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 APPROVAL OF A DEMAND SIDE MANAGEMENT PLAN AND APPROVAL OF FOSSIL FUEL-FIRED GENERATING UNIT RETIREMENTS	**)))))))))**	**CASE NO. 2022-00402**

RESPONSE OF
KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY
TO
THE COMMISSION STAFF'S POST-HEARING REQUEST FOR INFORMATION

DATED SEPTEMBER 1, 2023

FILED: SEPTEMBER 15, 2023

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Chief Operating Officer for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, 220 West Main Street, Louisville, KY 40202, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Lonnie E Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 14th day of September 2023.

Caroline J. Davison

Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

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

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **John Bevington**, being duly sworn, deposes and says that he is Director – Business and Economic Development for LG&E and KU Services Company, 220 West Main Street, Louisville, KY, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

John Bevington

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 13th day of September 2023.

Caroline J. Davison
Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

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

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **John R. Crockett III**, being duly sworn, deposes and says that he is President of Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, 220 West Main Street, Louisville, KY 40202, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

John R Crockett III

John R. Crockett III

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 13th day of September 2023.

Caroline J. Davison

Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

CAROLINE J. DAVISON
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ID # KYNP63286
STATE AT LARGE, KENTUCKY

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Philip A. Imber**, being duly sworn, deposes and says that he is Director – Environmental and Federal Regulatory Compliance for LG&E and KU Services Company, 220 West Main Street, Louisville, KY 40202, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Philip A. Imber

Philip A. Imber

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 14 day of September 2023.

Caroline J. Davison

Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

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

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Lana Isaacson**, being duly sworn, deposes and says that she is Manager – Emerging Business Planning and Development for Louisville Gas and Electric Company and Kentucky Utilities Company, 220 West Main Street, Louisville, KY 40202, and that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge, and belief.

Lana Isaacson

Lana Isaacson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 13th day of September 2023.

Caroline J. Davison

Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

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

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Charles R. Schram**, being duly sworn, deposes and says that he is Director – Power Supply for LG&E and KU Services Company, 220 West Main Street, Louisville, KY 40202, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Charles R. Schram

Subscribed and sworn to before me, a Notary Public in and before said County and State this 14th day of September 2023.

Caroline J. Davison
Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

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

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **David S. Sinclair**, being duly sworn, deposes and says that he is Vice President, Energy Supply and Analysis for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, 220 West Main Street, Louisville, KY 40202, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

David S. Sinclair

David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 14th day of September 2023.

Caroline J. Davison

Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

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

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, 220 West Main Street, Louisville, KY 40202, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and 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 14th day of September 2023.

Caroline J. Davison
Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

CAROLINE J. DAVISON
COMM EXPIRES 01/22/2027
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STATE AT LARGE, KENTUCKY

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated September 1, 2023

Case No. 2022-00402

Question No. 1

Responding Witness: Lana Isaacson

Q-1. Refer to the Excel spreadsheet filed with LG&E/KU's supplemental response to Commission Staff's Second Request for Information (Staff's Second Request) (filed May 11, 2023), Item 38, cells C4–C10, D4–D10, F4−F10, G4−G10, I4-I10, J4-J10, L4-L10, and M4-M1, which contain hardcoded dollar amounts. Provide the workpapers that support the DSM-EE program-specific TRC benefit amounts in cells C4–C10, TRC cost amounts in cells D4–D10, PAC benefit amounts in cells F4−10, PAC cost amounts in cells G4−G10, PCT benefit amounts in cells I4−I10, PCT cost amounts in cells J4−J10, RIM benefit amounts in cells L4−L10, and RIM cost amounts in cells M4−M10.

A-1. See attachments being provided in separate files. The attachments contain confidential and proprietary information and are being provided under seal pursuant to a petition for confidential protection.

KENTUCKY UTILITIES COMPANY
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Response to Commission Staff's Post-Hearing Request for Information
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Case No. 2022-00402

Question No. 2

Responding Witness: Lana Isaacson

Q-2. Refer to LG&E/KU's response to Staff's Second Request, Item 30, which was nonresponsive. Provide the Achievable Potential for the proposed Business Solutions program in a table similar to the Direct Testimony of Lana Isaacson, Exhibit LI2, 2023 LG&E/KU Demand Response Assessment, Appendix C, Table C-1, page C-27

A-2. The demand and energy values calculated at the Achievable Potential level represent a group of measures that are applicable to specific customer sectors over a 20-year term. A subset of the Achievable Potential is the Program Potential in which specific programs are outlined. The request to provide the Achievable Potential at a program level is not a typical way to view Achievable Potential. Therefore, to determine the requested values, the process begins at the end (i.e. proposed Program in a 7-year term) and works back to the Achievable Potential by including the measures that are within the proposed Business Solutions program offering.

The three tables are included to illustrate the values at the iterative steps which then lead to the requested data.

Table 1: 20-year Cumulative Achievable Potential – Medium Scenario (provided in Exhibit LI-1, Table 6 for Energy & Table 10 for Demand for the applicable sectors.)

Sector	Energy (GWh)	Demand (MW)
Commercial	542	94
Industrial	592	73
Total	1,134	167

Table 2 below represents the cumulative 20-year achievable potential for energy and demand of the selected measures that are available specifically within the Business Solutions Program. The resulting values are a subset of those shown Table 1.

Table 2: 20-year Cumulative Achievable Potential for Business Solutions Program

Business Solutions Component	Energy (GWh)	Demand (MW)
Nonresidential Rebates / Midstream Lighting	1,002.7	138
Small Business Audit / Direct Install	0.5	0
Total	1,003.2	138

Table 3 below reflects only the first seven years of Table 2 to compare to the proposed 7-year filed Program.

Table 3: 7-year Cumulative Achievable Potential for Business Solutions Program

Business Solutions Component	Energy (GWh)	Demand (MW)
Nonresidential Rebates / Midstream Lighting	567.1	79
Small Business Audit / Direct Install	0.3	0
Total	567.4	79

KENTUCKY UTILITIES COMPANY
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Response to Commission Staff's Post-Hearing Request for Information
Dated September 1, 2023

Case No. 2022-00402

Question No. 3

Responding Witness: John R. Crockett III

Q-3. Refer to Kentucky Coal Association (KCA) Hearing Exhibit 3. Provide a list of all LG&E/KU executives who received ESG-based performance units compensation and the maximum potential values as of the grant date for that compensation.

