

**COMMONWEALTH OF KENTUCKY**  
**BEFORE THE PUBLIC SERVICE COMMISSION**

**In the Matter of:**

<b>ELECTRONIC JOINT APPLICATION OF</b>	)	
<b>KENTUCKY UTILITIES COMPANY AND</b>	)	
<b>LOUISVILLE GAS AND ELECTRIC</b>	)	
<b>COMPANY FOR CERTIFICATES OF</b>	)	
<b>PUBLIC CONVENIENCE AND NECESSITY</b>	)	<b>CASE NO. 2022-00402</b>
<b>AND APPROVAL OF A DEMAND SIDE</b>	)	
<b>MANAGEMENT PLAN AND APPROVAL OF</b>	)	
<b>FOSSIL FUEL-FIRED GENERATING UNIT</b>	)	
<b>RETIREMENTS</b>	)	

**RESPONSE OF**  
**KENTUCKY UTILITIES COMPANY**  
**AND**  
**LOUISVILLE GAS AND ELECTRIC COMPANY**  
**TO**  
**THE COMMISSION STAFF'S FOURTH REQUEST FOR INFORMATION**  
**DATED MAY 30, 2023**

**FILED: JUNE 9, 2023**

**KENTUCKY UTILITIES COMPANY  
AND  
LOUISVILLE GAS AND ELECTRIC COMPANY**

**Response to Commission Staff's Fourth Request for Information  
Dated May 30, 2023**

**Case No. 2022-00402**

**Question No. 1**

**Responding Witness: Lonnie E. Bellar**

Q-1. Refer to the Direct Testimony of Lonnie E. Bellar (Bellar 2023-00122 Direct Testimony), page 4, lines 9–20. Explain whether it is technically feasible to install the required environmental controls at Mill Creek 1 before the compliance deadlines to continue operation beyond 2024.

A-1. No, it is not. The timeline to receive regulatory approval, permitting, design, and implementation of the required environmental controls is beyond 2024.

The Effluent Limitations Guidelines (“ELG”) require an update to the Companies’ 2020 ECR filing to include the Mill Creek 1 flows (6-12 months). Upon regulatory approval, it is anticipated to take 18-24 months to retrofit the current ELG system to accommodate Mill Creek Unit 1 flows. Compliance is not possible by the *as-soon-as-possible* or no later than December 31, 2025 deadline.

The current KPDES permit that expires June 30, 2023 includes 316(b) regulation requirements. These requirements include performance of 122.21(r) studies to assess impingement, mortality, and entrainment requirements. KDOW waived the requirement of some studies, according to statute, based on a retirement date of Unit 1 within the following permit cycle. To continue operating Mill Creek Unit 1, LG&E would need to petition KDOW to allow submittal of all 122.21(r) studies and implement controls in the next permit cycle which is anticipated to commence as early as August 2023 and end in 2028. To achieve compliance, the petition to resubmit 122.21(r) studies will take approximately six months; the conduct of the studies will take approximately one year; permitting will take approximately one year; regulatory approvals from the Commission and the U.S. Army Corps of Engineers (“USACE”) are estimated to be 12-18 months; and construction of controls (cooling tower) would take 12-18 months. In total, the critical path for implementing controls is likely beyond the compliance period of the next KPDES permit cycle.

Attainment of the 2015 Ozone National Ambient Air Quality Standards and the Good Neighbor Plan are based on EGU NO<sub>x</sub> reductions from the implementation of Selective Catalytic Reduction (“SCR”) in the 2026 ozone season. SCR cannot

be implemented by the 2026 ozone season given the critical path timeline including approval from the Commission (12-18 months) and an anticipated 28-32 months to design and construct the new SCR. See the response to AG 2-4 as reference to this discussion.

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**Question No. 2**

**Responding Witness: Lonnie E. Bellar**

- Q-2. Refer to the Bellar 2023-00122 Direct Testimony, page 5, lines 1–11. Explain the demarcation between ordinary maintenance and major mechanical issues. Include in the explanation examples of both and the minimum estimated expense that would precipitate retirement.
- A-2. In footnote 9 on page 5 of Mr. Bellar’s Direct Testimony in Case No. 2023-00122, the Companies defined a “major mechanical issue” as a mechanical issue the repair cost of which exceeds the reliability value the repair would provide:

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.

Major expenses that have rendered similar small-frame combustion turbines uneconomic to repair are shown in the table below.

