**COMMONWEALTH OF KENTUCKY**

**BEFORE THE PUBLIC SERVICE COMMISSION**

**In the Matter of:**

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

**RESPONSE OF**
**KENTUCKY UTILITIES COMPANY**
**AND**
**LOUISVILLE GAS AND ELECTRIC COMPANY**
**TO**
**THE COMMISSION STAFF'S FIFTH REQUEST FOR INFORMATION**
**DATED JUNE 27, 2023**

**FILED: JULY 7, 2023**

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

**Response to Commission Staff's Fifth Request for Information**
**Dated June 27, 2023**

**Case No. 2022-00402**

**Question No. 1**

**Responding Witness: Stuart A. Wilson**

Q-1. Refer to Case 2022-00402, Direct Testimony of Stuart A. Wilson (Wilson Direct Testimony), Exhibit SAW-1, 2022 Resource Assessment, pages 22–23, Section 4.4.1, "Stage One, Step One: Portfolio Development and Screening with PLEXOS," which describes the initial capacity expansion modeling performed in PLEXOS.[1]

a. Perform additional PLEXOS modeling runs using identical assumptions to those used in Stage One, Step One as described in the 2022 Resource Assessment, making no modifications, except set the summer and winter capacity value of solar resources to 0 for the base price scenario.

b. For the modeling runs in part a., provide the Selected Portfolio, Incremental Present Value Revenue Requirement (PVRR), Loss of Load Expectation (LOLE), Reserve Margin, Net Summer/Winter Capacity, and Dispatchable Summer/Winter Range.

A-1.

a. The results of these runs are summarized in the table below and are identical to the original Stage One, Step One results summarized in Table 5 of Exhibit SAW-1. Note that the <u>winter</u> firm capacity value for solar resources was already zero. In the Stage One, Step One analysis, the Rhudes Creek and Ragland solar PPAs were assumed to be added in all scenarios but were not considered "new" resources and therefore were excluded from "Total New Renewables." Based on the Companies' forecasted summer and winter peak demands under normal weather conditions and their summer and winter minimum reserve margin targets, the winter reserve margin constraint is the binding constraint in this step of the analysis where fully dispatchable and

[1] If LG&E/KU cannot complete the modeling runs by July 7, 2023, LG&E/KU may file a motion requesting an extension and providing the estimated date this response will be filed.

limited-duration resources are assumed to be available year round.[2] As a result, changing the summer firm capacity value for solar resources has no impact on the Stage One, Step One results.[3] In this step of the analysis, PLEXOS selected solar resources to reduce energy costs.

**Portfolio Development and Screening Results by Fuel Price Scenario (Firm Capacity Value of Solar Resources = 0 in Summer and Winter)**

| | Fuel Price Scenario (Gas, CTG Price Ratio) | Least-Cost Resource Portfolio | | |
|---|---|---|---|---|
| | | Changes to Dispatchable Resources by 2028 | Total New Renewables by 2028 (MW)[4] | Total New Renewables by 2035 (MW)[4] |
| Expected CTG | Low Gas, Mid CTG Ratio | Replace MC2, GH2, BR3 w/ MC5 and BR12 | N/A | N/A |
| | Mid Gas, Mid CTG Ratio | Replace MC2, GH2, BR3 w/ MC5 and BR12 | 104 Solar | 384 Solar |
| | High Gas, Mid CTG Ratio | Replace MC2, BR3 w/ MC5; Add SCR at GH2 | 637 Solar | 2,322 Solar |
| Atypical CTG | Low Gas, High CTG Ratio | Replace MC2, GH2, BR3 w/ MC5 and BR12 | N/A | N/A |
| | High Gas, Low CTG Ratio | Replace MC2, BR3 w/ MC5; Add SCR at GH2 | 384 Solar | 2,322 Solar |
| | High Gas, Current CTG Ratio | Replace MC2, GH2, BR3 w/ MC5 and BR12 | 2,322 Solar | 2,717 Solar<br>143 Wind |

b. See the tables below. Note that the values reflect the retirement of existing dispatchable DSM programs. Furthermore, consistent with Exhibit SB4-1 and unlike the table provided in the response to part (a), the capacities of "new" resources in the tables below include the Rhudes Creek and Ragland solar PPAs. For the workpapers supporting this response, see the attachment being provided in a separate file. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

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[2] In 2028, the Companies' forecasted summer and winter peak demands under normal weather conditions are 6,319 MW and 6,104 MW, respectively (see Table 25 on page 44 of Exhibit SAW-1). Thus, to meet the 17% minimum summer reserve margin, the Companies would need to have 7,393 MW of resources, whereas the Companies would need 7,569 MW of resources to meet their 24% winter minimum reserve margin.

[3] Note that changing the summer firm capacity value for solar resources could potentially impact the Stage Two portfolios that evaluate operating Mill Creek 2 and Ghent 2 only during the non-ozone season.

[4] In the Stage One, Step One analysis, the Rhudes Creek and Ragland solar PPAs were assumed to be added in all scenarios but were not considered "new" resources and therefore were excluded from "Total New Renewables."

## Incremental PVRR, LOLE, and Reserve Margins

| Fuel Price Scenario (Gas, CTG Price Ratio) | | Retired Resources | New Resources[5] | Incremental PVRR ($M) | LOLE | Summer Reserve Margin | Winter Reserve Margin |
|---|---|---|---|---|---|---|---|
| Expected CTG | Low Gas, Mid CTG Ratio | MC1-2, BR3, GH2, HF1-2, PR12, Existing DSM | MC5, BR12; 225 MW Solar PPAs | (777) | 1.33 | 22.2% | 28.4% |
| Expected CTG | Mid Gas, Mid CTG Ratio | MC1-2, BR3, GH2, HF1-2, PR12, Existing DSM | MC5, BR12; 329 MW Solar PPAs | (839) | 1.09 | 23.5% | 28.4% |
| Expected CTG | High Gas, Mid CTG Ratio | MC1-2, BR3, HF1-2, PR12, Existing DSM | MC5; 862 MW Solar PPAs | (1,321) | 1.11 | 28.0% | 25.8% |
| Atypical CTG | Low Gas, High CTG Ratio | MC1-2, BR3, GH2, HF1-2, PR12, Existing DSM | MC5, BR12; 225 MW Solar PPAs | (937) | 1.33 | 22.2% | 28.4% |
| Atypical CTG | High Gas, Low CTG Ratio | MC1-2, BR3, HF1-2, PR12, Existing DSM | MC5; 609 MW Solar PPAs | (996) | 1.34 | 24.8% | 25.8% |
| Atypical CTG | High Gas, Current CTG Ratio | MC1-2, BR3, GH2, HF1-2, PR12, Existing DSM | MC5, BR12; 2,547 MW Solar PPAs | (5,733) | 0.54 | 51.1% | 28.4% |

## Incremental Changes in Total and Dispatchable Capacity (MW)

| Fuel Price Scenario (Gas, CTG Price Ratio) | | Net Summer/Winter Capacity | | | Dispatchable Summer/Winter Range (Net Max less Net Min) | | |
|---|---|---|---|---|---|---|---|
| | | Retired Resources | New Resources[6] | Diff: New less Retired | Retired Resources | New Resources[7] | Diff: New less Retired |
| Expected CTG | Low Gas, Mid CTG Ratio | 1,576/1,565 | 1,419/1,282 | (157)/(283) | 864/845 | 790/760 | (74)/(85) |
| Expected CTG | Mid Gas, Mid CTG Ratio | 1,576/1,565 | 1,501/1,282 | (75)/(283) | 864/845 | 790/760 | (74)/(85) |
| Expected CTG | High Gas, Mid CTG Ratio | 1,095/1,083 | 1,299/641 | 204/(442) | 608/588 | 395/380 | (213)/(208) |
| Atypical CTG | Low Gas, High CTG Ratio | 1,576/1,565 | 1,419/1,282 | (157)/(283) | 864/845 | 790/760 | (74)/(85) |
| Atypical CTG | High Gas, Low CTG Ratio | 1,095/1,083 | 1,100/641 | 5/(442) | 608/588 | 395/380 | (213)/(208) |
| Atypical CTG | High Gas, Current CTG Ratio | 1,576/1,565 | 3,244/1,282 | 1,668/(283) | 864/845 | 790/760 | (74)/(85) |

[5] Includes 225 MW associated with Rhudes Creek and Ragland solar PPAs.
[6] Capacity values reflect 78.6% expected contribution to summer peak capacity and 0% expected contribution to winter peak capacity.
[7] The dispatchable range of solar PPAs is assumed to be zero.

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

**Response to Commission Staff's Fifth Request for Information**
**Dated June 27, 2023**

**Case No. 2022-00402**

**Question No. 2**

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

Q-2. Refer to Case 2022-00402, Wilson Direct Testimony, Exhibit SAW-1, 2022 Resource Assessment, pages 22–23, Section 4.4.1, "Stage One, Step One: Portfolio Development and Screening with PLEXOS," which describes the initial capacity expansion modeling performed in PLEXOS. Perform additional PLEXOS modeling runs using identical assumptions to those used in Stage One, Step One as described in the 2022 Resource Assessment, with only the below modifications, and provide the Selected Portfolio, Incremental PVRR, LOLE, Reserve Margin, Net Summer/Winter Capacity, and Dispatchable Summer/Winter Range. For model runs that include technologies not previously modeled, such as Carbon Capture and Sequestration (CCS), low-GHG hydrogen co-firing, or coal-to-gas conversion, provide the additional capital, operational, and fuel cost assumptions.

a. Coal resource decisions: For Brown 3, Ghent 2, and Mill Creek 1 and 2, model all the potential compliance routes for the newly proposed Environmental Protection Agency (EPA) carbon regulation rule as options for PLEXOS to select:

(1) Scenario 1: Economic retirement with Selective Catalytic Reduction (SCR)/Overhaul Option

(a) Add SCR to Ghent 2 and Mill Creek 1 and 2 in 2028, or retire by 2028. No additional capital investments, forced retirement by 2032.

(b) Complete overhaul of Brown 3 required for continued operation in 2028, or economic retirement by 2028. No additional capital investments, forced retirement by 2032.

(2) Scenario 2: Advanced Tech for EPA Compliance - NG Co-Firing.

(a) Add SCR to Ghent 2 and Mill Creek 1 and 2 in 2028, begin co-firing 40 percent natural gas on a heat input basis starting 2030, retire by 2040.

(b) Complete overhaul of Brown 3 in 2028, begin co-firing 40 percent natural gas on a heat input basis starting 2030, retire by 2040.