A-3. See attachment. Certain requested information is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

KENTUCKY UTILITIES COMPANY
AND
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Response to Commission Staff's Post-Hearing Request for Information
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Question No. 4

Responding Witness: John Bevington

Q-4. Refer to the Direct Testimony of John Bevington (Bevington Direct Testimony), page 6, lines 11−14, which references that LG&E/KU surveyed the demand Side Management-Energy Efficiency (DSM/EE) Advisory Group to solicit input for developing new and updated DSM-EE. Provide the results of the DSM-EE Advisory Group 2021 survey.

A-4. See attachment being provided in a separate file.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated September 1, 2023

Case No. 2022-00402

Question No. 5

Responding Witness: John Bevington

Q-5. Refer to the Bevington Direct Testimony, page 6, lines 13−14. Provide the minutes of LG&E/KU's 2021 meetings with the DSM-EE Advisory Group.

A-5. See attachments being provided in separate files.

KENTUCKY UTILITIES COMPANY
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Response to Commission Staff's Post-Hearing Request for Information
Dated September 1, 2023

Case No. 2022-00402

Question No. 6

Responding Witness: John Bevington

Q-6. Refer to Joint Intervenors' response to LG&E/KU's First Request for Information, Item 31, which is a letter dated December 14, 2022, from some of the DSMEE Advisory Group members regarding LG&E/KU providing material related to underlying inputs and assumptions in the DSM-EE analysis. Provide a copy of any documents referenced in that letter that were provided to the DSM-EE Advisory Group that have not already been filed into this proceeding.

A-6. All data sharing files referenced in the December 13, 2022 letter from certain DSM/EE Advisory Group members were included in Exhibit LI-6. In the documents provided to members of the DSM/EE Advisory Group that signed the non-disclosure agreement, the Companies provided a prior version of the file titled "LGE KU Program Measure Inputs FINAL – Public" that included confidential information. Pursuant to a Petition for Confidential Protection, the Companies are providing the file titled "CONFIDENTIAL LGE KU Program Measure Inputs" that was provided to the DSM-EE Advisory Group members that signed the non-disclosure agreement. The Companies are also providing related correspondence to members of the DSM/EE Advisory Group.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated September 1, 2023

Case No. 2022-00402

Question No. 7

Responding Witness: Lonnie E. Bellar

Q-7. Refer to the August 23, 2023 hearing testimony of Lonnie Bellar (Bellar August 23, 2023 Hearing testimony). Provide a detailed timeline and documentary support of Mr. Bellar's direction to LG&E/KU staff to reassess LG&E/KU's DSM-EE programs to address changing circumstances after October 2020, with the reassessment of generation retirement dates, changing environmental compliance laws, and changing load.

A-7. Changing circumstances, including environmental regulations affecting the economics of continuing to operate existing resources and the timing and cost of retiring and replacing those resources, can affect the avoided generating capacity costs used in DSM-EE cost-benefit analyses. The Companies have always sought to be consistent and forthcoming concerning their avoided generating capacity costs in all areas, including DSM-EE. Thus, to understand fully the Companies' actions in late 2020 and beyond concerning avoided generating capacity costs in DSM-EE cost-benefit analyses, it is necessary to understand the history of those avoided costs before 2020.

Prior to the Companies' DSM-EE Program Plan filing in Case No. 2017-00441, the Companies had used the cost of the next generating unit assumed to be added as the avoided capacity cost in their DSM-EE cost-benefit calculations. For example, in the Companies' DSM-EE Program Plan application proceeding in Case No. 2014-00003, the Companies used an avoided capacity cost of $100/kW-year based on the costs of a 2-on-1 NGCC unit.[2] At that time, the Companies'

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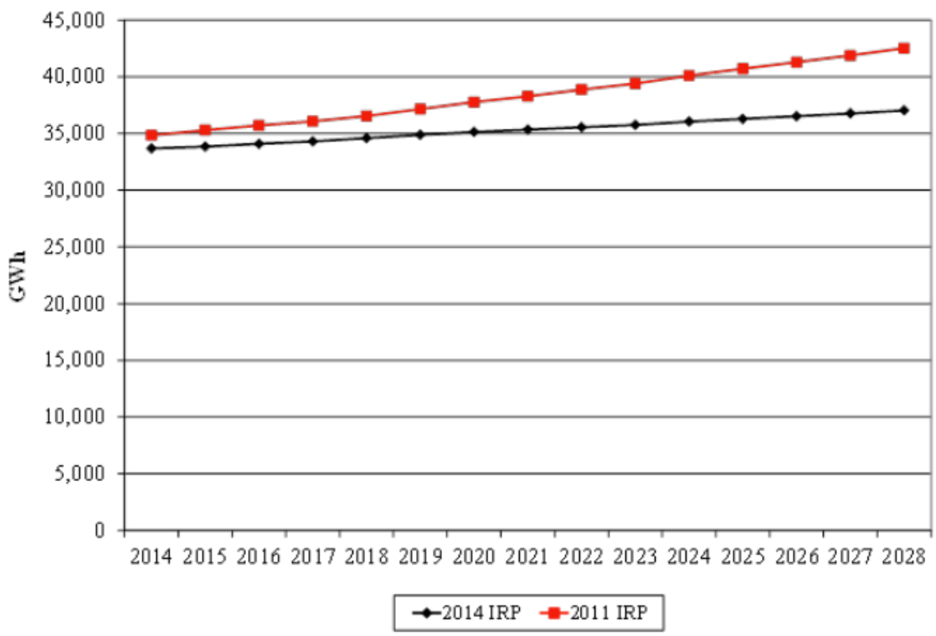
[2] *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of New, Demand-Side Management and Energy Efficiency Programs*, Case No. 2014-00003, Direct Testimony of Michael E. Hornung, Exhibit MEH-3 at 21 (Jan. 17, 2014) ("Utility avoided capacity costs: The Company's projections of the cost of supplying power during peak periods, estimated by the Company at $100/kW-year."); Case No. 2014-00003, Companies' Response to AG 1-21 (Mar. 3, 2014) ("For example, any energy-efficiency measure incentive is capped at the Companies' avoided cost of capacity ($100/kW-year), as it would be otherwise more economical to serve energy from supply-side resources."); Case No. 2014-00003, Companies' Response to Wallace McMullen and Sierra Club 1-25(a) (Mar. 12, 2014) ("The avoided capacity cost of $100/kW-year is based on deferring the next generating unit."); Case No. 2014-00003, Companies' Response to Wallace McMullen and Sierra

load forecasts showed steadily increasing demand and energy requirements over time, as reflected in the following graphs from the Companies' 2014 IRP:[3]

