters 10 of Title 56 with respect to the inclusion of charitable contributions in rates.[232]

Mr. Elmes sponsored Staff's recommended ROE, capital structure, and weighted average cost of capital.

He explained the significance of current trends in long-term interest rates to estimating the cost of equity. He recognized recent trends have been influenced by higher inflation in 2022

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[224] *Id.* at 22-23. Staff's revenue requirement figure is lower than the Company's because Staff recommended a lower cost of capital. *Id.* at 23, n.17.
[225] *Id.* at 23. Should actual costs exceed the amount reflected in this case, Mr. Morgan does not recommend the establishment of a regulatory asset. *Id.* at 23, n.18.
[226] *Id.* at 24 and attached Statement ET-2.
[227] Tr. at 62 (Morgan).
[228] Tr. at 69-70 (Morgan).
[229] Tr. at 63, 66-67 (Morgan).
[230] Tr. at 65 (Morgan).
[231] Tr. at 65-66 (Morgan).
[232] Tr. at 66-67 (Morgan).

through 2024 and changes in national monetary policy.[233] Mr. Elmes provided graphs showing 30-year U.S. Treasury rates, which have trended up since 2021 but are relatively low over a longer historic horizon.[234] He observed the spread between government securities and BBB/Baa-rated utility debt has decreased since 2022, when the Federal Reserve began raising the federal funds rate.[235]

Mr. Elmes concluded that the Company's cost of equity capital is within a range of 9.3% to 10.3% and recommended that the Commission use the midpoint of this range – 9.8% – for determining the Company's going-forward cost of service. To estimate KU-ODP's cost of equity, Mr. Elmes relied on DCF analysis in conjunction with risk premium estimates, including CAPM.[236] The results of his analysis are summarized in the table below.[237]

Model/Analysis	Proxy Group	Cost of Equity Estimate
DCF	Electric Utilities	9.01% - 9.95%, 9.48% midpoint
CAPM	Electric Utilities	11.03%
Ex Ante RPM	N/A	9.69%

From the analysis summarized above, Mr. Elmes derived a 9.10% to 10.10% proxy group cost of equity estimate range. To this range, he recommended adding a 20-basis-point upward risk adjustment, to arrive at Staff's estimated 9.3% to 10.3% cost of equity range.[238] Mr. Elmes included a 20-basis-point upward business risk adjustment to account for the Company's relative risk compared to other Virginia investor-owned electric utilities.[239] He opposed the size adjustment methodology used by Company witness McKenzie.[240]

Mr. Elmes summarized the primary differences between Staff's cost of equity analysis and the Company's as follows.[241]

> <u>DCF Model</u>: Staff's DCF analysis incorporates growth in earnings per share ("EPS") and dividends per share ("DPS"), consistent with longstanding Staff practice and Commission precedent. The Company's DCF analysis relies on model results that reflect three forecasted EPS growth rates and one sustainable retained earnings growth rate. Such emphasis on projected earnings growth has been rejected by the Commission. Based on Staff's review, use of the Company's average growth rate inflates the DCF cost of equity results by approximately 13 basis points.

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[233] Ex. 18 (Elmes) at 4-5.
[234] *Id.* at 6.
[235] *Id.* at 8.
[236] *See, e.g., id.* at 2-3 and attached Statement. 1.
[237] *See, e.g., id.* at attached Statements 1, 2, 7. He also identified an *ex post* equity return of 9.44% based on work by Ibbotson and Chen published in 2023 and a 9.67% base U.S. cost of equity capital based on the *ex ante* Kroll equity risk premium and risk-free rates. *See, e.g., id.* at 24 and attached Statement 1.
[238] *Id.* at 23 and attached Statement 1.
[239] *Id.* at 23.
[240] *Id.* at 15-17.
[241] *Id.* at 11-12 (footnotes omitted). *See also id.* at 13-22.

<u>CAPM and Empirical CAPM ("ECAPM")</u>: The Company's CAPM analysis is affected by three issues that substantially influences its results: (i) the Company factors in size adjustments that are unnecessary and on average inflate the Company's proxy group CAPM and ECAPM cost of equity estimates; (ii) the Company's broad market cost of equity analysis is used to calculate a high market risk premium … estimate of 7.5%; and (iii) the Company relies on an empirical form of the CAPM that is redundant when utilized with Value Line adjusted betas and unnecessarily inflates the Company's proxy group cost of equity estimates. Based on Staff's review, together, these three items inflate the Company's CAPM results by approximately 91 basis points compared to Staff's methodology.

<u>Utility Risk Premium Model</u>: The Company's utility risk premium model is based on Commission-authorized ROEs across the country. There are many non-market factors that may be reflected in these authorized ROEs, such as gradualism in setting rates, the give and take of settlement, incentive mechanisms, and varying regulatory adjustments. These non-market factors make these ROEs inappropriate for calculating a market based risk premium estimate. Based on Staff's review, the Company's methodology inflates the utility risk premium model cost of equity estimate by approximately 107 basis points compared to Staff's methodology.

<u>Expected Earnings Analysis</u>: The Company's utilized expected earnings analysis is not reliable because it is based on projected book rates of return on equity, which is not an appropriate measure of the market cost of equity. This method produces one of the Company's highest cost[] of equity results, 11.10%, creating a significant upward bias used to support the Company's 10.50% ROE recommendation. The 11.10% estimate from this analysis should be entirely disregarded, as discussed further below.

For ratemaking purposes, Mr. Elmes recommended a weighted average cost of capital rate of 7.289%, which is based on: (1) a capital structure comprised of 53.276% common equity, 45.996% long-term debt, and 0.728% short-term debt; (2) a long-term debt rate of 4.409%; (3) a short-term debt rate of 5.502%; and (4) a recommended ROE of 9.800%.[242]

Mr. Elmes explained that Staff's recommended ratemaking capital structure is based on the Company's actual year-end capital structure as of December 31, 2023.[243] Like the Company, Staff removed goodwill from the common equity balance.[244] However, to reflect more recent interest rates, Staff recommended updating the cost of the Company's variable rate securities as well as short-term debt obligations to a three-month average, ending July 31, 2024.[245]

Mr. Elmes also provided Staff's recommended cost of capital to use for earnings test purposes.[246]

[242] *Id.* at 28 and attached Statement 11.
[243] *Id.* at 27. While Staff reviewed KU-ODP's capital structure as of March 31, 2024, and June 30, 2024, Staff observed no material changes to the capitalization ratios or cost of debt. *Id.*
[244] *Id.* at 31.
[245] *Id.* at 27, 30-31.
[246] *Id.* at 32-33 and attached Statement 14.

Mr. Tufaro addressed the Company's cost-of-service studies. Staff found the Company's jurisdictional cost-of-service study reasonable and consistent with the study accepted in the 2021 Rate Case, except for a three-year average used to normalize coincident peaks that Mr. Tufaro did not oppose due to the coincident peak variability in 2022 and 2023.[247] Staff also found the Company's class cost-of-service study reasonable and consistent with the methodology approved in prior cases, including the 2021 Rate Case.[248]

Mr. Tufaro presented, through the table below, the jurisdictional rate of return results and relative return indices produced by the Company's current rates and proposed adjustments. He recognized that these results show, among other things, the residential service class producing the lowest rate of return and the power service-primary and retail transmission service classes producing the highest.[249]

Current Rate of Return

Rate Class	ROR on Rate Base	ROR Indices
Residential Service ("RS")	4.34%	0.78
General Service ("GS")	5.71%	1.03
Power Service-Secondary ("PS-S")	6.93%	1.25
Power Service-Primary ("PS-P")	11.05%	2.00
Time-of-Day Service-Secondary ("TOD-S")	6.86%	1.24
Time-of-Day Service-Primary ("TOD-P")	9.49%	1.72
Retail Transmission Service ("RTS")	18.75%	3.39
Private Outdoor Lighting Service ("POLT")	6.16%	1.11
Total Jurisdictional System	5.53%	1.00

Mr. Tufaro identified the Company's proposed revenue apportionment in the table below.[250]

