COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC JOINT APPLICATION OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND SITE COMPATIBILITY CERTIFICATES AND APPROVAL OF A DEMAND SIDE MANAGEMENT PLAN	))))))))	**CASE NO. 2022-00402**

DIRECT TESTIMONY OF
STUART A. WILSON
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KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: December 15, 2022

INTRODUCTION

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

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

Q. Have you previously testified before this Commission?

A. Yes. I provided live testimony before the Commission most recently at the hearing in the Companies' 2021 IRP case,[1] and I have provided written testimony to the Commission, as well.[2]

Q. Please describe your current job responsibilities.

A. I have three primary areas of responsibility: (i) gas and electric sales forecasting, (ii) generation planning, and (iii) economic analysis. Broadly speaking, the ongoing task of the Energy Planning, Analysis and Forecasting group is to ensure the Companies have adequate resources available to reliably and economically meet customers' needs at all times, in every weather condition, and across a wide range of possible future scenarios. To do that, our group regularly refreshes (at least annually) the Companies'

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[1] *Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2021-00393, July 12, 2022 H.V.T. at 17:43:05-18:10:32 and July 13, 2022 H.V.T. at 08:12:49-12:05:40 (Ky. PSC Oct. 7, 2022).

[2] *See, e.g., Electronic Application of Kentucky Utilities Company for Approval of Its 2020 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2020-00060, Direct Testimony of Stuart A. Wilson (Mar. 31, 2020); *Electronic Application of Louisville Gas and Electric Company for Approval of Its 2020 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2020-00060, Direct Testimony of Stuart A. Wilson (Mar. 31, 2020).

load forecast, which is the primary responsibility of Tim A. Jones, who is a witness in this proceeding. Also, we regularly analyze the Companies' existing resources to ensure they can reliably and economically meet forecasted load. As it pertains to this case, I oversaw the development and preparation of the 2022 Resource Assessment (Exhibit SAW-1) and personally performed some of the analysis.

Q. Please describe your experience in performing generation planning analysis and using the software and models that were employed in this case.

A. After working for three years in sales forecasting, I assumed responsibility for generation planning in 2009. Since then, my team has supported the development of four IRPs, three ECR filings, and two generation CPCN filings. We have also supported the decisions to enter into PPAs for the Bluegrass SCCTs and the Rhudes Creek and Ragland solar projects. As the need to evaluate generation planning decisions over a broader range of scenarios has increased, we have adopted new modeling tools and developed new tools internally. For example, we began using the Strategic Energy & Risk Valuation Model ("SERVM") to evaluate generation portfolio reliability when developing the 2014 IRP. Prior to developing the 2021 IRP, we replaced Strategist with PLEXOS for generation portfolio development and screening. The analysts that use these tools to model the Companies' generation portfolio all have extensive backgrounds in generation planning and were instrumental in leveraging the strengths of these tools to produce an optimal resource portfolio that is in the best interest of customers.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to summarize the Resource Assessment, which recommends taking the following actions as optimal for the Companies' customers:

- Retiring three coal-fired generating units (Mill Creek Unit 2, Brown Unit 3, and Ghent Unit 2) with a combined capacity of 1,194 MW;[3]
- Constructing two 621 MW natural gas combined cycle ("NGCC") units (Mill Creek Unit 5 ("Mill Creek NGCC" or "MC5") and Brown Unit 12 ("Brown NGCC" or "BR12"));
- Constructing a 120 MW AC solar facility ("Marion County Solar Facility");
- Acquiring a 120 MW AC solar facility ("Mercer County Solar Facility");
- Entering into four solar power purchase agreements ("PPAs") totaling 637 MW AC;
- Deploying the Companies' proposed 2024-2030 DSM-EE Program Plan; and
- Constructing a 125 MW, 500 MWh battery energy storage system at Brown ("Brown BESS").

My testimony also describes the methodology used to determine LG&E's and KU's ownership shares for the proposed resources.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring two exhibits:

Exhibit SAW-1 2022 Resource Assessment ("Resource Assessment")

Exhibit SAW-2 2022 Resource Assessment Workpapers

[3] Note that throughout: the E.W. Brown Generating Station is "Brown," the Mill Creek Generating Station is "Mill Creek," and the Ghent Generating Station is "Ghent."

IMPETUS FOR THE RESOURCE ASSESSMENT

Q. What caused the Companies to perform the Resource Assessment you are sponsoring in this proceeding?

A. The primary motivator of the Resource Assessment is the Good Neighbor Plan, which the U.S. Environmental Protection Agency issued in draft form in April 2022 and which Philip A. Imber discusses in his testimony. Briefly, the Good Neighbor Plan effectively creates significant new nitrogen oxides (NO_X) emissions constraints for all coal-fired generating units with a capacity greater than 100 MW that are not equipped with selective catalytic reduction ("SCR") technology to reduce NO_X emissions. As drafted, the Good Neighbor Plan would begin to affect non-SCR-equipped units' ability to operate during every ozone season (May through September) beginning in 2026, though there is reason to believe the final rule might delay that effective date to 2028, as Mr. Imber explains. Two of the Companies' coal-fired generating units, Mill Creek Unit 2 and Ghent Unit 2, are not SCR-equipped. To add SCR to these units would require capital investments of $110 million and $126 million, respectively. Therefore, the Companies needed to determine if investing in SCR technology for those units would be economical in light of updated load forecasting and the cost of other demand- and supply-side alternatives.

In addition, Brown Unit 3, which is the Companies' coal unit with the highest operating cost, requires a major overhaul in 2027 to operate safely beyond 2028. The capital cost of the overhaul would be $26 million. Thus, as with Mill Creek Unit 2 and Ghent Unit 2, it was necessary for the Companies to determine if investing in the major overhaul for Brown Unit 3 would be economical.

As a result, the Companies performed a holistic review to determine if, given an updated load forecast and considering a wide range of possible future scenarios, ongoing reliable and economical service would be best achieved by making necessary investments to continue to operate any or all of these three coal units or by retiring some or all of them and possibly replacing some or all of their energy and capacity with a mix of demand- and supply-side resources. The document that fully describes that holistic review and its results and conclusions is the 2022 Resource Assessment attached to my testimony as Exhibit SAW-1.

Q. What would be the effect of retiring Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 without taking any action to mitigate the loss of their capacity and energy production?

A. As shown in Tables 26 and 27 of the Resource Assessment, if the Companies retired Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 without taking any action to mitigate the loss of their capacity and energy production, the Companies' 2028 summer and winter reserve margins of 3.3% and 7.7%, respectively, would be significantly below their summer and winter minimum reserve margins of 17% and 24%, respectively. (I discuss these updated minimum reserve margins below.) The consequence would be a high likelihood of blackouts or brownouts in times of high demand.

Another way of quantifying the gravity of the issue is by considering loss of load expectation ("LOLE") for the Companies' system in 2028. The industry standard LOLE is one day in ten years. In stark contrast to that standard, if the Companies retired all three coal units listed above and took no action other than deploying the

Companies' proposed 2024-2030 Demand-Side Management and Energy Efficiency ("DSM-EE") Program Plan—and accounting for all of the projected effects of the Inflation Reduction Act ("IRA"), including increased distributed generation and energy efficiency—the Companies' LOLE would be over 130 days in ten years. Such unreliable service would be unacceptable to customers, the Commission, and the Companies, and it highlights the importance of acting now to address these pressing resource decisions.

OBJECTIVE OF THE RESOURCE ASSESSMENT

Q. What was the objective of the Resource Assessment?

A. At the highest level, the objective of the Resource Assessment was to provide an optimal resource portfolio to provide safe and reliable service to customers at the lowest reasonable cost. More specifically, the Companies' objective was to gather and analyze (1) updated load forecasting to understand customers' needs, (2) information about available demand- and supply-side alternatives, and (3) information about the Companies' existing resources, all to inform resource decisions the Companies must make to address the Good Neighbor Plan and the upcoming overhaul of Brown Unit 3. In short, the objective was to fully inform resource decisions that must be made now to address issues that will affect the Companies' ability to reliably and economically serve their customers beginning in the 2026-2028 timeframe while also considering the possible impacts of those resource decisions through 2050.