(3) Scenario 3: Advanced Tech for EPA Compliance – CCS.

(a) Add SCR to Ghent 2 and Mill Creek 1 and 2 in 2028, install CCS with 90 percent capture starting in 2030, retire any time after 2040.

(b) Complete overhaul of Brown 3 in 2028, install CCS with 90 percent capture starting in 2030, retire any time after 2040.

(4) Scenario 4 (Optional): Reduced Capacity Factor for EPA Compliance.

(a) Add SCR to Ghent 2 and Mill Creek 1 and 2 in 2028, begin operating at 20 percent maximum capacity factor in 2030, retire by 2035.

(b) Complete overhaul of Brown 3 in 2028, begin operating at 20 percent maximum capacity factor in 2030, retire by 2035.

(5) Scenario 5: Non-Ozone Season Operations.

(a) Repeat most economic option from Scenarios 2–4, but with non-ozone season operation instead of the SCR for Ghent 2 and Mill Creek 1 and 2.

(b) Continue with Complete overhaul of Brown 3 in 2028 or economic retirement and most economic EPA compliance option.

b. New thermal resource options: For each of the above scenarios, include all of the following candidate resource options in place of the standard, non-compliant Natural Gas Combined Cycle (NGCC) and Simple Cycle Combustion Turbine (SCCT) resources from the original modeled scenarios.

(1) For the proposed NGCC units, model the potential compliance routes for the newly proposed EPA carbon regulation rule as options for PLEXOS to select:

(a) Resource 1: Build NGCC with addition of CCS with 90 percent capture by 2035.

(b) Resource 2: Build NGCC, begin co-firing 30 percent low-GHG H2 by volume by 2032, co-firing 96 percent low-GHG H2 by volume by 2038.

(c) Resource 3: Build NGCC as proposed but operate with maximum capacity factor below 50 percent, begin co-firing 30 percent low-GHG H2 by volume by 2032.

(d) Resource 4: Build NGCC as proposed but operate with maximum capacity factor below 20 percent.

(e) Resource 5: Build NGCC as proposed but with a retirement date in 2032.

(2) For all the SCCT units resource options, operate with maximum capacity factor below 20 percent.

c. Existing thermal resources: Include with all above scenarios. Give the model the option to keep Haefling and Paddy's Run units online.

A-2. This request asks about the potential impact of the U.S. Environmental Protection Agency's ("EPA") proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units ("GHG NSPS") and Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units ("GHG Rule for Existing EGUs") (collectively, "New GHG Rules") promulgated under Clean Air Act Sections 111(b) and (d), respectively, on the Companies' applications. The Companies agree that it is appropriate to stress test their analyses of the RFP responses against possible major and material uncertainties such as the proposed New GHG Rules.

In short, in addition to the information the Companies previously provided concerning the impacts of the proposed New GHG Rules in response to KCA 3-3, the Companies provide below an approach to understanding possible impacts of the proposed New GHG Rules on the Companies' applications. The response begins by clarifying what the proposed New GHG Rules would require. The Companies then provide a "regrets analysis" stress test of their previous modeling results, making assumptions based on the proposed New GHG Rules that are unfavorable to the Companies' proposals in this proceeding. Fundamentally, the new stress-test analysis asks a straightforward question to address the potential impact of the New GHG Rules:

> If the EPA implements the New GHG Rules as proposed, what effect would the compliance alternative that can be modeled currently with a reasonable degree of accuracy (i.e., an operating constraint of a 50% annual capacity factor on the Mill Creek and

> Brown NGCCs) have on the Companies' least-cost compliance plan for the GNP and retirement of Brown Unit 3?

The results show that the Companies' proposed NGCC units and solar PPAs remain least-cost across a large majority of modeled scenarios. In fact, the only scenarios in which an alternative portfolio would be lower cost involve situations where compliance with the New GHG Rules is "free" for coal-fired units while constraining the use of lower $CO_2$-emitting NGCC units. Finally, the Companies provide a summary of the EPA's own modeling efforts regarding the Companies' balancing area through 2055. The results of EPA's modeling are directionally consistent with the Companies' proposals, particularly installing NGCC capacity in 2028—indeed, far more NGCC capacity in 2028 than the Companies have proposed.

**Clarifying the Recently Proposed Greenhouse Gas Rules and their Applicability**

As an initial matter, it is helpful to clarify what the New GHG Rules require and to which units they apply. The following table from EPA summarizes the GHG NSPS for new natural gas EGUs:[8]

[8] Table taken from slide 8 of EPA's presentation, "Overview Presentation: Clean Air Act Section 111 Regulation of Greenhouse Gas Emissions from Fossil Fuel-Fired Electric Generating Units," available at https://www.epa.gov/system/files/documents/2023-05/111%20Power%20Plants%20Stakeholder%20Presentation2_4.pdf (accessed June 3, 2023).

<table>
<tr><th>Phase I<br>(By date of promulgation or upon initial startup)</th><th>Phase II<br>Beginning in 2032-2035</th><th>Phase III<br>Beginning in 2038</th></tr>
<tr><td colspan="3">Low Load Subcategory (Capacity Factor <20%)</td></tr>
<tr><td>BSER: Use of low emitting fuels (e.g., natural gas and distillate oil)<br><u>Standard</u>: From 120 lb $CO_2$/MMBtu to 160 lb $CO_2$/MMBtu, depending on fuel type</td><td colspan="2">No proposed Phase II or Phase III BSER component or standard of performance</td></tr>
<tr><td colspan="3">Intermediate Load Subcategory (Capacity Factor 20% to ~50%*)<br>*Upper bound limit based on EGU design efficiency and site-specific factors</td></tr>
<tr><td>BSER: Highly efficient simple cycle generation<br><u>Standard</u>: 1,150 lb $CO_2$/MWh-gross</td><td>BSER: Continued highly efficient simple cycle generation with 30% (by volume) low-GHG hydrogen co-firing beginning in 2032<br><u>Standard</u>: 1,000 lb $CO_2$/MWh-gross</td><td>No proposed Phase III BSER component or standard of performance</td></tr>
<tr><td colspan="3">Base Load Subcategory (Capacity Factor >~50%*) *Limit</td></tr>
<tr><td>BSER: Highly efficient combined cycle generation<br><br><u>Standard</u>: 770 lb $CO_2$/MWh-gross (EGUs with a base load rating of 2,000 MMBtu/h or more)<br><br><u>Standard</u>: 770 lb – 900 lb $CO_2$/MWh-gross (EGUs with a base load rating of less than 2,000 MMBtu/h)</td><td>Low-GHG Hydrogen Pathway BSER: Continued highly efficient combined cycle generation with 30% (by volume) low-GHG hydrogen co-firing beginning in 2032<br><u>Standard</u>: 680 lb $CO_2$/MWh-gross<br>CCS Pathway BSER: Continued highly efficient combined cycle generation with 90% CCS beginning in 2035<br><u>Standard</u>: 90 lb$CO_2$/MWh gross</td><td>Low-GHG Hydrogen Pathway BSER: Co-firing 96% (by volume) low-GHG hydrogen beginning in 2038<br><u>Standard</u>: 90 lb $CO_2$/MWh-gross<br><br>CCS Pathway: No Phase III BSER component or standard of performance</td></tr>
<tr><td colspan="3">The proposed definition of low-GHG hydrogen is hydrogen produced with less than 0.45kg$CO_2$e/kg$H_2$ overall well to gate emissions, consistent with IRC section 45V(b)(2)(D).</td></tr>
</table>

Note that the GHG NSPS does *not* require carbon dioxide ("$CO_2$") capture and sequestration ("CCS") or hydrogen co-firing per se for new gas-fired units; rather, the GHG standard is based on EPA's proposed determination that these technologies are (or will be) the best system of emissions reduction ("BSER"). Thus, for baseload gas-fired units nothing is required prior to 2032 (at the earliest) other than achieving $CO_2$ emissions of no more than 770 lbs./MWh gross, which the Companies' proposed NGCC units will be capable of achieving. The rule then provides compliance flexibility for high-efficiency NGCCs beginning in 2032: (1) reducing capacity factor to 50% and operating as an intermediate-load unit indefinitely (which has a $CO_2$ emission restriction of no more than 1,000 lbs./MWh gross), (2) meeting the lowered 680 lbs./MWh gross $CO_2$ emission standard, which EPA has stated will be achievable by co-firing low-GHG hydrogen, or (3) meeting the 90 lbs./MWh gross $CO_2$ emission standard, which EPA has stated will be achievable through the CCS path, which does not require CCS to be operational until 2035.

Thus, the characterization in PSC data request 5-2(b) of the modeled NGCC units as "non-compliant" unless they (i) reduce their capacity factor to 50% and operate with 30% low-GHG co-firing by 2032 or (ii) reduce their capacity factor to 20% by 2032, all as set out in part (b) of this request, is incorrect because it does not accurately reflect the proposed GHG NSPS.

The following EPA table summarizes the GHG Rule for Existing EGUs:[9]

<table>
<tr><th>Coal-Fired Boilers</th><th>Natural Gas and Oil-Fired Boilers</th><th>Natural Gas Combustion Turbines</th></tr>
<tr><td>For units operating past December 31, 2039,<br>**BSER:** CCS with 90% capture of $CO_2$ an (88.4% reduction)</td><td rowspan="3">**BSER:** routine methods of operation and maintenance with an associated degree of emission limitation of no increase in emission rate (lb $CO_2$/MWh-gross).</td><td rowspan="3">For turbines >300MW, >50% capacity factor<br><br>**CCS Pathway BSER:** By 2035: highly efficient generation coupled with CCS with 90% capture of $CO_2$ (90 lb $CO_2$/MWh)<br><br>**Low-GHG Hydrogen Pathway BSER:** By 2032: highly efficient generation coupled with co-firing 30% (by volume) low-GHG hydrogen (680 lb $CO_2$/MWh) By 2038: highly efficient generation coupled with co-firing 96% low-GHG hydrogen (90 lb $CO_2$/MWh)</td></tr>
<tr><td>For units that cease operations before January 1, 2040 and are not in other subcategories,<br>**BSER**: co-firing 40% (by volume) natural gas with emission limitation of a 16% reduction in emission rate (lb $CO_2$/MWh-gross basis)</td></tr>
<tr><td>For units that cease operations before January 1, 2032, and units that cease operations after January 1, 2035, that adopt enforceable annual capacity factor limit of 20%,<br>**BSER**: routine methods of operation and maintenance with associated degrees of emission limitation of no increase in emission rate</td></tr>
<tr><td colspan="3">The proposed definition of low-GHG hydrogen is hydrogen produced with less than 0.45kg$CO_2$e/kg$H_2$ overall well to gate emissions, consistent with IRC section 45V(b)(2)(D).</td></tr>
</table>

Note that the proposed GHG Rule for Existing EGUs would place significant constraints on *all* existing coal-fired units by January 1, 2030, not just a small subset of coal units. Therefore, any modeling to address the GHG Rule for Existing EGUs should account for impacts to all coal-fired units, not only the units identified in this request.