Apportionment of the Proposed Rate Increase by Rate Class

Rate Class	Revenue at Current Rates	Revenue at Proposed Rates	$ Increase	% Increase
RS	$43,472,343	$49,501,027	$6,028,284	13.90%
GS	$8,484,559	$9,546,262	$1,061,703	12.50%
PS-S	$5,447,593	$6,075,591	$1,027,111	11.50%
PS-P	$3,760,454	$4,109,527	$627,998	9.30%
TOD-S	$1,963,147	$2,192,878	$229,731	11.70%
TOD-P	$7,711,795	$8,460,466	$748,671	9.70%
RTS	$1,744,702	$1,898,206	$153,504	8.80%
POLT	$1,239,098	$1,389,151	$150,053	12.10%

247 Ex. 19 (Tufaro) at 4-5.
248 *Id.* at 5-8.
249 *Id.* at 9 (table header modified).
250 *Id.* at 11.

Mr. Tufaro used the table below to present how the proposed revenue apportionment (shown above) would affect the current rates of return indicated by the Company's cost-of-service study (shown two tables above).[251]

Current and Proposed Rates of Return

Rate Class	Current ROR on Rate Base	Current ROR Indices	Proposed ROR on Rate Base	Proposed ROR Indices
RS	4.34%	0.78	6.43%	0.84
GS	5.71%	1.03	7.93%	1.04
PS-S	6.93%	1.25	9.06%	1.18
PS-P	11.05%	2.00	13.32%	1.74
TOD-S	6.86%	1.24	9.27%	1.21
TOD-P	9.49%	1.72	11.45%	1.49
RTS	18.75%	3.39	23.29%	3.04
POLT	6.16%	1.11	8.41%	1.10
Total	5.53%	1.00	7.66%	1.00

According to Mr. Tufaro, Staff reviewed the Company's cost-of-service results in conjunction with various criteria from James C. Bonbright's Principles of Public Utility Rates. These criteria, which he identified, were considered in the context of revenue apportionment and rate design.[252] In the instant case, Staff focused on: (i) effectiveness in yielding total revenue requirements; (ii) rate stability and predictability; and (iii) avoidance of undue discrimination in rate relationships.[253] Staff did not oppose the Company's proposed revenue apportionment in this case. Mr. Tufaro observed that the proposed revenue apportionment gradually moves rate classes toward parity. Should the Commission approve a revenue requirement lower than proposed by the Application, Mr. Tufaro recommended that the associated reduction be allocated proportionally to all classes based on their respective non-fuel revenues.[254]

Mr. Tufaro highlighted the Application's proposed increases to the residential basic service charge or "customer" charge, from $12.00 to $15.00, and energy charge, from $0.10122 per kWh to $0.11768 per kWh.[255] He asserted that determining the appropriate customer charge involves considerable judgment, with the rate design objective of revenue stability potentially conflicting with other objectives such as promoting conservation and differing views of equitable rates. He offered that "[l]ower customer charges may not recover an equitable share of costs from low usage customers and may create revenue stability problems for the company. Higher customer charges would shift more costs to low usage customers and produce greater revenue stability."[256]

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[251] *Id.* at 12 (table header modified).
[252] *Id.* at 9-10.
[253] *Id.* at 10-11.
[254] *Id.* at 12.
[255] *Id.* at 13-14.
[256] *Id.* at 14-15.

Mr. Tufaro opposed the Application's proposed increase to the residential customer charge. Of the $25.60 customer cost amount identified in KU-ODP's zero-intercept analysis, Mr. Tufaro pointed out that only $6.79 is directly related to the number of customers served while the remainder is attributable to shared distribution system costs not directly related to customers served.[257] He provided the table below to illustrate that the customer service expense portion of the Company's analysis has decreased from the Company's calculation in its two preceding rate cases.[258]

Year	Total Costs	Distribution Expenses	Customer Service Expenses	Meters and Services	Total Customer Related
2019	$23.76	$18.19	$5.56	$3.39	$8.95
2021	$24.69	$18.39	$6.30	$2.30	$8.60
2024	$25.60	$21.07	$4.53	$2.26	$6.79

Mr. Tufaro found it difficult to justify the Application's proposed 20% increase in the basic service charge given that the Company's own analyses indicate customer service expenses have decreased since the 2021 Rate Case and total customer related expenses have decreased since the 2019 Rate Case. Mr. Tufaro also pointed out that the Application's proposed $15.00 monthly basic service charge is nearly double the current customer charge amounts of Appalachian Power Company ("APCo") and Dominion Energy Virginia ("Dominion").[259]

Otherwise, Staff does not oppose the Application's proposed rate design, which Mr. Tufaro indicated is consistent with the methodology approved by the *2021 Rate Case Order*.[260] Should the Commission approve a revenue increase lower than requested by the Application, he recommended any decrease in revenues be allocated in a manner consistent with the energy and demand charge allocations the Company has proposed for all customers served. He further noted that final rates should be designed using any Staff adjustments accepted by the Commission that could impact billing determinants.[261]

Turning to the Application's proposal to add four limited new optional time-of-day rate schedules, Mr. Tufaro recognized that the partial stipulation approved by the *2021 Rate Case Order* included a commitment by the Company to propose such rate schedules for residential and general service customers in the instant case.[262] He testified that the proposed rates appear similar to rate schedules offered by the Company in its Kentucky jurisdiction and that the proposed schedules have a participation cap of 100 residential customers and 100 general service customers.[263] Because Staff believes optional rate programs should contain robust reporting to help determine whether such rates are in the public interest and potentially support a broader rollout, Mr. Tufaro recommended the Company be required to file various information in its next rate case:[264] With his recommended reporting requirements, Mr. Tufaro testified that Staff does

[257] *Id.* at 15.
[258] *Id.* at 15-16 (header omitted).
[259] *Id.* at 16.
[260] *Id.*
[261] *Id.* at 17.
[262] *Id.* at 17-18.
[263] *Id.* at 21.
[264] *Id.* at 21-22.

not oppose the proposed optional time-of-day rates.[265]

Mr. Tufaro testified that Staff does not oppose the Application's proposed new optional outdoor sports lighting rate. He indicated that this proposed rate is limited to ten customers and most eligible customers would be non-jurisdictional.[266]

Staff also did not oppose the Application's proposal to expand the late payment waiver to all standard rate schedules. Mr. Tufaro testified that this proposal would treat all customers the same by making such waiver automatic.[267]

Staff also did not oppose the Application's proposals to increase the monthly meter pulse charge, disconnect/reconnect charge, and the meter test charge. Mr. Tufaro described the Application's cost support for these proposals as detailed.[268]

Mr. Tufaro also found cost support for the Application's proposed increase to percentages used to calculate charges under the Company's excess facilities rider. However, because the percentages are based in part on the Application's proposed cost of capital, the excess facilities multiplier should reflect the cost of capital ultimately approved in this case.[269]

Turning to the Application's proposal to continue moving towards eliminating grandfathering, Mr. Tufaro found such actions conform with the *2015 Rate Case Order*.[270]

Mr. Tufaro provided the Company's response to Staff discovery asking the Company to address environmental justice. He reported that KU-ODP stated in part that the Company "is well aware of the pervasive amount of low-income and fixed-income customers in its service territory which is always an important consideration" and that in requesting the rate increase, "the Company weighted the impact" on such customers.[271]

Mr. Tufaro confirmed that the monthly impact of the Application on a residential customer using 1,000 kWh would be a 14% increase, from $139.03 to $158.49.[272]

KU-ODP – Rebuttal

The Company offered the rebuttal testimonies of Messrs. Conroy and McKenzie and Ms. Fackler.

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[265] *Id.* at 22.
[266] *Id.* at 23.
[267] *Id.* at 24.
[268] *Id.* at 24-25. Mr. Tufaro also recognized the Application's proposed changes to the various unauthorized reconnection charges and tariff language clarifying that all replacement meters would be AMI meters. *Id.* at 24. Staff did not oppose minor tariff revisions proposed by the Application to clarify existing language or achieve uniformity with the Company's Kentucky tariff. *Id.* at 26.
[269] *Id.* at 25.
[270] *Id.* at 27.
[271] *Id.* at 28 and Attachment MAT-1.
[272] *Id.* at 2-3.