Q. Does the Resource Assessment purport to provide a complete resource portfolio for the Companies through 2050?

A. No, it explicitly does not. As noted in the Resource Assessment, it is helpful to bear in mind that this is not the last time the Companies will make resource decisions. Thus, the Resource Assessment does not purport or even attempt to prescribe the ideal resource mix through 2050; rather, it provides an optimal portfolio to address the resource decisions that must be made today. Indeed, it would be inadvisable at best to attempt to prescribe today the optimal resource portfolio through 2050. Developments in resource technology and applicable regulations can and will affect resource decisions to be made five, ten, or even twenty years from now. Therefore, the focus of the Resource Assessment was the resource decisions that must be made today while thinking carefully about how those choices might affect future decisions.

SUMMARY OF THE RESOURCE ASSESSMENT

Q. Please summarize how the Companies conducted the Resource Assessment.

A. The Companies first updated their load forecast. The Companies produced a fully updated thirty-year hourly load forecast, which accounted for the BlueOval SK Battery Park load (almost 260 MW summer, about 225 MW winter, almost 90% load factor),[4] the effects of the IRA, and the energy efficiency effects of the Companies' proposed 2024-2030 DSM-EE Program Plan.[5]

Next, to evaluate possible changes to their resource portfolio, the Companies gathered information regarding the costs and operating characteristics of potential supply-side and demand-side replacement resources. On the supply side, the Companies' June 2022 request for proposals ("RFP") resulted in 22 respondents providing 101 proposals across 39 projects (which we later sub-divided into 110 proposals), including solar, wind, pumped hydro, battery energy storage, and natural

[4] As noted in the 2022 Load Forecast, Exhibit TAJ-1, the stated peak load figures represent BlueOval's non-coincident, peak hourly usage projections grossed up by a transmission loss factor of 1.02827. BlueOval's anticipated summer billing demand is 254 MW.

[5] Tim A. Jones sponsors the 2022 CPCN Load Forecast (Exhibit TAJ-1) and discusses it in his testimony.

gas units.[6] Dispatchable DSM programs from the Companies' 2024-2030 DSM-EE Program Plan, including existing and new programs, provided a variety of dispatchable demand-response options for the Resource Assessment.[7]

Finally, after screening the RFP responses for economics and practicability, 43 supply-side options and all dispatchable DSM options proceeded to the Companies' rigorous resource analysis, which consisted of three basic stages:

1. **Creating an economically optimal portfolio consistent with minimum reliability and environmental compliance.** This stage involved using models to choose optimal portfolios across six fuel price scenarios.
2. **Stress-testing the economically optimal portfolio.** This stage involved comparing the economically optimal portfolio from Stage One to other possible portfolios across six fuel price scenarios and three CO_2 price scenarios.
3. **Fine tuning the optimal portfolio.** This stage involved additional analysis to account for solar PPA execution risk, enhance reliability, and ensure reliability if the Ohio Valley Electric Corp.'s ("OVEC") coal units retire early.

The ultimate outcome of the Resource Assessment process is a resource portfolio that blends the reliability, cost, and lower-CO_2-emission benefits of natural gas combined cycle ("NGCC") units, the energy cost hedging and zero-CO_2-emission benefits of solar generation, and the demand-reducing and reliability-enhancing benefits of dispatchable DSM from the 2024-2030 DSM-EE Program Plan. It also hedges against the risks of the current solar market—namely that prices are rising and few projects are actually being built—by including a mix of solar PPAs and solar capacity to be owned

[6] Charles R. Schram discusses the June 2022 RFP process in his testimony.
[7] John Bevington and Lana Isaacson discuss the 2024-2030 DSM-EE Program Plan in their testimony.

by the Companies. Finally, as David S. Sinclair addresses in his testimony, it includes Kentucky's first utility-scale battery energy storage system to provide additional reliability benefits and give the Companies valuable first-hand experience with owning and operating at utility scale an energy storage technology that will support increasing amounts of renewable energy generation.

OVERVIEW OF CUSTOMER'S FORECASTED REQUIREMENTS

Q. Please describe the Companies' current forecast of customers' energy requirements.

A. The Companies' 2022 CPCN Load Forecast, sponsored by Tim A. Jones as Exhibit TAJ-1, projects that customers' energy and demand requirements will be above current levels for the duration of the forecasted period, due in large part to the BlueOval SK Battery Park to be located in KU's service territory in Glendale, Kentucky. Notably, this is true even though the 2022 CPCN Load Forecast fully accounts for IRA impacts and the energy efficiency effects of the Companies' proposed 2024-2030 DSM-EE Program Plan. The 2022 Load Forecast also shows that customers will continue to require significant amounts of energy in every hour and season. Thus, an optimal resource portfolio must be able to serve customers' considerable energy requirements in all hours, seasons, and weather and daylight conditions.

Notably, the Companies developed the 2022 CPCN Load Forecast assuming normal weather. Extreme weather conditions drive a need for additional reliability considerations, which the Companies addressed in Stage Three of the Resource Analysis.

Q. In addition to forecasted load, what reserve margins do the Companies project will be necessary to ensure reliable service?

A. To ensure reliable service, the Companies reanalyzed their reserve margins for the Resource Assessment.[8] That analysis demonstrates that the Companies' minimum reserve margins are 17% in the summer and 24% in the winter. This is consistent with the much greater variability of winter peak demands shown in the 2022 Load Forecast. Note that these minimum reserve margins assume a mix of resources that are fully dispatchable for long durations and resources that are intermittent or can be dispatched for only limited durations (primarily solar and dispatchable DSM). For example, the total summer reserve margin assumes a 12% reserve margin that is fully dispatchable and a 5% reserve margin comprising intermittent and limited-duration resources. Therefore, any portfolio that achieves a total summer reserve margin of 17% but includes significantly less than a 12% reserve margin consisting of fully dispatchable resources raises reliability concerns.

RESOURCES EVALUATED

Q. Please describe how the Companies determined which supply-side resources to analyze in the Resource Assessment.

A. The Companies issued an RFP for new generation capacity and energy in June 2022.[9] In total, 22 parties responded to the RFP with 101 proposals across 39 different projects, some of which the Companies subdivided into a total of 110 proposals.[10] To ensure they reviewed respondents' best proposals, the Companies asked all respondents to update their responses to account for the IRA. The majority indicated they had

[8] A full discussion of the Companies' reserve margins is in Appendix D of the Resource Assessment.
[9] The testimony of Charles R. Schram addresses the RFP at length, and it includes the RFP itself and all RFP responses as Exhibits CRS-1 and CRS-2, respectively.
[10] Resource Assessment Appendix B contains a full listing of the 110 proposals.

already accounted for it or did not need to adjust their responses; five respondents provided updated information.

The majority of the responses to the RFP were for solar PPAs or solar PPAs with battery storage options. The Companies' Project Engineering group submitted solar and battery storage proposals, as well as the only simple cycle combustion turbine ("SCCT") and NGCC proposals. Table 1 in the 2022 Resource Assessment summarizes the proposals by technology.

The Companies reviewed the RFP responses and screened them to create a more manageable set of alternatives for modeling based on several factors, including economics, reducing the number of proposals evaluated to 43.[11] The proposals the Companies reviewed in their economic analysis included solar PPAs, wind, pumped hydro, NGCCs, and SCCTs. In short, the RFP and the Companies' subsequent screening of the responses produced a wide array of supply-side resource options to analyze.

Q. Please describe how the Companies determined which demand-side resources to analyze in the Resource Assessment.

A. The Companies determined to analyze all dispatchable DSM programs in the 2024-2030 DSM-EE Program Plan, including the Companies' existing dispatchable DSM programs.[12]

[11] Resource Assessment Appendix B contains a full listing of the 43 proposals that proceeded to the Companies' economic analysis.