<b>Unit</b>	<b>Year Retired</b>	<b>Cost to Repair</b>	<b>Mechanical Issue</b>
Haefling 3	2013	\$500 k to \$1.5 M	Damaged turbine blades
Cane Run 11	2019	\$920 k to \$1.5 M	Damaged turbine section
Paddy’s Run 11	2021	\$2.55 M	Damaged compressor section
Zorn 1	2021	\$1.065 M	Damaged generator rotor

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**Question No. 3**

**Responding Witness: Lonnie E. Bellar**

- Q-3. Refer to the Bellar 2023-00122 Direct Testimony, page 17, lines 13–16.
- a. Will the same technology be installed at all natural gas generation resources, including the sites of the proposed natural gas combined cycle (NGCC) units, that allows combustion turbines 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.
  - b. Explain whether these improvements improve or support the reliability of the proposed NGCC units in addition to the existing simple-cycle combustion turbines (SCCT) and whether the combined cycle units will be able to operate at full load with lower gas pressure.
  - c. If the response to Item 3.b. is no, provide the partial load that the combined cycle units will be able to achieve under low gas pressure.
- A-3.
- a. The Companies are broadly assessing multiple potential technology options to mitigate the gas pressure issues experienced 12/23/2022 for the proposed units as well as our existing gas turbines. These options include incremental compression which would increase gas pressure delivery for a given plant site as well as unit logic upgrades designed to mitigate individual unit gas pressure limitations. The potential unit upgrades are very specific to the gas turbine provider and even more specific to certain models from that provider. While the broad technologies noted will apply to all proposed and existing gas turbines, the Companies cannot install the very specific improvement planned for the Trimble County gas turbines on other proposed or existing gas turbines.
  - b. As discussed in the response to part (a), these improvements will support reliability of existing and proposed units pending financial viability of the

solutions. To the extent incremental compression is installed, the proposed units will sustain full load at the gas pressures available on 12/23/2022.

- c. Not applicable.

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**Question No. 4**

**Responding Witness: Lonnie E. Bellar / Stuart A. Wilson**

Q-4. Refer to the Direct Testimony of Stuart B. Wilson (Wilson 2023-00122 Direct Testimony), Exhibit SB4-1, page 7.

- a. Provide a copy of the "PJM Glossary" referred to in footnote 14.
- b. State whether other transmission operators use the same or a similar definition of "dispatchable generation" proposed by LG&E/KU in Exhibit SB4-1, and if so, identify the transmission operators that use that definition and provide documents supporting that use.

A-4.

- a. See attachment being provided in a separate file.
- b. MISO describes Dispatchable Intermittent Resources ("DIRs") as "Generation Resources whose maximum limit is dependent on a forecast of their variable fuel source. Resources that are fueled by wind, solar, or other types of variable energy can be DIRs." See Section 4.2.11.11 (pp. 186-187) of their Business Practice Manual, *BPM 002 – Energy and Operating Reserve Markets*, (9/30/2022).<sup>1</sup> See attachments being provided in a separate files.

SPP defines Dispatchable Variable Energy Resources as "a variable energy resource capable of being incrementally dispatched down by the transmission provider."<sup>2</sup>

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<sup>1</sup> See MISO's Business Practice Manuals at <https://www.misoenergy.org/legal/business-practice-manuals/>.

<sup>2</sup> See SPP's glossary of terms at <https://www.spp.org/glossary/>.

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**Question No. 5**

**Responding Witness: Stuart A. Wilson**

Q-5. Refer to the Wilson 2023-00122 Direct Testimony, Exhibit SB4-1, page 14, Table 4.

- a. Explain why retiring Paddy's Run and Haefling units doesn't result in a change in the dispatchable range from Portfolio 2 to Portfolio 3.
- b. If the Commission were to deny any combination of the owned solar, Brown Battery Energy Storage System (BESS), dispatchable demand-side management (DSM), or the power purchase agreement (PPA) resource additions, explain whether the SB 4 dispatchability requirement is still satisfied.
- c. Explain whether DSM/Energy Efficiency (EE) portfolio meets the SB 4 requirement pertaining to replacing generating capacity for the retiring unit.
- d. Explain how the retirement of Ghent Unit 2 in Portfolio 4 and Portfolio 5 increases the full-year LOLE estimate in the summer and the full year.