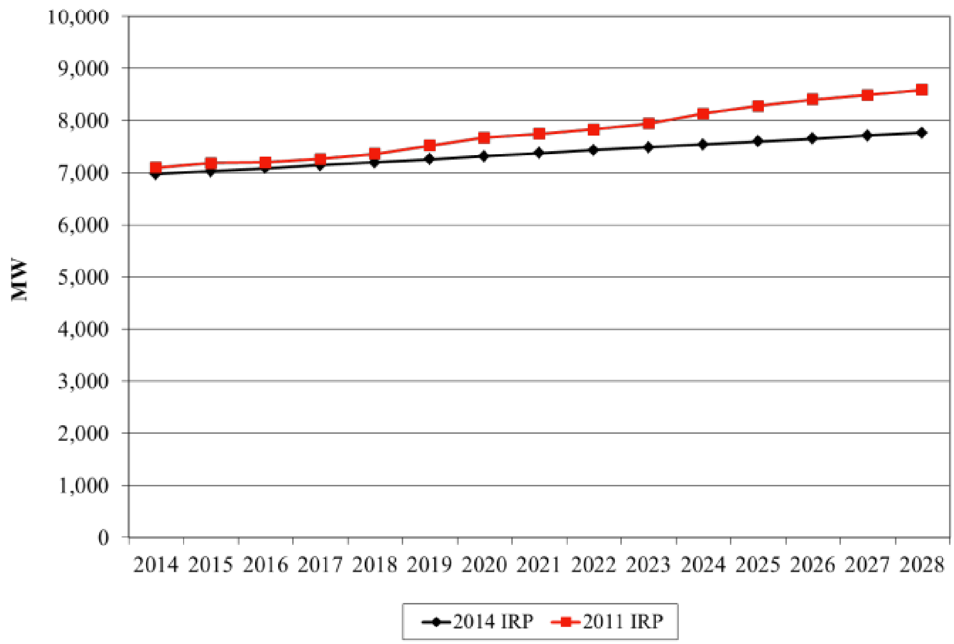
Graph 6.(1)-1
Combined Company Calendar Sales after DSM - 2014 vs. 2011 IRP Forecasts (GWh)



Club 2-3(a) (Apr. 3, 2014) ("Marginal generation capacity cost – This value was determined by applying a fixed charge rate to the capital cost of a 2x1 combined cycle generating unit. The capital cost for a 2x1 combined cycle generating unit was estimated to be $997.20/kW. The fixed charge rate used was 10.02%. The value is determined by multiplying capital cost and the fixed charge rate to annualize capital cost. ($997.20/kW) x (10.02%) = $99.92/kW-year.").

[3] *The 2014 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2014-00131, Volume I, page 6-5 (April 21, 2014).

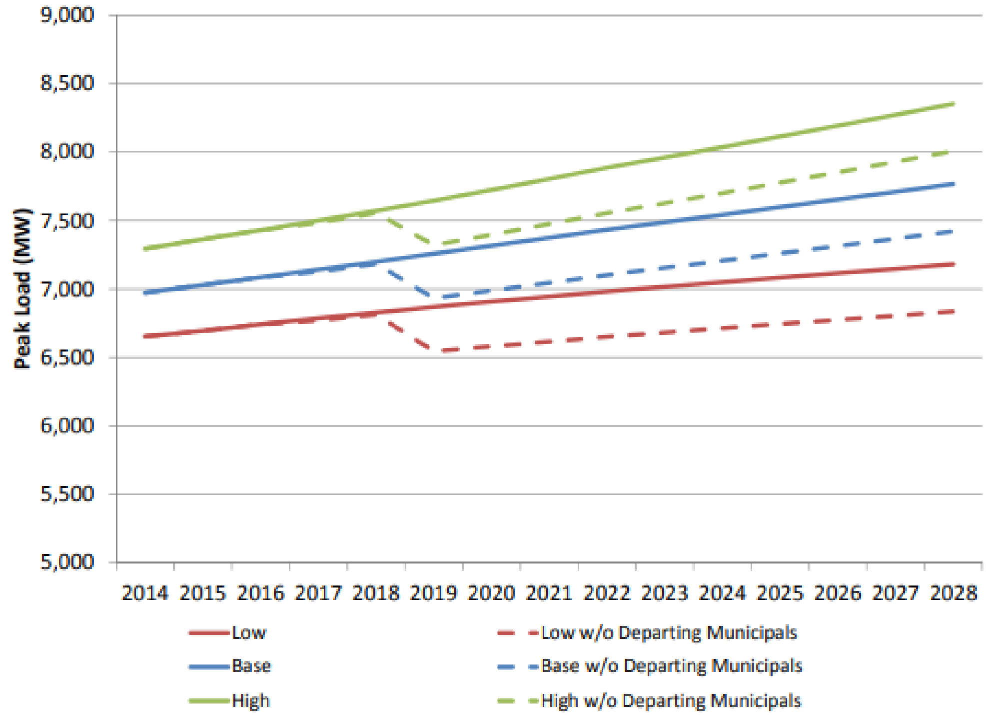
Graph 6.(1)-2
Combined Companies' Peak Demand – 2014 vs. 2011 IRP Forecasts after DSM (MW)



Even after accounting for the effect of the municipal load departure announced in 2014, the 2014 IRP base load forecast projected summer peak demand (net of DSM) increasing from 7,028 MW in 2015 to 7,421 MW in 2028:[4]