[12] As noted above, the Companies' 2022 CPCN Load Forecast fully accounts for the energy efficiency effects of the proposed 2024-2030 DSM-EE Program Plan. Resource Assessment Appendix B contains a full listing of the DSM programs that proceeded to the Companies' economic analysis.

Q. How did the Companies consider their existing resources in the Resource Assessment?

A. The Companies did not overlook their existing resources in the Resource Assessment, which would continue to serve the bulk of customers' demand and energy requirements. In addition to supply-side resources, the Companies' existing resources include, for example, the Companies' interruptible load under their Curtailable Service Riders.

To focus the Resource Assessment on the decision immediately at hand—namely, whether to retire and replace one or more of Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3—the Companies assumed that all of their existing resources would continue to operate throughout the analysis period with a few exceptions: Mill Creek Unit 1 retires as planned by the end of 2024, the Companies' small-frame SCCTs (Paddy's Run 12 and Haefling 1-2) retire in 2025, and OVEC retires as planned in 2040.[13]

Also, the Companies did not assume that existing dispatchable DSM programs would automatically continue for the entire Resource Assessment period; rather, those programs advanced for analysis in the Resource Assessment. Ultimately, they proved to be beneficial for reliability and are included in the optimal resource portfolio.

<u>RESOURCE ASSESSMENT ANALYSIS:</u>
<u>KEY CONSTRAINTS AND UNCERTAINTIES</u>

Q. What were the key constraints and uncertainties the Companies considered in their Resource Assessment analysis?

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[13] Due to their age and relative inefficiency, the Companies do not perform major maintenance on their small-frame SCCTs, Paddy's Run 12 and Haefling 1-2, but continue to operate them until they are uneconomic to repair. The Resource Assessment assumes they will retire in 2025.

A. In addition to considering customers' needs and the resources potentially available to meet them, the Companies considered the following key constraints and uncertainties in their Resource Assessment analysis:

- **Key Constraints.** All stages of the Resource Assessment's analysis assumed that compliance with the Good Neighbor Plan and all other environmental requirements and maintaining minimum reserve margins were absolute constraints.

- **Key Uncertainty: Fuel Prices.** To address fuel price uncertainty, the Companies used six different fuel price scenarios in which natural gas prices were the primary price setting factor, with coal prices primarily derived from gas prices beginning in 2028 based on different historical coal-to-gas ("CTG") price ratios.[14]

- **Key Uncertainty: CO_2 Prices.** To address CO_2 regulation uncertainty, the Companies considered three different CO_2 prices as proxies for different possible CO_2 regulations: $0/ton, $15/ton, and $25/ton.[15]

- **Key Uncertainty: Solar PPA Execution.** The Companies considered the uncertainty of solar PPA execution risk, i.e., the risk that a contracted facility will not be built on time or at all at the contracted price.

- **Key Uncertainty: OVEC Early Retirement.** To address the possibility that OVEC's coal units, which provide the Companies over 150 MW of dispatchable capacity, might retire prior to the currently expected retirement date of 2040, the Companies evaluated the reliability impact of OVEC retirement in 2028. Particularly because the Companies cannot unilaterally control the operation or retirement of OVEC's units, this was an important uncertainty to analyze.

RESOURCE ASSESSMENT ANALYSIS: MODELING TOOLS

Q. Please briefly describe the modeling tools the Companies used in the Resource Assessment analysis.

A. The Companies used four primary software tools to aid them in their analysis:

[14] A full description of the derivation of these fuel prices and coal-to-gas price ratios is in Section 7.7.1 in Resource Assessment Appendix A.

[15] For a full discussion, see the CO_2 Prices section in Resource Assessment Appendix A.

- **Portfolio Development and Screening: PLEXOS.** The Companies used PLEXOS to develop least-cost resource portfolios. A notable limitation of PLEXOS as the Companies use it is that its output for each run is only the least-cost portfolio for the assumptions entered; it does not provide a ranked listing or other comparison of the thousands of other portfolios it created and considered. (Note that, largely due to this limitation, Stage Two of the Companies' analysis involved comparing PLEXOS-selected portfolios to other portfolios formulated by the Companies to examine their relative reliability and economics.)

- **Production Cost Modeling: PROSYM.** Because production costs are an important component of total costs, after PLEXOS identifies which resources to include in a resource portfolio, the Companies modeled the portfolio's generation production costs in detail using PROSYM, an hourly chronological dispatch model.

- **Present Value of Revenue Requirements ("PVRR"): Excel Financial Model.** The Companies used a Financial Model built in Excel to calculate and compare PVRR values for various portfolios.

- **Reliability Analysis: SERVM.** The Companies uses SERVM to evaluate portfolios' reliability across a wide range of weather and unit availability scenarios.

RESOURCE ASSESSMENT ANALYSIS STAGE ONE: ECONOMIC OPTIMIZATION TO ACHIEVE MINIMUM RELIABILITY

Q. Please explain Stage One of the Companies' Resource Assessment analysis.

A. The objective of Stage One was to obtain an economically optimal resource portfolio across six fuel-price cases consistent with meeting minimum reserve margin requirements and complying with Good Neighbor Plan. All steps of this stage assumed a CO_2 price of zero; Stage Two analyzed other CO_2 prices and compared the optimal portfolio from Stage One with other portfolios to analyze differences in reliability and economics.

In the first step of Stage One, the Companies used PLEXOS to develop and screen resource portfolios for each of the Companies' six fuel price cases. In this step, PLEXOS could choose to add SCR to or retire either or both of Mill Creek Unit 2 and Ghent Unit 2, retire or invest $26 million to continue operating Brown Unit 3, and add any of the 43 RFP proposals or dispatchable DSM resources at any time.[16]

The results of this step showed:

- Adding NGCC capacity is optimal in all fuel price cases. In four of six fuel price cases, PLEXOS replaced Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 with Mill Creek NGCC and Brown NGCC. In two fuel price cases, PLEXOS replaced Mill Creek Unit 2 and Brown Unit 3 with Mill Creek NGCC and added SCR to Ghent Unit 2. The level of fuel prices does not materially impact the need for resources that can economically produce large amounts of energy at night.
- The desirability of renewables predictably correlates with the level of fossil fuel prices. Over the six fuel price scenarios, PLEXOS added between zero and 2,322 MW of solar by 2028.
- Dispatchable DSM and batteries are uneconomical for achieving minimum levels of reliability and meeting the significant need for energy created by the retirement of the three coal units.

Q. What occurred in the second step of Stage One of the Companies' Resource Assessment analysis?

A. The first step of Stage One revealed that retiring Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 was likely optimal. It further showed that only two basic combinations of replacement resources would be economically optimal in 2028: (1) Mill Creek NGCC and Brown NGCC with some amount of solar PPAs, or (2) Mill Creek NGCC, Ghent Unit 2 with an SCR, and some amount of solar PPAs.

[16] Due to the uncertainties involved in estimates of solar projects' transmission costs, the Companies have not included these costs in their analysis.