Mr. Conroy stood behind the Application's proposed increase to the Company's basic service charge. He testified that the zero-intercept methodology, which the Company has used and Staff has accepted since 2009, is the best methodology to identify the portions of distribution system costs that do not vary with demand.[273]

Mr. Conroy testified that the Company also included a portion of distribution system costs when proposing non-residential customer charges. He pointed out that Staff did not oppose those proposed customer charges.[274]

He also emphasized the Company's proposed $15.00 basic service charge is well below the $25.60 amount of customer-related costs identified in the Company's class cost-of-service study. He disagreed with Staff witness Tufaro's characterization of including such distribution costs as customer costs as controversial. In support of his position, Mr. Conroy, among other things, cited Bonbright's treatise, NARUC's cost allocation manual, and the customer charges of Virginia electric distribution cooperatives.[275] He asserted that the Company's proposed basic service charge meets what Bonbright's treatise describes as three primary ratemaking objectives: (1) revenue requirement or financial need; (2) the fair-cost-apportionment; and (3) optimum-use or consumer-rationing.[276] He also posited that "it seems unlikely anyone would change their decision about where to reside if the Company's [b]asic [s]ervice [c]harge increased $3.00 per month (with the resulting downward effect on the Company's energy charge), which is a strong reason to recover more fixed costs through the fixed residential [b]asic [s]ervice [c]harge."[277] He does not believe declines in the Company's customer service expenses and total customer related costs since prior rate cases, as identified by Staff witness Tufaro, undermine the Company's use of a zero-intercept analysis or the associated results.[278]

Mr. Conroy attempted to distinguish the Company from the other two investor-owned electric utilities in the Commonwealth, Dominion and APCo. He recognized that Dominion and APCo are regulated under Chapter 23 of Title 56 of the Code, from which the Company is largely exempt. He opined that Chapter 23 requires a difference in rate structures and that "Dominion's and [APCo's] customer charges are essentially only a meter charge as mandated by [Chapter 23]."[279] Mr. Conroy asserted that the Company is "much more similar" to Virginia electric distribution cooperatives.[280] Mr. Conroy provided a table that included the basic service/customer charges for the Virginia electric distribution cooperatives, ranging from $14.06 to $40.00.[281] He also recognized in a footnote to his testimony provisions of Code § 56-585.3, which allows the board of directors of such cooperatives to adjust their fixed monthly charges without Commission approval.[282]

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[273] Ex. 20 (Conroy rebuttal) at 2.
[274] *Id.* at 4.
[275] *Id.* at 4-8.
[276] *Id.* at 9-10.
[277] *Id.* at 10.
[278] *Id.* at 11.
[279] *Id.* at 11-12.
[280] *Id.* at 12.
[281] *Id.* at 14.
[282] *Id.* at 13, n.24.

Mr. Conroy indicated that KU's and LG&E's optional time-of-day rates that have been available for nine years in Kentucky remain under one-third of their participation caps, with a total of 252 residential participants as of August 2024. Based on this experience, he anticipates that customer interest in the time-of-day rates proposed by the instant Application will be minimal.[283] Mr. Conroy explained that KU does not collect or compile any reporting information in Kentucky similar to Staff's recommended reporting obligations. Given his expectation of minimal customer interest in Virginia, Mr. Conroy asserted that Staff's reporting recommendations would be burdensome and unlikely to lead to meaningful results. He proposed instead that KU-ODP include in its annual informational filings the number of customers participating in these tariffs and that the Company answer any questions resulting from Staff's review of such filings.[284]

Ms. Fackler disputed Staff witness Morgan's assertion that the Company's 2021 and 2022 depancaking costs were recurring. She acknowledged that the Company has incurred such expense since 2006 and that such expense is reasonably predicted to occur during the rate year, but asserted that the costs for 2021 and 2022 were unanticipated and non-recurring because a May 2023 FERC order reinstated such charges retroactive to March 2021. She testified that if the Company had continued to accept the FERC depancaking charges without challenge, they would have been incurred in 2021 and 2022, included in the Company's last rate case, and recovered from customers.[285] She stood by the Application's proposal for deferred accounting treatment for $245,939 of such costs and that such costs should be excluded from the Company's 2023 earnings test.[286]

Ms. Fackler opposed Staff witness Morgan's use of an apportioned tax rate. She also testified that the 4.81% tax rate used by Staff is – but should not be – lower than both the Kentucky and Virginia state income tax rates.[287]

According to Ms. Fackler, Staff witness Morgan's adjustment to update the pension/OPEB/other benefits expense did not include an adjustment for medical benefits. She asserted that including the most recent estimates of medical benefit costs would result in ratemaking expense that is $55,000 higher than Staff's adjustment.[288]

Ms. Fackler also stood by the Application's outage maintenance expense based on a blend of four historic years and four years of Company projections. She clarified that Staff's "five-year average" uses three years of actual data (ending with the test year) and two years of projected data (ending with the rate year).[289] She indicated that Staff's workpapers include a calculation that used a five-year historic average (2019-2023) that is consistent with Staff's methodology in past rate cases. Using that methodology would increase Staff's revenue requirement by $182,061.[290]

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[283] *Id.* at 15.
[284] *Id.* at 16.
[285] Ex. 21 (Fackler rebuttal) at 1-2.
[286] *Id.* at 3.
[287] *Id.* at 3-4.
[288] *Id.* at 4.
[289] *Id.* at 4-5.
[290] *Id.* at 5.

Ms. Fackler took issue with Staff updating cash working capital items for revenue requirement adjustments, but not first updating the jurisdictional separation study. Doing so results in a $4,956 difference from Staff's adjustment.[291]

Ms. Fackler disagreed with Staff witness Morgan's ratemaking adjustment to payroll, payroll taxes, and 401(k) expense. For overtime, she asserted that Staff's use of a five-year historical average plus a 2025 raise percentage gives no credit to increases expected to occur in 2024. Incorporating a 2024 raise into Staff's overtime adjustment would increase Staff's revenue requirement by $16,379.[292]

Ms. Fackler opposed Staff witness Morgan's regulatory expense adjustment. She indicated that using Staff's approach, if the Company files a base rate case on an interval less than three years, the Company would be unable to recover its rate case expenses. She asserted that the 2023 level is representative of a rate year level and is reasonable.[293]

Ms. Fackler did not oppose Staff's recommendation for the Company to establish a regulatory liability in the event that the Application's proposed wildfire mitigation costs are included in rate base but then the Company does not invest that full amount by the end of 2025. However, she described this event as unlikely.[294]

For all revenue requirement adjustments that Ms. Fackler did not address, she represented that the Company accepted their collective result even though the Company did not necessarily agree with them.[295]

Mr. McKenzie asserted that his rebuttal testimony demonstrates that:[296]

- Equally weighting the results of Staff's alternative analyses implies an ROE for KU-ODP of 10.3%.[297]
- Adjusting the ROE approved for KU-ODP in the 2021 Rate Case to reflect increases in bond yields implies an ROE of approximately 10.5%.[298]
- Average ROEs authorized when interest rates were comparable to present levels imply a fair ROE for KU-ODP on the order of 10.4%.[299]
- ROEs currently approved for the utilities in Staff's proxy group imply an ROE for KU-ODP of approximately 10.1%.[300]
- Expected earned returns for Staff's proxy group average 11.3%.[301]

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[291] *Id.* at 5-6.
[292] *Id.* at 6.
[293] *Id.* at 6-7.
[294] *Id.* at 7-8.
[295] *Id.* at 8.
[296] Ex. 22 (McKenzie rebuttal) at 3-4.
[297] *Id.* at 23-25.
[298] *Id.* at 8-9.
[299] *Id.* at 11.
[300] *Id.* at 10. While he indicated allowed ROE data has value, he recognized that standard regulatory practice is to establish ROEs based on current capital market evidence. *Id.*
[301] *Id.* at 19-21, n.40.