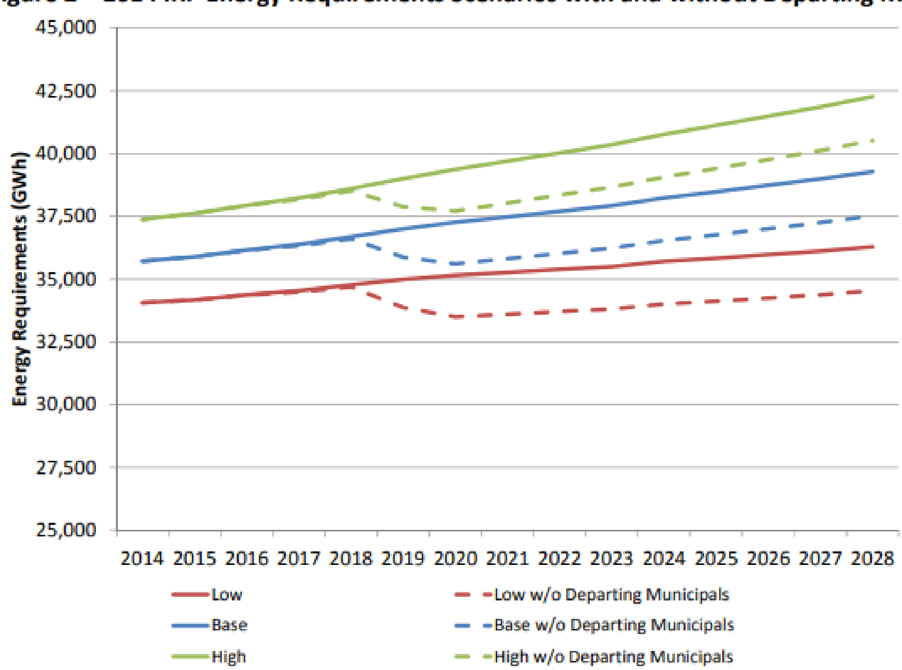
[4] *The 2014 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2014-00131, LG&E and KU 2014 Resource Addendum at 4-5 (Oct. 17, 2014).

Figure 1 – 2014 IRP Peak Load Scenarios with and without Departing Municipals



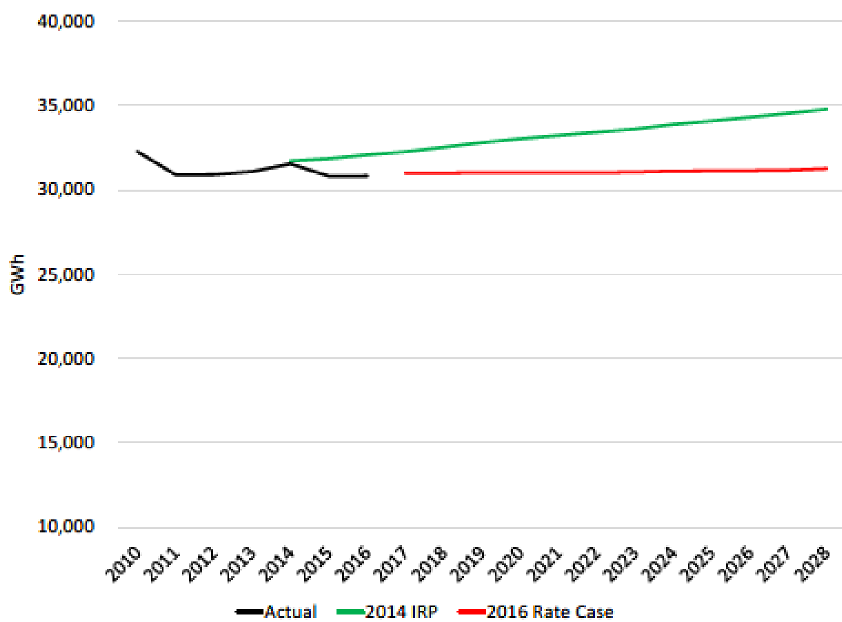
The 2014 IRP similarly projected increasing energy requirements:

Figure 2 – 2014 IRP Energy Requirements Scenarios with and without Departing Municipals



But by the time of the Companies' 2016 base rate cases, the effect of LED lighting and other efficiencies and residential housing trends had fundamentally shifted the Companies' load forecast downward, resulting in projected ***decreasing*** net summer demand from 6,806 MW in 2017 to 6,583 MW in 2028, as well as essentially flat energy sales:[5]

Figure 1 – LG&E and KU Retail Electricity Sales



At the same time, both national forecasts and other Kentucky utilities' forecasts shifted to project significantly lower energy and peak demand needs than previously forecasted.[6]

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[5] *Application of Kentucky Utilities Company For an Adjustment of Its Electric Rates and For Certificates of Public Convenience and Necessity*, Case No. 2016-00370, KU Municipal Departure Report at 6-7 (Sept. 20, 2017).

[6] The U.S. Department of Energy reduced its forecasted total energy sales for 2025 from 4,454 TWh in the 2014 Annual Energy Outlook to 4,025 TWh in the 2016 Annual Energy Outlook—a nearly 10% reduction in projected energy sales. (2014 Annual Energy Outlook available at https://www.eia.gov/outlooks/archive/aeo14/pdf/0383(2014).pdf at Table CP4, AEO2014 reference case (accessed Sept. 3, 2023); 2016 Annual Energy Outlook Available at https://www.osti.gov/servlets/purl/1329373 at Table CP4, AEO2016 No CPP (accessed Sept. 3, 2023). Kentucky Power Company reduced its energy-requirements forecast for 2028 from 7,158 GWh in 2013 to 6,254 GWh in 2016 (a 12.6% reduction). (*2016 Integrated Resource Plan of Kentucky Power Company*, Case No. 2016-00413, IRP Vol. A at 181, Exhibit C-11 (Dec. 20, 2016).) Similarly, Kentucky Power Company reduced its summer and winter peak-demand forecasts for 2028, from a 1,459 MW winter demand in 2013 to 1,329 MW winter demand in 2016 (an 8.9% reduction) and a 1,179 MW winter demand in 2013 to 1,038 MW winter demand in 2016 (a 12% reduction). (*Id.* at 183, Exhibit C-13.) And Big Rivers Electric Corporation reduced its projected native energy requirements for 2027 from 3,644 GWh in 2014 to 3,509 GWh in 2017. (*Big Rivers Electric Corporation's 2017 Integrated Resource Plan*, Case No. 2017-00384, IRP at 35, Table 3.2 (Sept. 21, 2017).) Similarly, Big Rivers Electric Corporation reduced its projected native peak demand for 2026 from 719 MW in 2014 to 683 MW in 2017. (*Id.* at 36, Table 3.3.).

