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 AND APPROVAL OF FOSSIL FUEL-FIRED GENERATING UNIT RETIREMENTS	)	**CASE NO. 2022-00402**

REBUTTAL TESTIMONY OF
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LOUISVILLE GAS AND ELECTRIC COMPANY

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I. BACKGROUND

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.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address criticisms of the Companies' modeling approaches, assumptions, and results made by Sierra Club, Louisville Metro, and LFUCG witness Andrew Levitt, Sierra Club witness Michael Goggin, Kentucky Coal Association witness Emily Medine, and Joint Intervenors' witnesses Andy McDonald and Anna Sommer. I demonstrate that the Companies' modeling remains reasonable for making the resource decisions that must be addressed in this proceeding.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibit to my direct testimony:

Rebuttal Exhibit SAW-1 Stuart A. Wilson Rebuttal Testimony Workpapers

Note that Rebuttal Exhibit SAW-1 consists of electronic workpapers and is being provided separately.

Q. Have any of the intervenors' witnesses identified fundamental flaws in the Companies' resource modeling efforts?

A. No. Mr. Levitt argues that the Companies can avoid the need for two NGCCs by joining PJM, but I show that his analysis of the Companies' capacity position in PJM is misleading and ignores significant uncertainties associated with PJM's capacity accreditation process moving forward. Ms. Sommer, Mr. Goggin, and Ms. Medine offer several criticisms that would suggest the Companies' modeling is flawed, but I show that the Companies' modeling is correct. Finally, Ms. Sommer developed a portfolio with one NGCC that she claims has a lower PVRR than the Companies' recommended portfolio. While the Joint Intervenors do not recommend Ms. Sommer's portfolio, I explain why her portfolio is not lower cost.

II. CONTRARY TO MR. LEVITT'S ASSERTIONS, THE COMPANIES WOULD HAVE A CAPACITY NEED AS PJM MEMBERS

Q. Mr. Levitt asserts that the Companies would be able to avoid adding the Mill Creek and Brown NGCCs as PJM members and provides an analysis suggesting that the Companies' proposed portfolio without the two NGCCs would exceed PJM's reserve margin requirements by 61 MW.[1] What are your thoughts regarding Mr. Levitt's analysis?

A. Mr. Levitt's analysis is misleading and ignores significant uncertainties associated with PJM's capacity accreditation process moving forward. First, Mr. Levitt evaluates the Companies' capacity need in Section II of his testimony, but his analysis considers thermal resources on an ICAP basis and not a UCAP basis like the process PJM uses to assess a member's capacity position. An estimate of the Companies' UCAP capacity need is appropriately included in Section III of his testimony for the purpose of computing capacity costs. However, contrary to Mr. Levitt's repeated assertions in Section II regarding a 2028 capacity surplus (see Figure 2, Table 2, and Table 3 of his testimony), his UCAP results in Section III (on which the Companies' capacity position would actually be based) show that the Companies do not have a capacity surplus in

[1] Levitt at 22-24; *see* Levitt at 8-30.

2028. Second and far more importantly, Mr. Levitt's analysis offers little consideration of PJM's "early stage proposal… for a seasonal capacity market" that he acknowledges "suggests a directional reduction in capacity benefits for LG&E-KU."[2] The impact of these changes could have a significant impact on the value of the Companies' resources in an RTO context.

Q. Why do you say the impact of potential changes to PJM's capacity accreditation process could be significant?

A. As an example, Mr. Goggin argues in his testimony based on a report recently completed by Astrape Consulting, the vendor of SERVM, that the Companies should be modeling correlated outages for their thermal units and that by not doing this, they are overstating their thermal resources' reliability and capacity value. According to this report, as a result of correlated outages, "the capacity value of conventional generators in part of PJM can be 24% lower in winter and 15% lower in summer relative to their nameplate capacity."[3]

Q. Is the Astrape report credible?

A. Yes. The Astrape report was completed to assess the impact of correlated outages on an RTO's capacity accreditation process. Its assessment of incremental outages due to hot and cold weather was based on an analysis of unit outage data from 1995-2018 for 1,845 generators in PJM.[4] The methodology used by Astrape to estimate the impact of

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[2] Levitt at 28.
[3] Goggin at 30.
[4] See Page 9 in Murphy, Sinnott, et. al. "A time-dependent model of generator failures and recoveries captures correlated events and quantifies temperature dependence." Applied Energy, November 2019. Available from https://www.sciencedirect.com/science/article/pii/S0306261919311870.

correlated outages on an RTO's capacity accreditation process is reasonable, and I agree that correlated outages are currently a concern in PJM.

Q. Does the Astrape report have any relevance to the Companies' capacity needs as non-RTO members?

A. No. As discussed by Messrs. Bellar and Sinclair, the Companies have taken steps historically to reduce the likelihood of correlated outages and the Companies and their vendors, including Texas Gas Transmission, are taking additional steps moving forward to reduce the likelihood of correlated outages in the wake of Winter Storm Elliott. Therefore, the risk of correlated outages remains low for the Companies moving forward.

Q. What are the implications of these recommendations on Mr. Levitt's analysis of the Companies' capacity need in PJM?

A. The implications are significant. Because the Companies have taken steps to address correlated outages with their resources, the capacity value of the Companies' resources would be inappropriately penalized if they joined PJM and PJM adopted changes to their capacity accreditation process that are like the changes Mr. Goggin recommends.

Q. If the capacity value of the Companies' thermal resources was reduced by 24% in the winter and 15% in the summer relative to their maximum capacity, what impact would this have on the Companies' capacity value in an RTO context?

A. With these changes, the capacity value for the Companies' thermal resources that they are not proposing to retire would decrease by approximately 1,100 MW in the winter and 500 MW in the summer. This is a significant consideration for joining an RTO.

Q. Is there any other evidence suggesting that the basic position of Messrs. Goggin and Levitt—namely that the Companies can economically maintain reliable service by retiring seven generating units and counting on others to provide energy—is flawed?

A. Yes. Although the Companies are not necessarily advocating for all the particulars of EPA's modeling, it is noteworthy that in *every scenario* EPA has modeled since the passage of the Inflation Reduction Act (for which it has publicly provided modeling data), EPA's economically optimal modeling results show more NGCC capacity being installed by 2028 in the SERC Central Kentucky region—where the Companies' service territories are—than the Companies are proposing in this proceeding.[5] This is both noteworthy and a rejoinder to Messrs. Goggin's and Levitt's arguments because EPA's modeling takes a nationwide view, attempting to optimize economics for America's entire power production system consistent with relevant constraints, including reliability and environmental compliance.[6]

Regarding reliability, EPA's modeling used a lower reserve margin constraint for the SERC Central Kentucky Region—just 15%—than the Companies' seasonal target reserve margins of 17% (summer) and 24% (winter), which is also lower than

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[5] See the "S_C_KY" tabs of the "[IPM Run Name] RegionalSummary" Excel files in the zip files available at https://www.epa.gov/power-sector-modeling/analysis-proposed-greenhouse-gas-standards-and-guidelines. As an example, see the "Integrated Proposal with LNG Update RegionalSummary" Excel file in the zip file available at https://www.epa.gov/system/files/other-files/2023-07/Integrated%20Proposal%20with%20LNG%20Update.zip.