A-5.

- a. As noted in footnote 36 on page 16 of Exhibit SB4-1, 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 to serve load. The Companies assume no ramping capabilities from these units. While these units can contribute to overall generating capacity, the Companies assume no contribution towards dispatchable range from these units.
- b. Yes, it is still satisfied. SB4 does not require that a retiring generating unit be replaced with *exactly the same amount* of new generating capacity that meets all the criteria of Section 2(2)(a)'s subparts, including the dispatchability requirement of Section 2(2)(a)(1); rather, it simply requires that "[t]he utility will replace the retired electric generating unit with new electric generating capacity" that meets the requirements of Section 2(2)(a). It was reasonable



for the General Assembly not to have created a megawatt-for-megawatt replacement requirement, which could have resulted in utilities having significant excess capacity over time in a declining load environment.

- c. No, it does not. SB4 Section 2(2)(a) requires that “[t]he utility will replace the retired electric generating unit with new *electric generating capacity*” (emphasis added). The Companies’ proposed DSM-EE Program Portfolio does not include any programs or measures that include electric generating capacity.
- d. Ghent 2 is available only during the non-ozone season in Portfolio 4 and not at all in Portfolio 5, which explains the higher winter and full-year LOLEs for Portfolio 5. Minor LOLE differences in the summer months (June through August) when Ghent 2 is unavailable in both portfolios are due to the way unit availability scenarios are developed for all resources by SERVVM and can be ignored.

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**Question No. 6**

**Responding Witness: Stuart A. Wilson**

Q-6. Refer to Wilson 2023-00122 Direct Testimony, Exhibit SB4-1, page 13. Explain how maintaining a loss of load expectation (LOLE) of 3.57 with the proposed replacement generation satisfies the SB 4 requirement pertaining to replacing generating capacity for the retiring unit.

A-6. SB4 Section 1(2) defines “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[.]” SB4 Section 2(2)(a)(2) requires that new electric generating capacity replacing a retiring unit must maintain or improve reliability.<sup>3</sup> The Companies’ minimum reserve margin targets are 17% in the summer and 24% in the winter. Those minimum reserve margin targets are consistent with “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.”

But portfolios with the same reserve margins can have very different LOLE depending on the composition of resources in the portfolios (i.e., the proportions of fully dispatchable, limited-duration, and intermittent resources). The analysis summarized in Section 5.2 of the 2022 Reserve Margin Analysis demonstrates this fact and is referenced on page 13 of Exhibit SB4-1.<sup>4</sup> In that analysis, the Companies evaluated four portfolios with identical reserve margins (17.9% summer; 26.0% winter) but markedly different LOLEs ranging from 3.57 for the SCCT portfolio (“Reference + SCCT”) to 15.14 for the dispatchable DSM portfolio (“Reference + Disp. DSM”).<sup>5</sup> Because (1) reserve margins in the SCCT portfolio are close to the Companies’ minimum reserve margins, (2) the

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<sup>3</sup> There is an apparent incongruity in SB4 between the electric generating capacity focus of the definition of “reliability” and the reliability-related requirement of SB4 Section 2(2)(a)(2)’s reference to the reliability of the “electric transmission grid.” As the Companies noted in Exhibit SB4-1 at page 12, footnote 25, the Companies assume the correct objective is on having adequate generating capacity, not transmission facilities.

<sup>4</sup> See Case No. 2022-00402, May 2023 Update to Exhibit SAW-1, Appendix D (May 4, 2023) beginning at page D-23.

<sup>5</sup> *Id.* at D-24, Table 15.

composition of resources in the portfolios used to determine the Companies' minimum reserve margin targets is very similar to the SCCT portfolio, (3) portfolios with the same reserve margins can have very different LOLEs, and (4) the Companies have not computed an LOLE for a generation portfolio with reserve margins precisely equal to 17% in the summer and 24% in the winter,<sup>6</sup> a 3.57 LOLE was used in the SB4 analysis as the threshold for determining adequate reliability (i.e., any portfolio with a lower LOLE than 3.57 provides more than adequate reliability). Therefore, the Companies believe that a portfolio with an LOLE equal to or less than 3.57 satisfies the reliability requirement of SB4 Section 2(2)(a)(2).

To interpret the reliability requirement otherwise, i.e., replacement capacity must always reduce LOLE relative to the utility's pre-retirement level, would result in an uneconomical one-way reliability ratchet that would harm customers as utilities would be compelled to maintain ever-growing amounts of uneconomic excess capacity.