In the Companies' 2016 base rate cases, the Companies noted that due to the changed load forecasts resulting from greatly increased customer efficiencies, "[T]he 2017 Business Plan shows no need for additional capacity, absent unit retirements, for the entire 30 year forecast period."[7] The Companies further noted that the emphasis on "additional" was intentional and important because "it may be more economical to retire existing generation units and acquire new capacity as a means to comply with environmental regulations in the future," though "the Companies are not likely to need ***additional*** capacity based on the forecasted future energy needs of our customers."[8]

Relatedly, in their 2016 base rate cases the Companies sought to close their Curtailable Service Rider ("CSR") tariff provisions to new participation and to decrease the credits provided to participating customers precisely because they did not anticipate any need for additional capacity at that time, making it inappropriate to offer CSR to new customers and to compensate CSR customers at avoided cost rates for ***future*** generating units.[9] Instead, the Companies proposed—and the Commission approved—CSR credits consistent with the embedded cost of the Companies' existing large-frame combustion turbines ("CTs"), effectively compensating CSR customers for their ongoing contribution to peak demand reduction as though they were existing, not new, CTs.[10] This approach was consistent with the Companies' projections that, barring retirements driven by future changes to environmental requirements, they would not need new generating capacity for the then-foreseeable future.

In the Commission's final order in KU's 2016 base rate case issued in June 2017, it instructed KU to "develop and implement a formal plan to address how KU will mitigate the loss of the approximately 325 MW municipal load, including, but not limited to, how KU will market the ***excess capacity*** and energy resulting from the municipals departing the system …."[11] The message from the Commission was clear: it was concerned about the Companies having too much capacity, not avoiding additional future capacity cost. As KU explained in its September 2017 report to the Commission on the announced municipal departures, the Companies' withdrawal of their 2014 CPCN application for Green River Unit 5 fully accounted for the effect of the municipal departures; the

[7] Case No. 2016-00370, Rebuttal Testimony of David S. Sinclair at 5 (Apr. 10, 2017) (emphasis in original).
[8] *Id.* at 6 (emphasis added.).
[9] *See, e.g.*, Case No. 2016-00370, Direct Testimony of W. Steven Seelye at 50-55 (Nov. 23, 2016); Case No. 2016-00371, Direct Testimony of W. Steven Seelye at 50-55 (Nov. 23, 2016).
[10] *See id.*; Case No. 2016-00370, Order (June 22, 2017) (approving stipulation with CSR credit reductions and closing CSR rates after limited additional participation); Case No. 2016-00371, Order (June 22, 2017) (approving stipulation with CSR credit reductions and closing CSR rates after limited additional participation).
[11] Case No. 2016-00370, Order at 27 (Ky. PSC June 22, 2017).

remaining changes to the load forecast were fundamental shifts caused by LED lighting and other factors.[12]

Just a few months earlier (in January 2017), the Commission announced it would more carefully scrutinize DSM-EE programs for cost-effectiveness:

> [T]he Commission further finds that Duke Kentucky should continue to scrutinize the results of each existing DSM program measure's cost-effectiveness test and provide those results in future DSM cases, along with detailed support for future DSM program expansions and additions. Duke Kentucky should also be mindful of the increasing saturation of energy-efficient products and be watchful for the opportunity to scale back on programs offering incentives for behavior that may be dictated by factors other than the incentives. *The Commission is concerned about the increasing number of utility DSM programs and the associated increase in costs to ratepayers*, particularly as the costs of the programs are borne by all customers in a rate class and are not limited to the participants in the DSM programs. *Therefore, the Commission will apply greater scrutiny in its review of all future DSM filings, with a particular emphasis on reviewing the cost-effectiveness of each program and measure.*[13]

Less than a month after issuing that order, the Commission opened an investigation into the reasonableness of Kentucky Power Company's DSM programs and rates. In the face of a declining number of customers and load, the Commission stated it was necessary to revisit the provisions of a settlement agreement the Commission approved in Kentucky Power's 2012 rate case that provided for prescribed DSM-EE expenditures beginning at $3 million annually in 2013 and rising to $6 million annually in 2016-2018.[14] In a later order in that investigation proceeding, the Commission stated, "This investigation of Kentucky Power's DSM spending was opened due to those changes in circumstances, which include the current adverse economic conditions in much of Kentucky Power's service territory, its declining electric sales, and its declining number of customers, which collectively have resulted in a significant level of excess generating capacity."[15] Finally, in its January 18, 2018 final order in the Kentucky Power DSM investigation proceeding, the Commission required Kentucky Power to terminate *all* of its existing DSM programs other than its low-

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[12] Case No. 2016-00370, KU Municipal Departure Report at 7-9 (Sept. 20, 2017).
[13] *Electronic Application of Duke Energy Kentucky, Inc. to Amend Its Demand Side Management Programs*, Case No. 2016-00289, Order at 15 (Ky. PSC Jan. 24, 2017) (emphases added).
[14] *Electronic Investigation of the Reasonableness of the Demand Side Management Programs and Rates of Kentucky Power Company*, Case No. 2017-00097, Order at 4-6 (Ky. PSC Feb. 23, 2017).
[15] Case No. 2017-00097, Order at 4 (Ky. PSC Nov. 2, 2017).

income programs until it could demonstrate a need for additional generating capacity:

> The Commission further finds that Kentucky Power's current significant excess capacity position, coupled with the lack of current cost-benefit analysis reflecting avoided costs that takes into account *Kentucky Power's lack of an immediate and near-term need for capacity and energy*, dictates that Kentucky Power be relieved of its commitment to spend $6 million on DSM programs. Kentucky Power should eliminate offering any DSM programs, other than those programs that target income-eligible residential customers, *until there is a change in Kentucky Power's capacity position that indicates a need for additional generation to serve its load*.[16]

Thus, it was in the following context that the Companies filed their 2017 DSM-EE application in December 2017: no anticipated need for additional generating resources to meet projected demand for 30 years (barring economic unit retirements to meet future environmental requirements, which were unknown at the time), a Commission clearly concerned about the Companies having "excess" capacity, and a clear Commission direction to reexamine and scrutinize DSM-EE programs—and possibly eliminate them, as in the case of Kentucky Power—in face of flat to declining load and a perception of utilities having excess capacity.