In the second step of Stage One, the Companies sought to optimize the portfolio by evaluating actionable alternatives based on the results of Stage One, Step One. To do that, the Companies created 11 different combinations of the solar PPAs PLEXOS selected in the first step (ranging from 0 MW to 2,322 MW depending on the level of fuel prices) and created 22 portfolios with (1) Mill Creek NGCC and Brown NGCC plus each of the 11 solar options and (2) Mill Creek NGCC and Ghent Unit 2 with SCR plus each of the 11 solar options. The Companies conducted detailed production cost runs in PROSYM for each of these 22 portfolios across all six fuel price cases (a total of 132 runs). Unlike the PLEXOS modeling, in this part of the analysis, each solar contract was assumed to begin on its RFP-specified start date. The results of this portfolio optimization are in Table 1 below:

Table 1: Portfolio Optimization Results

	Fuel Price Scenario (Gas, CTG Price Ratio)	**Least-Cost Resource Portfolio**
Expected CTG	Low Gas, Mid CTG Ratio	MC5/BR12; 104 Solar
	Mid Gas, Mid CTG Ratio	MC5/BR12; 637 Solar
	High Gas, Mid CTG Ratio	MC5/BR12; 2,322 Solar
	Average Low, Mid, High Gas w/ Mid CTG Ratio	MC5/BR12; 637 Solar
Atypical CTG	Low Gas, High CTG Ratio	MC5/BR12; 104 Solar
	High Gas, Low CTG Ratio	MC5/GH2 SCR; 2,222 Solar
	High Gas, Current CTG Ratio	MC5/BR12; 2,322 Solar
	Average Excluding High Gas, Current CTG Ratio	MC5/BR12; 637 Solar
	Average All Fuel Prices	MC5/BR12; 1,322 Solar

With detailed production cost modeling, we observed that retiring Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3, and adding Mill Creek NGCC and Brown NGCC is optimal in five of six fuel price cases. The Companies evaluated three fuel price scenarios based on expected coal-to-gas price ratios and three scenarios based on atypical coal-to-gas price ratios. Only in the atypical fuel price scenario most favorable to coal (High Gas, Low Coal-to-Gas Ratio) is retiring only Mill Creek 2 and Brown 3, adding Mill Creek NGCC, and adding SCR to Ghent 2 least-cost.

We further observed that the three fuel price scenarios with a Mid coal-to-gas price ratio had an average optimal amount of solar of four PPAs totaling 637 MW. The Mid coal-to-gas price ratio is consistent with history and appears most likely to persist over a long analysis period.[17] In addition, the most expensive of these PPAs is $40.02/MWh, which is consistent with broader solar PPA market pricing of solar.[18] Therefore, we determined that 637 MW of solar PPAs is the optimal amount to pursue given the responses to the RFP and current solar market conditions.

Q. What occurred in the third step of Stage One of the Companies' Resource Assessment analysis?

A. The third step of Stage One built on the results of the previous two steps and sought to determine how long Ghent 2 would have to operate to justify equipping it with an SCR in the single fuel price case in which it was least cost.

To do this, the Companies evaluated cases where, after being retrofitted with SCR in 2028, Ghent 2 is replaced with Brown NGCC later in the analysis period. The Companies' generation portfolio after Ghent 2 is replaced with Brown NGCC is the same as the portfolio with Mill Creek NGCC and Brown NGCC in 2028; the only material differences in revenue requirements after Ghent 2 is replaced results from the

[17] The Mid coal-to-gas price ratio of 0.57 approximates the ratio of NGCC and coal energy costs. Over a long analysis period, despite changing natural gas prices, the average coal-to-gas price ratio is expected to continue at this level.

[18] *See* LevelTen Energy "Q3 2022 PPA Price Index Executive Summary North America" at 7 (showing current LevelTen Energy PPA Price Index for third quarter of 2022, Solar P25 Market-Averaged National Index is at $42.21/MWh), available at: https://www.leveltenenergy.com/ppa.

newer Brown NGCC having higher capital revenue requirements than the Brown NGCC commissioned in 2028.

Table 2 compares the difference in PVRR between the portfolio with Mill Creek NGCC, SCR at Ghent Unit 2, and 637 MW of solar ("MC5/GH2 SCR; 637 Solar") and the portfolio with Mill Creek NGCC and Brown NGCC and 637 MW of solar ("MC5/BR12; 637 Solar") over all six fuel price cases and four different eventual retirement dates for Ghent 2 with SCR.[19] Positive values in Table 2 indicate that the portfolio with the Ghent 2 SCR is more expensive.

Table 2: PVRR Difference; "MC5/GH2 SCR; 637 Solar" less "MC5/BR12; 637 Solar" ($M, 2022 Dollars)

	Fuel Price Scenario (Gas Price, CTG Price Ratio)	**Year of GH2 Retirement in "MC5/GH2 SCR; 637 Solar" Portfolio**				**SCR Break-Even Year**
		2035	**2040**	**2045**	**Indefinite Operation**	
Expected CTG	Low Gas, Mid CTG Ratio	77	121	107	96	N/A
	Mid Gas, Mid CTG Ratio	71	110	94	64	N/A
	High Gas, Mid CTG Ratio	75	116	104	91	N/A
Atypical CTG	Low Gas, High CTG Ratio	95	149	144	163	N/A
	High Gas, Low CTG Ratio	33	52	20	-77	2049
	High Gas, Current CTG Ratio	373	595	738	1,390	N/A

In five of six fuel price cases, there is no scenario where adding SCR to Ghent 2 is favorable. In the one fuel price scenario most favorable to coal (High Gas, Low CTG Ratio), adding SCR to Ghent 2 is favorable only if Ghent 2 can continue to operate until at least 2049—all assuming no CO_2 pricing or other constraint. On balance, this indicates that Mill Creek NGCC and Brown NGCC plus 637 MW of solar PPAs is the

[19] Focusing solely on the resource portfolio with one NGCC and SCR at Ghent, the optimal amount of solar over the fuel price scenarios with a Mid coal-to-gas price ratio is also 637 MW.

economically optimal portfolio that satisfies both the Good Neighbor Plan and minimum reserve margin requirements.

RESOURCE ASSESSMENT ANALYSIS STAGE TWO: STRESS-TESTING THE ECONOMICALLY OPTIMAL PORTFOLIO

Q. Please explain Stage Two of the Companies' Resource Assessment analysis.

A. In Stage Two, the Companies sought to stress-test the Stage One results in two ways simultaneously: (1) by evaluating different CO_2 price scenarios and (2) by comparing the apparently optimal portfolio to other portfolios created by the Companies to test their relative reliability and economics. Particularly because PLEXOS as the Companies use it does not provide a listing or ranking of all the portfolios it evaluates, the Companies thought it was particularly important to explicitly evaluate other portfolios and compare their economics.

Q. What was the first step of Stage Two of the Companies' Resource Assessment analysis?

A. In the first step of Stage Two, the Companies developed ten total portfolios to evaluate. The first two are familiar: Portfolio 1 is the apparently economically optimal portfolio from Stage One (Mill Creek NGCC and Brown NGCC plus 637 MW of solar PPAs); Portfolio 2 is the other potentially optimal portfolio from Stage One (Mill Creek NGCC, SCR on Ghent 2, and 637 MW of solar PPAs). The other eight portfolios have varying levels of NGCC, coal unit retirements, SCR, dispatchable DSM from the 2024-2030 DSM-EE Program Plan, and renewables, as well as options to operate non-SCR-equipped coal units only in non-ozone-season months.

Table 3: Stress Testing (Portfolios 1-10)

Port Num	Portfolio Name	Description	NGCC Units	Coal Units	New SCR
1	MC5 & BR12	Replace MC2 in 2027 w/ MC5 Replace BR3 & GH2 in 2028 with 1 NGCC at E.W. Brown Add 637 MW of solar	+2	-3	0
2	MC5/GH2 SCR	Replace MC2 in 2027 w/ MC5 Add SCR at GH2 and retire BR3 in 2028 Add 637 MW of solar	+1	-2	+1
3	MC5; Non-Ozone GH2	Replace MC2 in 2027 w/ MC5 No GH2 SCR; Operate GH2 in non-ozone season only Add optimal portfolio of renewables, battery storage, and dispatchable DSM	+1	-1	0
4	MC5; Non-Ozone GH2 Retire BR3	Replace MC2 in 2027 w/ MC5 No GH2 SCR; Operate GH2 in non-ozone season only Add optimal portfolio of renewables, battery storage, and dispatchable DSM Retire BR3	+1	-2	0
5	MC2/GH2 SCR	No coal retirements Add SCR at MC2 and GH2 in 2026 Complete BR3 overhaul in 2027 Add 637 MW of solar[20]	0	0	+2
6	Non-Ozone MC2/GH2	No SCRs and no coal retirements Operate MC2 and GH2 in non-ozone season only Complete BR3 overhaul in 2027 Add optimal portfolio of renewables, battery storage, and dispatchable DSM	0	0	0
7	Non-Ozone MC2/GH2; Retire BR3	No SCRs; Retire BR3 Operate MC2 and GH2 in non-ozone season only Add optimal portfolio of renewables, battery storage, and dispatchable DSM	0	-1	0
8	All Renewables	Replace MC2, BR3, and GH2 with optimal portfolio of renewables, battery storage, and dispatchable DSM	0	-3	0
9	SCCT + Renewables	Replace MC2, BR3, and GH2 with optimal portfolio of renewables, battery storage, dispatchable DSM, and SCCT	0	-3	0
10	DSM Only	Retire MC2, BR3, and GH2 Meet energy and capacity shortfall with DSM	0	-3	0