[6] EPA, "Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model Post-IRA 2022 Reference Case, March 2023" at 1-1 ("IPM [EPA's Integrated Planning Model] is a multi-regional, dynamic, and deterministic linear programming model of the U.S. electric power sector. The model provides forecasts of least cost capacity expansion, electricity dispatch, and emission control strategies, while meeting energy demand, environmental, transmission, dispatch, and reliability constraints."). Available at https://www.epa.gov/system/files/documents/2023-03/EPA%20Platform%20v6%20Post-IRA%202022%20Reference%20Case.pdf (accessed July 27, 2023).

the reserve margin EPA modeled for all of the PJM regions (15.7%),[7] and it is essentially equivalent to PJM's Installed Reserve Margin for 2023 through 2027 (ranging from 14.7% to 14.9%).[8] Yet even with a lower reserve margin constraint than both the Companies' seasonal target reserve margins, all of EPA's modeled optimal economic solutions since the IRA have included more than 1,700 MW of new NGCC capacity being installed in the SERC Central Kentucky regional by 2028, and most have included more than 2,000 MW.[9]

EPA's modeling results are also generally consistent with the optimal capacity expansion plan in a PJM membership scenario modeled by the Companies' consultant Guidehouse as part of the Companies' most recent RTO membership study submitted to the Commission.[10]

All of this undermines the premise of the testimony of both Messrs. Goggin and Levitt that the Companies have improperly modeled their system as an island and are therefore proposing a sub-optimally resource-heavy portfolio, particularly with regard to the Companies' proposed NGCC units. To the contrary, the modeling conducted by the EPA, Guidehouse, and the Companies are consistent with the Companies' proposals in this proceeding, including the two proposed NGCC units. Moreover, as I discuss below, even the Joint Intervenors' modeling supports adding NGCC capacity

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[7] *Id.* at 3-16, Table 3-9.

[8] PJM, "2022 PJM Reserve Requirement Study" at 8 (Oct. 4, 2022), available at https://www.pjm.com/-/media/planning/res-adeq/2022-pjm-reserve-requirement-study.ashx (accessed July 27, 2023).

[9] *See* EPA modeling data, "S_C_KY" tabs of Excel files with "RegionalSummary" in the file name in the folders with "RPT" in the name embedded in .zip files available at https://www.epa.gov/power-sector-modeling/analysis-final-federal-good-neighbor-plan-addressing-regional-ozone-transport (sensitivity files with "+IRA" in file name) and https://www.epa.gov/power-sector-modeling/analysis-proposed-greenhouse-gas-standards-and-guidelines.

[10] See Attachment 1 to the response to SC 2-26(b).

by 2028—and their modeling assumptions, applied properly, support adding two NGCCs as the Companies have proposed.

III. THE COMPANIES' MODELING APPROACH, ASSUMPTIONS, AND RESULTS REMAIN REASONABLE AND SUPPORT THE COMPANIES' PROPOSED RESOURCE PORTFOLIO

A. <u>General Modeling – Sommer</u>

Q. Ms. Sommer asserts that the Companies' resource modeling is flawed because it essentially evaluated only one portfolio, whereas the Companies should use the same modeling approach for all portfolios evaluated, including running SERVM on all portfolios.[11] Is the Companies' modeling flawed?

A. No. It is helpful to recall that the Companies conducted their analysis in three stages:

- **Stage One: Economic Optimization.** In the first stage, the Companies used PLEXOS and PROSYM to create an economically optimized portfolio across six fuel price cases that met minimum reliability constraints and ensured Good Neighbor Plan compliance. Importantly, PLEXOS effectively considers *thousands* of potential resource portfolios before providing an economically optimized result that satisfies reliability and other constraints. The conclusion of the Stage One economic optimization process was that retiring Mill Creek 2, Ghent 2, and Brown 3 and adding two natural gas combined cycle ("NGCC") units, namely Mill Creek 5 and Brown 12, and 637 MW of solar power purchase agreements ("PPAs") would be economically optimal for meeting minimum reliability targets.

[11] Sommer at 4-6.

- **Stage Two: Stress Testing.** In the second stage, the Companies stress-tested the economically optimal portfolio by comparing it over a range of CO_2 prices to a wide variety of other portfolios created by introducing additional modeling constraints (e.g., the Stage Two analysis considered an "all renewables" portfolio and a portfolio with no coal retirements). The Stage Two analysis showed that the economically optimal portfolio from Stage One remained the economically optimal portfolio in scenarios in which future regulations place a cost on CO_2 emissions.
- **Stage Three: Fine Tuning.** The purpose of the Stage Three analysis was to fine tune the economically optimal portfolio to account for solar PPA execution risk and enhance reliability, and the Companies used SERVM to analyze alternatives for enhancing portfolio reliability. The Stage Three analysis provides the basis for including dispatchable DSM, the two owned-solar projects, and the Brown BESS in the Companies' recommended portfolio along with the economically optimal resources for assuring minimum reliability.

Ms. Sommer's criticism of the Companies' analysis pertains to the Stage Two analysis. According to Ms. Sommer, the Companies should have used SERVM to assess each Stage Two portfolio's reliability, potentially modified the portfolios to achieve a similar level of reliability, and then evaluated each portfolio's cost.

I disagree. Instead of assessing the reliability of each portfolio in SERVM, the Companies performed a high-level reliability assessment by comparing the portfolios' total and fully dispatchable reserve margins (see Table 12 in Exhibit SAW-1). Compared to the economically optimal portfolio (Portfolio 1), the other portfolios evaluated in the Stage Two analysis had similar total reserve margins in the winter, and only Portfolio 8 (All Renewables) and Portfolio 9 (SCCT + Renewables) had higher total reserve margins in the summer. Ms. Sommer and the Companies agree that two portfolios with the same reserve margin can have very different LOLEs depending on the portfolios' composition of resources (i.e., the proportion of fully dispatchable, limited-duration, and renewable resources), and the Companies' analysis shows that portfolios with a smaller share of fully dispatchable resources are less reliable (i.e., have higher LOLEs). Therefore, the Companies assessed differences in portfolio composition at a high level by comparing the portfolios' fully dispatchable reserve margins, and only Portfolios 4, 6, 7, and 8 had significantly different portfolio compositions than the economically optimal portfolio. Had the cost of any of these portfolios been remotely economically competitive with the optimal portfolio, it would have been appropriate to evaluate the reliability of the portfolios in SERVM. But each of these portfolios was significantly more expensive, particularly in scenarios where future regulations place a cost on CO_2 emissions. Therefore, it was not necessary to evaluate the reliability of the portfolios in detail using SERVM.

Q. Ms. Sommer argues that the Companies should explicitly model all DERs, including energy efficiency, in their resource modeling and apply their reliability analysis to all DERs "to determine the characteristics of resources that would help improve or meet reliability criteria such as seasonality and duration."[12] Is there a flaw in the way the Companies have modeled DERs?

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[12] Sommer at 51-52.

A. No. The Companies modeled the impact of distributed solar in their load forecast, and Mr. Jones demonstrates in his rebuttal testimony that the Companies' distributed solar forecast is reasonable. It is appropriate to include the impact of DERs such as distributed solar in the Companies' load forecast rather than supply-side modeling because the Companies cannot control customers' DER adoption (or the resulting energy savings), but the Companies can control whether they acquire supply-side resources. Demand response resources such as load control are an exception to that general approach because, although the Companies cannot control customers' adoption of such resources, they can determine how and when to use the resources after customers adopt them, which makes them more like a supply-side resource.

Also, prior to conducting our analysis, my team met with the Companies' DSM-EE team, including Cadmus, to discuss the operating characteristics of the coal units impacted by the Good Neighbor Plan and the winter focus of the Companies' resource planning. That discussion helped emphasize the importance of seasonality in DSM-EE program development from our group's perspective, including the growing importance of winter energy needs and the value of programs that could help meet those needs. Thus, the Companies' DSM-EE and supply-side resource planning efforts are indeed coordinated as Ms. Sommer suggests they should be.

