COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC JOINT APPLICATION OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY FOR APPROVAL OF SEVEN FOSSIL FUEL-FIRED GENERATING UNIT RETIREMENTS	)))))	**CASE NO. 2023-00122**

DIRECT TESTIMONY OF
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CHIEF OPERATING OFFICER
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: May 10, 2023

INTRODUCTION

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

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

Q. Have you previously testified before this Commission?

A. Yes. I have testified in numerous proceedings before the Kentucky Public Service Commission ("Commission") for many years. I testified before the Commission most recently in Case No. 2022-00402, which is the case concerning the Companies' currently pending application for a number of certificates of public convenience and necessity and approval of a new demand-side management and energy efficiency program plan ("CPCN-DSM case"), among other items.[1]

Q. What is the purpose of your direct testimony?

A. My testimony supports the seven fossil fuel-fired electric generating unit retirements assumed or proposed in the CPCN-DSM case, which retirements the Companies must now demonstrate meet the requirements of Senate Bill 4 as enacted by the Kentucky General Assembly in March 2023.[2] More specifically, I support the data concerning

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[1] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan*, Case No. 2022-00402, Direct Testimony of Lonnie E. Bellar (Dec. 15, 2022).

[2] 2023 Ky. Acts 118. The seven units the Companies have assumed or proposed to retire by the end of 2027 are E.W. Brown Unit 3, Ghent Unit 2, Mill Creek Units 1 and 2, Haefling Units 1 and 2, and Paddy's Run Unit 12.

the operational characteristics and costs of the Companies' existing and proposed supply-side resources, as well as information concerning the reliability and resilience of those resources. My testimony also explains how the quantitative analysis provided by Stuart A. Wilson meets the requirements of Senate Bill 4.

Note that because other witnesses for the Companies and I have provided voluminous testimony, exhibits, and discovery responses in the CPCN-DSM case, as well as LG&E's 2020 ECR case,[3] which the Companies are proposing to incorporate by reference into the CPCN-DSM proceeding along with this proceeding, this testimony is summary in nature and does not restate what the Companies have addressed at length elsewhere.

Q. Are you sponsoring any exhibits?

A. Yes, I am co-sponsoring Exhibit SB4-1 with Mr. Wilson, which is attached to his testimony:

Exhibit SB4-1 2023 Fossil Fuel-Fired Electric Generating Unit Retirement Assessment ("Retirement Assessment")

Q. Why did the Companies prepare the Retirement Assessment?

A. In March 2023, the Kentucky General Assembly enacted Senate Bill 4, which created a set of requirements a utility must satisfy before it can receive Commission approval to retire a fossil fuel-fired electric generating unit. Under Senate Bill 4, a utility may receive Commission approval to retire a fossil-fuel fired generating unit if it rebuts a presumption against such retirement by demonstrating that:

[3] *See, e.g., Electronic Application of Louisville Gas and Electric Company for Approval of Its 2020 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2020-00061, Direct Testimony of Stuart A. Wilson, Exhibit SAW-1 (Mar. 31, 2020).

- Replacement generating capacity for the retiring unit is dispatchable, will maintain or improve system reliability and resilience, and will maintain sufficient reserve margins (Senate Bill 4 Section 2(2)(a));
- The unit retirement will not harm utility ratepayers (Senate Bill 4 Section 2(2)(b));
- The unit retirement does not result from federal financial incentives or benefits (Senate Bill 4 Section 2(2)(c)); and
- The unit retirement will result in cost savings for customers after accounting for all known direct and indirect costs of the retirement (Senate Bill 4 Section 2(3)).

Although the Companies previously provided information and analysis to meet all or nearly all of Senate Bill 4's requirements in the Companies' CPCN-DSM case and LG&E's 2020 ECR case,[4] the Companies prepared the Retirement Assessment to summarize the relevant information in one document and provide additional analysis sufficient to meet all of Senate Bill 4's requirements regarding the seven fossil fuel-fired electric generating units the Companies assumed or proposed to retire in the CPCN-DSM case.

Q. Which are the seven fossil fuel-fired electric generating unit retirements assumed or proposed in the CPCN-DSM case, and why are the Companies proposing to retire them?

A. The Companies are seeking Commission approval to retire four coal-fired units (E.W. Brown Unit 3 ("Brown 3"), Ghent Unit 2 ("Ghent 2"), and Mill Creek Units 1 and 2

[4] *See, e.g.,* Case No. 2022-00402, Attachment to Companies' Response to JI 2-60(a), May 2023 Update to Exhibit SAW-1 (May 4, 2023) (referred to herein as "May 2023 Update to Exhibit SAW-1"); Case No. 2020-00061, Direct Testimony of Stuart A. Wilson, Exhibit SAW-1 (Mar. 31, 2020).

("Mill Creek 1-2")), and they are seeking approval to retire three small-frame natural gas simple-cycle combustion turbines (Haefling Units 1 and 2 ("Haefling 1-2") and Paddy's Run Unit 12 ("Paddy's Run 12")) upon each unit's experiencing a major mechanical issue, which the Companies have assumed in their resource planning will occur by 2025.[5] All of these units will be at least 50 years old by their proposed retirement dates, are at or near the end of their useful lives, and would require significant investments to continue to operate in compliance with all applicable laws beyond their proposed retirement dates.