- Staff's ROE analyses are undermined by errors and methodological flaws, including:
  - Errors in specification of the proxy group.[302]
  - Unsupported DCF growth rate assumptions that do not reflect investors' expectations.[303]
  - Reliance on historic CAPM inputs that are not consistent with this method.[304]
  - Failure to account for the impact of firm size in applying the CAPM.[305]
  - Application of the risk premium method using stale data for a limited historical period.[306]
- Staff's criticisms of his size adjustment, market return calculation, ECAPM, and expected earnings range are without merit.[307]

Mr. McKenzie provided the following table to compare key capital cost indicators in September 2024 to the timeframe of the 2021 Rate Case.[308]

	Sept. 2021 to May 2022	Sept. 2024	Change (bps)
10-Yr. Treasury	1.94%	3.72%	178
30-Yr. Treasury	2.27%	4.04%	177
Baa Public Utility	3.83%	5.41%	158
Average			171
Federal Funds Rate	0.24%	5.18%	493

He asserted that the increase in bond yields, among other things, suggests the ROE for KU-ODP should be higher than Staff's recommended 9.80%.[309] Because bond yields did not decrease when the Federal Reserve announced a rate cut in September 2024, he concluded that the rate cut was already accounted for in current bond yields.[310]

Mr. McKenzie plotted on a chart authorized electric ROEs and bond yields since 1990. From this data, he concluded that allowed ROEs have not yet caught up with the dramatic and swift upward shift in capital costs that began in 2022.[311]

[302] *Id.* at 25-27. Mr. McKenzie described Staff witness Elmes' selection criteria as arbitrary, inconsistent, and with no clear link to investors' overall risk perceptions for KU-ODP. He called Staff's $10 billion market capitalization screening criterion as misplaced given KU-ODP's implied market value of approximately $329 million. *Id.* at 26-27.

[303] *Id.* at 27-35.

[304] *Id.* at 35-37.

[305] *Id.* at 40-43.

[306] *Id.* at 44-48.

[307] *See, e.g., id.* at 40-43, 48-49.

[308] *Id.* at 7-8.

[309] *Id.* at 8-9.

[310] *Id.* at 17-18.

[311] *Id.* at 12-14.

Stipulation

The Stipulation proposed by the Company and Staff (referred to as the Stipulating Participants) states in part as follows:

1. The Stipulating Participants agree that increasing KU-ODP's operating revenues by $8,300,000 effective February 1, 2025, is a fair, just, and reasonable resolution of KU-ODP's request for an increase in base rates in this case and accordingly recommend the Commission authorize KU-ODP to collect additional operating revenues of $8,300,000 annually, effective for service rendered on and after February 1, 2025.

2. The $8,300,000 increase in total operating revenues is the product of compromise and settlement between the Stipulating Participants based upon the evidence of the record in this case and represents a settlement as to a specific revenue number but not on a specific [ROE], accounting adjustments, or ratemaking methodologies at issue in this proceeding unless otherwise set forth herein.

3. The Stipulating Participants agree that an ROE of 9.95% will be used to evaluate earnings, beginning with the calendar year 2024, for purposes of the Commission's review of earnings test schedules filed under § 56-234.2, Review of rates, in Chapter 10 of Title 56 of the Code of Virginia and an ROE range of 9.50% to 10.50% will be used for purposes of the Commission's review of going-forward earnings test schedules filed under the Commission's Rules Governing Rate Applications and Annual Informational Filings (20 VAC 5-204-5 *et seq.),* beginning with the calendar year 2025 and continuing thereafter until KU-ODP's [ROE] is reset by the Commission. The ROE and ROE range are inclusive of the risk adjustment recognized in Staff testimony for KU-ODP.

4. The Stipulating Participants agree that the reduction to the as-filed revenue requirement resulting from the submission of this Stipulation should be allocated proportionally to all classes based on their respective non-fuel revenues. This allocation is shown on Stipulation Exhibit No. 1 to this Stipulation. The Stipulating Participants agree to the specific rates for each rate class as shown in Stipulation Exhibit No. 2. Illustrative calculations of the impact on customers at various levels of consumption by rate class using the rates shown in Stipulation Exhibit No. 2 are shown in Stipulation Exhibit No. 3.

5. The Stipulating Participants agree that KU-ODP will establish a regulatory liability to recognize the revenue requirement impact if its wildfire risk mitigation plan capital spending as described in KU-ODP's application is less than $10 million in the rate year.

6. The Stipulating Participants agree that the terms and conditions, outdoor sports lighting service rate schedule, new optional Time of Day ("TOD") rate schedules for residential and general service customers, and special charges proposed in KU-ODP's tariffs are reasonable and should be approved.

7. The Stipulating Participants agree that the residential basic service charge will remain at $12.00 per month as of the change in base rates on February 1, 2025.

8. The Stipulating Participants agree that KU-ODP will track the number of customers who elect to receive service under each of the optional TOD rate schedules for residential and general service customers, provide this information in its annual information filings and future base rate proceedings, and answer questions from Staff as part of Staff's review of such filings.

9. The Stipulating Participants agree KU-ODP's proposal to expand its existing late payment waiver to all customers and to make such waiver automatic is reasonable and should be approved.

10. The Stipulating Participants agree that KU-ODP will file a motion in Case No. PUR-2020-00110 for an extension of time through June 30, 2026, to complete the remaining portion of the Company's Rebuild Project. Staff has no objection to the motion for extension of time and authorizes KU-ODP to represent Staff's position in the motion.

11. The Stipulating Participants agree to recommend the Commission declare that Virginia Code § 56-89 does not require Commission approval to dispose of the Company's five vacant Virginia properties as described in KU-ODP's application in this proceeding.

12. The Stipulating Participants agree it is reasonable that KU-ODP be relieved of the reporting obligations established in Ordering Paragraph No. 11 in the Commission's Final Order in Case No. PUE-2010-00060, and ask that KU-ODP's request to be relieved of this annual reporting requirement be granted.

13. The Stipulating Participants agree that KU-ODP's 2024 Annual Informational Filing will be limited to the schedules required for an earnings test per 20 VAC 5-204-30.

14. The Stipulating Participants agree and recommend that the pre-filed direct and rebuttal testimony and exhibits filed by KU-ODP, affidavit of publication, the pre-filed testimony and exhibits of the Staff, and this Stipulation should be made a part of the record without cross- examination or briefs on the issues.

15. This Agreement and its three exhibits shall constitute the entire agreement of the Stipulating Participants. The three exhibits to this Stipulation are: Stipulation Exhibit No. 1 reflecting the stipulated revenue increase as allocated among the rate classes, Stipulation Exhibit No. 2 reflecting the specific rates for each rate class that will achieve the stipulated revenue increase, and Stipulation Exhibit No. 3 showing illustrative calculations of the impact on customers at various levels of consumption by rate class using the rates shown in Stipulation Exhibit No. 2.

16. The Stipulating Participants agree that this Stipulation represents a full and fair resolution of all the issues in this case. This Stipulation represents a settlement in this case only and shall not be regarded as a precedent or principle in any future case, except as specifically provided above.[312]

[312] Ex. 23 (Stipulation). At the hearing, Staff and the Company agreed that the 9.95% ROE proposed for earnings test purposes in Stipulation Paragraph 3 would also be used to calculate the Company's excess facilities charge. *See* Ex. 19 (Tufaro) at 25; Tr. at 63 (Morgan), 76 (Riggs).

CODE

Code § 56-235.2 A states in part as follows:

Any rate, toll, charge or schedule of any public utility operating in this Commonwealth shall be considered to be just and reasonable only if: (1) the public utility has demonstrated that such rates, tolls, charges or schedules in the aggregate provide revenues not in excess of the aggregate actual costs incurred by the public utility in serving customers within the jurisdiction of the Commission, including such normalization for nonrecurring costs and annualized adjustments for future costs as the Commission finds reasonably can be predicted to occur during the rate year, and a fair return on the public utility's rate base used to serve those jurisdictional customers, which return shall be calculated in accordance with § 56-585.1 for utilities subject to such section; (1a) the investor-owned public electric utility has demonstrated that no part of such rates, tolls, charges or schedules includes costs for advertisement, except for advertisements either required by law or rule or regulation, or for advertisements which solely promote the public interest, conservation or more efficient use of energy; and (2) the public utility has demonstrated that such rates, tolls, charges or schedules contain reasonable classifications of customers. ...

Code § 56-234 states in part as follows:

A. It shall be the duty of every public utility to furnish reasonably adequate service and facilities at reasonable and just rates to any person, firm or corporation along its lines desiring same. ...