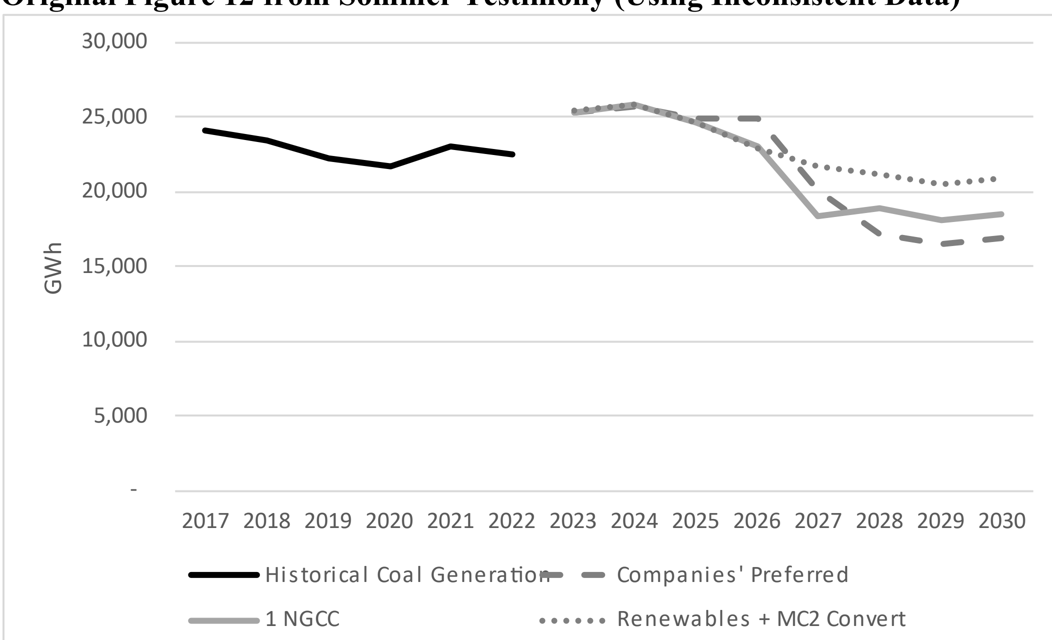
Q. How do you respond to Ms. Sommer's assertions about the reasonableness of the Companies' CO_2 emissions forecasts?[13]

A. Ms. Sommer's assertions are incorrect. In Figure 12 of Ms. Sommer's testimony, she compared a forecast of coal generation from PLEXOS to historical coal generation,

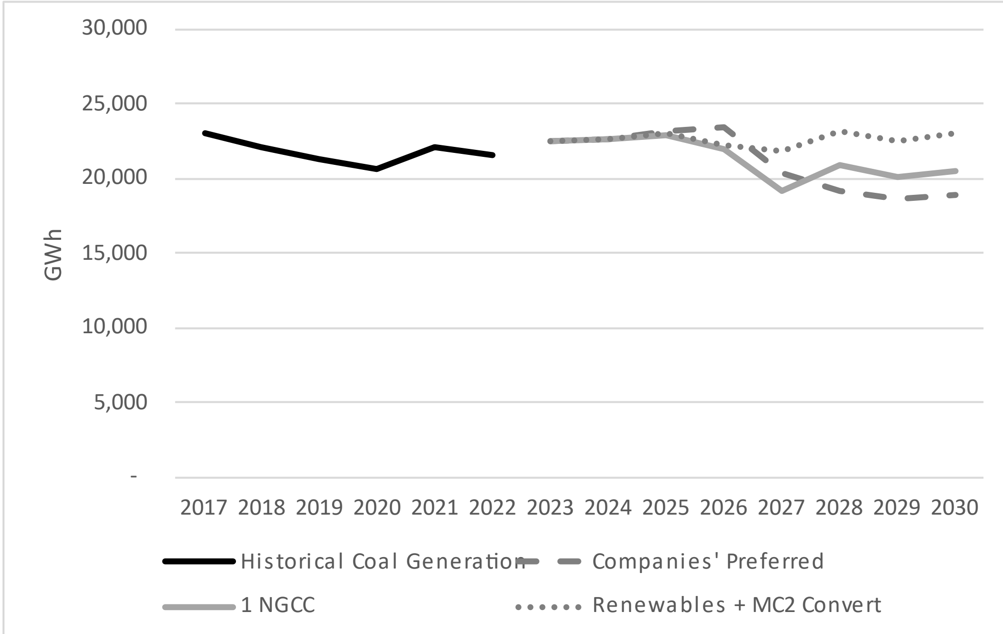
[13] Sommer at 33-35.

observed a 12 percent increase from the last year of history (2022) to the first year of the forecast (2023), and concluded that PLEXOS is over-dispatching coal units. In fact, both the historical and forecasted data Ms. Sommer used are incorrect. According to the Joint Intervenors' response to the Companies' request to JI 1-2(a), "The figure compares only the generation from units that are retained through the planning horizon." While this would imply Brown Unit 3, Mill Creek Unit 1, Mill Creek Unit 2, and Ghent Unit 2 are excluded from both the history and forecast, Ms. Sommer's historical data included Brown Unit 3, and her forecasted data included Brown Unit 3, Mill Creek Unit 1, Mill Creek Unit 2, and Ghent Unit 2. Removing the generation from these units from both the historical and forecasted data results in only a 4 percent increase when comparing 2023 to 2022, and near-term coal generation is well aligned with historical coal generation, as seen in the original and updated figures below.

Original Figure 12 from Sommer Testimony (Using Inconsistent Data)



Updated Figure 12 from Sommer Testimony (Using Corrected Data)



B. Portfolio Screening – Sommer and Goggin

Q. Ms. Sommer recommends adjustments to the Companies' PLEXOS modeling settings regarding chronology and solution step size.[14] What are your thoughts regarding these adjustments?

A. The Companies agree that steps must be taken to reduce the problem size so that the model is tractable, and there are many valid ways to do this. Some of the model features that Ms. Sommer recommends were not available in the version of PLEXOS the Companies used to complete their analysis. My team has reviewed the new features and agree that this is a valid way to set the model step size, chronology, and granularity. With these new features, PLEXOS breaks the solution into rolling horizon steps of 6

[14] Sommer at 6-7.

years (rather than solving the study period in one step) that are each solved at a granularity of 5 blocks per day.

Q. What is the impact of these new PLEXOS features on the Companies' analysis?

A. The Companies reran their Stage One PLEXOS models using Ms. Sommer's proposed solution step size and chronology but increased the granularity setting by modeling a full 24 blocks per day (rather than 5 blocks per day) to capture hourly detail and more granularly evaluate batteries, as Ms. Sommer recommends.[15] The results of these models are summarized in Table 1. In the Companies' original analysis, Mill Creek 2, Ghent 2, and Brown 3 were replaced by the Mill Creek and Brown NGCCs in four of six fuel price scenarios. However, with the new modeling features, this portfolio is optimal in five of the six fuel price scenarios. Like the original results, battery storage and new dispatchable DSM programs are not selected, but as Ms. Sommer noted, the Companies' existing dispatchable DSM programs were not retired.

[15] Sommer at 3.