**<u>The Companies' Modeling Rationale, Methodology, and Results in Response to this Request</u>**

This request asks the Companies to model a number of investment alternatives that are hypothetical and for which the Companies do not possess real, actionable proposals or cost estimates. That contrasts sharply with the analyses the Companies have filed in this case to address the very real need for timely compliance with the EPA's now-final Good Neighbor Plan ("GNP") and to seek lower cost alternatives to continued investment in the aging and high-cost Brown Unit 3. All the supply-side alternatives the Companies have evaluated in this proceeding were responses to a Request for Proposals ("RFP") to possibly address GNP compliance and the future of Brown Unit 3.

[9] Table taken from slide 13 of EPA's presentation, "Overview Presentation: Clean Air Act Section 111 Regulation of Greenhouse Gas Emissions from Fossil Fuel-Fired Electric Generating Units," available at https://www.epa.gov/system/files/documents/2023-05/111%20Power%20Plants%20Stakeholder%20Presentation2_4.pdf (accessed June 3, 2023).

In addition, because the alternatives this data request asks the Companies to evaluate are hypothetical, the Companies do not have such necessary information needed to perform the analysis requested such as:

- Pipeline routing and cost estimates for supplying natural gas at Ghent. Given the challenges facing pipeline routing throughout the U.S., this is unlikely to be an immaterial matter.

- Carbon capture costs, transportation costs to storage fields, and storage field costs. Furthermore, based on work by the Kentucky Geological Survey,[10] the Companies already know that potential $CO_2$ storage volumes are limited near Ghent, Mill Creek, and Brown. Therefore, storage sites outside of Kentucky would likely need to be identified and the necessary pipelines would need to be sited and built, perhaps for hundreds of miles.

- Low-GHG hydrogen sources have not been developed and pricing is uncertain. As discussed below and in response to KCA 3-3, even the EPA did not address hydrogen production in their Regulatory Impact Analysis ("RIA") of the proposed New GHG Rules.

- The Companies do not have any information from gas turbine manufacturers on the feasibility of using 96% hydrogen even if the fuel were available. As discussed in the previous section concerning the requirements of the proposed New GHG Rules, hydrogen utilization or CCS would be necessary only if a NGCC operated above a 50 percent annual capacity factor or a SCCT operated above a 20 percent annual capacity factor.[11] Therefore, the Companies would retrofit the proposed Mill Creek and Brown NGCCs for hydrogen or CCS only if it would be lower cost than constraining operations to a 50 percent annual capacity factor. That is a decision the Companies and the Commission do not need to make at this time.

The Companies also note that this data request asks the Companies to perform the analysis assuming the proposed GHG Rules for Existing EGUs applied only to Mill Creek Units 1&2, Ghent Unit 2, and Brown Unit 3. As discussed in the previous section, any analysis of the proposed regulations should include the impact on the Companies' entire generation fleet.

These concerns aside, the Companies agree it is appropriate to stress test their analyses to date for possible material uncertainties such as the proposed New

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[10] https://kgs.uky.edu/kgsweb/olops/pub/kgs/CNR1_12.pdf
[11] The proposed 111 requirements are discussed below and in response to KCA 3-3.

GHG Rules. The Companies believe that the analysis already presented in this case combined with one additional set of stress tests presented below can be used to answer the important question that the Companies believe is the objective of this particular data request, namely:

> If the EPA implements the New GHG Rules as proposed, what effect would an operating constraint of a 50% annual capacity factor on the Mill Creek and Brown NGCCs have on the Companies' least-cost compliance plan for the GNP and retirement of Brown Unit 3?

To that end, the analysis the Companies have already provided in this case shows:

- The Companies analyzed nine possible portfolios with three net $CO_2$ compliance costs of $0/ton, $15/ton, and $25/ton.[12] In only one of the 18 combinations of coal-gas price spreads and net $CO_2$ cost scenarios was the Companies' recommended portfolio not the lowest PVRR. The only exception was Portfolio 2 (MC5 & GH2 SCR; 637 MW Solar) in the scenario of $0/ton of incremental $CO_2$ costs and high gas and low coal prices. In that scenario, the Companies' recommended portfolio was second best.

- As discussed in Exhibit SAW-1, Section 4.4.3, the Companies analyzed the addition of an SCR to Ghent Unit 2 to determine how long it would have to operate to justify the investment. The analysis showed that in the one coal-gas price spread scenario that was favorable for the SCR (see above), Ghent Unit 2 would have to operate through 2049 to breakeven. Note that this price scenario assumed a $0/ton net $CO_2$ cost. Thus, 90 percent CCS is the only possible compliance option that could be considered for Ghent Unit 2 that would extend its life to 2049 under the proposed GHG Rules for Existing EGUs, and it would have to be installed and operational by January 1, 2030 at $0/ton net cost through 2049.

- Installing an SCR on Mill Creek Units 1&2 and operating them through the end of the analysis period (2050) is never lower cost than retiring these units and building the Mill Creek NGCC. There was no breakeven date within the analysis period that supported SCR installation. Unless CCS is installed and capturing 90 percent of $CO_2$ by 2030, the proposed GHG Rules for Existing EGUs require coal plants to shut down no later than 2040. Thus, 90 percent CCS is the only possible compliance option that could be considered for the Mill Creek coal units that would extend their life beyond 2040 under the proposed GHG Rules for Existing EGUs. Yet

[12] See Exhibit SAW-1, Section 4.5.2. Note that this section erroneously labeled the $CO_2$ prices in $/MWh instead of $/ton.

even if the net CCS cost was $0/ton (i.e., 45Q tax credits covered 100 percent of the cost), it would not change the recommendation to retire the units and build the Mill Creek NGCC.

- As stated in response to SC 1-20 and JI 1-1, converting coal units to burn large quantities of natural gas is not economic compared to burning gas efficiently in a new NGCC. Though the proposed GHG Rules for Existing EGUs provide the option to utilize at least 40 percent natural gas in a coal unit, it is an option only through 2040. The GHG NSPS would allow a NGCC to operate up to a 50 percent annual capacity factor utilizing just natural gas, which would be more efficient and have lower $CO_2$ emissions.

Therefore, the Companies have, in effect, already modeled and analyzed a number of key components or entailments of the proposed New GHG Rules.

Indeed, setting aside questions regarding whether certain technologies will or will not be commercially available (and for which the Companies have no actionable proposals), the one key potential limitation of the New GHG Rules *if they are made final in their current form* is that the annual capacity factor on the new Mill Creek and Brown NGCCs could be limited to 50 percent annually beginning in 2032; under the proposed New GHG Rules, any capacity factor above that level would require either the use of low-GHG hydrogen or CCS. Therefore, modeling the 50 percent annual capacity factor limitation is the worst case scenario because the only reason to incur the incremental cost of hydrogen or CCS to operate the units at a greater capacity factor would be if it were lower cost.

To test the cost implications of such a limitation, the Companies repeated the previous $CO_2$ cost analysis discussed in Exhibit SAW-1, Section 4.5.2 but with the following changes in assumptions:

- The Mill Creek and Brown NGCCs are limited to a 50 percent annual capacity factor beginning in 2032.

- $CO_2$ pricing begins in 2030 for all coal units (the original analysis assumed 2028). In effect, because this analysis assumes that the remaining coal fleet operates throughout the analysis period, this means that 90 percent CCS can be installed and operating across the fleet by January 1, 2030, for the net \$/ton $CO_2$ cost reflected in each $CO_2$ cost scenario.

- $CO_2$ pricing does not apply to emissions from the Mill Creek NGCC or Brown NGCC, which comply with the New GHG Rules through the 50% capacity factor limitation. $CO_2$ pricing likewise does not apply to emissions from simple cycle gas turbines, which the Companies' modeling already limited to a 20% annual capacity factor for new units and a 25% capacity factor for existing units, fully satisfying the proposed New GHG Rules.[13]

The benefits of this approach for stress testing the Companies' recommended portfolio are:

- It reflects possible $CO_2$ compliance costs across all generation assets.
- It reflects the timing of the proposed New GHG Rules.
- It evaluates the proposed Mill Creek and Brown NGCCs with the worst-case compliance cost (i.e., 50 percent annual capacity factor limitation).
- It evaluates the Ghent and Mill Creek SCR investment decisions and continued Brown Unit 3 investments in the best light:
  - The \$0/ton $CO_2$ case would require that an extension of the 45Q tax credits pay for 100 percent of CCS cost.[14] Note that this would also be true for the rest of the coal fleet.
  - It allows the units to operate throughout the study period. The Companies' analysis already in the record has demonstrated that a shorter service life does not favor SCR investment for Ghent Unit 2 or making additional investments in Brown Unit 3.

Table 1 below shows the original analysis results from Exhibit SAW-1, Table 13. Table 2 shows the results of the new stress test reflecting the New GHG Rules assumptions discussed above. Table 3 shows the differences in PVRR between the New GHG Rules stress test and the original Table 13 results (positive values mean the New GHG Rules assumptions increased PVRR and negative values mean they decreased PVRR). The key results are:

- The 50 percent annual capacity factor limitation increases the PVRR of all cases that have the Mill Creek NGCC or the Mill Creek and Brown NGCCs (see Table 3) because the loss of low-cost energy must be replaced. This is offset somewhat in the non-zero $CO_2$ cost cases

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[13] Like the proposed 111(d) regulations, new simple cycle gas turbines were constrained to a 20 percent annual capacity factor in the original analysis. The EPA is soliciting comment on the capacity and capacity factor threshold for existing simple cycle gas turbines with capacities between 100 and 300 MW. However, the proposed 111(b) regulations do not apply any restrictions to these units and do not impact these units' assumed 25 percent annual capacity factor limit from the original analysis.
[14] It was assumed for this analysis that the enhanced 45Q tax credits would be extended for the entire study period rather than 12 years of operation under current law.

by the elimination of a $CO_2$ cost on the NGCC and SCCT energy because the capacity factor limitation is their compliance cost.