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<sup>6</sup> *Id.* at D-22, Table 12 and D-23, Table 13. LOLE was not considered in the analysis to determine minimum reserve margins.

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**Question No. 7**

**Responding Witness: Stuart A. Wilson**

- Q-7. Refer to the Wilson 2023-00122 Direct Testimony, Exhibit SB4-1, page 14, Table 5.
- a. Explain how the retirement of Ghent Unit 2 in Portfolio 4 and Portfolio 5 increases the full year LOLE estimate in the summer and the full year.
  - b. If the Commission were to deny any combination of the owned solar, Brown BESS or the PPA resource additions, explain whether the SB4 reliability requirement is still satisfied.
  - c. Provide a version of Table 5 in which the DSM programs are removed from all portfolios, 0–8.
  - d. Provide a version of Table 5 in which the Solar PPAs are added to all portfolios 0-8.
- A-7.
- a. See the response to Question No. 5 part (d).
  - b. Yes, it would be satisfied. Portfolio 5 in Table 5 excludes the owned solar, Brown BESS, and solar PPA resource additions and has an LOLE of 1.22. Because 1.22 is less than the 3.57 LOLE threshold for determining adequate reliability, a portfolio without the referenced resource additions would satisfy SB4 requirements. See the response to Question No. 6. Likewise, Table 7 on page 18 of Exhibit SB4-1 shows that Portfolio 5 results in a summer reserve margin of 22.7% and a winter reserve margin of 30.2%, which exceed the Companies' summer and winter minimum reserve margin targets (17% and 24%, respectively).

c. See the table below.

	Portfolio	LOLE (days/10 years)		
		Summer (Jun-Aug)	Winter (Jan-Feb, Dec)	Full Year
0	No Retirements;	0.45	0.24	<b>0.74</b>
<i>Fossil retirements and dispatchable electric generating replacements:</i>				
1	Ret MC1-2; Add MC5	0.47	0.21	<b>0.72</b>
2	Ret MC1-2/BR3; Add MC5/BR12	0.14	0.09	<b>0.23</b>
3	Ret MC1-2/BR3/PR12/HF1-2; Add MC5/BR12	0.16	0.11	<b>0.28</b>
4	Ret MC1-2/BR3/PR12/HF1-2; GH2 (Non-Ozone); Add MC5/BR12	1.37	0.10	<b>1.60</b>
5	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add MC5/BR12	1.39	0.57	<b>2.11</b>
6	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add MC5/BR12/Owned Solar	0.59	0.54	<b>1.18</b>
<i>Add dispatchable non-generating resources:</i>				
7	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add MC5/BR12/Owned Solar/ Brown BESS	0.33	0.34	<b>0.71</b>
<i>Add non-dispatchable electric generating resources:</i>				
8	<b>Final CPCN Portfolio:</b> Ret MC1-2/BR3/PR12/HF1-2/GH2; Add MC5/BR12/Owned Solar/ Brown BESS/Solar PPAs	0.05	0.34	<b>0.39</b>

d. See the table below.

	Portfolio	LOLE (days/10 years)		
		Summer (Jun-Aug)	Winter (Jan-Feb, Dec)	Full Year
0	No Retirements; Add DSM/Solar PPAs	0.01	0.16	0.17
<i>Fossil retirements and dispatchable electric generating replacements:</i>				
1	Ret MC1-2; Add DSM/Solar PPAs/MC5	0.01	0.14	0.15
2	Ret MC1-2/BR3; Add DSM/Solar PPAs/MC5/BR12	0.00	0.06	0.06
3	Ret MC1-2/BR3/PR12/HF1-2; Add DSM/Solar PPAs/MC5/BR12	0.01	0.06	0.07
4	Ret MC1-2/BR3/PR12/HF1-2; GH2 (Non-Ozone); Add DSM/Solar PPAs/MC5/BR12	0.06	0.06	0.12
5	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/Solar PPAs/MC5/BR12	0.07	0.39	0.46
6	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/Solar PPAs/MC5/BR12/ Owned Solar	0.04	0.40	0.44
<i>Add dispatchable non-generating resources:</i>				
7	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/Solar PPAs/MC5/BR12/ Owned Solar/Brown BESS	0.03	0.25	0.28
<i>Add non-dispatchable electric generating resources:</i>				
8	<b>Final CPCN Portfolio:</b> Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar/ Brown BESS/Solar PPAs	0.03	0.25	0.28

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**Question No. 8**

**Responding Witness: Lonnie E. Bellar / Stuart A. Wilson**

Q-8. Refer to the Wilson 2023-00122 Direct Testimony, Exhibit SB4-1, page 14, footnote 32.