Table 1: Comparison of Least-Cost Resource Portfolios

	Fuel Price Scenario (Gas, CTG Price Ratio)	Original Results				New Modeling Results			
		Retired	SCR Added	NGCC Added	Solar Added by 2028 (MW)	Retired	SCR Added	NGCC Added	Solar Added by 2028 (MW)
Expected CTG	Low Gas, Mid CTG Ratio	MC2, GH2, BR3	N/A	MC5, BR12	N/A	MC2, GH2, BR3	N/A	MC5, BR12	N/A
Expected CTG	Mid Gas, Mid CTG Ratio	MC2, GH2, BR3	N/A	MC5, BR12	104	MC2, GH2, BR3	N/A	MC5, BR12	384
Expected CTG	High Gas, Mid CTG Ratio	MC2, BR3	GH2	MC5	637	MC2, GH2, BR3	N/A	MC5, BR12	1,322
Atypical CTG	Low Gas, High CTG Ratio	MC2, GH2, BR3	N/A	MC5, BR12	N/A	MC2, GH2, BR3	N/A	MC5, BR12	N/A
Atypical CTG	High Gas, Low CTG Ratio	MC2, BR3	GH2	MC5	384	MC2, BR3	GH2	MC5	1,322
Atypical CTG	High Gas, Current CTG Ratio	MC2, GH2, BR3	N/A	MC5, BR12	2,322	MC2, GH2, BR3	N/A	MC5, BR12	2,322

Q. Ms. Sommer suggests these adjustments in PLEXOS settings explain the "disagreement" between the Companies' SERVM and PLEXOS modeling as it pertains to existing DSM. How do you respond?

A. I would not say there is any disagreement between SERVM and PLEXOS as it pertains to existing dispatchable DSM or dispatchable DSM generally. The fact that the new settings caused the existing dispatchable DSM program not to be retired simply indicates that this program, with lower fixed costs than the new dispatchable DSM programs, is on the margin in the context of normal weather load conditions. PLEXOS is a portfolio screening model that the Companies used to screen portfolios under normal weather load conditions. SERVM is used to evaluate reliability in more detail and considers all weather conditions experienced over the last 49 years. While dispatchable DSM is not an effective resource for meeting the significant need for energy created by coal unit retirements, the Companies' analysis showed it was a cost-effective addition to the other proposed resources for improving reliability during extreme weather events.

Q. Mr. Goggin argues that the Companies understate the capacity value of solar. Do you agree?

A. No. Mr. Goggin says the Companies' assumed capacity contribution for solar is reasonable in the summer but too low in the winter. He argues based on a report for the Southwest Power Pool that the assumed winter capacity contribution should be 15%. Needless to say, the Companies' service territories are not part of the Southwest Power Pool. The Companies developed their summer and winter capacity contributions based on their own load and solar irradiance data. This data was provided in response to SC 2-35 and provides a reasonable basis for estimating the capacity contribution of solar.

Q. Mr. Goggin argues that the Companies' assumed capacity contribution for 4-hour battery storage (82%) should be higher. Do you agree?

A. No. Mr. Goggin argues based on the Companies' current lack of battery storage and "high" planned solar penetration that a more reasonable estimate for a 4-hour battery's capacity contribution is "nearly 100%." A capacity contribution of nearly 100% would imply that a 4-hour battery (with limited duration) has nearly the same capacity contribution as a simple cycle combustion turbine, but this is not correct. The Companies calculated the capacity contribution of 4-hour battery storage in the context of their load and generation portfolio and its impact on LOLE was 82% of the LOLE impact for a like amount of SCCT capacity.

Q. Is the Companies' portfolio screening analysis particularly sensitive to changes in the assumed capacity contribution for 4-hour battery storage?

A. No. Recognizing that a capacity contribution of nearly 100% is not reasonable in the context of the Companies' load and generation portfolio, the Companies re-ran their Stage One portfolio screening models with capacity contribution for 4-hour batteries of 92% (10% higher than 82%) and the results were unchanged.

C. Reliability Modeling – Sommer, Goggin, Levitt, and Wilson

Q. Ms. Sommer claims the Companies understated the value of solar in SERVM by modeling a solar profile based on the Brown solar project, which is a fixed tilt project and not a single-axis tracking project like the projects the Companies are proposing.[16] Is this correct?

A. No. The Companies modeled a single-axis tracking project based on *weather* at the Brown station. They did not model a fixed-tilt solar array.

Q. Do you agree that the Companies could improve their SERVM modeling by using a solar profile that accounts for geographic diversity (i.e., not one based on weather at a single site)?

A. Yes, but based on Ms. Sommer's updated SERVM results, the impact of this change is not material. I comment more on this below.

[16] Sommer at 8-11.

Q. Ms. Sommer also recommends adjustments to the Companies' modeling of batteries in SERVM: using a charging schedule for batteries based on load rather than economics and using a 0 MW capmin setting to allow for a broader range of battery output levels. Do you agree?

A. I agree that a 0 MW capmin is appropriate. The Companies model batteries based on economics because their objective is to provide reliable service at the lowest reasonable cost. Regardless, because load and market prices are highly correlated, I would not expect this change to have a material impact.

Q. What is the impact of Ms. Sommer's recommended changes to battery storage settings on your analysis?

A. The Companies re-calculated the capacity contribution for a 4-hour battery in SERVM using Ms. Sommer's recommended battery storage settings, and the capacity contribution increased from 82% to 84%. This change would have no impact on the Companies' analysis. As I noted earlier, the Companies increased the capacity contribution for 4-hour battery storage to 92% in their Stage One PLEXOS models and the results were unchanged.

Q. Why then are the Companies proposing to construct the Brown battery storage facility?

A. As discussed throughout these proceedings, the Companies are proposing the Brown battery storage facility to gain operational experience with battery storage at utility-scale.

Q. What is the combined impact of Ms. Sommer's recommended solar and battery storage modeling changes on LOLE?

A. Based on Ms. Sommer's analysis, these changes reduced LOLE for the Companies' recommended portfolio by 0.04 days from 0.28 to 0.24. This change is not material.

Q. Mr. Goggin argues that the Companies' reliability modeling in SERVM significantly understates their import capability, which would conservatively reduce the Companies' capacity need by 600 MW.[17] Is he correct?

A. No. As Mr. Sinclair discusses in his rebuttal testimony, Mr. Goggin's conclusions are based on data for the Companies' balancing authority area, which includes entities other than the Companies, and are therefore incorrect.

Q. In Mr. Goggin's assessment of the Companies' import capabilities, he argues that the Companies should consider Total Transfer Capability ("TTC") rather than just ATC because in addition to ATC, TTC includes the Companies' Capacity Benefit Margin ("CBM") and transmission reservations. Is this reasonable?

A. No. Again, Mr. Goggin's conclusions are based on data for the Companies' balancing authority area ("LGEE BA"), which includes entities other than the Companies, and are therefore incorrect. For the reasons mentioned in Mr. Sinclair's testimony, the Companies do not have CBM or transmission reservations. The Companies are correct in modeling their import capability based on ATC.

Q. Mr. Goggin is critical of the Companies because they modeled the availability of ATC based on historical transmission capacity that is available for all hours in a day. Why did the Companies do this?

A. The most granular form of firm transmission capacity is day-ahead transmission, and it is available for all hours of the day. Transmission capacity that can be purchased

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[17] Goggin at 15-23.

hourly is non-firm, which is why the Companies do not consider hourly ATC when assessing the availability of ATC historically. It would not be prudent to plan generation based on the availability of hourly non-firm transmission. Furthermore, the Companies' peaks typically occur on weekdays, making the Companies' review of weekday ATC entirely appropriate.

Q. Mr. Goggin asserts that "the Companies' reliability analysis randomly assigns … zero import hours across peak demand hours," the effect of which "is to give imports essentially zero credit towards meeting peak needs."[18] Does that accurately characterize how the Companies' reliability modeling addresses import capability?