- Removing the $CO_2$ cost related to emissions from the SCCTs lowered costs, particularly for the cases that relied heavily on SCCT energy, but this reduction did not cause any of these cases to be least-cost (see Table 3).

- The Companies' recommended portfolio remains least cost in 13 of the 18 scenarios. Notably, it is least cost in *all* of the non-zero cost per ton $CO_2$ cost cases for 90 percent CCS.

- In 1 of the 18 scenarios, Portfolio 7 (No SCRs and MC2/GH2 operation in non-ozone only, retire Brown Unit 3, no new NGCCs, and 785 MW of additional solar PPAs for 1,422 MW of total solar) would have resulted in savings compared to the proposed portfolio. This case requires high natural gas prices, low coal prices, and $0/ton net $CO_2$ cost for 90 percent CCS for the entire coal generation fleet through 2050.

    - The proposed portfolio (Portfolio 1) is much lower cost than Portfolio 7 in 16 of the 18 fuel price and $CO_2$ cost scenarios. Therefore, opting to pursue Portfolio 7 as a GNP compliance plan due to concerns about possible NGCC capacity limitations under the proposed New GHG Rules would be very risky. Also, the Companies would need to execute additional solar PPAs from the RFP, and those projects would all need to be developed because summer reliability would depend heavily on solar generation without the ability to operate Ghent Unit 2 and Mill Creek Unit 2 in the summer and due to the retirement of Brown Unit 3.

- In 4 of the 18 scenarios, Portfolio 2 (MC NGCC, GH2 SCR; 637 MW Solar) was the lowest NPVRR. This occurred only in scenarios where there was $0/ton net cost of installing 90 percent CCS and in selected coal and natural gas price scenarios. Portfolio 2 was also lower cost than Portfolio 1 in the price scenario where Portfolio 7 was the lowest cost overall.

    - Selecting this portfolio for GNP compliance would also be risky given the heavy reliance on 90 percent CCS at zero net cost as the only means to extend the life of Ghent Unit 2 to justify the SCR investment.

- The Companies' proposed Portfolio 1 is lower cost than keeping Ghent Unit 2 for just non-ozone season operations (Portfolio 3) in 17 of the 18 scenarios.
    - In the one price scenario that Portfolio 1 is not lower cost than Portfolio 3, it is only \$56 million PVRR more expensive (\$468 million NPVRR versus \$412 million NPVRR), whereas in all of the other 17 scenarios, Portfolio 1 is lower cost than Portfolio 3 by hundreds of millions of dollars to over a billion dollars. Hence, the risk profile for pursuing Portfolio 3 as a GNP compliance plan due to the risk of an annual capacity factor limitation on the Brown NGCC would be very risky (in addition to the 90 percent CCS at zero net cost requirement).

**Table 1: PVRR Delta from Best, No NGCC CF Limit (Original Table 13 from Exhibit SAW-1)**

| | | Difference from Best Case (PVRR, $M, 2022 Dollars) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
| Fuel Price Scenario (Gas, CTG Price Ratio) | $CO_2$ Price | MC5 and BR12; 637 Solar | MC5 & GH2 SCR; 637 Solar | MC5; Non-Ozone GH2 | MC5; Non-Ozone GH2; Ret BR3 | MC2/ GH2 SCR | Non-Ozone MC2/ GH2 | Non-Ozone MC2/ GH2 Ret BR3 | All Renew | SCCT+ Renew |
| Low Gas, Mid CTG | 0 | 0 | 96 | 561 | 117 | 604 | 697 | 1,019 | 2,375 | 1,568 |
| Mid Gas, Mid CTG | 0 | 0 | 64 | 540 | 126 | 583 | 728 | 844 | 2,096 | 1,580 |
| High Gas, Mid CTG | 0 | 0 | 91 | 499 | 218 | 571 | 844 | 428 | 1,521 | 1,712 |
| Low Gas, High CTG | 0 | 0 | 163 | 627 | 181 | 749 | 835 | 1,116 | 2,439 | 1,653 |
| High Gas, Low CTG | 0 | 77 | 0 | 372 | 166 | 265 | 599 | 216 | 1,301 | 1,620 |
| High Gas, Curr CTG | 0 | 0 | 1,390 | 1,885 | 1,376 | 3,459 | 3,481 | 2,379 | 2,958 | 3,212 |
| Low Gas, Mid CTG | 15 | 0 | 644 | 1,121 | 654 | 1,796 | 1,851 | 1,812 | 2,865 | 2,278 |
| Mid Gas, Mid CTG | 15 | 0 | 634 | 1,113 | 663 | 1,781 | 1,877 | 1,643 | 2,638 | 2,281 |
| High Gas, Mid CTG | 15 | 0 | 603 | 1,057 | 706 | 1,705 | 1,929 | 1,187 | 2,087 | 2,337 |
| Low Gas, High CTG | 15 | 0 | 714 | 1,188 | 720 | 1,940 | 1,987 | 1,920 | 2,927 | 2,361 |
| High Gas, Low CTG | 15 | 0 | 393 | 823 | 510 | 1,231 | 1,488 | 854 | 1,821 | 2,102 |
| High Gas, Curr CTG | 15 | 0 | 1,940 | 2,466 | 1,852 | 4,637 | 4,528 | 3,019 | 3,348 | 3,812 |
| Low Gas, Mid CTG | 25 | 0 | 1,009 | 1,511 | 997 | 2,591 | 2,609 | 2,291 | 3,154 | 2,703 |
| Mid Gas, Mid CTG | 25 | 0 | 996 | 1,493 | 1,010 | 2,569 | 2,651 | 2,117 | 2,980 | 2,736 |
| High Gas, Mid CTG | 25 | 0 | 979 | 1,447 | 1,056 | 2,488 | 2,678 | 1,696 | 2,433 | 2,800 |
| Low Gas, High CTG | 25 | 0 | 1,074 | 1,601 | 1,054 | 2,752 | 2,764 | 2,383 | 3,206 | 2,766 |
| High Gas, Low CTG | 25 | 0 | 755 | 1,202 | 856 | 2,012 | 2,239 | 1,367 | 2,189 | 2,553 |
| High Gas, Curr CTG | 25 | 0 | 2,269 | 2,834 | 2,131 | 5,385 | 5,237 | 3,437 | 3,544 | 4,124 |

**Table 2: PVRR Delta from Best, 50% NGCC CF Limit**

| | | Difference from Best Case (PVRR, $M, 2022 Dollars) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
| Fuel Price Scenario (Gas, CTG Price Ratio) | $CO_2$ Price | MC5 and BR12; 637 Solar | MC5 & GH2 SCR; 637 Solar | MC5; Non-Ozone GH2 | MC5; Non-Ozone GH2; Ret BR3 | MC2/ GH2 SCR | Non-Ozone MC2/ GH2 | Non-Ozone MC2/ GH2 Ret BR3 | All Renew | SCCT+ Renew |
| Low Gas, Mid CTG | 0 | 134 | 0 | 439 | 64 | 276 | 369 | 691 | 2,047 | 1,240 |
| Mid Gas, Mid CTG | 0 | 181 | 0 | 439 | 110 | 261 | 406 | 523 | 1,775 | 1,258 |
| High Gas, Mid CTG | 0 | 228 | 0 | 363 | 199 | 158 | 431 | 15 | 1,109 | 1,300 |
| Low Gas, High CTG | 0 | 82 | 0 | 440 | 60 | 331 | 416 | 698 | 2,021 | 1,234 |
| High Gas, Low CTG | 0 | 468 | 78 | 412 | 322 | 49 | 383 | 0 | 1,086 | 1,404 |
| High Gas, Curr CTG | 0 | 0 | 726 | 1,204 | 758 | 2,029 | 2,051 | 950 | 1,529 | 1,782 |
| Low Gas, Mid CTG | 15 | 0 | 377 | 1,022 | 341 | 1,363 | 1,311 | 1,111 | 2,000 | 1,397 |
| Mid Gas, Mid CTG | 15 | 0 | 356 | 835 | 358 | 1,191 | 1,189 | 911 | 1,863 | 1,437 |
| High Gas, Mid CTG | 15 | 0 | 296 | 722 | 414 | 1,044 | 1,189 | 461 | 1,276 | 1,422 |
| Low Gas, High CTG | 15 | 0 | 411 | 1,090 | 358 | 1,490 | 1,403 | 1,156 | 1,963 | 1,393 |
| High Gas, Low CTG | 15 | 0 | 134 | 541 | 271 | 704 | 888 | 262 | 1,187 | 1,309 |
| High Gas, Curr CTG | 15 | 0 | 1,242 | 1,843 | 1,122 | 3,176 | 3,023 | 1,459 | 1,617 | 2,017 |
| Low Gas, Mid CTG | 25 | 0 | 711 | 1,411 | 504 | 2,119 | 1,842 | 1,355 | 1,728 | 1,247 |
| Mid Gas, Mid CTG | 25 | 0 | 708 | 1,371 | 573 | 2,044 | 1,893 | 1,216 | 1,777 | 1,522 |
| High Gas, Mid CTG | 25 | 0 | 641 | 1,104 | 677 | 1,785 | 1,832 | 802 | 1,398 | 1,613 |
| Low Gas, High CTG | 25 | 0 | 770 | 1,480 | 547 | 2,238 | 1,957 | 1,423 | 1,759 | 1,289 |
| High Gas, Low CTG | 25 | 0 | 487 | 939 | 564 | 1,460 | 1,542 | 636 | 1,341 | 1,519 |
| High Gas, Curr CTG | 25 | 0 | 1,572 | 2,293 | 1,315 | 3,950 | 3,624 | 1,758 | 1,579 | 2,053 |