The Companies were also cognizant of the Commission's longstanding precedent concerning avoided costs in the qualifying facility ("QF") context about when a zero avoided capacity cost would appropriate:

> If a utility demonstrates to the Commission's satisfaction that it simultaneously faces insignificant load growth, excess capacity, minimum off-system sales and is neither planning nor constructing capacity within its 10-year planning horizon, then the utility cannot avoid capacity related costs at that time so a capacity payment would not be justified. However, the Commission emphasizes that it would be contradictory for utilities to argue for zero avoided capacity costs while proceeding to plan for or construct generating facilities. The burden is on the utility to demonstrate zero avoided capacity costs.
>
> …
>
> The Commission has given the utilities great leeway in their choices of methodologies to evaluate avoided capacity cost. The Commission is aware that there is no universally accepted

[16] Case No. 2017-00097, Order at 13 (Ky. PSC Jan. 18, 2018).

> methodology because each utility has a different system generation mix and load configuration. The Commission is of the opinion that if a method properly reflects the savings from changes in system planning conditions and is reproducible by other interested parties, then it is acceptable for current use.[17]

It was therefore consistent with the Companies' load and generation expectations in mid to late 2017, the Commission's longstanding avoided capacity cost precedent, and the Commission's announced views about how to consider DSM-EE programs that the Companies' witnesses testified in December 2017 that:

- "[T]he significant decreases in projected customer loads over the next 30 years resulting from energy efficiency, both utility-run and otherwise, as well as lower avoided energy costs and increasing energy-efficiency baselines in the marketplace, have created a situation where additional cost-effective DSM-EE measures have become more difficult to identify and implement."[18]

- "Since the Commission approved the current DSM-EE Program Plan in Case No. 2014-00003, the Companies have experienced changing market conditions, including declining load growth projections, very low fuel costs, and consequently low production costs. Additionally, the Companies' most recent annual 30-year demand and energy forecast and resource plans project relatively flat demand and sufficient generating capacity. Therefore, the Companies project no significant investment in new generation over the next 30 years."[19]

- "The Companies' most recent annual 30-year demand and energy forecast and resource plans project relatively flat demand and sufficient generating capacity over the next 30 years. Therefore, the Companies project no significant investment in new generation, which indicates zero avoided capacity cost benefits from DSM-EE programs."[20]

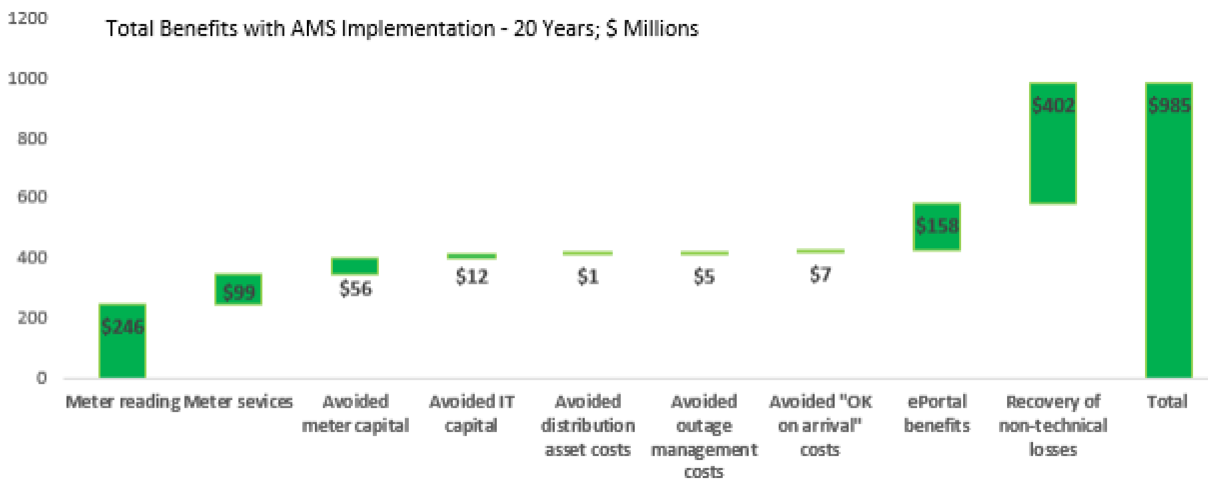
- "[T]he recent dramatic decrease in projected customer load means the Companies do not reasonably foresee a need for additional capacity for at least 30 years. For that reason, a $0/kW-year avoided capacity cost is appropriate to use in analyzing DSM-EE programs."[21]

Notably, the Companies proposed to *reduce* but not eliminate incentive payments for their ongoing DSM load control programs. That was consistent with the

[17] Case No. 8566, Order at 5-6 (Ky. PSC June 28, 1984).
[18] Case No. 2017-00441, Direct Testimony of Gregory S. Lawson at 4 (Dec. 6, 2017).
[19] *Id.* at Exh. GSL-1 at 5.
[20] *Id.* at 9.
[21] Case No. 2017-00441, Direct Testimony of David E. Huff at 12-13 (Dec. 6, 2017).

approach the Companies proposed and the Commission approved in the Companies' 2016 base rate cases concerning CSR credits: the ongoing credits were necessary to support *ongoing* demand savings that would disappear if the credits stopped. The DSM-EE programs that the Companies proposed not to continue beyond 2018 did not involve credits to support ongoing savings; rather, they were targeted at attracting new participants, not retaining prior participants. Therefore, it was appropriate to use a zero avoided generating capacity value to evaluate those programs because *at that time* additional demand savings would not have helped avoid then-foreseeable generating capacity additions.