Beginning with the first unit the Companies propose to retire, Mill Creek 1, the Companies have previously provided evidence (proposed to be incorporated by reference) that retiring the unit by the end of 2024 is economical due to the cost of additional environmental compliance equipment required for the unit to operate beyond 2024, namely process water equipment for Effluent Limitation Guidelines ("ELG") compliance, and because it would require a cooling tower to operate beyond 2027 in compliance with Clean Water Act 316(b) regulations.[6] Based on this evidence, the Commission found LG&E ECR Project 31, which explicitly excluded ELG compliance equipment for Mill Creek 1, to be the lowest reasonable cost alternative in LG&E's 2020 ECR case.[7] In addition, the Companies would need to add Selective Catalytic Reduction ("SCR") equipment to the unit prior to the 2027 ozone season to allow it to operate in compliance with the Good Neighbor Plan in 2027 and beyond.[8]

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[5] *See* Case No. 2022-00402, Direct Testimony of Stuart A. Wilson at 12 (Dec. 15, 2022).
[6] *See, e.g.,* Case No. 2020-00061, Direct Testimony of Stuart A. Wilson, Exhibit SAW-1 at 4 (Mar. 31, 2020).
[7] Case No. 2020-00061, Order (Ky. PSC Sept. 29, 2020).
[8] *See, e.g.,* Case No. 2022-00402, Companies' Response to AG 2-4 (May 4, 2023). Note that per an agreement with the Louisville Air Pollution Control District, the Mill Creek Station is subject to a NO_x limit of 15 tons per

Concerning Haefling 1-2 and Paddy's Run 12, all three units are over 50 years old (Haefling 1-2 went in service in 1970; Paddy's Run 12 went in service in 1968). Though they have served the Companies well for decades, they currently serve only as secondary peaking units. Although they remain economical with minimal routine maintenance expenses to operate on a limited basis as peaking units (primarily during extreme weather events), they are among the least efficient units in the Companies' fleet and would not be economical to repair and return to service if they encountered any major mechanical issue (i.e., any failure that ordinary maintenance could not address).[9] Nonetheless, because they add value to the system as peaking units, the Companies are seeking approval to retire them upon each unit's experiencing a major mechanical issue rather than authority to retire the units by a certain date.

The cost-benefit and reliability analyses the Companies provided in the CPCN-DSM proceeding showed that retiring Mill Creek 2, Ghent 2, and Brown 3 would be economical and would enhance system reliability when all of the Companies' proposed supply- and demand-side resources are deployed to replace the retired capacity.[10] As I testified in the CPCN-DSM case, Mill Creek 2 and Ghent 2 would require SCR equipment costing hundreds of millions of dollars to continue to operate beyond the

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day between May and October, which effectively eliminates the ability to operate Mill Creek 1 and Mill Creek 2 simultaneously during these months. For a demonstration that retiring Mill Creek 1 by 2025 is economical even without the additional constraints of the Good Neighbor Plan, see Case No. 2020-00061, Direct Testimony of Stuart A. Wilson, Exhibit SAW-1 at 17-24 (Mar. 31, 2020).

[9] A mechanical issue the repair cost of which exceeds the reliability value the repair would provide is a "major mechanical issue." More precisely, each of the 12 MW Haefling units provides approximately $130,000 per year of reliability value. Therefore, any repair cost that exceeded that amount multiplied by the number of years of expected added service would not be cost-effective to incur. For example, a $1 million repair for Haefling 1 that provided only five years of expected service life would exceed the added reliability value of $650,000 (5 years * $130,000 reliability value/year) and would therefore be uneconomical to make. For the 23 MW Paddy's Run 12 unit, the annual reliability value is roughly twice that annual amount, i.e., about $260,000 per year.

[10] *See, e.g.,* Case No. 2022-00402, May 2023 Update to Exhibit SAW-1 (May 4, 2023).

end of 2027 in compliance with the Good Neighbor Plan.[11] The Environmental Protection Agency's ("EPA") recently issued, final version of the Good Neighbor Plan does not affect the date by which SCRs would be needed for Mill Creek 2 or Ghent 2 to operate in compliance with the final rule.[12] Although Brown 3 is SCR-equipped, it would require a significant overhaul to allow it to continue operating reliably beyond 2028.[13]

Table 1 below summarizes the seven units the Companies assume or propose to retire by or in 2028.

[11] *See, e.g.,* Case No. 2022-00402, Direct Testimony of Lonnie E. Bellar at 5 (Dec. 15, 2022).
[12] *See, e.g.,* Case No. 2022-00402, Companies' Response to AG 2-4 (May 4, 2023).
[13] *See* Case No. 2022-00402, May 2023 Update to Exhibit SAW-1 (May 4, 2023).