- a. Explain in detail how the forced outage rates included in the SERVVM analysis account for credible fuel assurance issues.
- b. Explain in detail the measures taken by LG&E/KU and by Texas Gas Transmission to avoid a reoccurrence of the December 2022 load shedding event.

A-8.

- a. Forced outage rates for the SERVVM analysis are developed based on multiple years of historical forced outage rates. Therefore, the impact of fuel assurance issues would be captured in forecasted forced outage rates to the extent fuel assurance issues impact unit availability. Aside from the rolling service interruptions in December 2022, the Companies have not experienced correlated outages that have materially impacted unit availability or reliability, and therefore do not model correlated outages when assessing resource adequacy. See the response to part (b) for the measures the Companies and Texas Gas are taking to avoid a reoccurrence of this low-pressure event moving forward. In addition to these measures, the Companies have firm gas transportation contracts and cold weather operating procedures that limit the potential for correlated outages. The Companies can evaluate the impact of correlated outages, but there is no reason to believe the risk of correlated outages will be significant to the point of suggesting material changes to the Companies' recommended portfolio.
- b. See the response to PSC 1-58 and PSC 2-67. The Companies will continue to communicate with Texas Gas Transmission regarding progress on its initiatives to avoid a recurrence of the December 2022 low pressure event. See the response to Question No. 3 for additional measures currently under assessment by LG&E/KU.

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**Question No. 9**

**Responding Witness: Charles R. Schram**

Q-9. Refer to the Wilson Direct Testimony, Exhibit SB4-1, page 16, Table 6, and footnotes 37–39.

- a. Explain whether contractually obligated generation output from the Solar PPAs will be dispatched before any of LG&E/KU's other generation resources.
- b. Explain whether any of LG&E/KU current or planned fossil-fuel generation units has a lower marginal cost of energy than either the owned solar or the solar PPA facilities. If so, explain whether these units would be dispatched before the solar facilities.

A-9.

- a. Energy from solar PPAs would be must-take and therefore non-dispatchable. It would displace energy the Companies would otherwise have to generate or acquire, resulting in offsetting avoided fuel or energy costs.
- b. See the response to part (a). The marginal cost of the energy from the Companies' owned solar units is effectively zero (marginal cost is negative for the 10-year duration of the IRA's production tax credit), similar to the Companies' hydro units. Depending on fuel and other variable costs, some—but not all—of the Companies' current and planned fossil-fuel-fired generating resources have lower marginal energy costs than the four solar PPAs discussed in this proceeding. To the extent off-system sales occur during times when the Companies are purchasing solar PPA energy, the cost of that energy will be allocated to off-system sales as appropriate in the Companies' after-the-fact billing ("AFB") process.



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**Question No. 10**

**Responding Witness: Stuart A. Wilson**

Q-10. Refer to the Wilson 2023-00122 Direct Testimony, Exhibit SB4-1, page 17 and page 18, Table 7.

- a. Explain whether the SB 4 capacity requirement is fulfilled if LG&E/KU's summer and winter reserve margins exceed LG&E/KU minimum reserve margins.
- b. Explain why Portfolio 8 with summer and winter reserve margins of 38.4 percent and 32.3 percent respectively is reasonable, given that the planning minimum reserve margin is 17 percent and 24 percent respectively.

A-10.

- a. Yes, the SB 4 capacity requirement is fulfilled if the Companies' summer and winter reserve margins exceed the Companies' minimum reserve margins. As the Companies stated in Exhibit SB4-1, 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. Therefore, meeting the Companies' seasonal reserve margin targets is a sufficient demonstration of a reasonable reserve capacity. Table 7 on page 18 of Exhibit SB4-1 shows that the Companies' proposed replacement resources for the retiring units will exceed the Companies' own minimum reserve margin targets and therefore satisfy the reserve capacity requirement of SB4 Section 2(2)(a)(3). But because portfolios with the same reserve margin can have very different LOLE, it is important to assess the reliability and capacity requirements together. See the response to Question No. 6.
- b. To understand why it is reasonable, compare Portfolio 5 to Portfolio 8. Portfolio 5 includes no new solar or battery resources; it includes only existing resources minus the proposed unit retirements plus the two proposed NGCC units. It has a summer reserve margin of 22.7% and a winter reserve margin of 30.2% and a full-year LOLE of 1.22; therefore, it is within the Companies' target reserve margin range. (Notably, it also results in hundreds of millions