**Table 3: Net Effect of 50% NGCC CF Limit compared to original Table 13 Results**

| Fuel Price Scenario (Gas, CTG Price Ratio) | $CO_2$ Price | Difference from Best Case (PVRR, $M, 2022 Dollars) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
| | | MC5 and BR12; 637 Solar | MC5 & GH2 SCR; 637 Solar | MC5; Non-Ozone GH2 | MC5; Non-Ozone GH2; Ret BR3 | MC2/ GH2 SCR | Non-Ozone MC2/ GH2 | Non-Ozone MC2/ GH2 Ret BR3 | All Renew | SCCT+ Renew |
| Low Gas, Mid CTG | 0 | 462 | 232 | 206 | 275 | 0 | 0 | 0 | 0 | 0 |
| Mid Gas, Mid CTG | 0 | 503 | 258 | 220 | 305 | 0 | 0 | 0 | 0 | 0 |
| High Gas, Mid CTG | 0 | 641 | 321 | 277 | 394 | 0 | 0 | 0 | 0 | 0 |
| Low Gas, High CTG | 0 | 500 | 255 | 232 | 298 | 0 | 0 | 0 | 0 | 0 |
| High Gas, Low CTG | 0 | 606 | 293 | 255 | 372 | 0 | 0 | 0 | 0 | 0 |
| High Gas, Curr CTG | 0 | 1,429 | 766 | 748 | 811 | 0 | 0 | 0 | 0 | 0 |
| Low Gas, Mid CTG | 15 | 25 | -242 | -73 | -288 | -408 | -514 | -676 | -840 | -856 |
| Mid Gas, Mid CTG | 15 | -25 | -303 | -303 | -330 | -615 | -714 | -758 | -800 | -870 |
| High Gas, Mid CTG | 15 | -23 | -329 | -357 | -314 | -684 | -763 | -748 | -833 | -938 |
| Low Gas, High CTG | 15 | 214 | -90 | 116 | -149 | -236 | -370 | -550 | -751 | -755 |
| High Gas, Low CTG | 15 | -146 | -405 | -427 | -385 | -673 | -745 | -737 | -779 | -938 |
| High Gas, Curr CTG | 15 | 831 | 133 | 208 | 102 | -629 | -674 | -730 | -900 | -964 |
| Low Gas, Mid CTG | 25 | 158 | -141 | 58 | -335 | -314 | -610 | -779 | -1,269 | -1,299 |
| Mid Gas, Mid CTG | 25 | -146 | -435 | -269 | -583 | -672 | -904 | -1,047 | -1,350 | -1,361 |
| High Gas, Mid CTG | 25 | -428 | -766 | -770 | -807 | -1,130 | -1,273 | -1,321 | -1,463 | -1,614 |
| Low Gas, High CTG | 25 | 195 | -109 | 75 | -312 | -319 | -613 | -765 | -1,252 | -1,282 |
| High Gas, Low CTG | 25 | -579 | -847 | -842 | -871 | -1,131 | -1,276 | -1,310 | -1,426 | -1,613 |
| High Gas, Curr CTG | 25 | 715 | 18 | 174 | -100 | -720 | -898 | -964 | -1,250 | -1,356 |

As stated above, in order to use this stress test as a basis to deny the CPCN for the Brown NGCC and commit to installing an SCR on Ghent Unit 2, one would have to have confidence that 90 percent CCS could be installed and operating by January 1, 2030 at a $0/ton net $CO_2$ cost through 2049. It is likely that the EPA will get comments regarding whether 90 percent CCS is "adequately demonstrated" as required by the Clean Air Act. For example, the U.S. Chamber of Commerce Global Energy Initiative recently released a paper stating:

> Given that no power plant in the world is currently capturing 90% of its carbon emissions, meeting the 'adequately demonstrated' standard is a dubious claim.[15]

[15] A Closer Look at EPA's Powerplant Rule, page 10. [USCC_EPA Powerplant Rule Analysis_2023.FINAL_.pdf (globalenergyinstitute.org)]

The results of this new stress test clearly demonstrate that the Companies' recommended portfolio is the most robust portfolio for compliance with the GNP, replacing Brown Unit 3, *and* complying with the proposed New GHG Rules.

Also, as discussed below, the results of this new stress test are consistent with EPA's analysis of the impact of the proposed New GHG Rules on the Companies' balancing area, namely that adding significant amounts of new NGCC capacity in 2028 and retiring coal capacity are the least-cost means of complying with existing and proposed EPA regulations.

**<u>EPA's Modeling Results Are Consistent with the Companies' Proposals</u>**

As the Companies explained in response to KCA 3-3, the EPA has published its own extensive modeling results in the technical support documents of the New GHG Rules. EPA's modeling results show that in both its reference case (including the Good Neighbor Plan but not the New GHG Rules) and in the case in which the New GHG Rules go into effect, it is economically optimal for the Companies' balancing area to add far more NGCC capacity *in 2028* than the Companies are proposing in this proceeding: 3,173 MW in the reference case and 2,886 MW in the New GHG Rules case. Therefore, regardless of whatever additional modeling the Companies are able to perform, it is noteworthy that the modeling conducted by EPA—the independent federal agency that promulgated the proposed New GHG Rules—is consistent with the Companies' proposals in this proceeding.[16]

***EPA Model Overview***

EPA's Regulatory Impact Analysis ("RIA") for the New GHG Rules describes how EPA modeled the impact of the rules using their Integrated Planning Model ("IPM"). According to EPA, "IPM is a state-of-the-art, peer-reviewed, dynamic linear programming model that can be used to project power sector behavior under future business-as-usual conditions and to examine prospective air pollution control policies throughout the contiguous United States for the entire electric power system."[17] EPA's RIA further states that IPM "provides estimates of least cost capacity expansion, electricity dispatch, and emissions control strategies while meeting energy demand and environmental, transmission,

[16] Nothing in this response is intended to reflect the positions the Companies may take on the substantive issues raised by the EPA's New GHG Rules rulemaking or to be an unqualified endorsement of EPA's modeling or approaches.

[17] U.S. Environmental Protection Agency, "Regulatory Impact Analysis for the Proposed 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" ("RIA") at 3-7 (May 2023), available at https://www.epa.gov/system/files/documents/2023-05/utilities_ria_proposal_2023-05.pdf.

dispatch, and reliability constraints."[18] EPA has used the IPM for over three decades to analyze a wide range of options for reducing power sector air emissions.[19]

Notably, EPA's model allowed all resources to be retired or added at any time, and it modeled all compliance options (e.g., reducing capacity factors or retrofitting appropriate control or mitigation technologies).[20] As described at greater length below, EPA modeled all technology options this request describes and more.

***EPA Modeling Assumptions***

EPA first uses the IPM to establish a baseline (reference case) for comparison to evaluate the impact of proposed regulations. The IPM baseline reflects a business-as-usual forecast of the electricity sector in the absence of the proposed regulation. The baseline includes information from such sources as the U.S. Energy Information Administration ("EIA") and expected costs for new and existing generation technologies, fuels, and existing regulation and law. In this case, the recently passed Inflation Reduction Act ("IRA") is reflected in the baseline case, as well as the final Good Neighbor Plan and all other applicable federal environmental requirements.[21]

*Fuel prices*

An important consideration in any electric system model are fuel prices. IPM has a detailed representation of the natural gas and coal markets that it uses to estimate prices for these commodities.[22] In other words, the demand for these fuels in the electric generation in the model is used to help determine their market clearing prices. Though the prices for natural gas and coal are determined endogenously in IPM, low-GHG hydrogen is an exogenous input represented as a fuel that is available at a delivered cost of $1/kg under the baseline, and at a delivered cost of $0.5/kg in years when the second phase of the proposed NSPS is assumed to be active, all of which includes $3/kg subsidies under the IRA.[23] Subsidies for other technologies such as renewables and CCS are also included in the baseline and other IPM-modeled cases.[24]

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[18] *Id.*
[19] *Id.* at 3-7 to 3-8.
[20] *See, e.g.,* EPA Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model Post-IRA 2022 Reference Case at Section 2.3 (March 2023), available at https://www.epa.gov/system/files/documents/2023-03/EPA%20Platform%20v6%20Post-IRA%202022%20Reference%20Case.pdf.
[21] *Id.* at 3-10 to 3-11.
[22] *Id.* at 3-8.
[23] *Id.* at ES-12 and 3-11 to 3-14.
[24] *Id.* at 3-13.

*Generating and retrofit technologies modeled and their costs*

In addition to modeling existing generating units, the EPA's modeling included numerous new generating unit options: NGCC, NGCC with hydrogen retrofit, NGCC with CCS retrofit, NGCC with CCS, SCCT, SCCT with hydrogen retrofit, hydro, nuclear, small modular reactor, biomass, geothermal, landfill gas, battery storage, offshore wind, onshore wind, solar PV, solar thermal, fuel cell, ultrasupercritical coal without CCS, ultrasupercritical coal with 30% CCS, and ultrasupercritical coal with 90% CCS.[25] The model also included a variety retrofit options for existing coal units: activated carbon injection ("ACI"), coal-to-gas ("C2G"), CCS, flue-gas desulfurization ("FGD"), heat rate improvements ("HRI"), natural gas cofiring ("NGC"), selective catalytic reduction ("SCR"), and selective non-catalytic reduction ("SNCR").[26]

In short, EPA modeled the technology options this request asks the Companies to model—and more.

Regarding the costs EPA used to model these various technologies, see Section 4 of EPA's "Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model Post-IRA 2022 Reference Case (March 2023),"[27] as well as certain spreadsheets showing the results of EPA's modeling.[28]

*Reliability assumptions*

EPA's modeling maintains a 15% reserve margin at all times (including capacity contributions of renewable resources).[29]

[25] Taken from "S_C_KY" tab of the "Proposal_RegionalSummary" Excel file in the zip file available at https://www.epa.gov/system/files/other-files/2023-04/Proposal.zip.

[26] *Id.*

[27] EPA Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model Post-IRA 2022 Reference Case (March 2023), available at https://www.epa.gov/system/files/documents/2023-03/EPA%20Platform%20v6%20Post-IRA%202022%20Reference%20Case.pdf.

[28] *See* "S_C_KY" tabs of the "Proposal RPE File" and "Proposal Cost_TotalAnnual" Excel files in the zip file available at https://www.epa.gov/system/files/other-files/2023-04/Proposal.zip.

[29] EPA Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model Post-IRA 2022 Reference Case at 3-15 to 3-16 (March 2023), available at https://www.epa.gov/system/files/documents/2023-03/EPA%20Platform%20v6%20Post-IRA%202022%20Reference%20Case.pdf.

*Wholesale market and transmission assumptions*

EPA's IPM model simulates electricity production and market activity to minimize production costs, which is the desired outcome of wholesale electricity markets, and captures transmission costs and losses between regions.[30] The model also includes existing transmission facilities and capabilities, and it models transmission additions on an economic basis.[31]

***EPA Model Results for SERC-KY***

The IPM model includes information on individual generating units and optimizes reliability and energy costs within NERC subregions while allowing for electricity trade between the subregions. One of the NERC subregions modeled in IPM is SERC-KY. Based on a review of the data, this subregion appears to be the LG&E-KU balancing area ("LKE-BA"). The LKE-BA includes all of the Companies' generation and load as well as the load of various Kentucky municipal entities. Because these municipal entities have very little generation in the LKE-BA, the IPM model essentially reflects the Companies' generation fleet and EPA's projections of how that will change over time based on their modeling.