Table 1: Summary of Unit Retirements Addressed in CPCN-DSM Case

Unit(s)	Fuel	Net Summer/ Winter Capacity (MW)	Dispatchable Summer/ Winter Range (MW)	In-Service Date	Additional Information
Mill Creek 1 ("MC1")	Coal	300/300	Current: 185/185 w/ SCR: 145/145	1972	SCR required today for either Mill Creek 1 or 2 to operate units simultaneously during May-October.[14] Operation beyond 2024 would require ELG retrofits, and operation beyond 2027 would require a cooling tower. SCR required for ozone-season (May-September) operation beginning in 2027 due to Good Neighbor Plan.[15]
Mill Creek 2 ("MC2")	Coal	297/297	Current: 183/183 w/ SCR: 145/145	1974	SCR required today for either Mill Creek 1 or 2 to operate units simultaneously during May-October.[14] SCR required for ozone-season operation beginning in 2027 due to Good Neighbor Plan.
Brown 3 ("BR3")	Coal	412/416	272/276	1971	SCR-equipped but least economical of the Companies' coal units to operate. Major overhaul required in 2027 for reliable operation beyond 2028.
Haefling 1-2 ("HF1-2"); Paddy's Run 12 ("PR12")	Gas	47/55	0/0	1970; 1968	Economical for limited peaking operation. Uneconomical to repair any major mechanical issue. Companies anticipate mechanical failures will require retirement by 2025.[16]
Ghent 2 ("GH2")	Coal	485/486	Current: 260/261 w/ SCR: 256/257	1977	SCR required for ozone-season operation beginning in 2027 due to Good Neighbor Plan.

Q. Please summarize the Companies' proposed resource additions in the CPCN-DSM case.

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[14] Per an agreement with the Louisville Air Pollution Control District, the Mill Creek Station is subject to a NO_x limit of 15 tons per day between May and October, which effectively eliminates the ability to operate Mill Creek 1 and Mill Creek 2 simultaneously during these months.

[15] The Companies initially demonstrated the economics of retiring Mill Creek 1 in LG&E's 2020 ECR case. *See* Case No. 2020-00061, Direct Testimony of Stuart A. Wilson, Exhibit SAW-1 (Mar. 31, 2020).

[16] Four similar small-frame CTs (Haefling 3, Cane Run 11, Paddy's Run 11, and Zorn 1) have experienced major mechanical issues and retired in the past 10 years. Such mechanical issues could occur before or after 2025, but the Companies believe it is reasonable for system planning to assume their retirement by 2025.

A. In the CPCN-DSM case, the Companies have proposed adding the following supply- and demand-side resources to ensure ongoing reliable and low-cost service to customers:

- Two new 1-on-1 natural gas-fired combined cycle ("NGCC") generation units (Mill Creek NGCC and Brown NGCC, 621 MW summer-net each);
- Two Companies-owned 120 MWac solar facilities;
- A 125 MW, 500 MWh battery energy storage system at the E.W. Brown Generating Station ("Brown BESS");
- Four solar power purchase agreements ("PPAs"); and
- The Companies' 2024-2030 Demand-Side Management and Energy Efficiency ("DSM-EE") Program Plan portfolio of dispatchable DSM programs and non-dispatchable energy efficiency programs.[17]

Table 2 below summarizes relevant characteristics of the resources the Companies propose to add in the CPCN-DSM case.

[17] *See, e.g.,* Case No. 2022-00402, Joint Application at 22-23 (Dec. 15, 2022).

Table 2: Summary of the Companies' Proposed Supply- and Demand-Side Resource Additions in the CPCN-DSM Case

Resource	Input Energy Source	Net Summer/ Winter Capacity (MW)[18]	Dispatchable Summer/ Winter Range (MW)	In-Service Date(s)	Dispatchable?	Electric Generating Capacity?
Mill Creek NGCC (Mill Creek 5, or "MC5")	Gas	621/641	395/380	2027	Yes	Yes
Brown NGCC (Brown 12, or "BR12")	Gas	621/641	395/380	2028	Yes	Yes
Companies-owned solar	Solar	189/0[19]	240/240[20]	2026-2027	Yes[21]	Yes
Brown Battery Energy Storage System (Brown BESS)	Various	125/125	125/125	2026	Yes	No
Dispatchable DSM	N/A	102/89[22]	102/89	2024-2025[23]	Yes	No
Solar PPAs	Solar	678/0[19]	0/0	2024-2027	No	Yes

THE COMPANIES' RETIREMENT ASSESSMENT SHOWS THAT THE ASSUMED AND PROPOSED UNIT RETIREMENTS AND REPLACEMENT CAPACITY SATISFY THE REQUIREMENTS OF SENATE BILL 4

Q. How does the Retirement Assessment address Senate Bill 4's requirement that retiring fossil fuel-fired electric generating units must be replaced with electric

[19] Capacity values reflect 78.6% expected contribution to summer peak capacity and 0% expected contribution to winter peak capacity.
[20] The dispatchable range for the Companies' owned solar assets will be a function of availability of solar irradiance and will vary up to the units' nameplate capacity of 240 MW.
[21] The Companies' owned solar assets will not be dispatchable at all the same times and in all the same conditions as a thermal unit or battery, but the Companies will have full operational control to curtail or re-dispatch these assets when they are able to produce energy.
[22] Values reflect expected contributions in 2028 under normal peak weather conditions.
[23] The in-service dates shown here reflect when the Companies anticipate having at least some participants in each of their new dispatchable DSM programs. *See* Case No. 2022-00402, Direct Testimony of John Bevington, Exhibit JB-1 at 45-52 (Dec. 15, 2022).

generating capacity that is dispatchable by the utility (Senate Bill 4 Section 2(2)(a)(1))?