of dollars of PVRR savings compared to continuing to operate the existing fleet over the same period.) Adding battery and solar resources to arrive at Portfolio 8 results in *additional* PVRR benefits in all mid- and high-gas price scenarios and reduces LOLE. That is why targeting only a single reserve margin target is misleading; it is not always the case that having a higher reserve margin results in higher PVRR, as Table 8 in Exhibit SB4-1 shows. An optimal resource portfolio should reduce costs while achieving or exceeding minimum reliability requirements. For the Companies, Portfolio 5 does achieve that result, *but Portfolio 8 improves upon it*. For that reason, Portfolio 8 and its associated reserve margins are reasonable.

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**Question No. 11**

**Responding Witness: Lonnie E. Bellar / Stuart A. Wilson**

- Q-11. Refer to the Wilson 2023-00122 Direct Testimony, Exhibit SB4-1, page 26, Table 11. Describe any analysis done to assess the present value of revenue requirement (PVRR) of an alternate portfolio that keeps Paddy's Run 12 and Haefling 1-2 online and reduces the size of the planned NGCC capacity build-out.
- A-11. The Companies have not performed this analysis. Given the age of these units and the fact that four similar units (Haefling 3, Cane Run 11, Paddy's Run 11, and Zorn 1) have experienced major mechanical issues and retired in the past 10 years, the Companies do not believe it is prudent to make future resource decisions with the assumption that these units will operate beyond 2025. In addition, these units have very high heat rates and are unreliable compared to the Companies' other resources, and they therefore operate at extremely low capacity factors. Given the significant need for energy created by retiring the coal units, these units would not be an economic alternative for NGCC capacity. Moreover, it is important to note that (1) a 1x1 NGCC's capacity is largely fixed for a given OEM, (2) the range of capacities across different OEMs is relatively narrow, and (3) a 1x1 NGCC with a slightly lower capacity will not necessarily be less costly than a 1x1 NGCC with a higher capacity. Therefore, the option to construct a smaller NGCC at a lower cost may not exist. The total capacity of the three cited CTs is 47 MW summer and 55 MW winter.

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**Question No. 12**

**Responding Witness: Stuart A. Wilson**

Q-12. Refer to LG&E/KU's response to Commission Staff's Second Request for Information (Staff's Second Request), Item 50, filed in Case No. 2022-00402.

- a. State whether, and if so, explain how the forced outage rates for Mill Creek Unit 2 and Ghent Unit 2 used to calculate the LOLE were affected by the addition of new selective catalytic reduction (SCR) on those units.
- b. If the addition of new SCRs on Mill Creek Unit 2 and Ghent Unit 2 did not affect forced outage rates, explain what variable was used to reflect the unavailability of the units during ozone season if SCRs were not added and how that variable was reflected in the calculation of the LOLE.

A-12.

- a. The Companies assumed that forced outage rates are not affected by the addition of SCR.
- b. The availability variable in SERVVM was used to model these units as unavailable during the ozone season in cases where SCR is not added.

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**Question No. 13**

**Responding Witness: Stuart A. Wilson**

- Q-13. Refer to LG&E/KU’s response to Staff’s Second Request, Question 81, which provided the results of a run using a 20-year life for both NGCC and SCCT unit, and determined the optimal portfolio was continuing to operate Ghent 2, but in non-ozone-season months only (October through April); retiring Mill Creek 2 and Brown 3; constructing two 250 MW combustion turbines at Mill Creek; 100 MW battery storage PPA; and between 518 MW and 2,772 MW of Solar PPAs, depending on the fuel price scenario. Provide the LOLE value for this portfolio and discuss how the reliability compares relative to the other portfolios listed in Exhibit SB4-1, Table 5.
- A-13. The table below contains the LOLE for the portfolio developed for the Mid Gas, Mid Coal-to-Gas Ratio fuel price scenario. This portfolio contains 737 MW of solar PPAs which is comparable to the amount of solar PPAs in the proposed portfolio. Compared to the LOLE of the portfolios in Table 5, this portfolio’s LOLE is significantly higher, meaning reliability is much worse. Even though the summer and winter reserve margins of this portfolio are 21.0% and 25.4%, respectively, a smaller portion of resources in this portfolio are fully dispatchable. This result further demonstrates that the composition of a portfolio is a key factor in determining reliability.