The two tables on the following pages summarize installed capacity in the LKE-BA in EPA's reference case (i.e., without the New GHG Rules) and the proposed New GHG Rules case.[32] In both cases the IPM model constructs much more NGCC capacity (about 3,000 MW) in 2028 than the Companies have proposed in this proceeding (about 1,300 MW), all of which operates through the end of EPA's modeling period. Note also that in the New GHG Rules case, IPM:

- Retrofits only 1,097 MW of new NGCC capacity with hydrogen-firing capability by 2035, with the remaining almost 1,800 MW of NGCC capacity installed in 2028 operating through the end of EPA's modeling period without hydrogen or CCS retrofit;

- Retires nearly all coal capacity by 2035;

- Retrofits CCS to a limited amount of coal capacity (only 526 MW capacity after CCS retrofit); and

- Adds 419 MW of solar in 2028 and 382 MW of battery capacity by 2035.

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[30] *Id.* at 2-7.
[31] *Id.* at 2-10 and Section 3.3.
[32] The Companies have omitted existing and new landfill gas generation from both tables, which are less than 10 MW in total and are not the Companies' generating units.

**EPA's Modeled Installed Capacity for the LKE-BA (Reference Case)**[33]

| Capacity Type | 2028 | 2030 | 2035 | 2040 | 2045 | 2050 | 2055 |
|---|---|---|---|---|---|---|---|
| **New Combined Cycle (MW)** | 3,173 | 3,173 | 3,173 | 3,173 | 3,173 | 3,173 | 3,173 |
| **Capacity Factor (%)** | 87 | 87 | 87 | 85 | 64 | 52 | 49 |
| **New Combustion Turbine (MW)** | 0 | 0 | 583 | 1,774 | 2,330 | 2,808 | 3,240 |
| **Capacity Factor (%)** | 0 | 0 | 14 | 5 | 2 | 1 | 1 |
| **New Battery Storage (MW)** | 0 | 44 | 382 | 382 | 382 | 382 | 382 |
| **Capacity Factor (%)** | 0 | 14 | 15 | 17 | 17 | 17 | 17 |
| **New Onshore Wind (MW)** | 0 | 0 | 0 | 845 | 3,250 | 4,856 | 5,655 |
| **Capacity Factor (%)** | 0 | 0 | 0 | 39 | 39 | 39 | 39 |
| **New Solar PV (MW)** | 419 | 419 | 419 | 419 | 697 | 1,693 | 2,171 |
| **Capacity Factor (%)** | 23 | 23 | 23 | 23 | 24 | 24 | 24 |
| **Existing & New Distributed Solar PV (MW)** | 34 | 38 | 47 | 62 | 80 | 104 | 135 |
| **Capacity Factor (%)** | 16 | 16 | 16 | 16 | 16 | 16 | 16 |
| **Existing Combined Cycle (MW)** | 663 | 663 | 663 | 663 | 663 | 663 | 663 |
| **Capacity Factor (%)** | 74 | 85 | 79 | 55 | 42 | 36 | 36 |
| **Existing Combustion Turbine (MW)** | 2,176 | 2,176 | 2,176 | 2,176 | 2,176 | 2,176 | 2,176 |
| **Capacity Factor (%)** | 1 | 5 | 1 | 0 | 0 | 0 | 0 |
| **Existing Coal (MW)** | 3,535 | 2,111 | 234 | 0 | 0 | 0 | 0 |
| **Capacity Factor (%)** | 45 | 40 | 10 | 0 | 0 | 0 | 0 |
| **Existing Hydro (MW)** | 137 | 137 | 137 | 137 | 137 | 137 | 137 |
| **Capacity Factor (%)** | 28 | 28 | 28 | 28 | 28 | 28 | 28 |
| **Existing Solar PV (MW)** | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| **Capacity Factor (%)** | 19 | 19 | 19 | 19 | 19 | 19 | 19 |

[33] Taken from "S_C_KY" tab of the "Post-IRA_2022_Reference_Case_RegionalSummary" Excel file in the zip file available at https://www.epa.gov/system/files/other-files/2023-04/Post%20IRA%202022%20Reference%20Case.zip.

**EPA's Modeled Installed Capacity for the LKE-BA (New GHG Rules Case)[34]**

| Capacity Type | 2028 | 2030 | 2035 | 2040 | 2045 | 2050 | 2055 |
|---|---|---|---|---|---|---|---|
| **New Combined Cycle (MW)** | 2,886 | 2,886 | 1,789 | 1,789 | 1,789 | 1,789 | 1,789 |
| **Capacity Factor (%)** | 87 | 87 | 50 | 50 | 50 | 50 | 50 |
| **New Combined Cycle with Hydrogen Retrofit (MW)** | 0 | 0 | 1,097 | 1,097 | 1,097 | 1,097 | 1,097 |
| **Capacity Factor (%)** | 0 | 0 | 87 | 87 | 69 | 49 | 46 |
| **New Combustion Turbine (MW)** | 0 | 0 | 886 | 1,650 | 2,617 | 3,095 | 3,527 |
| **Capacity Factor (%)** | 0 | 0 | 14 | 3 | 2 | 1 | 1 |
| **New Battery Storage (MW)** | 0 | 0 | 382 | 382 | 382 | 382 | 382 |
| **Capacity Factor (%)** | 0 | 0 | 16 | 15 | 16 | 17 | 17 |
| **New Onshore Wind (MW)** | 0 | 0 | 60 | 1,388 | 4,047 | 4,856 | 5,655 |
| **Capacity Factor (%)** | 0 | 0 | 40 | 39 | 39 | 39 | 39 |
| **New Solar PV (MW)** | 419 | 419 | 419 | 419 | 962 | 2,050 | 2,528 |
| **Capacity Factor (%)** | 23 | 23 | 23 | 23 | 24 | 24 | 24 |
| **Existing & New Distributed Solar PV (MW)** | 34 | 38 | 47 | 62 | 80 | 104 | 135 |
| **Capacity Factor (%)** | 16 | 16 | 16 | 16 | 16 | 16 | 16 |
| **Existing Combined Cycle (MW)** | 663 | 663 | 663 | 663 | 663 | 663 | 663 |
| **Capacity Factor (%)** | 75 | 85 | 85 | 81 | 45 | 38 | 39 |
| **Existing Combustion Turbine (MW)** | 2,176 | 2,176 | 2,176 | 2,176 | 2,176 | 2,176 | 2,176 |
| **Capacity Factor (%)** | 1 | 8 | 1 | 0 | 0 | 0 | 0 |
| **Existing Coal (MW)** | 3,535 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Capacity Factor (%)** | 48 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Existing Hydro (MW)** | 137 | 137 | 137 | 137 | 137 | 137 | 137 |
| **Capacity Factor (%)** | 28 | 28 | 28 | 28 | 28 | 28 | 28 |
| **Existing Solar PV (MW)** | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| **Capacity Factor (%)** | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| **Existing Coal with CCS Retrofit (MW)** | 0 | 526 | 526 | 526 | 0 | 0 | 0 |
| **Capacity Factor (%)** | 0 | 79 | 79 | 79 | 0 | 0 | 0 |
| **Existing Coal with Designated Retirement Date (MW)** | 0 | 1,916 | 0 | 0 | 0 | 0 | 0 |
| **Capacity Factor (%)** | 0 | 20 | 0 | 0 | 0 | 0 | 0 |

[34] Taken from "S_C_KY" tab of the "Proposal_RegionalSummary" Excel file in the zip file available at https://www.epa.gov/system/files/other-files/2023-04/Proposal.zip.

In sum, regardless of whether the New GHG Rules take effect in their current form, EPA's IPM modeling results show:

- NGCC technology is a reliable, economic generation resource to meet long-term energy needs.

- Also, though it is prudent to explore options to use some quantity of hydrogen in the future, the Companies and the Commission do not have to make that decision now. Future hydrogen use will depend on the future generating portfolio and capacity factor needs from NGCC units. The Companies' proposed NGCC units will be capable of combusting gas and hydrogen at levels exceeding any blending rates continuously used today, and they will be capable of combusting even higher levels of hydrogen with appropriate retrofits.

- Beginning to transition from coal-fired generation to gas-fired generation now as part of GNP compliance is also prudent given the effect of the New GHG Rules on existing coal units. If the Commission approves the Companies' CPCN and SB4 requests in this proceeding, the Companies will still have about 3,200 MW of other coal generation that could have to be replaced in a relatively short period of time.

- Adding some quantity of solar in the near-term is prudent, but it is certainly not the only generation resource the Companies should add.

- Battery energy storage will likely play an important role in the Companies' future resource mix, which is consistent with the Companies' reasoning for including a modest amount of battery storage in their proposed CPCN-DSM portfolio.

For the workpapers supporting this response, see the attachment being provided in a separate file. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

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**Question No. 3**

**Responding Witness: Stuart A. Wilson**

Q-3. Refer to LG&E/KU's response to Staff's Second Request for Information (Staff's Second Request), Item 81, in which LG&E/KU produced the results of a modeling run in which a 20-year life was used for both NGCC and SCCT units.

a. Confirm that the optimal portfolio included the continued operation of Ghent Unit 2, but in non-ozone season months only (October through April) with a resulting capacity factor between 35 percent and 47 percent. If this cannot be confirmed, explain each reason why it cannot be confirmed.

b. Re-run this scenario using the preferred compliance method from Item 3.a. above and provide the results.

A-3.

a. Partially confirmed. The optimal portfolios with the requested assumptions did include the continued operation of Ghent Unit 2, but in non-ozone season only. However, the resulting capacity factors across the scenarios ranged between 33 percent and 50 percent. These capacity factors are annual capacity factors and reflect the unavailability of Ghent 2 during the ozone season.

b. The Companies assume that this question should refer to Item 2.a, rather than Item 3.a.

See the response to Question No. 2. The Companies do not have the necessary information to perform this analysis.

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**Question No. 4**

**Responding Witness: Stuart A. Wilson**

Q-4. Refer to LG&E/KU's response to Staff's First Request for Information (Staff's First Request), Item 47(a), Exhibit SAW-1, Appendix D, pages D-22 through D-24.

a. Explain whether the results of the economic minimum reserve margin analysis (17 percent summer and 24 percent winter) correspond to a LOLE of 3.87 days in 10 years.

b. Using the resources LG&E/KU used to calculate the economic reserve margin, explain what the minimum reserve margin and resource portfolio would correspond to a LOLE 1 day in 10 years.

c. Explain why a LOLE of 1 day in 10 years is not appropriate for determining the minimum reserve margin target.