As noted in Table 3, Portfolios 3, 4, and 6-9 all required further specification of the renewable, dispatchable DSM from the 2024-2030 DSM-EE Program Plan, and battery resources to be added to address anticipated energy shortfalls (Portfolio 9 also included SCCT as an option). To do that optimally and meet the portfolio specifications, the

[20] Portfolio 5 has the same amount of solar as Portfolios 1 and 2 because the economics of replacing generation that can economically serve nighttime energy requirements are not materially impacted by solar.

Companies conducted a PLEXOS run for each portfolio in the high gas price, mid coal-to-gas price ratio case, which tends to favor renewables. As in Stage One, these PLEXOS runs included a zero CO_2 price and met minimum reserve margin requirements.

The Companies' reasoning in creating Portfolios 3-10 follows:

- Portfolios 3, 4, 6, and 7 explored different combinations of retaining Ghent 2 or Mill Creek 2 and Ghent 2 to serve only during non-ozone season months, with or without Brown 3. The purpose of these portfolios was to explore the relative reliability and economics of retaining one or both of these units without investing in SCR.
- Portfolio 5 tested the economics and reliability of investing in SCR for Mill Creek 2 and Ghent 2 and conducting the major overhaul of Brown 3, i.e., the reliability and economics of retaining all current coal units (other than Mill Creek Unit 1, which is already scheduled to retire by the end of 2024).
- Portfolio 8 tested the economics and reliability of retiring Mill Creek 2, Ghent 2, and Brown 3 and replacing their energy as needed with only renewables, batteries, and dispatchable DSM. The purpose was to test the reliability and economics of a replacement portfolio for complying with the Good Neighbor Plan that excluded all fossil fuel options.
- Portfolio 9 had the same retirements as Portfolio 8 but added SCCT to Portfolio 8's potential replacement resources. This was to test the impact of SCCT as a reliability resource in a replacement portfolio otherwise devoid of fossil fuel units.

- Portfolio 10 retires Mill Creek 2, Ghent 2, and Brown 3 and adds all dispatchable DSM from the proposed 2024-2030 DSM-EE Program Plan for the purpose of assessing the reliability of the portfolio with no other replacement resources.[21]

Table 4 below summarizes the total generation changes (i.e., retirements and resource additions) in all ten portfolios:

Table 4: Stress Testing (Portfolios 1-10); Generation Changes by 2028 (Net Summer MW)

	Portfolio Name	NGCC	Coal	SCCT	Solar	Wind	DSM[22]	Battery Storage[23]
1	MC5 & BR12	+1,242	-1,194	-	+637	-	-46	-
2	MC5/GH2 SCR	+621	-709	-	+637	-	-46	-
3	MC5; Non-Ozone GH2	+621	-782[24]	-	+637	-	-46	-
4	MC5; Non-Ozone GH2; Ret BR3	+621	-1,194[25]	-	+637	-	-46	-
5	MC2/GH2 SCR	-	-	-	+637	-	-46	-
6	Non-Ozone MC2/GH2	-	-782[26]	-	+637	-	-46	-
7	Non-Ozone MC2/GH2; Ret BR3	-	-1,194[27]	-	+1,422	+143	-46	+400
8	All Renewables	-	-1,194	-	+1,972	+143	-46	+1,270
9	SCCT + Renewables	-	-1,194	+972	+1,522	-	-46	-
10	DSM Only	-	-1,194	-	-	-	+102	-

The reserve margins achieved by these portfolios are important to observe, which are shown in Table 5 below (note that “fully dispatchable resources” exclude intermittent and limited-duration resources):

[21] Note that all portfolios effectively assume the full deployment of all non-dispatchable programs and measures in the 2024-2030 DSM-EE Program Plan because those effects are embedded in the 2022 Load Forecast.
[22] Values reflect expected load reductions under normal peak weather conditions.
[23] In Portfolio 7, battery storage consists of 300 MW of 2-hour duration batteries and 100 MW of 4-hour duration batteries. In Portfolio 8, all battery storage consists of 4-hour duration batteries.
[24] In Portfolio 3, MC2 is retired. GH2 is available only in the non-ozone season.
[25] In Portfolio 4, MC2 and BR3 are retired. GH2 is available only in the non-ozone season.
[26] In Portfolio 6, MC2 and GH2 are available only in the non-ozone season.
[27] In Portfolio 7, BR3 is retired. MC2 and GH2 are available only in the non-ozone season.

Table 5: Stress Testing (Portfolios 1-10); 2028 Summer and Winter Reserve Margins

	Summer	Winter
Minimum Reserve Margin Target	17%	24%
Fully Dispatchable Reserve Margin		
Portfolio 1: MC5 & BR12	15.7%	25.1%
Portfolio 2: MC5/GH2 SCR	13.6%	22.6%
Portfolio 3: MC5; Non-Ozone GH2	12.4%	29.4%
Portfolio 4: MC5; Non-Ozone GH2; Retire BR3	5.9%	22.6%
Portfolio 5: MC2/GH2 SCR	15.0%	23.7%
Portfolio 6: Non-Ozone MC2/GH2	2.6%	23.7%
Portfolio 7: Non-Ozone MC2/GH2; Retire BR3	-3.9%	16.9%
Portfolio 8: All Renewables	-3.9%	4.1%
Portfolio 9: SCCT + Renewables	11.4%	21.0%
Portfolio 10: DSM Only	-3.9%	4.1%
Total Reserve Margin		
Portfolio 1: MC5 & BR12	30.1%	28.4%
Portfolio 2: MC5/GH2 SCR	28.0%	25.8%
Portfolio 3: MC5; Non-Ozone GH2	26.8%	32.6%
Portfolio 4: MC5; Non-Ozone GH2; Retire BR3	20.3%	25.8%
Portfolio 5: MC2/GH2 SCR	29.4%	27.0%
Portfolio 6: Non-Ozone MC2/GH2	17.0%	27.0%
Portfolio 7: Non-Ozone MC2/GH2; Retire BR3	27.1%	27.5%
Portfolio 8: All Renewables	47.7%	28.9%
Portfolio 9: SCCT + Renewables	36.9%	24.3%
Portfolio 10: DSM Only	4.9%	9.2%

Notably, PLEXOS again did not select dispatchable DSM in any portfolio; rather, it retired existing dispatchable DSM in every portfolio it created as an uneconomical means of satisfying minimum reserve margins. To obtain dispatchable DSM in Portfolio 10, the Companies had to add it outside PLEXOS.

Also, some portfolios rely heavily on intermittent and limited-duration resources to meet reserve margins. The non-ozone-operation portfolios and the renewables-only portfolio rely heavily on intermittent and limited-duration resources to meet summer reserve margins, and the renewables-only portfolio relies heavily on intermittent and limited-duration resources to meet winter reserve margins. Therefore, although these portfolios meet minimum reserve margin constraints in total, the differences in their fully dispatchable reserve margins indicate that the reliability of these portfolios is very different. As previously discussed, there is real risk to this approach, including solar PPA execution risk.