B. It shall be the duty of every public utility to charge uniformly therefor all persons, corporations or municipal corporations using such service under like conditions. However, no provision of law shall be deemed to preclude voluntary rate or rate design tests or experiments, or other experiments involving the use of special rates, where such experiments have been approved by order of the Commission after notice and hearing and a finding that such experiments are necessary in order to acquire information which is or may be in furtherance of the public interest....

Code § 56-235.3 states in part as follows:

At any hearing on the application of a public utility for a change in a rate, toll, charge or schedule, the burden of proof to show that the proposed change is just and reasonable, shall be upon the public utility....

Code § 56-238 establishes the timeline for this case and for the implementation of any resulting rate changes, stating in part as follows:

> [T]he Commission shall suspend the enforcement of all of the proposed rates, tolls, charges, rules or regulations of an investor-owned electric public utility until the Commission's final order in the proceeding, during which times the Commission shall investigate the reasonableness or justice of such proposed rates, tolls, charges, rules and regulations and thereupon fix and order substituted therefor such rates, tolls, charges, rules and regulations as shall be just and reasonable. The Commission's final order in such a proceeding involving an investor-owned electric public utility that is filed after January 1, 2010, shall be entered not more than nine months after the date of filing, at which time the suspension period shall expire, and any revisions in rates or credits so ordered shall take effect not more than 60 days after the date of the order. ... If the proceeding has not been concluded and an order made at the expiration of the suspension period, after notice to the Commission by the public utility making the filing, the proposed rates, tolls, charges, rules or regulations shall go into effect.
> ...

ANALYSIS

As discussed above, KU-ODP's Application proposed a $9.5 million base rate revenue requirement increase based in part on a proposed 10.5% ROE. After investigating the Application, Staff recommended a $7.9 million increase based in part on Staff's recommended 9.8% ROE. KU-ODP and Staff ultimately recommended the Stipulation, which includes a proposed $8.3 million revenue requirement increase.[313] While the Stipulated revenue requirement is a "black box" and the Stipulation does not propose approval of a specific ROE for purposes of setting rates, the Stipulation proposes approval of a 9.95% ROE, and a 9.50% to 10.50% ROE range, for purposes of future earning test reviews.[314] The Stipulation indicates that its proposed ROE and ROE range are inclusive of the 20-basis-point risk adjustment Staff recommended to account for the Company's risk relative to other Virginia investor-owned electric utilities.[315]

The Company and Staff proposed their Stipulation as a fair and reasonable resolution of all issues in this case.[316] Although not a signatory, Consumer Counsel did not oppose the Stipulation, but expressed support for a universal Commission policy to continue excluding all charitable contributions from rates.[317] Consumer Counsel recognized that the stipulated revenue requirement and ROE (for future earnings test purposes) are lower than proposed by the Application.[318] Consumer Counsel also highlighted the Stipulation's provision requiring

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[313] Ex. 23 (Stipulation) at ¶2.
[314] *Id.* at ¶3.
[315] *Id.*; Ex. 18 (Elmes) at 23.
[316] Ex. 23 (Stipulation) at ¶16.
[317] Tr. at 80-81 (Browder).
[318] Tr. at 15-16 (Bartley).

KU-ODP to establish a regulatory liability to recognize the revenue requirement impact if its wildfire risk mitigation plan capital spending in the rate year is less than the $10 million level identified in KU-ODP's Application.[319]

The Stipulation addresses ratemaking issues and some issues involving other aspects of the Commission's regulatory authority. I agree with the Stipulation's resolution of the three matters that are not ratemaking issues. First, the relevant CPCN proceeding, and not a general rate case, is where KU-ODP (and other Virginia electric utilities) should seek any extension(s) of a construction sunset provision that is a condition of that CPCN.[320] Second, disposing of vacant property previously used by the Company for business offices, storerooms, and a pole yard does not appear to require prior approval under the Utility Transfers Act.[321] Third, it appears reasonable to relieve KU-ODP of its annual obligation to report general corporate objectives, which was a condition for Commission approval of the 2010 upstream corporate change in control and ownership between E.ON U.S. and PPL Corporation.[322]

Turning to the Stipulation's proposed resolution of ratemaking issues, I generally find that the proposed Stipulation is just and reasonable and satisfies the statutory ratemaking standards for approval, subject to two issues further developed at the evidentiary hearing. The evidentiary hearing focused on: (1) a nascent carbon capture research and development project; and (2) whether charitable contributions have been excluded from the stipulated revenue requirement that the Company and Staff propose using to set the Company's rates. These two issues are discussed below.

Carbon Capture Research and Development Project

The Application identifies PPL Corporation's plan to host a carbon capture research and development project at Cane Run 7, a natural gas combined-cycle unit in Kentucky that is jointly owned by KU and LG&E. The Company currently estimates the capital cost of the project would be approximately $103 million, but DOE has awarded this project $72 million.[323] More specifically, DOE has agreed to reimburse 70% of project costs, beginning with a front-end engineering and design ("FEED") study that will be conducted during the next 18 months and is estimated to cost $7 million.[324]

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[319] Tr. at 16 (Bartley).
[320] Ex. 23 (Stipulation) at ¶10. The Commission regularly addresses requests to extend sunset provisions in the relevant CPCN proceedings, and has previously done so for the transmission project that was the subject of the Application's initial request. Ex. 6 (McFarland direct) at 12-13.
[321] Ex. 23 (Stipulation) at ¶11; Ex. 4 (Conroy direct) at 23. The relevant provisions of the Utility Transfers Act require Commission approval prior to disposing of "utility assets," which are defined as the "facilities in place of any public utility … for the production, transmission or distribution of electric energy …." Code §§ 56-88, 56-89.
[322] Ex. 23 (Stipulation) at ¶12; Ex. 4 (Conroy direct) at 24. The relevant reporting obligation is that "KU/ODP shall provide Staff annually with information regarding the general corporate objectives of the consolidated operations of E.ON U.S. and their potential impact on KU/ODP." *2010 Transfer Order*, 2010 S.C.C. Ann. Rep. at 536.
[323] Ex. 5 (Bellar direct) at 23; Tr. at 34 (Bellar).
[324] Tr. at 34 (Bellar). At this time, funds for DOE's contribution have only been allocated for the FEED study. Tr. at 45 (Bellar).

After the FEED study is completed in 2026, the Company, DOE, and other participants collaborating on this project would jointly decide whether to move forward.[325] Project partners include the University of Kentucky, EPRI, Siemens, and Vogt Power.[326] According to the DOE agreement, project partners would be responsible for 30% of the project costs. KU-ODP represented that KU and LG&E, combined, are expected to be responsible for approximately $15 million of the project's estimated $103 million capital cost.[327] KU-ODP represented that cost will also be a consideration when determining whether to move forward with the project.[328] The Company highlighted the federal award and indicated that a current target is for project operating and maintenance costs lower than the offtake provider revenue stream.[329]

If pursued, the current estimated construction timeline for the project contemplates completion around June 2029.[330] After the project has operated for 18 months to gather data and information, DOE's relationship with the project would cease and the project could either be deconstructed or, if economically feasible, continue to operate.[331]

Company witness Bellar agreed that the compliance options under EPA's 2024 Section 111 Rules suggest a significant shift from coal-fired generation to natural gas generation. The limited options for compliance by certain fossil-fueled generation facilities, including natural gas combined cycle units, include carbon capture and sequestration.[332]

Company witness Bellar recognized that the 2024 Section 111 Rules are on appeal at the D.C. Circuit Court of Appeals. He also acknowledged that the incoming federal administration could view these rules much differently than the outgoing administration that promulgated the rules.[333] He indicated that the Company must play "the long game" and consider how durable its decisions will be under different administrations.[334] However, he represented that the status of the rules in approximately 18 months, when engineering has been completed, will factor into the decision on whether to move forward with actual construction of the Cane Run 7 carbon capture project.[335]

The Cane Run 7 carbon capture research and development project is currently proceeding under the expectation that LG&E and KU's share of costs would be allocated based on ownership of the underlying generation facility (22% and 78%, respectively). The test year for KU-ODP's Application included no carbon capture project costs, but the Application's 2025 rate year did include projected construction work in progress for approximately $1.1 million, which