<b>LOLE (days/10 years)</b>		
<b>Summer (Jun-Aug)</b>	<b>Winter (Jan-Feb, Dec)</b>	<b>Full Year</b>
3.05	1.02	4.38

Note also that there is no reason to expect that either of the Companies’ NGCCs will have a 20-year service life. Such an expectation would be inconsistent with the U.S. Environmental Protection Agency’s (“EPA”) recently proposed New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units and Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-

Fired Electric Generating Units, as well as EPA's own resource modeling associated with its proposed rulemaking, which indicates adding *far more* NGCC capacity in 2028 than the Companies have proposed would be economical. See the response to KCA 3-3.

**KENTUCKY UTILITIES COMPANY  
AND  
LOUISVILLE GAS AND ELECTRIC COMPANY**

**Response to Commission Staff's Fourth Request for Information  
Dated May 30, 2023**

**Case No. 2022-00402**

**Question No. 14**

**Responding Witness: Charles R. Schram**

- Q-14. Refer to the Direct Testimony of Charles R. Schram, page 6, lines 1–12, regarding concerns regarding the impact of supply chain constraints and solar component tariffs on pricing raised by responded to a 2021 request for proposal (RFP). On May 18, 2023, S&P Global published an article that documented an increase in solar imports in 2023 Q1, due to a temporary tariff waiver in photovoltaic cells and modules from Southeast Asia, and projections that costs for imported solar components will not increase in the near term, based upon President Biden's May 16, 2023, veto of proposed legislation to end a two-year moratorium on additional solar tariffs from Vietnam, Cambodia, and Thailand.<sup>7</sup>
- a. Given a changing market trend regarding imported solar component availability and costs since the 2021 RPF, explain whether LG&E/KU will reopen the 2021 RFP to assess whether cheaper, more reliable applications are submitted by developers.
  - b. Refer also to Direct Testimony of Tim A. Jones (Jones Direct Testimony), CONFIDENTIAL-Exhibit TAJ-3, Confidential Workpapers folder, Hourly\_Forecast\_Updates, PV, Price Needed to Meet Total Project Costs, Price Needed for Energy Exported to Grid to Meet Total Project Costs\_SAW.xlsx, Model tab, filed in Case No. 2022-00402. If the 2021 RFP is reopened, state whether LG&E/KU will update the escalation rate used to convert private solar costs from real to nominal.
- A-14.
- a. The Companies assume the reference is to the RFP issued in June 2022 with responses due in August 2022.

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<sup>7</sup> S&P Global, S&P Capital IQ, May 18, 2023.

[https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/article?id=75789625&KeyProductLinkType=58&utm\\_source=MIAalerts&utm\\_medium=realtime-minewsresearch-newsfeature-energy%20and%20utilities-the%20daily%20dose&utm\\_campaign=Alert\\_Email&redirected=1](https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/article?id=75789625&KeyProductLinkType=58&utm_source=MIAalerts&utm_medium=realtime-minewsresearch-newsfeature-energy%20and%20utilities-the%20daily%20dose&utm_campaign=Alert_Email&redirected=1)

See the response to PSC 1-27. The Companies have four fully executed PPAs, three of which have provisions for price reopeners. Therefore, revisiting the overall RFP process is not practicable. Additional RFPs will be issued when needed as part of future resource planning activities.

While the cited S&P report notes that the tariff freeze on solar panel imports will continue as a “temporary bridge that concludes in June 2024”, LevelTen Energy’s PPA price index for the first quarter of 2023 cites an 8.5 percent increase in solar PPA prices since the end of 2022.<sup>8</sup> Furthermore, considering that the IRA’s tax credit provisions and specific incentives require the use of U.S. made solar panels, it is unclear how additional solar panel imports over the next year will affect longer-term pricing.

- b. See the response to part (a).

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<sup>8</sup> <https://www.utilitydive.com/news/renewable-solar-wind-power-prices-rising-ira-ppa-demand/647892/>