A. Senate Bill 4 does not define "dispatchable," but an industry definition of "dispatchable generation" is, "Generation that can follow dispatch instructions between economic minimum and economic maximum."[24] Note that under this industry definition of "dispatchable generation," a solar facility at midnight and a combustion turbine that is offline are equally not "dispatchable generation" at that moment. Under the same definition, a functioning solar facility in full sun and a combustion turbine that is online and has adequate fuel supply and pressure are equally dispatchable by the entity with the right to adjust their output from economic minimum to maximum. Therefore, a more complete definition of "dispatchable" that explicitly states these implicit concepts is "capable of following dispatch instructions between economic minimum and economic maximum when (i) the generating unit is physically capable of producing electricity and (ii) the unit's power source is available." Under this definition, the dispatchable generating resources the Companies propose to add in the CPCN-DSM case are the two NGCC units and the two Companies-owned solar facilities, all of which the Companies will have the full right to dispatch between their economic minimum and maximum outputs. The Brown BESS and dispatchable DSM will also be dispatchable resources, though neither will be a generating resource. Finally, the solar PPAs will provide valuable energy to the Companies' system, but the Companies

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[24] PJM Glossary, available at https://www.pjm.com/Glossary#index_D (accessed Apr. 12, 2023); Indiana Utility Regulatory Commission, "2022 Glossary of Electric and Natural Gas Terms and Concepts" at 73, available at https://pubs.naruc.org/pub/DD7DB67E-1866-DAAC-99FB-36526B06C7C6?_gl=1*1qdnvr8*_ga*MTM5OTA2NzQzNi4xNjgxMzIxMTU3*_ga_QLH1N3Q1NF*MTY4MTMyMTE1Ny4xLjEuMTY4MTMyMTE5OS4wLjAuMA (accessed Apr. 12, 2023).

will not have the right to control those facilities' output ranges, so they are not dispatchable for Senate Bill 4 purposes.

Also relevant to dispatchability considerations is a unit's dispatchable range, meaning the difference between a unit's economic maximum and minimum output levels in kW or kVA. Having a greater dispatchable range gives the Companies greater flexibility in operating their system to meet customers' needs in real time.

As summarized in Table 3 below, the Companies will actually have a greater range of dispatchable capacity with their proposed CPCN-DSM replacement resources than they currently have with the retiring units. The portfolio numbers shown reflect the portfolio numbers used in the Retirement Assessment.

Table 3: Incremental Changes in Total and Dispatchable Capacity (MW)

		Net Summer/Winter Capacity[26]			**Dispatchable Summer/Winter Range (Net Max less Net Min)[26]**		
	Portfolio[25]	Retired Resource	Proposed Resource	Diff: Proposed less Retired	Retired Resource	Proposed Resource	Diff: Proposed less Retired
0	No Retirements; Add DSM	0/0	0/0	0/0	0/0	0/0	0/0
Fossil retirements and dispatchable electric generating replacements:							
6	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar	1,530/ 1,543	1,431/ 1,282	(99)/ (261)	818/ 823	1,030/ 1,000	212/ 177
Add dispatchable non-generating resources:							
7	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar/Brown BESS	1,530/ 1,543	1,556/ 1,407	26/ (136)	818/ 823	1,155/ 1,125	337/ 302
Add non-dispatchable electric generating resources:							
8	**Final CPCN Portfolio**: Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar/ Brown BESS/Solar PPAs	1,530/ 1,543	2,234/ 1,407	704/ (136)	818/ 823	1,155/ 1,125	337/ 302

[25] "MC1-2" means Mill Creek 1 and 2; "BR3" means Brown 3; "PR12" means Paddy's Run 12; "HF1-2" means Haefling 1 and 2; "MC5" means Mill Creek NGCC; "BR12" means Brown NGCC.

[26] Values for Mill Creek 1-2 and Ghent 2 reflect the expected net capacity and dispatchable ranges after commissioning of environmental controls required for continued operation.

Therefore, the proposed retirements and replacements will not just maintain but will actually improve the dispatchability of the Companies' generating fleet, fully satisfying the dispatchability requirement of Senate Bill 4 Section 2(2)(a)(1).

Q. How does the Retirement Assessment address Senate Bill 4's reliability requirement (Senate Bill 4 Section 2(2)(a)(2))?

A. Section 2(2)(a)(2) requires that replacement electric generating capacity "[m]aintain[] or improve[] the reliability … of the electric transmission grid[.]"[27] Senate Bill 4 defines "reliability" in Section 1 as "having adequate electric generation capacity to safely deliver electric energy in the quantity, with the quality, and at a time that the utility customers demand[.]"