Finally, with all the dispatchable DSM in the Companies' proposed 2024-2030 Program Plan, Portfolio 10 could not meet any reserve margin requirement.[28] Thus, it did not advance to the next step of the Stage Two analysis.

Q. Please explain the second step of Stage Two of the Companies' Resource Assessment analysis.

A. In the second step of Stage Two, the Companies conducted detailed production cost modeling with PROSYM and developed revenue requirements for each of the nine portfolios that advanced from the first step of Stage 2. They performed PROSYM runs and developed revenue requirements for each portfolio across the six fuel price cases previously discussed and three CO_2 pricing cases ($0/MWh, $15/MWh, and $25/MWh) for a total of 18 cases analyzed per portfolio.

Table 6 below summarizes the differences in present value revenue requirements ("PVRR") for Portfolios 1-9. Note that non-zero CO_2 prices begin in 2028 and that these results do not include all potential incremental transmission system upgrade costs for Portfolios 3, 4, and 6 through 9, which tends to favor those portfolios. For each fuel price scenario, the PVRR differences are presented as differences from the least-cost portfolio.

[28] A further discussion of Portfolio 10 is in Resource Assessment Appendix C.

Table 6: Stress Testing Results (PVRR Difference from Best Case, $M, 2022 Dollars)

		Difference from Best Case (PVRR, $M, 2023-2050)								
		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

Interestingly, the lowest-cost portfolio across 17 of 18 scenarios (Portfolio 1: MC5 and BR12 plus 637 MW solar PPAs) is also the least CO_2-emitting, as shown in Table 7 below:

Table 7: 2030 CO_2 Emissions (Million Short Tons, Fuel Price Scenario: Mid Gas, Mid CTG Price Ratio)

Port Number	Portfolio Name	Total CO_2 Emissions: CO_2 Price: $0/MWh	Difference from $0/MWh CO_2 Price Scenario: CO_2 Price: $15/MWh	Difference from $0/MWh CO_2 Price Scenario: CO_2 Price: $25/MWh
1	MC5 & BR12; 637 Solar	22.8	-0.5	-0.5
2	MC5 & GH2 SCR; 637 Solar	25.4	-0.3	-0.3
3	MC5; Non-Ozone GH2	25.6	-0.3	-0.4
4	MC5; Non-Ozone GH2; Ret BR3	25.2	-0.3	-0.4
5	MC2/GH2 SCR	28.5	-0.2	-0.2
6	Non-Ozone MC2/GH2	28.1	-0.1	-0.2
7	Non-Ozone MC2/GH2; Ret BR3	25.9	-0.2	-0.2
8	All Renewables	24.3	-0.1	-0.1
9	SCCT + Renewables	25.1	-0.1	-0.1

These CO_2 emissions results tie directly to the energy mix for each portfolio, as Table 8 below illustrates by comparing Portfolio 1 (Mill Creek NGCC and Brown NGCC plus 637 MW solar PPAs) to Portfolio 8 (all renewables):

Table 8: 2030 Energy Mix Comparison (Fuel Price Scenario: Mid Gas, Mid Coal-to-Gas Price Ratio)

Resource Type	Portfolio 1: MC5 & BR12; 637 Solar: $0/MWh CO_2 Price	Portfolio 1: $15/MWh CO_2 Price	Portfolio 1: $25/MWh CO_2 Price	Portfolio 8: All Renewables: $0/MWh CO_2 Price	Portfolio 8: $15/MWh CO_2 Price	Portfolio 8: $25/MWh CO_2 Price
Coal	50%	47%	47%	60%	59%	58%
NGCC	41%	42%	42%	15%	15%	15%
SCCT	2%	3%	4%	8%	10%	10%
Solar	6%	6%	6%	15%	15%	15%
Wind	0%	0%	0%	1%	1%	1%
Hydro	1%	1%	1%	1%	1%	1%

This second step of Stage Two showed that a portfolio of Mill Creek NGCC and Brown NGCC plus 637 MW solar PPAs is clearly optimal in the non-zero CO_2 pricing scenarios the Companies studied. This result is unsurprising; adding SCR to

Ghent 2 allows a coal unit to continue operating, which is unfavorable in CO_2 pricing scenarios due to its higher CO_2 emissions per MWh.

Also, the all-renewables replacement portfolio (Portfolio 8) is markedly more expensive than all other portfolios except the renewables plus SCCT portfolio (Portfolio 9), and then only in high gas price cases. The cost of adding large amounts of renewables and batteries to serve load—under normal weather conditions—far exceeds the cost of paying even $25/MWh in CO_2 costs for all other portfolios except the portfolio that adds only renewables and SCCT. Even that portfolio is less expensive than the all-renewables portfolio in all cases except high gas cost cases.

Finally, we observed that increasing amounts of renewables require increasing dispatch of existing coal and SCCT generation, increasing CO_2 emissions relative to two NGCCs. Table 8 shows that the inability of solar to provide energy in non-daylight hours, as well as its limited daylight production profile, requires more dispatch of coal and SCCT. This results in increased CO_2 emissions because coal and SCCT have higher CO_2 emissions per MWh than NGCC.

Q. What did you conclude from Stages One and Two of the Companies' Resource Assessment analysis?

A. The Companies concluded from the results of Stages One and Two that, considering fuel price and CO_2 regulatory uncertainties, it would be economically optimal to satisfy Good Neighbor Plan requirements and minimum reserve margin requirements in 2028 by:

- Retiring Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 (1,1194 MW of coal-fired generation);

- Adding two NGCC units, the 621 MW Mill Creek NGCC and the 621 MW Brown NGCC; and
- Adding 637 MW of solar PPAs.

RESOURCE ASSESSMENT ANALYSIS STAGE THREE: FINE-TUNING THE OPTIMAL PORTFOLIO FOR RISK AND RELIABILITY

Q. Please explain Stage Three of the Companies' Resource Assessment analysis.

A. In Stage Three, the Companies sought to fine-tune the economically optimal portfolio to address certain risks not yet addressed (solar PPA project execution risk and OVEC early retirement risk) and to add reliability to the extent it would be cost-effective or otherwise advisable to do so.

Q. What was the first step of Stage Three of the Companies' Resource Assessment analysis?

A. An uncertainty associated with solar generation, particularly solar PPAs, is execution risk, i.e., the risk that the contracted capacity will not be built on time or at all. It is a particularly acute risk in the current solar market, as the Companies have experienced with the two solar PPAs they executed in 2019 and 2021 (Rhudes Creek and Ragland, respectively); neither project has received all necessary approvals, neither is on schedule or has begun construction, and neither is likely to proceed any time soon because it will be difficult or impossible to finance the projects at the contracted price in today's solar market and interest rate environment, as Mr. Sinclair addresses in his testimony.

The same risk applies to the four PPAs selected as part of the economically optimal portfolio, although two of the PPAs have price reopeners to partially mitigate this risk. The modeling of Stages One and Two assumed that each PPA's capacity would be installed and operational as specified in the PPA proposal. In other words, it assumed zero solar PPA execution risk.

One means of mitigating actual, non-zero solar PPA execution risk would be to add solar capacity the Companies would own, either through acquisition or self-building. Mr. Sinclair discusses this and other solar ownership considerations in his testimony.