In addition, the Companies' position in their 2017 DSM-EE case was entirely consistent with the Companies' 2018 Advanced Metering Systems ("AMS") application, which did *not* include avoided capacity cost benefits among the benefits of AMS deployment:[22]



The Rebuttal Testimony of John P. Malloy in the Companies' 2018 AMS case did *not* contradict the Companies' application in that proceeding, the 2017 DSM-EE case, or the Companies' 2016 base rate cases. The entirety of Mr. Malloy's rebuttal on the topic of avoided capacity cost in that proceeding is below. Note that the witness to whom Mr. Malloy was responding was the Attorney General's witness, Paul Alvarez:[23]

<u>Avoided Capacity Cost Is a *Potential* Benefit of AMS</u>

Q. Mr. Alvarez next asserts, "[O]ne of the largest potential economic benefits from a smart meter deployment [i.e.,

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[22] *Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Certificates of Public Convenience and Necessity For Full Deployment of Advanced Metering Systems*, Case No. 2018-00005, Direct Testimony of John P. Malloy, Exh. JPM-1 at 36 (Jan. 10, 2018).

[23] Case No. 2018-00005, Rebuttal Testimony of John P. Malloy at 6-7 (June 15, 2018) (bold and underline in original; italics added for emphasis).

avoided capacity cost] is not available due to the Companies' extensive excess capacity." How do you respond?

A. First, the Companies disagree with the characterization of their reserve margin as "excess capacity." Though the Companies do not currently have a need for additional capacity absent unexpected retirements or significant changes in load or new capacity costs, all of their generating resources are used in appropriate ways to serve their customers' needs, including maintaining a reasonable reserve margin to ensure customers' needs can be met at times of peak demand. Moreover, compared to other utilities and RTOs, the Companies' projected reserve margin is reasonable. For example, the results of the PJM RTO's Base Residual Auction for the delivery years 2019-2020, 2020-2021, and 2021-2022 ranged from 21.5% to 23.3%. Moreover, according to the North American Electric Reliability Corporation ("NERC") 2018 Summer Reliability Assessment, both PJM and the Southwest Power Pool ("SPP") have anticipated reserve margins over 30% for the summer of 2018.

Second, though the Companies' reserve margin appears to be adequate based on currently foreseeable conditions and circumstances, and *the Companies did not include any avoided-capacity-related savings in their AMS Business Case*, it is possible circumstances could change to allow such a benefit to eventuate. If it did, it would add net benefits to a project the Companies have already demonstrated will have net benefits. So rather than seeing Mr. Alvarez's point as detracting from the argument for approving AMS deployment, *I believe it adds support to it in the form of potential additional benefits*.

In short, the Companies did *not* claim in the 2018 AMS case that avoided generating capacity costs would be a benefit of AMS and did not attempt to quantify any such benefit; rather, the Companies stated such avoided costs *could* be a benefit of AMS in the future *if circumstances changed*.

Nonetheless, the Attorney General argued in the 2017 DSM-EE case that the Companies were being inconsistent by using a zero avoided generating capacity cost for their DSM-EE cost-benefit analyses while also stating in rebuttal in the AMS case that avoided generating capacity costs could possibly be a future benefit of AMS if circumstances changed, even though the Companies assumed *zero* avoided generating capacity cost in the AMS case.[24] Notably, the

[24] Case No. 2017-00441, Attorney General's Initial Brief at 3 (June 26, 2018).

Commission directly addressed and rejected the Attorney General's argument in its final order in the 2017 DSM-EE case:

> In making our findings in this case, the Commission recognizes that, unlike prior LG&E/KU DSM cases in which the utilities were projecting capacity shortfalls which resulted in a positive avoided capacity cost, they now have a capacity surplus of approximately 100 MW, *resulting in an avoided capacity cost of zero*. …
>
> The Attorney General also challenges LG&E/KU's capacity valuation of zero for DSM programs as being inconsistent with the positive capacity valuation they used earlier this year when requesting approval to install AMS meters. *The Commission finds that using a zero value for capacity is not inconsistent, since the study period covered by this DSM filing is 2019-2025, whereas the study period used in the AMS case was significantly longer, covering 2018-2040*. Under the current facts, it is no longer reasonable to require LGE/KU's ratepayers to either bear the costs of any DSM programs that can reasonably be scaled back or eliminated, or to bear the costs of any studies to establish new DSM programs.[25]

Thus, at least as recently as October 2018, the Commission explicitly determined that a lack of a need for new capacity over a timeframe as short as seven years (i.e., 2019-2025) supported using a zero avoided generating capacity cost for DSM-EE cost-benefit analyses.

Notably, in the Companies' 2018 IRP filed in October 2018, the Companies anticipated being able in 2019 to retire Brown Units 1 and 2 (272 MW) and allow the Bluegrass CT tolling agreement (165 MW) to expire without replacing their capacity due to decreased customer load projections,[26] which they were ultimately able to do. In addition, the Companies' 2018 IRP showed that although it was possible that additional coal unit retirements might occur prior to 2033 if they were assumed to be limited to 55-year operating lives, no such retirements would be needed if they were assumed to have 65-year operating lives:[27]

[25] Case No. 2017-00441, Order at 26-27 (Ky. PSC Oct. 5, 2018) (emphases added).
[26] *The 2018 Joint Integrated Resource Plan of Kentucky Utilities Company and Louisville Gas and Electric Company*, Case No. 2018-00348, 2018 IRP Vol. 1 at 5-36 (Oct. 19, 2018).
[27] *Id.* at 5-21.

Table 5-4: Unit Retirement Scenarios

	55-Year Operating Life		65-Year Operating Life	
Year	**Retired Summer Net Capacity (MW)**	**Retired Units**	**Retired Summer Net Capacity (MW)**	**Retired Units**
2023	49	LG&E Small-Frame SCCTs		
2024				
2025	24	Haefling 1-2		
2026	415	Brown 3		
2027	299	Mill Creek 1		
2028				
2029	770	Ghent 1, Mill Creek 2		
2030				
2031				
2032	481	Ghent 2		
2033	390	Mill Creek 3	49	LG&E Small-Frame SCCTs
Total	2,428		49	

At that time, there were no environmental requirements compelling the coal unit retirements shown in the 55-year operating life scenario; it was merely one of two possible cases run in the 2018 IRP analysis.