The Companies have historically ensured reliable service for their customers by maintaining adequate reserve margins, which is consistent with Senate Bill 4's definition of "reliability." The Companies' most recent reserve margin study, which involved in-depth analysis of the economically optimal reserve margin to ensure reliability, established seasonal minimum reserve margin targets of 17% in the summer and 24% in the winter. In the first two stages of the 2022 Resource Assessment in the CPCN-DSM case, the Companies developed their economically optimal portfolio for meeting these reserve margin targets and complying with the Good Neighbor Plan.[28]

As the Retirement Assessment discusses, another metric the Companies use to evaluate reliability is the widely used loss-of-load expectation ("LOLE") value,

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[27] This analysis is based on the focus of Section 2(2)(a)(2) on the reliability and resilience of electric supply, particularly given the statute's definition of "reliability" as "having adequate electric ***generation capacity*** to safely deliver electric energy in the quantity, with the quality, and at a time that the utility customers demand" (emphasis added).

[28] *See* Case No. 2022-00402, May 2023 Update to Exhibit SAW-1, Appendix D (May 4, 2023).

expressed as the number of expected loss of load days in a ten-year period. In the Companies' most recent reserve margin study, the Companies calculated the LOLE for four portfolios with reserve margins moderately above the minimum seasonal reserve margin targets (17.9% summer and 26% winter).[29] The lowest LOLE portfolio (i.e., the most reliable) with those reserve margins had an LOLE of 3.57.[30] The Companies therefore have assumed in the Retirement Assessment that a portfolio that meets the Companies' minimum reserve margin targets and has an LOLE lower than 3.57 provides more than adequate reliability for Senate Bill 4 purposes.

As shown in Table 4 and Table 5 below, the Companies' proposed and assumed unit retirements and replacements with CPCN-DSM resources meet both of these reliability metrics, even when considering only dispatchable generating resources (i.e., Portfolio 6).

[29] *Id.*at D-23 – D-24.
[30] *Id.* at D-24, Table 15.

Table 4: 2028 Reliability Analysis (LOLE)

	Portfolio	LOLE (days/10 years) Summer (Jun-Aug)	LOLE (days/10 years) Winter (Jan-Feb, Dec)	LOLE (days/10 years) Full Year
0	No Retirements; Add DSM	0.23	0.21	**0.45**
Fossil retirements and dispatchable electric generating replacements:				
6	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar	0.33	0.42	**0.77**
Add dispatchable non-generating resources:				
7	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar/Brown BESS	0.18	0.25	**0.45**
Add non-dispatchable electric generating resources:				
8	**Final CPCN Portfolio**: Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar/ Brown BESS/Solar PPAs	0.03	0.25	**0.28**

Table 5: 2028 Reserve Margins

	Portfolio	Reserve Margin Summer	Reserve Margin Winter
0	No Retirements Add DSM	27.4%	34.7%
Fossil retirements and dispatchable electric generating replacements:			
6	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar	25.7%	30.2%
Add dispatchable non-generating resources:			
7	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar/Brown BESS	27.7%	32.3%
Add non-dispatchable electric generating resources:			
8	**Final CPCN Portfolio**: Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar/ Brown BESS/Solar PPAs	38.4%	32.3%

Therefore, the proposed fossil fuel-fired electric generating unit retirements and proposed replacement resources meet the reliability requirement of Senate Bill 4. Note that retiring the fossil fuel-fired electric generating units without adding at least the two

NGCC units the Companies have proposed would not achieve adequate reliability, and therefore would not satisfy Senate Bill 4's requirements. As shown in the Companies' most recent reserve margin study (presented in the CPCN-DSM case), retiring the seven units at issue and adding only one NGCC unit (the Mill Creek NGCC) would result in a 10.3% summer reserve margin and a 17.6% winter reserve margin, as well as an LOLE of 21.32.[31]

Q. How does the Retirement Assessment address Senate Bill 4's resilience requirement (Senate Bill 4 Section 2(2)(a)(2))?

A. Section 2(2)(a)(2) requires that replacement electric generating capacity "[m]aintain[] or improve[] the … resilience of the electric transmission grid[.]"[32] Senate Bill 4 defines "resilience" in Section 1 as "having the ability to quickly and effectively respond to and recover from events that compromise grid reliability," but it does not provide any metrics for evaluating these criteria. Thus, the Companies selected objective, established metrics to determine responsiveness to events affecting the Companies' ability to serve load, namely generating units' start-up times, ramp rates, and dispatchable range.

As shown in Table 6 below, the Companies' proposed CPCN-DSM portfolio results in better resilience across all three metrics compared to continuing to operate and maintain the seven units the Companies propose or assume to retire, thereby satisfying Senate Bill 4's resilience requirement:

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[31] Case No. 2022-00402, May 2023 Update to Exhibit SAW-1, Appendix D at D-23 – D-24 (May 4, 2023).

[32] This analysis is based on the focus of Section 2(2)(a)(2) on the reliability and resilience of electric supply, particularly given the statute's definition of "reliability" as "having adequate electric ***generation capacity*** to safely deliver electric energy in the quantity, with the quality, and at a time that the utility customers demand" (emphasis added).