A. No. Mr. Goggin is incorrect that assuming zero ATC in 42% of hours in SERVM and zero ATC 33% of hours in ELDCM is equivalent to assuming imports provide "essentially zero credit towards meeting peak needs." Moreover, the example he provides to bolster his assertion does not comport with how either SERVM or ELDCM works:

> For example, if demand is comparably high in the top three peak hours, the hour in which imports are assumed to be zero will primarily set the need for capacity as it now has the highest net demand by far, while the two hours in which imports are assumed to be 500 MW will receive little to no weight for setting the capacity need.[19]

Because the Companies' reliability models do not function as Mr. Goggin suggests, the concern he raises is a nullity.

[18] Goggin at 7 lines 17-19.
[19] Goggin at 7 lines 19-23.

For a given load scenario, SERVM evaluates 300 unit availability scenarios and the availability of ATC in each hour is determined by the following distribution. ATC is indeed zero 42% of the time in that distribution based on the Companies' historical experience. But ATC is at least 1,000 MW more than 30% of the time in the same distribution, as shown in Table 7 of Exhibit SAW-1:

Table 7: Daily ATC

Daily ATC Range	Count of Days	% of Total
0	98	42%
1 – 199	2	1%
200 - 399	10	4%
400 - 599	17	7%
600 - 799	11	5%
800 - 999	21	9%
>= 1,000	73	31%
Total	232	

Because each SERVM simulation is equally weighted in the calculation of LOLE, LOLH, and EUE, these reliability metrics correctly reflect that ATC is zero 42% of the time. It is incorrect that having ATC be zero in *any* simulation is equivalent to having ATC be zero in *every* simulation.

Second, ELDCM is a formula-based model in which imports are modeled the same way as a conventional unit. Thus, rather than using the ATC distribution I described above for SERVM, the Companies modeled imports collectively as a 500 MW resource with, conservatively, a 33% forced outage rate. That is equivalent to the model having 500 MW of ATC two thirds of the time and zero ATC one third of the time, but it is not equivalent to modeling no resource at all, as Mr. Goggin suggests. Indeed, the Companies model all their resources in ELDCM with forced outage rates, which is not equivalent to modeling zero resources.

Finally, as Mr. Sinclair shows definitively in his rebuttal testimony, Mr. Goggin's related claim that he "illustrate[d] using eight years of historical data [that] … imports have never been zero during the highest peak demand hours, contrary to the Companies' assumptions in these two models [SERVM and ELDCM]" is entirely incorrect. It is a claim based on the wrong data set. In reality, the Companies had zero imports (other than firm imports from OVEC) for nearly 80% of the hours Mr. Goggin analyzed. Therefore, the correct data for the hours Mr. Goggin analyzed in no way contradicts the Companies' modeling of zero ATC 42% of the time in SERVM and 33% of the time in ELDCM.

Q. Mr. Goggin asserts that the Companies have understated the amount of available capacity that they modeled in PJM, TVA, and MISO.[20] How do you respond?

A. Mr. Sinclair addresses this issue at length and demonstrates that Mr. Goggin's assertions are incorrect. Regardless, because Mr. Goggin's assertions regarding the Companies' import capabilities are incorrect, his arguments regarding available capacity in neighboring regions are largely moot.

Q. Ms. Sommer argues the Companies should model the risk of incremental outages from extreme temperatures on thermal units. Do you agree?

A. No. The basis for Ms. Sommer's argument is the same report that Mr. Goggin referenced to argue that the Companies are overstating the reliability and capacity value of gas and coal generation. As I noted earlier, this report's assessment of incremental outages due to hot and cold weather was based on an analysis of unit outage data from

[20] Goggin at 9-15.

1995-2018 for 1,845 generators in PJM.[21] I agree that these correlated outages are a concern currently in PJM, but the risk of correlated outages remains low for the Companies moving forward.

Q. Mr. Goggin argues that the Companies' economic reserve margins are too high because the Companies have overstated the cost of unserved energy (which he calls the value of lost load, "VOLL").[22] How do you respond?

A. Mr. Goggin's proposed VOLL would result in a significant decrease in the reliability of the Companies' service to customers and is therefore unreasonable and inconsistent with the reliability requirement of Senate Bill 4. Mr. Goggin asserts that the Companies' \$21,000/MWh VOLL is too high because MISO's VOLL is \$3,527/MWh.[23] The economic reserve margins associated with this VOLL would be approximately 9.0% in the summer and 16.0% in the winter, and they would result in an LOLE greater than 20. That LOLE is well in excess of the LOLE reliability benchmark of 3.57 I proposed in my testimony concerning Senate Bill 4. The Companies do not believe such unreliable service would be consistent either with the Companies' obligation to provide reliable service or with Senate Bill 4's reliability requirements.[24]

Mr. Goggin goes on to argue that because "[p]rices are capped at \$3,500/MWh in MISO and \$3,700/MWh in PJM,"[25] a \$21,000/MWh VOLL is unreasonable "in a non-RTO market where there are no centralized market prices, as a shortage would not

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[21] See Page 9 in Murphy, Sinnott, et. al. "A time-dependent model of generator failures and recoveries captures correlated events and quantifies temperature dependence." Applied Energy, November 2019. Available from https://www.sciencedirect.com/science/article/pii/S0306261919311870.
[22] Goggin at 38-42.
[23] Goggin at 38.
[24] *See* KRS 278.264(2)(a)(2).
[25] Goggin at 41.

impose a cost on customers until firm load is shed."[26] But it is a categorical error to conflate the value a customer places on an item with the price the customer pays; by definition, a free exchange between a buyer and seller will not occur if the buyer does not value the good or service purchased *at least as much* as the value the customer places on what the customer must give to obtain the good or service. Thus, the maximum price a regulator permits a seller to charge in a given marketplace says nothing at all about how much a customer would be willing to pay, particularly if the good or service is scarce.

Mr. Goggin also asserts that the Companies' VOLL is too high because, "ERCOT has … used estimates of \$2,000/MWh, \$5,000/MWh, and \$9,000/MWh for the VOLL. … Analysis for ERCOT … [showed] the economically optimal reserve margin was … 10.25% at a \$5,000/MWh VOLL, 11% at \$9,000/MWh, and 13.25% at \$30,000."[27] What Mr. Goggin does not explain is what VOLL would correspond with ERCOT's actual minimum target reserve margin of 13.75%,[28] though presumably it would exceed \$30,000/MWh.

Finally, it is instructive to observe that both PJM and MISO plan to a 1-in-10 LOLE standard, not an economic reserve margin. MISO's annual ICAP planning reserve margin for the 2022/2023 planning year is 17.9%; for the 2027/2028 planning

[26] Goggin at 42.
[27] Goggin at 39.
[28] ERCOT Resource Adequacy page, Planning Reserve Margin Analysis section (" "The current minimum target reserve margin established by the ERCOT Board of Directors is 13.75 percent of peak electricity demand …."), available at https://www.ercot.com/gridinfo/resource (accessed July 30, 2023). *See also* NERC, "2022 Long-Term Reliability Assessment" at 80, available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf (accessed July 30, 2023).

year, it is 17.0%.[29] MISO's winter planning reserve margin for 2023/2024 is 25.5%.[30] PJM's installed reserve margin targets for 2023-2027 range from 14.7% to 14.9%,[31] and its winter weekly reserve targets ("WWRTs") for the winter of 2022-2023 ranged from 21% to 27%.[32] PJM states concerning its WWRTs, "Monthly WWRT values were introduced for the first time in the 2016 RRS with the objective of addressing the larger load uncertainty in January compared to February and December. … [T]he PJM Operations Department will coordinate generator maintenance scheduling over the winter period seeking to preserve a 21% margin in December 2022, 27% margin in January 2023 and 23% margin in February 2023 after units on planned and maintenance outages are removed."[33] Thus, because neither PJM nor MISO uses a market price cap as the VOLL to establish a target reserve margin—and because doing so for the Companies would result in unacceptably high LOLE that would not comport with Senate Bill 4's reliability requirements—PJM's and MISO's market price caps should have no bearing on the Companies' reserve margin targets.