Thus, the first step of Stage Three analyzed 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 analyzed are in Table 9 below:

Table 9: 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 Replace BR3 & GH2 in 2028 with BR12 No Solar (i.e., No Rhudes Creek or Ragland PPAs)	-
12	Portfolio 11 +Asset Purchase +Self-Build	Portfolio 11 + 120 MW Solar Asset (Asset Purchase) + 120 MW Solar Asset (Self-Build)	+240

The Companies conducted PROSYM runs for both portfolios across all six fuel price cases and all three CO_2 price cases, then used the Companies' financial model to create revenue requirements for each portfolio in each run over three cases for the price of renewable energy certificates ("RECs"), namely \$0, \$5, and \$10 per REC.[29] The

[29] Over the last three years, the Companies have sold Brown Solar RECs for between \$8 and \$13 per REC.

results of that analysis are in Table 17 of the Resource Assessment (Section 4.6.1). They demonstrate that:

- **Adding the solar self-build and asset purchase is favorable in the majority of cases evaluated.** In the nine cases comprising expected fuel prices (i.e., low, mid, and high gas prices with a mid coal-to-gas price ratio) and \$0 to \$10 REC prices, adding the Mercer County Solar Facility and the Marion County Solar Facility is favorable in three of nine cases with a \$0/MWh CO_2 price, five of nine cases with a \$15/MWh CO_2 price, and eight of nine cases with a \$25/MWh CO_2 price.
- **The economics of the solar self-build improve with higher gas prices, higher REC prices, and higher CO_2 prices.** The PVRR improves by approximately \$35 million for every \$5 increase in REC prices. Compared to cases with no CO_2 price, the favorability of the Mercer County Solar Facility and the Marion County Solar Facility improves by approximately \$100 million with a \$15 CO_2 price.

On the whole, based on the PVRR results and given the uncertainties concerning the solar industry, gas prices, and future carbon regulations (for which CO_2 prices are a proxy), the Companies concluded that adding the solar asset purchase proposal (Marion County Solar Facility) and their self-build solar project (Mercer County Solar Facility) to the optimal portfolio of the Mill Creek NGCC, Brown NGCC, and 637 MW of solar PPAs is a reasonable hedge against these market uncertainties in the transition to a lower carbon future.

Q. What was the second step of Stage Three of the Companies' Resource Assessment analysis?

A. In the second step of Stage Three, the Companies' goal was to optimally enhance reliability. To do this, the Companies evaluated SCCT, batteries, and dispatchable DSM programs from the 2024-2030 DSM-EE Program Plan as potential reliability-enhancing resources.

The SCCT and battery options the Companies evaluated were the SCCT and Brown BESS proposals provided as RFP responses by the Companies' Project Engineering group with input from HDR, an engineering consulting firm. The Companies chose the Brown BESS to evaluate over other battery options because battery ownership will allow the Companies to gain valuable operational experience with such systems at utility scale, which will likely be an integral part of integrating increasing amounts of renewable generation in future. Mr. Sinclair discusses the benefits of battery ownership in his testimony, as well.

The dispatchable DSM programs the Companies considered are all of the existing and new dispatchable DSM programs included in the Companies' 2024-2030 DSM-EE Program Plan. In total, the capacity of the DSM programs is 192 MW in the summer and 102 MW in the winter. In this analysis, the Companies treated all dispatchable DSM as being 100% available when needed.

The Companies then determined that, given the solar PPA execution risk previously discussed, they would evaluate the reliability-enhancing resources discussed above as additions to two portfolios: (1) Mill Creek NGCC and Brown NGCC only; and (2) Mill Creek NGCC and Brown NGCC with 1,127 MW of solar consisting of the four new PPAs totaling 637 MW, the existing Rhudes Creek and Ragland PPAs, and two owned assets (Marion County Solar Facility and the Mercer

County Solar Facility). The Companies then used SERVM to model the LOLE impact and average reliability and production costs of each portfolio.

Table 10 below summarizes the results of this analysis for the portfolios without solar; Table 11 below summarizes the results of this analysis for the portfolios with solar. Capacity costs reflect the annual carrying cost of each resource (e.g., the annual carrying cost of the SCCT in 2028 is $19 million). Average reliability and generation production costs were computed over all load and unit availability scenarios. Total costs are the sum of capacity costs and average reliability and generation production costs.

Table 10: Reliability Assessment Results without Solar

	LOLE (10 Years)			Difference from MC5/BR12 Portfolio:		
Generation Portfolio	**Summer**	**Winter**	**Total**	**Capacity Cost ($M/year)**	**Average Reliability and Generation Production Costs ($M/year)**	**Total Cost: Capacity Costs + Avg Reliability and Generation Production Costs ($M/year)**
MC5/BR12	1.32	0.51	2.00	-	-	-
MC5/BR12 + SCCT	0.45	0.18	0.66	19	-4	15
MC5/BR12 + DSM	0.74	0.39	1.20	5	0	5
MC5/BR12 + BESS	0.77	0.32	1.16	26	-3	23
MC5/BR12 + DSM + BESS	0.43	0.28	0.75	31	-3	28

Table 11: Reliability Assessment Results with 1,127 MW Solar

	LOLE (10 Years)			Difference from MC5/BR12 + Solar Portfolio:		
Generation Portfolio	**Summer**	**Winter**	**Total**	**Capacity Cost ($M/year)**	**Average Reliability and Generation Production Costs ($M/year)**	**Total Cost: Capacity Costs + Avg Reliability and Generation Production Costs ($M/year)**
MC5/BR12 + Solar	0.09	0.41	0.51	-	-	-
MC5/BR12 + Solar + SCCT	0.02	0.15	0.18	19	-2	17
MC5/BR12 + Solar + DSM	0.04	0.32	0.36	5	0	5
MC5/BR12 + Solar + BESS	0.05	0.29	0.34	26	-2	24
MC5/BR12 + Solar + DSM + BESS	0.02	0.22	0.24	31	-2	29

These tables show that adding DSM is the most cost-effective means of enhancing reliability in these portfolios. Table 10 shows that with only the Mill Creek NGCC and Brown NGCC, the Companies' expected LOLE is 2.00 days in 10 years, which is higher than the physical reliability guideline of one day in 10 years. Adding an SCCT reduces LOLE 67% to 0.66, but at a cost of $15 million per year, whereas adding DSM reduces LOLE 40% to 1.20, but at one-third of the cost of SCCT ($5 million per year). Table 11 shows similar results: SCCT provides a 65% LOLE reduction, but DSM provides a 30% LOLE reduction, again at approximately one-third of the SCCT cost. DSM is therefore markedly more cost-effective than SCCT for enhancing the reliability of these portfolios.

The tables further show that adding Brown BESS further enhances reliability. Tables 10 and 11 above show that Brown BESS adds reliability in portfolios with and without solar. But it is not the most cost-effective means of enhancing reliability as modeled, and it increases PVRR in all fuel price scenarios, as shown in Table 12 below.

Table 12: Impact of Brown BESS on PVRR ($M, 2022 dollars, $0/MWh CO_2 price)

	Fuel Price Scenario (Gas, CTG Price Ratio)	**PVRR Impact**
Expected CTG	Low Gas, Mid CTG	206
	Mid Gas, Mid CTG	203
	High Gas, Mid CTG	171
Atypical CTG	Low Gas, High CTG	154
	High Gas, Low CTG	154
	High Gas, Curr CTG	206

Therefore, as Mr. Sinclair discusses, the primary benefit of Brown BESS would be to provide the Companies valuable operational experience with a technology at utility scale that will likely be vital to integrating large amounts of renewable generation reliably in the future.

It is notable that Brown BESS might provide quantifiable benefits the Companies have not attempted to quantify here. For example, battery energy storage systems can provide instantaneous load following and compensation for fluctuations in intermittent generation that might otherwise require rapid ramping from the Companies' SCCT and NGCC units, reducing wear (and related costs) on such units. The Brown BESS might also allow the Companies to carry lower amounts of spinning reserves, which could also provide savings.

Based on this analysis and given the uncertainty facing the solar industry, the Companies believe it is appropriate to add the dispatchable DSM programs in the 2024-2030 DSM-EE Program Plan, which are a cost-effective means of improving reliability, and to add the Brown BESS to the optimal resource portfolio.

Q. What was the third step of Stage Three of the Companies' Resource Assessment analysis?

A. In the third and final step of Stage Three, the Companies evaluated the impact of a possible early retirement of OVEC on the optimal resource portfolio. To be clear, the Companies cannot unilaterally determine when OVEC will retire, which is precisely why its retirement date is an important uncertainty to analyze. In particular, the Companies sought to determine if an early OVEC retirement had a reliability impact that would require adding any demand- or supply-side resources to the optimal portfolio.