Table 6: Comparison of Resilience of Retired and Proposed Supply-Side Resources

	Start-up Times (Hours)[33]	Ramp Rate (MW/min)	Dispatchable Summer/Winter Range (Net Max less Net Min, MW)[34]
Retired Resources:			
Mill Creek 1	11-34	3	145/145
Mill Creek 2	11-34	3	145/145
Ghent 2	18-32	7	256/257
Brown 3	12-20	6	272/276
Haefling 1-2	1	0[35]	0/0
Paddy's Run 12	1	0[35]	0/0
Total			818/823
Proposed Resources:			
Mill Creek 5	1-3	85	395/380
Brown 12	1-3	85	395/380
Owned Solar	Instantaneous	Varies[36]	240/240[37]
Brown BESS	Instantaneous	125	125/125
PPA Solar[38]	N/A	N/A	0/0
Total			1,155/1,125
Net			337/302

Q. How have the Companies accounted for fuel assurance issues in the Retirement Assessment?

A. The Companies did not treat fuel assurance as a separate reliability or resilience criterion because the forced outage rates included in the Companies' SERVM reliability analysis already account for credible, reasonably foreseeable fuel assurance

[33] Values reflect a range of hot start times to cold start times.

[34] Values for Mill Creek 1-2 and Ghent 2 reflect the expected dispatchable ranges after commissioning of environmental controls required for continued operation.

[35] Paddy's Run 12 and Haefling 1-2 are not very effective at following load and would be expected to maintain a stable output level when dispatched to serve load. The Companies assume no ramping capabilities from these units.

[36] The ramp rate for the Companies' owned solar assets will be a function of availability of solar irradiance and will vary up to the units' nameplate capacity of 240 MW.

[37] The Companies' owned solar assets will not be dispatchable at all the same times and in all the same conditions as a thermal unit or battery, but the Companies will have full operational control to curtail or re-dispatch these assets when they are able to produce energy.

[38] The Companies will be contractually obligated to take generation output from the solar PPAs and will be unable to control their dispatch in normal operations.

risks. Those risks exist for all generating units, not only gas units: coal piles can and do freeze in extreme conditions; fuel transportation by rail, barge, and truck can be interrupted, just as it can by pipeline. The Companies attempt to mitigate those risks for coal and gas units by ensuring that their fuel assurance practices are informed by NERC's fuel assurance principles.[39] In addition, as the Companies stated in the CPCN-DSM case, the Companies are contracting for firm gas transport for the proposed NGCC units to ensure their reliable operation.[40]

Also, following the unprecedented load shedding event in December 2022, the Companies worked with the pipeline operator at issue, Texas Gas Transmission, to ensure it was taking appropriate measures to mitigate the risk that the malfunction that resulted in inadequate pipeline pressures for the Companies' Cane Run Unit 7 combined-cycle unit and Trimble County simple-cycle combustion turbines would reoccur.[41] The Companies are also working to install software upgrades at Trimble County by November 2023 that would allow the simple-cycle combustion turbines there to operate at full load at lower gas pressures than are required to start the units and to operate at reduced load if gas pressures further decreased. Finally, the Companies are evaluating if there are additional prudent actions to take, including the possibility of adding gas compression equipment at their generating stations.

Because the Companies have reasonable fuel assurance practices and policies, and because they have taken additional steps recently to protect against future fuel

[39] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Fuel_Assurance_and_Fuel-Related_Reliability_Risk_Analysis_for_the_Bulk_Power_System.pdf

[40] *See, e.g.*, Case No. 2022-00402, Direct Testimony of Charles R. Schram at 12-16 (Dec. 15, 2022).

[41] *See, e.g.,* Case No. 2022-00402, Attachment to Companies' Response to PSC 1-58(a) (Mar. 10. 2023) (letter from Texas Gas Transmission to the Companies listing system improvements Texas Gas Transmission was developing to address issues that caused December 2022 gas pressure drop that led to load shedding event).

assurance concerns, the Companies' assumed forced outage rates remain reasonable and sufficient to address fuel assurance risks.

Q. How does the Retirement Assessment address Senate Bill 4's reserve capacity requirement (Senate Bill 4 Section 2(2)(a)(3))?

A. Section 2(2)(a)(3) requires that replacement electric generating capacity "[m]aintain[] the minimum reserve capacity requirement established by the utility's reliability coordinator[.]" Because the Companies are not RTO members, they do not have a reliability coordinator that prescribes a reserve capacity requirement.

The Companies have contracted with the Tennessee Valley Authority ("TVA") to act as the Companies' reliability coordinator since the Companies exited Midwest Independent System Operator ("MISO"), but in that role TVA does not have the obligation or authority to prescribe a reserve capacity requirement for the Companies. Instead, the Companies establish their reserve margins using reserve margin studies that are subject to Commission review in integrated resource plan and CPCN cases, among others.[42] Therefore, the Companies assume that meeting the Companies' seasonal reserve margin targets is a sufficient demonstration of a reasonable reserve of capacity.

As shown in Table 5 above, the Companies' CPCN-DSM portfolio exceeds the Companies' seasonal minimum reserve margins. Therefore, the proposed and assumed retirements and replacement resources satisfy Senate Bill 4's reserve capacity requirements.

[42] *See, e.g., Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2021-00393, IRP Vol. III, "2021 IRP Reserve Margin Analysis" (Oct. 19, 2021); Case No. 2022-00402, May 2023 Update to Exhibit SAW-1, Appendix D (May 4, 2023).