Q. Relatedly, Mr. Levitt states that the Companies' proposed portfolio would result in reserve margins far in excess of the Companies' seasonal economic reserve margin,[34] which is an issue Joint Intervenors witness John Wilson addresses, as

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[29] MISO, "Planning Year 2022-2023 Loss of Load Expectation Study Report" at 24-26, available at https://cdn.misoenergy.org/PY%202022-23%20LOLE%20Study%20Report601325.pdf (accessed July 29, 2023).

[30] MISO, "Planning Resource Auction Results for Planning Year 2023-24" at 34, available at https://cdn.misoenergy.org/2023%20Planning%20Resource%20Auction%20(PRA)%20Results628925.pdf (accessed July 29, 2023).

[31] PJM, "2022 PJM Reserve Requirement Study" at 8, available at https://www.pjm.com/-/media/planning/res-adeq/2022-pjm-reserve-requirement-study.ashx (accessed July 29, 2023).

[32] *Id.* at 44.

[33] *Id.* at 45.

[34] Levitt at 18-19.

well.[35] Have the Companies proposed to construct excessive capacity in this proceeding?

A. No. As explained in the response to PSC 2-10b, the Companies' proposed portfolio's reserve margins are reasonable. Compared to a portfolio that minimally meets minimum reserve margin targets, a portfolio that includes incremental battery and solar resources results in additional PVRR and reliability benefits and reduces exposure to fuel price volatility and potential future CO_2 regulations.

D. <u>Financial Modeling – Medine and Kollen</u>

Q. Ms. Medine argues that it would be to customers' advantage to delay the Mill Creek and Brown NGCC units by installing SCR on Mill Creek 2 and Ghent 2.[36] Do you agree?

A. No. To reach this conclusion, Ms. Medine compared the capital revenue requirements of the Mill Creek and Brown NGCCs through 2034 to the capital revenue requirements of the Mill Creek 2 and Ghent 2 SCRs over the same period with the assumption that the capital revenue requirements for the SCRs would be recovered over seven years. Setting aside the fact that Ms. Medine used the wrong capital cost for the NGCCs, I agree that the capital revenue requirements for the NGCCs through 2034 are higher than the capital revenue requirements for the SCRs. However, a near-term comparison of only capital revenue requirements is not the correct way to evaluate the cost of delaying the NGCC units. Ms. Medine's analysis should have considered all revenue requirements, including revenue requirements beyond 2034.

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[35] J. Wilson at 14-16.

[36] *See, e.g.,* Medine at 4, lines 13-16.

Q. Did the Companies evaluate delaying either of the proposed NGCC units?

A. Yes. Recognizing that this is a reasonable question, the Companies evaluated in their original filing delaying the Brown NGCC by installing SCR on Ghent 2.[37] Section 4.4.3 of Exhibit SAW-1 summarizes this analysis and considers all revenue requirements (not just capital revenue requirements) over the entire analysis period (not just through 2034). In this analysis, the Companies evaluated cases where, after being retrofitted with SCR in 2028, Ghent 2 is replaced with the Brown NGCC later in the analysis period. The Companies' generation portfolio after Ghent 2 is replaced with the Brown NGCC is the same as the portfolio with the Mill Creek NGCC and Brown NGCC in 2028; the only material differences in revenue requirement after Ghent 2 is replaced result from the later-commissioned Brown NGCC having higher capital revenue requirements than commissioning it in 2028. The results of this analysis show there are high costs to adding SCR to Ghent 2 in five of six fuel price scenarios and that adding SCR is unfavorable even in the fuel price scenario most favorable to coal (High Gas, Low Coal-to-Gas Ratio) unless Ghent 2 can continue to operate until at least 2049 – all assuming *zero* net cost for CO_2 emissions or other constraints. Thus, even when the proposed 111(b) and (d) greenhouse gas regulations are ignored, installing SCR on Ghent 2 is not least-cost.

Q. Is a PVRR analysis rather than a rate-impact analysis more appropriate for resource decision-making, including taking into account a long-term rather than short-term PVRR impact perspective?[38]

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[37] The Companies did not evaluate delaying the Mill Creek NGCC because it was part of the least-cost portfolio in all Stage One fuel price scenarios.

[38] *See, e.g.,* Medine at 7 and 24-25.

A. Yes. The Companies' resource planning decisions impact all customers for more than just a handful of years. Therefore, the appropriate objective function for the Companies' resource planning is to minimize the present value of revenue requirements over a reasonably long timeframe, all consistent with providing safe and reliable service. That approach best ensures reasonable rates for all customers across a broad time span. As discussed by Mr. Conroy, attempting a rate-impact analysis for a particular customer class at a particular point in time would be unnecessarily speculative concerning the specifics of ratemaking. Thus, the kind of PVRR analysis the Companies have provided in this proceeding best serves all customers across the decades analyzed by optimizing total present value revenue requirements, not the rates one group of customers might pay at one particular point in time.

Q. Mr. Kollen asserts that the Companies' "reference portfolio" includes the retirements of Mill Creek 2, Ghent 2, and Brown 3, as well as the additions of Mill Creek 5 and Brown 12, but excludes any solar PPAs. Is this correct?

A. No. In this context, the Companies' "reference portfolio" includes 637 MW of solar PPAs. The Companies do not use the term "reference portfolio." Rather, the portfolio Mr. Kollen describes with 637 MW of solar PPAs is the economically optimal portfolio from the Companies' Stage One analysis for achieving minimum reliability.

Q. In a scenario where the Companies construct the Mill Creek and Brown NGCCs, Mr. Kollen estimates the incremental cost of continuing to operate Ghent 2 with SCR through 2035 based on the analysis summarized in Section 4.4.3 of Exhibit SAW-1 that evaluates delaying the Brown NGCC by installing SCR on Ghent 2. Is this the correct comparison for assessing this cost?

A. No. I summarized this analysis earlier. To assess this cost, he would need to compare the cost of a portfolio with the two NGCCs and Ghent 2 operating through 2035 with SCR to a portfolio with only the two NGCCs. This comparison is not in the record. Particularly given the proposed 111(d) greenhouse gas regulations, it does not make sense to consider adding SCR to Ghent 2 at this time.

Q. In a scenario where the Companies construct the Mill Creek and Brown NGCCs, Mr. Kollen estimates the incremental cost of continuing to operate Ghent 2 in the non-ozone season (i.e., without SCR) through 2035 by comparing the costs of Portfolios 1 and 4 in Table 13 of Exhibit SAW-1. Is this the correct comparison for assessing this cost?

A. No. To assess this cost, he would need to compare the cost of a portfolio with the two NGCCs and Ghent 2 operating through 2035 only in the non-ozone season to a portfolio with only the two NGCCs. Mr. Sinclair provides this comparison in Rebuttal Exhibit DSS-2.

Q. In a scenario where the Companies construct the Mill Creek and Brown NGCCs, what is the incremental cost of continuing to operate Ghent 2 in the non-ozone season (i.e., without SCR) through 2035?

A. As shown in Exhibit DSS-2 to Mr. Sinclair's rebuttal testimony, depending on fuel prices, the incremental PVRR is \$17 to \$58 million, with a cost of \$46 million across the average of the three typical coal-to-gas price ratio gas price scenarios. As seen in Table 8 of Exhibit SB4-1, the incremental PVRR of continuing to operate Ghent 2 indefinitely in the non-ozone season is \$153 million across these same gas prices scenarios due primarily to the life extension costs that would be required to operate Ghent 2 through 2050.