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[325] *See, e.g.*, Tr. at 32, 34-35 (Bellar).
[326] Tr. at 35 (sic), 42-43 (Bellar).
[327] Tr. at 41-42 (Bellar)
[328] Tr. at 40-41 (Bellar).
[329] *See, e.g.*, Tr. at 34, 41 (Bellar).
[330] Tr. at 32 (Bellar).
[331] Tr. at 32 (Bellar).
[332] Tr. at 35-36, 38-39 (Bellar).
[333] Tr. at 39 (Bellar).
[334] Tr. at 40 (Bellar).
[335] Tr. at 39-40 (Bellar).

is net of the DOE award, or approximately $41,000 on a Virginia jurisdictional basis. This equates to less than $4,000 in the Application's revenue requirement.[336]

In 2010, the Commission denied cost recovery of a carbon capture and storage (or "CCS") demonstration project planned by APCo[337] and subsequently denied cost recovery for an associated FEED study.[338] In denying cost recovery for APCo's project, the Commission's *2010 APCo Order* stated in part as follows:

> It is reasonable for [APCo's parent, American Electric Power Co. ("AEP")] to evaluate and explore options regarding potential federal legislation or regulation regarding [greenhouse gas] emissions. We do not find, however, that it was reasonable for APCo to incur the Mountaineer CCS project costs and then seek recovery from Virginia ratepayers. For example: (i) although AEP asserts that this demonstration project will benefit customers of all of AEP's operating companies and of all utilities in the United States, APCo's ratepayers (and not shareholders) are being asked to pay for all of the costs incurred by AEP for this project; and (ii) as stated by Consumer Counsel, "AEP is undertaking no other [CCS] initiatives at any of its other subsidiaries' plants," and "APCo and its customers are being asked to shoulder the entire financial burden and risk associated with AEP's [CCS] research and development." Accordingly, we deny the Company's request for cost recovery of the Mountaineer CCS demonstration project under the facts presented herein.[339]

The *2010 APCo Order* also noted that benefits to Virginia ratepayers from APCo's project were speculative and that the project would: (1) significantly increase operation and maintenance expenses at the host power plant; (2) decrease the efficiency of the host power plant, resulting in increased fuel costs; and (3) decrease the host power plant's operating capacity, which further increases capacity expenses.[340]

In 2011, the Commission denied cost recovery for APCo's FEED study for the same carbon capture and sequestration project. The Commission's *2011 APCo Order* stated in part as follows:

> We find that APCo has not shown that it is reasonable to recover FEED study costs from Virginia ratepayers at this time. For example: (i) APCo has not shown how its ratepayers have or will benefit from this study; (ii) there are no existing laws or regulations requiring CCS at this time; (iii) as stated by Consumer Counsel, APCo has acknowledged that AEP is no longer "moving forward with

[336] Tr. at 48-49 (Conroy).
[337] *Application of Appalachian Power Company, For a statutory review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 A of the Code of Virginia*, Case No. PUE-2009-00030, 2010 S.C.C. Ann. Rep. 308, 315, Final Order (July 15, 2010) ("*2010 APCo Order*").
[338] *Application of Appalachian Power Company, For a 2011 biennial review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 A of the Code of Virginia*, Case No. PUE-2011-00037, 2011 S.C.C. Ann. Rep. 477, 488, Final Order (Nov. 30, 2011) ("*2011 APCo Order*").
[339] *2010 APCo Order*, 2010 S.C.C. Ann. Rep. at 315 (footnotes and citations omitted).
[340] *Id.* at 315, n.72.

the development of the commercial scale carbon capture project;" and (iv) the outcome of potential future carbon legislation, the success of any commercial scale project at Mountaineer, and the value of collecting and sequestering CO_2 are all unknown at the present time.[341]

Comparing APCo's carbon capture and sequestration demonstration project (as described by the *2010* and *2011 APCo Orders*) with KU and LG&E's planned carbon capture project, I find these two out-of-state projects have some similarities and some differences. Some similarities are due to the nature of this type of project. These are research and development projects that involve testing equipment and processes for capturing and/or sequestering carbon dioxide. Carbon capture and/or sequestration projects also involve parasitic load, meaning some of a host power plant's capacity and energy that would otherwise be available for customer supply must be repurposed to meet station power needs.[342] Research and development projects like these also raise ratemaking equity considerations regarding who should pay, and how much. Such considerations can include, among other things, project funding, potential beneficiaries, and whether there is an underlying compliance need.

However, KU-ODP's carbon capture project also differs from APCo's carbon capture and sequestration project in several ways. Unlike APCo, which would have had 100% cost responsibility, KU-ODP anticipates that KU would be responsible for approximately 11% of the research and development project's capital costs.[343] Based on the Company's representations, the Company's cost responsibility has been lowered by significant DOE funding, joint ownership in Cane Run 7, and the enlistment of various project partners. Additionally, the costs at issue in this case are projected FEED study costs that will help KU, DOE, and the other project partners decide whether to move forward with the project. The decision on whether to construct the project will not be made until 2026. Should the project move forward, any capital and operating costs resulting from that decision, if proposed for cost recovery, will be subject to future Commission review for prudence and reasonableness. In contrast, APCo sought a broad recovery of its project costs first and then, after Commission denial, pared its request down to FEED study costs.

Regulatory compliance considerations currently offer another distinction between the two projects, although the recent history of regulation under Section 111 of the Clean Air Act sounds a cautionary note on this current distinction, in my opinion. When KU-ODP's Application was filed, EPA's 2024 Section 111 Rules were being finalized.[344] The finalized rules incorporate carbon capture and sequestration – which requires technology and processes KU-ODP's project would test[345] – as part of a "best system of emissions reductions" for fossil fueled generation

[341] *2011 APCo Order*, 2011 S.C.C. Ann. Rep. at 488 (footnotes and citations omitted).

[342] Tr. at 38 (Bellar). As described by Company witness Bellar, the purpose of this project would be to prove that carbon capture equipment and solvents previously deployed at the Company's coal-fired Brown Generating Station during a prior pilot can be deployed at a natural gas combined cycle facility. The planned carbon capture at Cane Run 7 would be for a larger slip stream than at Brown (20 MW versus 0.7 MW). Tr. at 31-32, 36-37 (Bellar).

[343] Tr. at 42, 48 (Conroy). $15 million *78% = $11.3 million. This is a total company figure. Virginia jurisdictional cost responsibility (for APCo and KU-ODP) is less than total company percentages/figures.

[344] Ex. 5 (Bellar direct) at 16.

[345] The Company described its carbon capture research and development project as "an important step in assessing the future viability of utility-scale carbon capture technology on natural gas units." Ex. 5 (Bellar direct) at 23.

facilities.[346] The rules, for example, require natural gas combined cycle plants by a date certain to either: (a) meet a 90% carbon capture standard; or (b) limit operations to a 40% capacity factor.[347] However, the rules are currently on appeal at the D.C. Circuit Court of Appeals, and then potentially the Supreme Court of the United States.[348] Additionally, as KU-ODP acknowledged, the incoming federal administration could take a much different approach to federal carbon regulation than the outgoing administration that promulgated the rules.[349] During the past 12 years, the executive and judicial branches of the federal government have effected significant directional changes to rules proposed and finalized under Section 111 of the Clean Air Act.[350] Accordingly, whether or when carbon capture and sequestration will be a legal compliance requirement for fossil-fueled generators remains unresolved, in my opinion.

Based on the record, and assuming significant financial commitments made by project partners – especially the DOE – I do not have concerns at this time about the inclusion of FEED study costs in KU-ODP's stipulated revenue requirement.[351] During the next 18 months, the FEED study and federal appellate and regulatory processes should provide the Company with additional information as to whether it may be prudent to construct and operate the project. If the project ultimately goes forward, the prudence of KU-ODP's future decision can be evaluated in a future rate case if the Company proposes to seek from Virginia ratepayers any costs of constructing and operating the project. Additionally, the reasonableness of such costs incurred and allocated to KU-ODP could be evaluated at that time.[352]

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[346] *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, 89 Fed. Reg. 39798-01 at 39,938 (May 9, 2024) ("*2024 Section 111 Final Rules*").

[347] *2024 Section 111 Final Rules*, 89 Fed. Reg. at 39,938.