Q. How does the Retirement Assessment address Senate Bill 4's requirements that unit retirements cause no harm to utility ratepayers (Senate Bill 4 Section 2(2)(b)) and result in cost savings for customers when accounting for all known direct and indirect costs of retirement (Senate Bill 4 Section 2(3))?

A. The Retirement Assessment provides calculations of the present value of revenue requirements ("PVRR") associated with nine total resource portfolios beginning with operating the Companies' current resource portfolio plus proposed DSM-EE programs (i.e., no retirements; Portfolio 0) and ending with the Companies' full proposed CPCN-DSM resource portfolio in 2028 (Portfolio 8). By their nature, the Companies' PVRR calculations are designed to include all known direct and indirect costs of the proposed unit retirements that will be included in customers' rates, including on-site costs associated with retiring the units (direct costs) and the costs of replacing their capacity (indirect costs). Table 7 below shows the categories of direct and indirect costs included in the Companies' PVRR calculations.

Table 7: Direct and Indirect Costs of Unit Retirements Considered in Analysis[43]

Cost Item	Direct Costs	Indirect Costs
Generation Production Costs	Variable fuel and reagent costs directly consumed by affected units.	Variable fuel and reagent costs directly consumed by other existing and proposed units in the Companies' fleet, and the cost of purchased power such as OVEC and solar PPAs.
Coal Combustion Residuals (CCR) Beneficial Re-use	Revenue of CCR sales associated with affected units.	Revenue of CCR sales associated with other existing units in the Companies' fleet.
Existing Unit Undepreciated Capital	Undepreciated capital cost associated with past investment in affected units.	Undepreciated capital cost associated with past investment in other existing units in the Companies' fleet.
Existing Unit Stay-Open Costs	Ongoing capital and fixed O&M associated with affected units.	Ongoing capital and fixed O&M associated with other existing units in the Companies' fleet.
Environmental Compliance Costs	Capital and O&M associated with compliance costs of affected units for new regulations, such as SCRs to comply with the Good Neighbor Plan, or incremental ELG spend to allow continued operation of Mill Creek 1.	
New Generation Capital and Stay-Open Costs		Capital and O&M associated with new generation assets.

As the Retirement Assessment shows, there is no fuel-price scenario modeled in which implementing the CPCN-DSM portfolio results in PVRR detriments relative to incurring the costs to maintain the Companies' existing resource portfolio; rather, in every scenario modeled, the Companies' proposed CPCN-DSM portfolio provides hundreds of millions of dollars of PVRR benefit relative to maintaining the existing

[43] Cost items reflected in this table are the same as those reflected in Table 4 from the Resource Assessment (May 2023 Update to Exhibit SAW-1 in the CPCN-DSM case), with the additions of Coal Combustion Residuals (CCR) Beneficial Re-use and Existing Unit Undepreciated Capital. These additional items were reflected in the Resource Assessment, just not explicitly listed in Table 4.

portfolio when accounting for all known direct and indirect costs of retiring the seven units at issue.

Table 8: Cumulative PVRR Changes ($M)

	Portfolio	Mid CTG Ratio Low Gas, Mid CTG	Mid Gas, Mid CTG	High Gas, Mid CTG	Avg of Mid CTG Scenarios
0	No Retirements; Add DSM	NA	NA	NA	NA
Fossil retirements and dispatchable electric generating replacements:					
5	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12	(662)	(607)	(495)	(588)
6	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar	(497)	(514)	(573)	(528)
Add dispatchable non-generating resources:					
7	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar/Brown BESS	(364)	(383)	(473)	(407)
Add non-dispatchable electric generating resources:					
8	**Final CPCN Portfolio:** Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar/ Brown BESS/Solar PPAs	(344)	(609)	(1,284)	(745)[44]

Therefore, retiring the seven units at issue and replacing them with the Companies' proposed CPCN-DSM resources will not harm customers in any way, but rather it will provide significant savings when considering all direct and indirect costs of unit retirements. This fully satisfies the requirements of Senate Bill 4 Sections 2(2)(b) and 2(3).

Q. How do the proposed and assumed unit retirements and replacements address Senate Bill 4's requirement that "[t]he decision to retire the fossil fuel-fired

[44] This is not (747) due to rounding.

electric generating unit is not the result of any financial incentives or benefits offered by any federal agency" (Senate Bill 4 Section 2(2)(c))?

A. As noted in the Retirement Assessment, the Companies' decision to retire the seven units at issue here does not result from such incentives; indeed, the Companies are unaware of any such financial incentives or benefits for retiring fossil fuel fired electric generating units. There are, however, federal tax credits provided for certain renewable generation resources included in the CPCN-DSM proposals. As these inure completely to the benefit of customers, they must be included in any reasonable PVRR analysis to appropriately reflect the cost of such generation supply alternatives. It would be unreasonable and unfair to customers to have such benefits eliminated from consideration when evaluating generation units. Therefore, the Companies' CPCN-DSM proposals fully satisfy this Senate Bill 4 requirement.

Q. Do any anticipated or proposed environmental regulations of which you are aware affect any of the conclusions you have presented here or in the Retirement Assessment?