IV. CRITIQUES OF THE JOINT INTERVENORS' MODELING

Q. Have you reviewed the resource modeling presented by Ms. Sommer and the workpapers associated with the two alternative portfolios she developed?[39]

A. Yes.

Q. Please summarize her analysis.

A. First, as I explained earlier, the Companies' analysis was completed in three stages. After developing the economically optimal portfolio for meeting minimum reliability in Stage One, the Companies compared that portfolio to a wide variety of other portfolios in Stage Two. Ms. Sommer did not present any modeling results that disagreed with the Companies' economically optimal portfolio. Rather, like the Companies did in their Stage Two analysis, Ms. Sommer developed two alternative portfolios by introducing additional modeling constraints and new energy efficiency programs based on Mr. Grevatt's testimony.

Q. How did Ms. Sommer model the new energy efficiency programs?

A. In PLEXOS, Ms. Sommer modeled the energy efficiency programs as a reduction to load in years 2025 through 2040. To do this, she applied load reductions up to 1.62 percent, as shown in Table 3, using the same percentage reduction in all hours of each year. In her financial models, she assumed a non-escalating nominal cost for the programs of $30/MWh in all years. In SERVM, Ms. Sommer modeled the 2028 hourly

[39] Sommer at 25-35.

load reductions for the energy efficiency programs as a resource (rather than a load reduction) and assumed the same hourly profile for all load scenarios.

Table 2: Sommer's Energy Efficiency Hourly Load Reductions

	Load Reduction			Load Reduction
2025	0.15%		2033	1.49%
2026	0.40%		2034	1.49%
2027	0.74%		2035	1.49%
2028	1.03%		2036	1.49%
2029	1.32%		2037	1.42%
2030	1.62%		2038	1.25%
2031	1.49%		2039	1.01%
2032	1.49%		2040	0.74%

Q. Do you have any concerns about the Joint Intervenors' modeled energy efficiency program savings?

A. Yes. As discussed in Ms. Isaacson's testimony, the new energy efficiency programs proposed by Mr. Grevatt are largely duplicative of the Companies' proposed programs. Moreover, as Mr. Jones explained in direct testimony and Exhibit TAJ-1, the Companies' load forecast assumed significant amounts of customer-initiated energy efficiency savings beyond those created by the Companies' proposed DSM-EE programs. Thus, it is not clear to what extent Mr. Grevatt's proposed savings are illusory because they are duplicative of what the Companies have already proposed in their DSM-EE portfolio or are effectively double-counting other energy-efficiency savings the Companies already included in their load forecast.

Q. Do you have concerns with the way Ms. Sommer modeled the new energy efficiency program?

A. Yes. Using the same hourly profile for all load scenarios in SERVM is not correct as this assumes the programs' impact is uncorrelated with weather. To model a weather-sensitive energy efficiency program as a resource, its hourly load reduction profile should be correlated with weather.

Q. If the new energy efficiency programs were viable, would it have any impact on the Companies' recommended portfolio?

A. No. The Companies reran their Stage One PLEXOS models with the new energy efficiency program and Ms. Sommer's proposed model settings. In addition, the Companies increased the models' granularity setting by modeling a full 24 blocks per day. The results of these models are unchanged from the New Modeling Results shown in Table 1, demonstrating that the new energy efficiency program would not change the Companies' recommended portfolio.

Q. Please describe the two portfolios included in Ms. Sommer's modeling, including how she arrived at the portfolios.[40]

A. Ms. Sommer developed two portfolios, both of which included the assumed retirements of Brown 3, Mill Creek 1, and Ghent 2, the addition of PPAs for renewables and batteries, the addition of the new energy efficiency programs, and a 30 percent capital cost increase for new gas-fired units. One portfolio assumed the conversion of Mill Creek 2 to gas ("Renewables Plus MC2 Conversion") and was presented as $807 million higher cost in PVRR terms compared the Companies' recommended portfolio. The second portfolio assumed the retirement of Mill Creek 2 and the addition of Mill Creek 5 ("Renewables Plus One NGCC") and was presented as $104 million lower cost than the Companies' recommended portfolio.

Q. Do you have any concerns with the way Ms. Sommer developed her portfolios?

[40] Sommer at 28-29.

A. Yes. First, as discussed by Mr. Bellar, HDR's study for the proposed Mill Creek 5 and Brown 12 NGCC units was accurate and thorough. Increasing the capital cost of new gas-fired resources by 30 percent is not reasonable, especially when the factors driving the increase are assumed to have no impact on the cost of other resources. Second, in the Companies' Stage One analysis, the Companies allowed PLEXOS to add RFP responses at any point during the analysis period. Then, when computing detailed production costs, the Companies included only the RFP responses added by 2028 and assumed these contracts would begin on their RFP-specified contract start date. Ms. Sommer did not follow this process and instead always assumed that the Companies could add RFP responses any time at the RFP-specified price. As a result, Ms. Sommer's "Renewables Plus One NGCC" portfolio and associated PVRR analysis includes 550 MW of solar and 450 MW of battery storage PPAs that are added in or after 2040, despite the fact that all of these contracts have RFP-specified start dates before 2030.[41] Finally, Ms. Sommer included a wind PPA sourced from Ohio in both portfolios but did not include an estimate for the cost of firm transmission to deliver the power to the Companies' service territory. This is clearly incorrect. Based on PJM's published rates, the cost of annual point-to-point firm transmission from PJM is $69,600 per MW-year in 2022 dollars. For a 143 MW wind PPA, this equates to $10 million per year.

Q. Did the Companies include this transmission cost in their PLEXOS modeling?

A. No. The wind PPA was the only resource located outside the Companies' Balancing Area. The cost of transmission was considered in the process to screen RFP responses

[41] Ms. Sommer also added 885 MW of solar PPAs to the Companies' portfolio after 2040.

for economics and practicability, but it was not included in their PLEXOS modeling, which was an oversight. Regardless, this cost should clearly be included when the wind PPA is included in a modeled portfolio like Ms. Sommer's.

Q. What impact does adding the omitted transmission costs have on Ms. Sommer's analysis?

A. When Ms. Sommer's financial model is updated to include the omitted transmission costs, the PVRR increases by $186 million. This update alone changes the claimed $104 million NPVRR benefit of her "Renewables Plus One NGCC" portfolio in the 30% increased capital cost case to being $82 million NPVRR more expensive than the Companies' proposed portfolio.

Q. What is another concern you have regarding Ms. Sommer's modeled portfolios?

A. As I discussed above, Ms. Sommer included a significant amount of additional energy efficiency savings in her modeled portfolio at a levelized cost of $30/MWh.[42] Regardless of the reasonableness of assuming such savings (I noted my concerns about them above), Ms. Sommer provides no justification for assuming them only in her selected portfolios and not the Companies' portfolio, and I am unaware of any reason why they should not be applied to the Companies' portfolio if they are to be assumed for Ms. Sommer's portfolio. Indeed, the Joint Intervenors recommend that the Commission "[m]odify and approve an expanded portfolio of DSM/EE, as recommended by Witness Grevatt";[43] if the Commission did so, the Joint Intervenors' claimed savings would presumably apply regardless of the approved supply-side portfolio. As I show in Table 5 below, adding these savings results in a reduction to

[42] *See* Joint Intervenors' Response to Companies' DR 21.
[43] McDonald Corrected Testimony at 4.

the PVRR of the Companies' portfolio of $51 million. Adding this effect to the transmission cost adjustment discussed above results in Ms. Sommer's "Renewables Plus One NGCC" portfolio being $133 million NPVRR more expensive than the Companies' proposed portfolio.