A-4.

a. They do not. As noted on page 13 of Exhibit SB4-1, an LOLE of 3.87 days in 10 years corresponds to a portfolio with a similar composition of resources (i.e., similar proportions of fully dispatchable, intermittent, and limited duration resources) but with slightly higher reserve margins (17.9% summer, 26.0% winter). A portfolio with (1) a similar resource composition and (2) 17% summer and 24% winter reserve margins would have a somewhat higher LOLE.

b. As discussed in Appendix D of Exhibit SAW-1, page D-22, the Companies calculated their economic reserve margins based on their existing portfolio except Mill Creek 1 (planned retirement in 2024) and the small-frame SCCTs (assumed retirement in 2025). In addition, the analysis, which was completed for 2028, assumed the Rhudes Creek and Ragland solar PPAs are not completed. Consistent with the methodology used to calculate the maximums of the Companies' summer and winter reserve margin ranges for the 2021

IRP, the Companies evaluated adding SCCT capacity to this portfolio to achieve an LOLE of 1 day in 10 years. Achieving an LOLE of 1 day in 10 years requires 240 MW of SCCT capacity and the associated reserve margins are 23% in the summer and 31% in the winter.

For the workpapers supporting this response, see the attachments being provided as separate files in Excel format as well as the SERVM database file named "SERVM.D20230703.T084051.Daily.BAK," which is included in the confidential attachment to Question No. 1(b) at the filepath: \CONFIDENTIAL_WORKPAPERS\SERVM_PSC5_01\SERVM.zip.

c. The Companies have not said that an LOLE of 1 day in 10 years is inappropriate for determining the minimum reserve margin target. LOLE gives no consideration to the cost of unserved energy. Therefore, the Companies also consider the economic reserve margin, which minimizes the sum of (1) generation capacity costs and (2) reliability and generation production costs.[35] Either method could produce lower minimum reserve margins depending on the input assumptions.

[35] See Appendix D to Exhibit SAW-1, page D-8.

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**Question No. 5**

**Responding Witness: David S. Sinclair / Stuart A. Wilson**

Q-5. Refer to LG&E/KU's Response to Staff's First Request, Item 47(a), Exhibit SAW-1, pages 34–35, in which the assessment of the cost effectiveness of adding the two utility owned solar facilities appears to be predicated on the possibility of the Rhudes Creek and Ragland PPAs not being built.

a. Confirm that the analysis implicitly assumes that the 640 MW from the four solar PPAs identified in Stage Two are not being built.

b. Explain what risks and issues could prevent Rhudes Creek, Ragland, and the four solar PPAs from being built that will not prevent the Owned Solar projects from being completed.

A-5.

a. Confirmed. The referenced analysis assumes the 637 MW from the four solar PPAs identified in Stage Two are not being built. Note that this assumption is *explicit* in the cited text, not implicit:[36]

> Thus, this first step of Stage Three analyzes the economic impacts of adding a 120 MW self-build solar facility (originally Muhlenberg Solar, now Mercer County Solar Facility) and a 120 MW asset purchase facility (the BrightNight Frontier project, also called the Marion County Solar Facility) to a portfolio where Mill Creek 2, Ghent 2, and Brown 3 are replaced with two NGCC units *and no solar PPAs, including the Rhudes Creek and Ragland PPAs*. The portfolios the Companies analyzed are in Table 16 below. Portfolio 11 includes no solar PPAs. Portfolio 12 builds on Portfolio 11 as described in Table 16.

[36] Companies' Response to PSC 1-47(a), Exhibit SAW-1 at 34 (emphasis and shading added).

**Table 16: Solar PPA Execution Risk (Portfolios 11-12); Solar Added (Nameplate MW)**

| Port Num | Portfolio Name | Description | Total Solar Added |
|---|---|---|---|
| 11 | MC5 & BR12; No Solar | Replace MC2 in 2027 w/ MC5<br>Replace BR3 & GH2 in 2028 with BR12<br>No Solar (i.e., No Rhudes Creek or Ragland PPAs) | - |
| 12 | Portfolio 11<br>+Asset Purchase<br>+Self-Build | Portfolio 11<br>+ 120 MW Solar Asset (Asset Purchase)<br>+ 120 MW Solar Asset (Self-Build) | +240 |

b. See Section 5 of Sinclair testimony. Also, Exhibit DSS-1 to Mr. Sinclair's testimony describes the differences in local approvals required for merchant developers versus the Companies.

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**Question No. 6**

**Responding Witness: Charles R. Schram / Stuart A. Wilson**

Q-6. Refer to the Application in Case No. 2023-00122,[37] Direct Testimony of Stuart A. Wilson (Case No. 2023-00122 Wilson Direct Testimony), Exhibit SB4-1, page 7. Also refer to the LG&E/KU's Response to Staff's First Request, Item 47(a), Section 4.1.5, page 21. According to the LG&E/KU's definition of dispatchable generation resources in Exhibit SB4-1, the solar power purchase agreements (PPAs) are not dispatchable, but the two proposed company owned solar facilities are considered dispatchable.

a. Explain why the energy received from the Ohio Valley Electric Corporation (OVEC) is considered dispatchable. Include in the response whether LG&E/KU have ever not dispatched all of the OVEC energy when it was available.

b. Explain the differences between the energy received from OVEC and the energy received from the solar PPAs. Include in the response how the energy received from OVEC is treated differently from that of the solar PPAs toward satisfying hourly demand.

A-6. The cited definition of "dispatchable" proposed by the Companies 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." Note that this definition applies to a supply resource, not energy. Also, for a resource to be dispatchable *by the Companies*, the resource must be physically able to adjust its output between economic minimum and economic maximum *and* the Companies must have the right to control the resource's dispatch.

a. The Companies consider OVEC a dispatchable resource because the OVEC units are physically capable of adjusting their output between economic

[37] Case No. 2023-00122, *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Approval of Fossil Fuel-Fired Generating Unit Retirements* (filed May 10, 2023), Application.

minimum and economic maximum *and* the Companies have a contractual right to dispatch their share of OVEC's hourly available generation between their minimum contractual obligation and the maximum generation available. The Companies have frequently not dispatched all of the available OVEC generation available to them. See the Sinclair Direct Testimony, page 15, Table 2 and the responses to PSC 1-48(a) and PSC 2-61(a) and (c).

b. The energy received from OVEC is exactly the same as what the Companies anticipate receiving via their proposed solar PPAs: 60 Hz alternating current. All such energy, whether from OVEC or via the proposed solar PPAs, would help serve hourly demand. The difference between the resources themselves is that the Companies have a contractual right to adjust the amount of OVEC generation dispatched to serve their customers, but the Companies' energy from the proposed solar PPAs will be must-take, making the solar PPAs *non*-dispatchable resources for the Companies. See the response to part (a) above.

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**Question No. 7**

**Responding Witness: Stuart A. Wilson**

Q-7. Refer to the Case No. 2023-00122 Wilson Direct Testimony, Exhibit SB4-1, page 7 and page 8, Table 2.

a. During periods when the sun is shining and LG&E/KU's proposed owned solar facilities are producing energy, explain when the companies would not fully dispatch all of the energy produced.

b. During periods when the sun is shining and LG&E/KU's proposed owned solar facilities and the proposed solar PPAs are producing energy, explain whether LG&E/KU would not fully dispatch the energy from the owned solar facilities.

c. During periods when the sun is shining and LG&E/KU's proposed owned solar facilities and the solar PPAs are producing energy, explain whether the PLEXOS, PROSYM, and SERVM models treated these two resources differently, and if so, explain how.

A-7.

a. See the response to AG-KIUC 3-13.

b. See the responses to AG-KIUC 3-13 and JI 4-1.

c. The Companies' modeling of solar PPAs and owned solar is the same (i.e., both are modeled as fixed energy resources that are not curtailable by the model). Solar is modeled this way because at currently proposed levels of solar generation, both owned and PPAs, the Companies do not anticipate having to curtail solar output. However, in the context of SB4, which requires the dispatchability of a resource to be addressed, the ability to curtail or re-dispatch the owned solar assets is a key differentiating factor between these assets and solar PPAs. See also the response to Question No. 6.

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**Question No. 8**

**Responding Witness: Stuart A. Wilson**

Q-8. Refer to the Case No. 2023-00122 Wilson Direct Testimony, Exhibit SB4-1, page 14, Table 5, which provides a 2028 Reliability Analysis for incremental resource additions to the current portfolio. Refer also to LG&E/KU's response to Staff's Second Request, Item 50, providing the LOLE for certain portfolio options.

a. Provide the LOLE for the Final portfolio for which approval was initially sought in Case No. 2022-00402 with both the owned solar and the solar PPAs removed.

b. Using all of the same assumptions used to calculate the loss of load exceptions in Table 5, provide the LOLH and EUE values for all portfolios listed in Table 5.

c. Using all of the same assumptions used to calculate the loss of load exceptions in response to Staff's Second Request, Item 50, provide the LOLH and EUE values for all portfolios listed in Staff's Second Request, Item 50.