A. No. What is clear is that the environmental regulations that exist today—including the Good Neighbor Plan—and the other cost and operational considerations addressed above and in the Retirement Assessment will require significant investment and construction very soon to ensure the Companies can continue to provide safe, reliable, and low-cost service to their customers. Therefore, proceeding with implementing the CPCN-DSM portfolio, including the proposed and assumed unit retirements, is the most prudent course to pursue for the Companies' customers.

Q. Do any recently expressed reliability concerns resulting from fossil fuel-fired generating unit retirements and additional renewable resource additions affect your view that the Companies should pursue their assumed and proposed unit retirements and the full CPCN-DSM portfolio?[45]

A. No. The Companies' 2022 Resource Assessment in the CPCN-DSM case, their analysis in LG&E's 2020 ECR case, and their Retirement Assessment in this case demonstrate that the Companies have carefully considered and evaluated how to maintain safe, reliable, and low-cost service for customers while satisfying all applicable environmental requirements across a wide range of possible fuel price scenarios and several carbon price scenarios. The Companies have an established history of pursuing environmental compliance facilities to extend existing units' lives when it is in customers' best interest to do so to maintain reliable, low-cost service. But the Companies' analyses at issue here show that the Companies' proposed CPCN-DSM portfolio, along with the proposed retirements, will maintain reliability and enhance resilience—including cost-effective deployment of renewable resources—while providing customers hundreds of millions of dollars of expected PVRR benefits compared to incurring the costs of retrofitting their existing units with required environmental compliance facilities and making other required capital investments. Therefore, I fully support the Companies' assumed and proposed unit retirements and

[45] *See, e.g.,* S&P Market Intelligence, "Outlook 2023: MISO expects net addition of 8.9 GW, may face capacity strain" (May 3, 2023), available at https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/article?id=75027715&KeyProductLinkType=58&utm_source=MIAlerts&utm_medium=realtime-minewsresearch-newsfeature-energy%20and%20utilities-the%20daily%20dose&utm_campaign=Alert_Email&redirected=1 (accessed May 9, 2023).

deploying the CPCN-DSM portfolio as being consistent with safe, reliable, and low-cost service for customers.

Q. Do you have a recommendation for the Commission in this case?

A. Yes. I recommend that the Commission grant the Companies' Joint Application and approve the retirements of Mill Creek 1-2, Haefling 1-2, Paddy's Run 12, Brown 3, and Ghent 2 as assumed and proposed in the CPCN-DSM case.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

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

Lonnie Bellar
Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of May 2023.

Caroline J. Davison
Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

CAROLINE J. DAVISON
COMM EXPIRES 01/22/2027
NOTARY PUBLIC
ID # KYNP63286
STATE AT LARGE, KENTUCKY

APPENDIX A

Lonnie E. Bellar

Chief Operating Officer
Kentucky Utilities Company
Louisville Gas and Electric Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-4830

Education

Bachelors in Electrical Engineering; University of Kentucky, May 1987
Bachelors in Engineering Arts; Georgetown College, May 1987
E.ON Academy, Intercultural Effectiveness Program: 2002-2003
E.ON Finance, Harvard Business School: 2003
E.ON Executive Pool: 2003-2007
E.ON Executive Program, Harvard Business School: 2006
E.ON Academy, Personal Awareness and Impact: 2006
Tuck Executive Education Program, Dartmouth University: 2015

Professional Experience

Louisville Gas & Electric Company
Kentucky Utilities Company

Chief Operating Officer	Mar. 2018 – Present
Sr. Vice President – Operations	Jan. 2017 – Mar. 2018
Vice President, Gas Distribution	Feb. 2013 –Jan. 2017
Vice President, State Regulation and Rates	Nov. 2010 – Jan. 2013

E.ON U.S. LLC

Vice President, State Regulation and Rates	Aug. 2007 – Nov. 2010
Director, Transmission	Sept. 2006 – Aug. 2007
Director, Financial Planning and Controlling	April 2005 – Sept. 2006
General Manager, Cane Run, Ohio Falls and Combustion Turbines	Feb. 2003 – April 2005
Director, Generation Services	Feb. 2000 – Feb. 2003
Manager, Generation Systems Planning	Sept. 1998 – Feb. 2000
Group Leader, Generation Planning and Sales Support	May 1998 – Sept. 1998

Kentucky Utilities Company

Manager, Generation Planning	Sept. 1995 – May 1998
Supervisor, Generation Planning	Jan. 1993 – Sept. 1995
Technical Engineer I, II and Senior, Generation System Planning	May 1987 – Jan. 1993

Professional Memberships

Institute of Electrical and Electronics Engineers

Civic Activities

Metro United Way – Board of Directors – 2022-Present
Trees Louisville – Board of Directors – 2022-Present
South East Energy Exchange Market – Board of Directors 2022
Greater Louisville, Inc.
  Board of Directors, Chair – 2020-2021
  Board of Directors, Executive Committee – 2016–Present
LG&E and KU Power of One Chair - 2018
Kentucky Science Center – Board of Directors – 2008–2016
UK College of Engineering Advisory Board – 2009 – Present
American Gas Association – Board of Directors – 2013 – Present
Southern Gas Association – Board of Directors – 2013 – Present
Metro United Way Campaign – 2008
E.ON U.S. Power of One Co-Chair – 2007