Q. Before turning to your concerns with Ms. Sommer's modeling of detailed production costs using PLEXOS, do you have any other concerns regarding Ms. Sommer's modeled portfolios?

A. Yes. The Joint Intervenors recommend that the Commission approve the Companies' requested CPCNs for the Brown BESS and the Companies' owned solar projects.[44] It would be reasonable for Ms. Sommer to include the effect of these recommendations—the Joint Intervenors' own recommendations—in her modeled portfolios, but she did not do so.

These omissions are significant. For example, excluding the Brown BESS from the Companies' portfolio would reduce its PVRR by $127 million in the Mid Gas, Mid CTG fuel price scenario and would not require any replacement capacity. I have not attempted to reconfigure Ms. Sommer's portfolios to include Brown BESS and the owned solar projects, which presumably would displace other battery and solar resources already included in her portfolios. But the impact of doing so would be to increase the PVRR of both of her portfolios, making them even more expensive relative to the Companies' proposed portfolio. Thus, the $133 million NPVRR I noted above by which her "Renewables Plus One NGCC" portfolio is *more* expensive than the Companies' proposed portfolio is certainly understated, even before accounting for the

[44] McDonald Corrected Testimony at 4.

effect of my concerns with Ms. Sommer's modeling of detailed production costs using PLEXOS.

Q. What are your concerns with Ms. Sommer's modeling of detailed production costs using PLEXOS?

A. Table 4 compares production costs from PROSYM through 2030 to the production costs Ms. Sommer developed using PLEXOS for the Companies' recommended portfolio. While PLEXOS is a proven tool for computing detailed production costs, the Companies have not calibrated its inputs and settings for this purpose. For example, for portfolio screening, PLEXOS necessarily utilizes a simplified heat rate curve to dispatch thermal units and estimate fuel costs. However, Ms. Sommer inappropriately used the same simplified heat rate curve to model detailed production costs. In addition, the Companies capture the cost of SCCT starts in PROSYM, but these costs are modeled as shadow costs in PLEXOS such that they impact dispatch decisions but not production costs. Ms. Sommer should have configured PLEXOS to include the cost of SCCT starts when computing detailed production costs. The fact that the production costs from Ms. Sommer's PLEXOS modeling are consistently lower than PROSYM is concerning from a modeling perspective.

Table 3: Production Cost Differences (Companies Recommended Portfolio; $M)

Year	PROSYM	PLEXOS	Difference (PROSYM less PLEXOS)
2023	875	842	33
2024	928	896	32
2025	1,008	974	34
2026	1,074	1,041	33
2027	1,091	1,057	34
2028	1,095	1,047	48
2029	1,099	1,055	45
2030	1,109	1,069	40

Q. What is the impact of using PROSYM for detailed production cost modeling on Ms. Sommer's analysis of the Companies' recommended portfolio and her "Renewables Plus One NGCC" portfolio?

A. Table 5 below shows the results of the impact of using PROSYM for detailed production cost modeling on Ms. Sommer's analysis of the Companies' recommended portfolio and her "Renewables Plus One NGCC" portfolio. The first line of the table begins with the PVRR difference between the portfolios according to Ms. Sommer, i.e., it shows the "Renewables Plus One NGCC" portfolio as having a $104 million lower PVRR than the Companies' portfolio. In the second line of the table, the Companies add the $186 million PVRR impact of including transmission cost for the wind resource in the "Renewables Plus One NGCC," which cost Ms. Sommer had omitted.

The third through fifth lines of the table reflect the Companies' use of PROSYM to model their proposed portfolio and the "Renewables Plus One NGCC" portfolio. Note that the Companies modeled their proposed portfolio in PROSYM as Ms. Sommer modeled it in PLEXOS, including the RFP resources Ms. Sommer added to her portfolio and the Companies' portfolio after 2040.

The third line of the table reflects the PVRR difference between modeling the portfolios in PROSYM versus PLEXOS. Based on Ms. Sommer's analysis using PLEXOS, annual production costs for her portfolio were higher than the Companies' portfolio. This difference is slightly greater with the Companies' calibrated model (PROSYM), resulting in a $211 NPVRR increase in the relative cost of Ms. Sommer's portfolio.

The fourth line of the table shows the impact of including SCCT start costs. Doing so increases production costs for both portfolios, but the increase is greater for Ms. Sommer's portfolio because it relies more heavily on SCCTs for serving load.

In the fifth and final line, the Companies account for the effect of adding Ms. Sommer's proposed increased energy efficiency to the Companies' portfolio.

In total, Ms. Sommer's portfolio is $628 million more expensive than the Companies' portfolio with these changes, even when the cost of NGCC is assumed to be 30% higher.

Table 4: PVRR Comparison ($M)

Modeling Step	PVRR		Renewables Plus One NGCC Portfolio less Companies' Portfolio (30% NGCC Cost Increase)	
	Companies' Portfolio	Renewables Plus One NGCC	PVRR Difference	Incremental PVRR
Base (Sommer's Model)	35,343	35,240	(104)	NA
Base + Wind Transmission	35,343	35,425	82	186
Base + Wind Transmission, PROSYM Prod. Costs w/o CT Start Costs	35,766	36,059	292	211
Base + Wind Transmission, PROSYM Prod. Costs w/ CT Start Costs	36,148	36,725	577	285
Base + Wind Transmission, PROSYM Prod. Costs w/ CT Start Costs + EE Programs for Companies' Portfolio	36,097	36,725	628	51

Q. The Joint Intervenors stated in response to a data request, "The portfolios developed by Ms. Sommer are not intended as alterative portfolios that should be pursued. Rather, those portfolios test the sufficiency of the Companies' evidence by illustrating how even a limited number of improvements to the modeling yields informative results and demonstrates shortcomings in the Companies'

planning."[45] Given the Joint Intervenors' stance toward Ms. Sommer's modeled portfolios, why do the corrections you noted above matter?

A. If the sole purpose of Ms. Sommer's modeling was to demonstrate that the Companies' modeling was flawed (as the Joint Intervenors assert), then the corrections to Ms. Sommer's work show that they failed to make any such demonstration. Instead, they succeeded in producing two portfolios that are significantly more expensive than the Companies' proposed portfolio and did so while making some modeling errors of their own. The point of showing this is not to criticize Ms. Sommer or her team as modelers; indeed, I take their work seriously and respect them as modelers. Rather, the point of these corrections is to show that the Joint Intervenors' claimed "shortcomings" in the Companies' modeling are either not shortcomings at all or have no effect on the ultimate conclusion that the Companies' proposed portfolio is an optimal blend of resources for the Companies and their customers that merits Commission approval.

V. CONCLUSION

Q. After having reviewed the intervenors' testimony and responses to data requests, what do you conclude about the reasonableness of the Companies' modeling in this proceeding?

A. I conclude that the Companies' modeling remains reasonable and is a reliable basis on which the Commission may confidently grant the Companies' requested relief in this proceeding. The intervenors leveled a multitude of criticisms against the Companies' modeling, assumptions, and methodologies. But as my testimony and that of the

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[45] Joint Intervenors' Response to Companies' DR 6.

Companies' other witnesses show, the vast majority of these criticisms are themselves flawed or plainly incorrect, and the few that remain do not materially affect the conclusions of the modeling. I therefore conclude that the Companies' modeling remains reasonable and demonstrates that the Companies' proposed portfolio will result in safe, reliable, and economical service while also positioning the Companies well for a wide variety of possible future eventualities, including a broad array of possible fuel prices, carbon regulations, and possible RTO membership.

Q. Does this conclude your testimony?

A. Yes, it does.

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 3rd day of August 2023.

Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

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