Therefore, as a final scenario, the Companies used SERVM to evaluate the LOLE impact on the optimal resource portfolio (both with and without solar) if the

OVEC units ceased operating in 2028 rather than 2040 as currently forecasted. Table 13 below contains the results of this analysis.

Table 13: Impact of 2028 OVEC Retirement on Optimal Resource Portfolio

	LOLE (10 Years)		
Portfolio	**Summer (Jun, Jul, Aug)**	**Winter (Dec, Jan, Feb)**	**Total Year**
MC5/BR12 + DSM + BESS	0.43	0.28	0.75
MC5/BR12 + DSM + BESS - OVEC	0.93	0.42	1.44
MC5/BR12 + Solar + DSM + BESS	0.02	0.22	0.24
MC5/BR12 + Solar + DSM + BESS - OVEC	0.05	0.39	0.45

These results show that the optimal resource portfolio would provide excellent reliability even if OVEC retired early. Therefore, there is no reason to adjust the optimal portfolio to address the possibility of early OVEC unit retirements.

RESOURCE ASSESSMENT ANALYSIS CONCLUSION: A NO-REGRETS PORTFOLIO

Q. How would you describe the final outcome of the Resource Assessment analysis?

A. As discussed previously, the objective of this Resource Assessment is not to make every resource decision for the Companies and their customers for through 2050; rather, it is only to provide an optimal resource portfolio for the decisions that the Companies must make today due to the Good Neighbor Plan and the upcoming major capital investment at Brown 3. In other words, the objective is to provide an optimal resource portfolio for the resource decisions that must be made now concerning possible unit retirements in the 2026 to 2028 timeframe, and to do so in a way that ensures safe and reliable service at the lowest reasonable cost—ideally with a no-regrets resource portfolio.

Part of having no regrets is recognizing that, as the 2022 CPCN Load Forecast shows, customers will continue to have significant energy needs in all hours, seasons, and weather and daylight conditions. Thus, a no-regrets portfolio must be able to serve customers reliably 8,760 hours every year, not just for a handful of peak hours, not just when the sun is shining, and not just when customers are willing to voluntarily reduce their load in response to pricing signals.

The Companies' optimal resource portfolio resulting from the Resource Assessment's analysis is such a no-regrets portfolio. It economically retires three large coal units (1,194 MW total) that provide around-the-clock energy. It replaces those units with an optimal blend of resources offered in the Companies' competitive RFP process and cost-effective dispatchable DSM programs from the Companies' 2024-2030 DSM-EE Program Plan:

<u>The 2022 Resource Assessment's Optimal Resource Portfolio</u>

- Reliable, fully dispatchable, around-the-clock generation (1,242 MW total)
  - Mill Creek NGCC (621 MW NGCC)
  - Brown NGCC (621 MW NGCC)
- Clean renewable generation, hedging fuel price and CO_2 risk (877 MW total)
  - Mercer County Solar Facility (self-build; 120 MW)
  - Marion County Solar Facility (asset purchase; 120 MW)
  - Song Sparrow PPA (Clearway Energy; 104 MW)
  - Gage Solar PPA (BrightNight; 115 MW)
  - Nacke Pike PPA (ibV; 280 MW)
  - Grays Branch PPA (ibV; 138 MW)

- Cost-effective dispatchable DSM programs (192 MW summer; 102 MW winter)
- Additional reliability and valuable operational experience with Brown BESS (125 MW, 500 MWh)

The Companies' rigorous three-stage analysis ensured that the optimal portfolio appropriately balances economics, reliability, and risk; provides valuable experience with new technologies to accommodate greater renewable power generation in the future; and reduces CO_2 emissions considerably, more than other portfolios analyzed, which reduces future regulatory risk and potential cost related to CO_2 emissions. It is a no-regrets portfolio:

- **Low load or increased efficiencies, no regrets.** If actual load is materially lower than projected load for any reason, including if technological advances or economic changes result in additional energy and demand savings (through DSM-EE programs or otherwise), retiring additional aging coal capacity would likely be the most economical option, further reducing CO_2 emissions.
- **High load, no regrets.** If actual load is materially higher than projected load, nothing in the Companies' proposed portfolio precludes adding demand- or supply-side resources to address the need. If the increased load results from electric space heating or electric vehicle charging, the proposed NGCC units could prove to be particularly valuable given their ability to cost-effectively serve non-daylight energy requirements.
- **Increased renewable generation or CO_2 constraints, no regrets.** The proposed portfolio's rapid-ramping NGCC units and Brown BESS well position the Companies to provide reliable service if renewable energy generation increases,

and the lower CO_2 emissions of NGCCs and zero emissions of solar and DSM-EE all improve the Companies' positioning to address any CO_2 emissions pricing or regulations that might eventuate.

In sum, the optimal resource portfolio this Resource Assessment recommends will help ensure that customers receive safe, reliable, and lowest-reasonable-cost service for years to come.

UTILITY OWNERSHIP

Q. Do you have a recommendation concerning the Companies' ownership shares of the facilities for which the Companies are seeking CPCNs in this proceeding, as well as energy allocations for the solar PPA facilities?

A. Yes. Based on the analysis of this issue in the Resource Assessment, for the Mill Creek and Brown NGCC units, the optimal ownership allocation is 69% for KU and 31% for LG&E. For the Mercer County Solar Facility and the Marion County Solar Facility, the optimal allocation is 63% for KU and 37% for LG&E; the same allocation is optimal for energy from the solar PPA facilities. (These allocations are also close to the allocation of total energy between the Companies: KU's share of total energy is approximately 64%; LG&E's share is 36%.) Finally, the optimal ownership allocation for the Brown BESS is 100% to LG&E to better balance the Companies' summer reserve margins.

CONCLUSION

Q. What is your recommendation for the Commission?

A. Based on my extensive experience in performing and supervising generation planning activities as well as the use of generation planning software and models, I am confident that the rigorous analysis discussed in the Resource Assessment can be relied upon by the Companies and this Commission for the decisions that must be made to address Good Neighbor Plan compliance and the retirement of Brown Unit 3. Therefore, I recommend the Commission approve all of the CPCNs the Companies are requesting in this proceeding. I further recommend that the Commission approve the Companies' proposed 2024-2030 DSM-EE Program Portfolio, which provides energy consumption reductions upon which the 2022 CPCN Load Forecast depends and which provides cost-effective reliability enhancements to the optimal resource portfolio recommended in the Resource Assessment.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Stuart A. Wilson**, being duly sworn, deposes and says that he is Director, Energy Planning, Analysis & Forecasting for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Stuart A. Wilson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of December 2022.

Notary Public

Notary Public ID No. KYNP53381

My Commission Expires:

July 11, 2026

APPENDIX A

Stuart A. Wilson, CFA
Director, Energy Planning, Analysis and Forecasting
Kentucky Utilities Company
Louisville Gas and Electric Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-4993

Previous Positions

Manager, Generation Planning & Analysis	October 2009 – April 2016
Manager, Sales Analysis & Forecasting	May 2008 – October 2009
Supervisor, Sales Analysis & Forecasting	Aug 2006 – April 2008
Economic Analyst	Aug 2000 – July 2006
Compensation Analyst	Aug 1999 – July 2000
Business Analyst	June 1997 – July 1999

Civic Activities

Big Brothers Big Sisters of Kentuckiana – Board of Directors: 2017 – Present
Barren Heights Christian Retreat – Board of Directors: 2015 – 2021

Professional Memberships

CFA Society of Louisville

Education/Certifications

E.ON Emerging Leaders Program: 2004-2006

CFA Charterholder: September 2003

LG&E Energy Leadership Development Program: 1997-2002

Master of Business Administration;
Indiana University, May 1997

Master of Engineering in Electrical Engineering;
University of Louisville, December 1995

Bachelor of Science in Electrical Engineering;
University of Louisville, December 1995