[348] In allowing the D.C. Circuit appeal to proceed without a stay, two justices of the Supreme Court of the United States stated their opinion that the appellants challenging EPA's rule "have shown a strong likelihood of success on the merits to at least some of their challenges." *West Virginia et al. v. EPA et al.*, No. 24A105, 2024 WL 4501235, at *1, On Application For Stay (U.S. Oct. 16, 2024).

[349] Tr. at 39 (Bellar).

[350] *See, e.g., American Lung Ass'n v. EPA*, 985 F.3d 914, 936-38, 995 (D.C. Cir. 2021) (providing some history of the Clean Power Plan, which was stayed by the United States Supreme Court then repealed by the EPA, and vacating and remanding the Clean Power Plan's successor, the Affordable Clean Energy Rule), *overturned by West Virginia v. EPA*, 597 U.S. 697 (2022); *2024 Section 111 Final Rules* (repealing the Affordable Clean Energy Rule).

[351] Consistent with my analysis of charitable contributions below, the Stipulation's "black box" stipulated revenue requirement, if approved, would not obscure that capital investment in this project would be included in the resulting retail rates, in my view. This view is consistent with the Company's assertion in the instant case that certain capital investments are not presently included in the Company's existing rates, which are also based on a "black box" revenue requirement, as discussed below.

[352] KU-ODP indicated that the percentage of ownership in Cane Run 7 is how project costs would be allocated between KU (78%) and LG&E (22%). Tr. at 48 (Conroy). That historic allocation was based on an assessment of relative energy needs at the time the utilities requested a CPCN from the Kentucky commission. Tr. at 52 (Conroy). Cane Run 7 has been operational since 2015. Ex. 5 (Bellar direct) at 7. It is unclear why the costs of constructing and operating carbon capture equipment to test a potential compliance option for new and existing natural gas combined cycle facilities would be treated the same way as run-of-the-mill costs for constructing and operating Cane Run 7. The relative energy (and/or capacity) needs of these two utilities at the time Cane Run 7 was proposed for construction, and ownership was determined, approximately ten years ago have no obvious relationship to the relative needs or benefits associated with the future carbon capture test at the facility.

Charitable Contributions

The Commission's ratemaking treatment of charitable contributions has evolved over time. During the 20th century, the Commission allowed 100% of charitable contributions made by a utility to be included as a ratemaking expense recoverable from customers through retail rates.[353] By the beginning of the 21st century, the Commission used a 50/50 policy, which generally allowed 50% of such contributions to be included in retail rates but leaving the other 50% with shareholders. This was a general policy in that not all charitable contributions were subject to the 50/50 split; the Commission would remove certain contributions entirely from rates or adopt normalization adjustments, for example, if supported by the record.[354]

In 2011, one Commissioner dissented from continuation of the general 50/50 policy in a rate case for APCo. The reason for this dissent was as follows:

> Expenses for charitable contributions have nothing to do with the reason APCo received from the state an exclusive service territory. The Company holds its monopoly franchise in order to provide the public with electricity service - a necessity of modern life - that is reliable and is at prices that are in accordance with law. APCo's monopoly does not include a mission of collecting money from captive customers and spending it on charitable causes of the Company's choosing. Many of the charities to which APCo gives are no doubt highly meritorious, do valuable work for the people they serve, and are worthy of continued support. The Company is free to continue its support of those charities with stockholders' funds if it wishes. APCo's customers, however, can choose their own charitable causes to which to donate and should not have to pay for the Company's choices as part of their monthly bills for electricity service.[355]

By 2019, this minority view became the majority view of the Commission. The Commission announced its policy change in a Washington Gas Light Company ("WGL") rate case, stating that:

> We find that all charitable donations should be removed from the cost of service for ratemaking purposes. The Commission has been moving in this direction in recent years. We find that ratepayers should not be charged for any of the utility's charitable contributions. A utility holds a monopoly franchise to provide reliable service at just and reasonable rates. We find that a utility is free to support charities of its choice with shareholder funds; however, captive ratepayers can

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[353] *See, e.g., Application of: Virginia Electric and Power Company*, Case. No. 11788, 1954 S.C.C. Ann. Rep. 57, 64, Opinion, *aff'd in Bd. of Sup'rs of Arlington Cnty v. Virginia Elec. & Power Co.*, 196 Va. 1102, 1118 (1955); *Application of the Chesapeake & Potomac Telephone Co. of Virginia, For an increase in rates,* Case No. 19152, 1974 S.C.C. Ann. Rep. 111, 121-22, Order (Jan. 28, 1974).
[354] *See, e.g., 2011 APCo Order*, 2011 S.C.C. Ann. Rep. at 485; *Application of Appalachian Power Company, For an increase in electric rates*, Case No. PUE-2006-00065, 2007 S.C.C. Ann. Rep. 321, 329, Final Order (May 15, 2007).
[355] *2011 APCo Order*, 2011 S.C.C. Ann. Rep. at 491.

> choose their own charitable causes to support and should not have to pay for the utility's choices....[356]

This policy of excluding 100% of charitable contributions from rates – announced five years ago – has been implemented in subsequent rate cases for other public utilities. Those public utilities include others that, like WGL, are regulated under Chapter 10 of Title 56 of the Code, as is KU-ODP.[357]

In calculating the Application's proposed revenue requirement, KU-ODP failed to reflect the Commission's current ratemaking policy and removed only 50% of charitable contributions.[358] Staff did the same.[359] The inclusion of charitable contributions was not contested, and therefore it was not the subject of any rebuttal testimony. This means that when KU-ODP and Staff entered into their Stipulation, their prefiled positions for the revenue requirement that Virginia retail customers should pay included donations made to, among others:

- a central Kentucky apple festival and fair;
- the Kentucky Department of Fish and Wildlife;
- the Kentucky Association of Manufacturers; and
- "other various vendors."[360]

More specifically, the Application's recommended annual revenue requirement included $13,665 of annual revenue requirement,[361] and neither the Staff testimony nor rebuttal testimony removed it. Accordingly, the starting points for negotiations – for each of the case participants who entered the Stipulation – included charitable contributions in rates.[362]

At the hearing, Staff and KU-ODP asserted that the Commission could nonetheless approve the stipulated revenue requirement because the terms of the Stipulation state that the stipulated $8.3 million increase represents "a specific revenue number but not a specific [ROE], accounting adjustments, or ratemaking methodologies at issue in this proceeding unless otherwise set forth herein."[363] Based on this language, Staff suggested that the Commission could approve the Stipulation and make a finding that charitable contributions are not included in the stipulated revenue requirement.[364]

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[356] *Application of Washington Gas Light Company, For authority to increase existing rates and charges and to revise the terms and conditions applicable to gas service pursuant to § 56-237 of the Code of Virginia*, Case No. PUR-2018-00080, 2019 S.C.C. Ann. Rep. 199, 205, Final Order (Dec. 20, 2019) ("*WGL Order*").
[357] *See, e.g., Application of Roanoke Gas Company, For a general increase in rates*, 2020 S.C.C. Ann. Rep. 213, 220, Final Order (Jan. 24, 2020).
[358] Ex. 2 (Application) at Filing Sched. 19, p. 1.
[359] *See, e.g.*, Ex. 17 (Morgan) at Statement I; Tr. at 69 (Morgan).
[360] Ex. 2 (Application) at Filing Sched. 34A.
[361] Tr. at 56-57 (Conroy); Tr. at 69 (Morgan). $10,113 (Schedule 19, p. 1, line 20)/0.740041 (Schedule 26, p. 4, line 9) = $13,665. *See, e.g.*, Tr. at 60 (Conroy); Ex. 2 (Application) at Filing Sched. 26, p. 4 (gross-up factor).
[362] Tr. at 58-59 (Conroy).
[363] Ex. 23 (Stipulation) at ¶2.
[364] Tr. at 19 (Major), 83 (Doggett).