A-8.

a. See Generation Portfolio "MC5/BR12+DSM+BESS" in Table 20 on page 37 of Exhibit SAW-1. The LOLE for this portfolio is 0.77.

b. See the table below. Note that the impact on each reliability metric of adding intermittent and limited-duration resources in Portfolios 6 through 8 is fairly proportional. These results indicate that LOLE is a good reliability metric for the level of intermittent and limited-duration resources considered in these proceedings. For the workpapers supporting this response, see the attachments being provided as separate files in Excel format.

| | | LOLE (days/ 10 years) | LOLH (hours/ 10 years) | EUE (MWh/ 10 years) |
|---|---|---|---|---|
| 0 | No Retirements; Add DSM | 0.45 | 1.00 | 211 |
| 1 | Ret MC1-2; Add DSM/MC5 | 0.41 | 0.91 | 191 |
| 2 | Ret MC1-2/BR3; Add DSM/MC5/BR12 | 0.13 | 0.27 | 58 |
| 3 | Ret MC1-2/BR3/PR12/HF1-2; Add DSM/MC5/BR12 | 0.15 | 0.29 | 55 |
| 4 | Ret MC1-2/BR3/PR12/HF1-2; GH2 (Non-Ozone); Add DSM/MC5/BR12 | 0.92 | 1.88 | 402 |
| 5 | Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12 | 1.22 | 2.75 | 600 |
| 6 | Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar | 0.77 | 1.85 | 442 |
| 7 | Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar/ Brown BESS | 0.45 | 0.99 | 218 |
| 8 | **Final CPCN Portfolio**: Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar/ Brown BESS/Solar PPAs | 0.28 | 0.57 | 131 |

c. See the table below. For the workpapers supporting this response, see the attachment being provided as separate files in Excel format.

| | LOLE (days/10 years) | LOLH (hours/10 years) | EUE (MWh/10 years) |
|---|---|---|---|
| (1) | 37.51 | 92.56 | 23,842 |
| (2) | 2.86 | 6.08 | 1,317 |
| (3) | 37.37 | 91.87 | 23,689 |
| (4) | 0.82 | 1.65 | 326 |
| (5) | 35.15 | 86.20 | 22,188 |
| (6) | 0.74 | 1.46 | 280 |

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**Question No. 9**

**Responding Witness: Stuart A. Wilson**

Q-9. Refer to the Case No. 2023-00122 Wilson Direct Testimony, Exhibit SB4-1, page 20, Table 8.

a. Provide an update to the table that recalculates portfolio 6 except that it uses the Solar PPAs instead of the Owned Solar and that recalculates portfolio 8 except that it uses the Owned Solar instead of Solar PPAs.

b. Based on the results in part a., comparing the cumulative results of updated Portfolio 6 with the updated Portfolio 8, explain which portfolio has the lowest overall present value revenue requirement (PVRR). If one portfolio has a lower PVRR early and then is higher later over the forecast period, explain why and include the cross over year PVRR.

A-9.

a. See attachment being provided in a separate file as Attachment 1. For the workpapers supporting this response, see the attachment being provided in a separate file as Attachment 2. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection

b. The updated Portfolio 6 has a lower PVRR than the updated Portfolio 8 and its annual revenue requirements are lower in every year of the analysis period.

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**Question No. 10**

**Responding Witness: Lonnie E. Bellar**

Q-10. Refer to "Louisville Gas and Electric and Kentucky Utilities Generator Interconnection Request Queue Updated as of June 8, 2023."[38]

a. Explain generally what information is included in this document.

b. Provide a copy of the interconnection queue with the updates as of June 8, 2023.

c. Identify the LG&E/KU affiliate that made the interconnection requests identified by queue numbers LGE-GIS-2022-003 and LGE-GIS-2022-004.

d. Confirm that the interconnection requests identified by queue numbers LGE-GIS-2022-003 and LGE-GIS-2022-004 pertain to the NGCC units for which LG&E/KU are requesting CPCNs in this matter.

e. Explain how the LG&E/KU affiliate or division that made the interconnection requests identified by queue numbers LGE-GIS-2022-003 and LGE-GIS2022-004 was able to do so on June 21, 2022, a day before LG&E/KU sent its 2022 request for proposal for new generation (2022 RFP).

f. Provide any correspondence prior to June 22, 2022 between the LG&E/KU division responsible for sending out the 2022 RFP and the LG&E/KU affiliate or division that made the interconnection requests identified by queue numbers LGE-GIS2022-003 and LGE-GIS-2022-004 regarding the 2022 RFP or the need for generation discussed in the RFP.

g. Describe any communications not provided above prior to June 22, 2022 between the LG&E/KU division responsible for sending out the 2022 RFP and the LG&E/KU affiliate or division that made the interconnection requests

[38] LG&E/KU, *Louisville Gas and Electric and Kentucky Utilities Generator Interconnection Request Queue* (updated June 8, 2023) available at: https://www.oasis.oati.com/woa/docs/LGEE/LGEEdocs/LGE_and_KU_GI_Queue_Posting_June_08,_2023.pdf (last accessed on June 23, 2023).

identified by queue numbers LGE-GIS-2022-003 and LGE-GIS-2022-004 regarding the 2022 RFP or the need for generation discussed in the RFP.

h. Explain why the Generator Interconnection Request Queue Updated as of June 8, 2023 shows that LGE-GIS-2022-004 has been withdrawn by the customer "after scoping meeting," including what happened at the scoping meeting that prompted the withdraw and explain whether LG&E/KU still plans to move forward with that NGCC unit.

A-10.

a. The "Louisville Gas and Electric and Kentucky Utilities Generator Interconnection Request Queue Updated as of June 8, 2023" document publicly available on LG&E/KU's OASIS shows the status of all Generator Interconnection Requests to the LG&E/KU Transmission System as of June 8, 2023. This particular document, as is true with all version updates of this document, shows the unique Queue Number identifier for each request. Additionally, the GI Queue shows the application date, county of interconnection, and point of interconnection on LG&E/KU's Transmission System. The GI Queue also shows information specific about the generator, such as size and fuel type. Among other important information, the GI Queue communicates the status of the Generator Interconnection's study status.

b. See attachment being provided in a separate file.

c. The Companies themselves, not an affiliate, made the interconnection requests. The Companies' Project Engineering team provides required details about the projects to the Companies' Power Supply team, which acts as the transmission customer and submits generation interconnection and other transmission service requests for the Companies.

d. Confirmed, queue numbers LGE-GIS-2022-003 and LGE-GIS-2022-004 are for the Mill Creek and Brown NGCC units, respectively; however, LGE-GIS-2022-004 was withdrawn. A new request, LGE-GIS-2022-011, was submitted on October 28, 2022 to connect the Brown NGCC unit to the 138kV system. Subsequently, request LGE-GIS-2023-002 was submitted on April 14, 2023 to connect the Brown NGCC unit to the 345kV system. Also see the response to JI 1-15.

e. This request could be read to suggest something inappropriate about the Companies' Project Engineering group having worked on developing possible new generating unit options prior to the Companies' issuance of their June 2022 RFP. But there is nothing inappropriate about it; it was not in any way prejudicial to the RFP respondents or—more importantly—the Companies' customers.

LG&E/KU, and any other generation developer, can submit generator interconnection requests at any time to secure a position in the interconnection study queue. In fact, based on the Companies' most recent 2021 IRP filings, it was publicly known that the Companies were going to need additional capacity, so any generation developer could have relied on that information to submit an interconnection request at any time before the June 2022 RFP was issued. Had any of the responses to that RFP been favorable to the Companies' self-build proposals and therefore better for customers, the Companies would have withdrawn their interconnection request and given up their position in the queue if necessary to facilitate the RFP proposal. Other generation developers in the LG&E/KU queue would have no incentive or obligation to forgo their position in the queue to facilitate a Company self-build proposal.

The Companies' Project Engineering team began work on possible self-build resources prior to the RFP issuance. The June 2022 RFP sought other options to compare to the Companies' own proposals, giving the Companies and their customers the benefit of competitive options for meeting anticipated future needs. The Companies did not review or compare any RFP responses, including those from Project Engineering, prior to the final RFP response submission deadline, so the responses provided by Project Engineering were not influenced by any RFP response from any other bidder. Regarding whichever of the Companies' proposed self-build resources the Commission ultimately approves, the Companies will also use RFP processes to ensure that the engineering, procurement, and construction of the approved resources are lowest reasonable cost. Therefore, there is no way in which Project Engineering's submission of a generator interconnection request in June 2022 was inappropriate or harmful to customers.

f. See attached emails being provided in separate files from the Project Engineering team to the Power Supply team regarding the interconnection requests for the proposed NGCCs.

g. See the response to part (f).

h. See the response to part (d). The decision to withdraw LGE-GIS-2022-004 was based on internal project development, as indicated in response to JI 1-15, and was not tied to the scoping meeting. Confirmed, the Companies plan to move forward with the Brown NGCC.

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**Question No. 11**

**Responding Witness: Lonnie E. Bellar**

Q-11. Provide any written analysis or report, excluding any integrated resource plan and testimony in prior Commission cases, prepared by or on LG&E/KU's behalf discussing the cost or feasibility of CCS for any fossil fuel units or hydrogen co-firing of natural gas units.

A-11. The Companies are evaluating the cost and feasibility of carbon capture at Natural Gas Combined Cycle power plants through the $7.3 million, Department of Energy funded, Cane Run 7 Front-End Engineering Design (FEED) study, DOE Award DE-FE0032223, with the final report expected in June 2024. The Companies are teaming with the University of Kentucky, the Electric Power Research Institute (EPRI), and National Energy Technology Laboratory (NETL). Project updates are publicly available through the Department of Energy project site at: https://netl.doe.gov/project-information?p=FE0032223

The Companies have posted joint work done with, or for, the Companies on carbon capture, including more than 70 academic publications and 17 patents, in the *Carbon Capture* section of our public website at: https://www.pplweb.com/innovation/technology-research/academic-publications/.

In 2020, a summary report of the carbon capture research done at the Companies' E.W. Brown Generating Station from 2011 to 2020 was completed in partnership with the University of Kentucky, the Electric Power Research Institute, and the Department of Energy as part of DE-FE-0007395. The final report "Application of a Heat Integrated Post-combustion $CO_2$ Capture System with Hitachi Advanced Solvent into Existing Coal-Fired Power Plant" was published and discusses the cost and feasibility of carbon capture at a coal-fired power plant at https://doi.org/10.2172/1635102.

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**Question No. 12**

**Responding Witness: Lonnie E. Bellar**

Q-12. State whether it would be possible to use natural gas co-firing for Brown 3, Ghent 2, Mill Creek 1, or Mill Creek 2. If it would not be possible, explain why it would not be possible for each unit. If it would be possible, explain what work would be necessary to allow for natural gas co-firing for each unit, provide an estimate or an estimated range of the cost of such work, and explain how the estimate was determined and identify uncertainties with respect to the estimate.

A-12. Gas co-firing is possible on the units in the question. In 2016 the Company contracted Black & Veatch (B&V) to perform a $NO_x$ emissions reduction feasibility study on the coal fired non-SCR units Mill Creek 1-2, Brown 1-2, and Ghent 2. The B&V $NO_x$ Reduction Study draft report dated 1-27-2017 is being provided in response to JI 4-33. Several $NO_x$ reduction technologies are discussed in the report including 30-40% natural gas co-firing. Brown 3 was excluded from the study because its SCR was in-service at the time of the study.

While the body of the B&V report discusses Mill Creek 1-2 in detail, Table 2-1 on page 11 of the report provides the expected modifications, risk/concerns, estimated schedule, differential O&M costs, and the capital cost for the five units studied. As noted in Table 2-1 page 11, the capital cost estimates exclude all off-site gas pipeline construction or modification.