I agree that Commission approval of a "black box" stipulated revenue requirement, as proposed here, leaves open-ended the *levels* of the ROE and various cost components that are used in the stipulated revenue requirement and associated rates. But the Code appears to require assurance that a *category* of costs that should be *categorically* excluded from rates is, in fact, excluded from rates.[365] Code § 56-235.2 A provides that rates can "be considered to be just and reasonable only if: … the public utility has demonstrated that such rates, tolls, charges or schedules in the aggregate provide revenues not in excess of the aggregate actual costs incurred by the public utility in serving customers within the jurisdiction of the Commission" and a fair rate of return on rate base. Five years ago, the Commission decided that charitable contributions are not part of a utility's cost of service[366] or, in the words of Code § 56-235.2 A, that charitable contributions are not "incurred … in serving customers." My concern is that the answer to whether the stipulated revenue requirement includes charitable contributions appears to be "yes" or possibly "maybe." Either answer presents tension with the Code, which requires KU-ODP to demonstrate that: (i) the stipulated revenue requirement does not provide for aggregate revenues above the aggregate cost of service;[367] and (ii) the stipulated rates are just and reasonable.[368]

That a stipulated "black box" revenue requirement includes and excludes categories of costs (at unspecified amounts) is also supported by the Company's own evidence. According to KU-ODP testimony, the Application's proposed increase is driven by investments and operating costs that are not yet incorporated into rates.[369] Notably, KU-ODP's current rates are the result of a stipulation that, similar to the instant proposal, included a "black box" revenue requirement.[370] Were Staff and KU-ODP's view of the black box revenue requirement they propose in the instant case correct, the Company could not have ascertained whether any category of costs are, or are not, currently incorporated in base rates (much less delineated which investments within such categories are and are not in rates). In my opinion, and consistent with this testimony, a black box stipulated revenue requirement provides the utility with assurance that certain types of investments and costs, including a cost of capital, are being recovered through rates. And I question why the categorical transparency of a black box would be partial in this respect – providing a public utility with assurance that categories of cost of service are being recovered in rates, but not providing ratepayers with assurance that categories of costs that are not proper cost of service items are not being recovered in rates. Just as a stipulated revenue requirement provides KU-ODP assurance that plant and operating costs for serving its customers, plus a rate of return, are included in stipulated rates, it should seemingly provide ratepayers similar assurance that charitable donations are excluded, in my opinion.

[365] Staff likened the "black box" settlement to a scenario in which a buyer negotiates a total price to purchase a car fleet even though the buyer and seller disagree on the value of each car in that fleet. Tr. at 65 (Morgan). However, there was no disagreement on charitable contributions in this case. Staff and KU-ODP's revenue requirements were in full agreement with each other, with both including in their respective revenue requirements the same approximately $14,000 amount of costs that the Commission previously determined should not be in rates. And a fleet buyer presumably knows which cars it did and did not purchase in a transaction, consistent with my analysis.

[366] *WGL Order*, 2019 S.C.C. Ann. Rep. at 205 ("We find that all charitable donations should be removed from the cost of service for ratemaking purposes.").

[367] Code § 56-235.2 A.

[368] Code § 56-235.3.

[369] Ex. 4 (Conroy direct) at 8.

[370] *2021 Rate Case Order*, 2022 S.C.C. Ann. Rep. at 330 ("The Partial Stipulation provides that the recommended increase in operating revenues was the product of compromise and settlement based upon the evidence in the record and represented a settlement as to a specific revenue number, but not on a specific determination of ROE, accounting adjustments, or ratemaking methodologies, except as otherwise provided therein.").

Counsel for KU-ODP asserted that in reaching the stipulated revenue requirement figure agreed to with Staff – but not Consumer Counsel – KU-ODP assessed the risk of issues that Consumer Counsel could have raised in a fully litigated hearing.[371] I follow this logic to a point. But one place it falls short of persuading me that zero charitable contributions are in the stipulated revenue requirement is that KU-ODP's argument seems to require an assumption that the Company, when entering a settlement for an $8.3 million increase, assigned 100% litigation risk and therefore zero value to charitable contributions – an issue no filing raised in this case. I cannot square a zero negotiation value assumption with the facts that: (1) KU-ODP included charitable contributions as a cost of utility service in its most recent Annual Informational Filing with the Commission;[372] (2) KU-ODP proposed cost recovery for charitable contributions in the instant Application;[373] and (3) KU-ODP did not deviate, in any filing in this case, from the Application's position that provides for recovery of charitable contributions through rates. For KU-ODP to have taken and maintained – across multiple filings – its position, good faith pleading requirements suggest that the Company must have believed it had some colorable argument. Indeed, the record suggests that KU-ODP had such a belief rooted in the fact that, while the Company has been aware of Commission orders that changed the charitable contribution policy,[374] the Commission has not yet taken such voluntary contributions out of KU-ODP's rates.[375] This case presents the Commission with that very opportunity.

So, should the Commission's charitable contribution ratemaking policy apply to KU-ODP? Based on the clear policy rationale provided in 2019, there is no apparent reason for treating KU-ODP (and its customers) different than other Commission-regulated utilities (and their customers). Nor do I see a compelling reason to wait until a future rate case to implement this clear policy and remove charitable contributions from KU-ODP's rates.

Because I find that KU-ODP has failed to demonstrate that the stipulated revenue requirement would not produce aggregate revenues above the aggregate cost of service, or that the stipulated revenue requirement would result in just and reasonable rates, I do not recommend approval of the stipulated revenue requirement. Based on the record and my analysis, I find that the stipulated revenue requirement is excessive by $13,665 – the amount that the Application included in its proposed revenue requirement, and which was never removed by the case participants.[376] However, if the Commission disagrees with my analysis, I find the record can support approval of the Stipulation.

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[371] Tr. at 87 (Riggs).
[372] Tr. at 77 (Morgan).
[373] Tr. at 56-57 (Conroy).
[374] Tr. at 59-60 (Conroy), 77 (Morgan).
[375] Tr. at 60 (Conroy) ("I'm familiar with some of the orders that were referenced by [S]taff in the … previous rate case….ODP has not had a order that specifically addressed that."). *See also* Tr. at 63, 77 (Morgan).
[376] If adopted, this recommendation would require calculation of the approved retail rates, which regularly occurs during the post-order compliance process of Commission rate cases, rather than adoption of the rates proposed in Stipulation Exhibit No. 2. I find the proportional allocation methodology proposed in Stipulation Paragraph 4 reasonable, whether for the calculation of the stipulated rates proposed in Stipulation Exhibit No. 2 or, alternatively, for the calculation of slightly lower rates that remove charitable contributions.

FINDINGS AND RECOMMENDATIONS

Based on the Code and the record developed in this case, I find that:

(1) The record can support a finding that the proposed Stipulation is just and reasonable and satisfies the applicable statutory standard for approval, provided the costs encompassed by the stipulated revenue requirement exclude charitable contributions.

(2) KU-ODP has not demonstrated that the stipulated revenue requirement proposed by KU-ODP and Staff excludes $13,665 of charitable contributions that was included in the Application's proposed revenue requirement and was not removed by the case participants.

Accordingly, **I RECOMMEND THAT** the Commission enter an order that:

(1) ***ADOPTS*** the findings and recommendations in this Report; and

(2) ***REJECTS*** the proposed Stipulation or, alternatively, ***APPROVES*** the proposed Stipulation with a revenue requirement that is $13,665 lower and with corresponding lower rates.

COMMENTS

Staff and parties are advised that, pursuant to Rule 5 VAC 5-20-120 C of the Commission's Rules of Practice and Procedure ("Rules of Practice") and Code § 12.1-31, any comments on this Report must be filed on or before December 30, 2024. To promote administrative efficiency, the parties are encouraged to file electronically in accordance with 5 VAC 5-20-140 of the Rules of Practice. If not filed electronically, an original and fifteen (15) copies must be submitted in writing to the Clerk of the Commission, c/o Document Control Center, P.O. Box 2118, Richmond, Virginia 23218. Any party filing such comments shall attach a certificate to the foot of such document certifying that copies have been sent by electronic mail to all counsel of record and any such party not represented by counsel.

Respectfully submitted,

D. Mathias Roussy, Jr.
Chief Hearing Examiner

Document Control Center is requested to send a copy of the above Report to all persons on the official Service List in this matter. The Service List is available from the Clerk of the State Corporation Commission, c/o Document Control Center, 1300 East Main Street, Tyler Building, First Floor, Richmond, VA 23219.