By late 2019, circumstances changed. The U.S. Environmental Protection Agency ("EPA") issued a proposed rulemaking in November 2019 revising the 2015 Effluent Limitation Guidelines ("ELG") for steam electric generators,[28] which became final in October 2020.[29] The Companies filed their 2020 ECR applications in March 2020 in response to the proposed ELG rule revisions, and their compliance plans included ELG compliance facilities sufficient for only three of the four Mill Creek units based on the assumption that either Mill Creek Unit 1 or 2 could retire by 2025 *without the need for replacement generation* and that Mill Creek Unit 1 would likely retire first due to uncertainty associated with Clean Water Act 316(b) regulations.[30] Notably, the Companies' analysis in the 2020 ECR cases contemplated a number of different possible retirement years for their remaining coal-fired units, but they were merely that: possibilities, not certainties or even likelihoods.[31]

[28] 84 Fed. Reg. 64,620 (Nov. 22, 2019), available at https://www.govinfo.gov/content/pkg/FR-2019-11-22/pdf/2019-24686.pdf.
[29] 85 Fed. Reg. 64,650 (Oct. 13, 2020), available at https://www.govinfo.gov/content/pkg/FR-2020-10-13/pdf/2020-19542.pdf.
[30] *Electronic Application of Louisville Gas and Electric Company for Approval of Its 2020 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2020-00061, Direct Testimony of Stuart A. Wilson, Exh. SAW-1 at 17-24 (Mar. 31, 2020); Case No. 2020-00061, Order at 6-9, 16-17, and 21 (Ky. PSC Sept. 29, 2020).
[31] *See generally* Case No. 2020-00061, Direct Testimony of Stuart A. Wilson, Exh. SAW-1 (Mar. 31, 2020).

By late 2020, it was becoming increasingly clear that tightening environmental constraints for Mill Creek Unit 2 and planned major maintenance costs for Brown Unit 3 would likely make their retirement by 2028 economical, as explained in the Companies' October 2020 Analysis of Generating Unit Retirement Years filed in the Companies' 2020 base rate cases.[32] Consistent with this analysis and as shown in the attachment to PSC 2-29(a), the Companies' Generation Planning team developed in November 2020 and provided to the Companies' DSM-EE team in December 2020 a set of avoided generating capacity costs to use in considering and evaluating possible DSM-EE programs and measures. That is consistent with the Direct Testimony of John Bevington in this proceeding that "[i]n late 2020, although the Companies were less than three years into a seven-year DSM-EE Program Plan, the Companies increased the pace of their DSM-EE Program Plan development due to an anticipated possible future capacity need and the evolving and increasing avoided cost of capacity …."[33]

It is important to note that in late 2020 the Companies began to consider non-zero avoided generating capacity costs for future DSM-EE program plan filings and that such consideration was not inconsistent with the Companies' position in their 2020 base rate cases that NMS-2 net metering rates should have zero avoided generating capacity costs associated with them. In May 2020 the Commission issued an order construing a non-firm energy-only solar PPA that "include[d] no capacity" not to be evidence of indebtedness or to require a CPCN.[34] The order further denied the Companies' request for Green Tariff Option #3 customers to receive any demand-charge offset associated with solar PPAs:

> The Commission agrees with the provision of the RPAs [Renewable Power Agreements] not to reduce base demand charges because the RPA customers continue to utilize distribution and transmission systems that are associated with and recovered through the base demand charge. However, the Commission disagrees with the provision that intermediate and peak demand charges should be reduced by coincident solar energy production because intermediate and peak demand costs

[32] *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00349, Direct Testimony of Lonnie E. Bellar, Exh. LEB-2 (Nov. 25, 2020*); Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Meter Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00350, Direct Testimony of Lonnie E. Bellar, Exh. LEB-2 (Nov. 25, 2020).
[33] Bevington Direct at 6; see also the Companies' response to PSC 1-2.
[34] *Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Solar Power Contract and Two Renewable Power Agreements to Satisfy Customer Requests for a Renewable Energy Source Under Green Tariff Option #3*, Case No. 2020-00016, Order at 11-12 (Ky. PSC May 8, 2020).

> should not be re-allocated to other customers in a future rate proceeding. The Commission notes that in addition to the distribution and transmission systems, LG&E/KU's generation capacity and assets were constructed in order to serve existing customer needs. Toyota and Dow continue to be all-requirements customers of KU, and LG&E/KU's generating assets will continue to be available to serve Dow and Toyota's demands. The RPAs with Dow and Toyota do not relieve LG&E/KU's obligation to plan for the provision of all customers' energy needs, including Dow and Toyota. Therefore, the RPA customers, *as all other customers*, should bear their fair share of the costs to provide reliable energy.[35]

As the Companies noted in their 2020 rate cases, net metering customers' generating facilities—which are almost exclusively solar—would be most likely to avoid future *solar PPA* costs, not other kinds of generating costs. Given the Commission's clear position on the capacity value and demand credits associated with solar PPAs for large customers—i.e., zero for both—it was neither unreasonable nor inconsistent for the Companies to propose NMS-2 rates with a zero avoided generating capacity value. The Commission ultimately disagreed with the Companies' position, but that did not make the Companies' view unreasonable at the time. Moreover, it was not inconsistent with the Companies' approach to begin developing new DSM-EE programs and measures in late 2020 with a non-zero avoided generating capacity value; because DSM-EE programs can help avoid energy needs at times that do not exactly coincide with solar production profiles, the capacity costs DSM-EE can help avoid are not necessarily or exclusively solar costs, which is why basing DSM-EE avoided capacity costs on fossil-fired units is appropriate.

Finally, the Companies have attempted to be consistent with regard to their avoided generating capacity costs across all their filings with the Commission, including those not already addressed in this response. For example, the Companies' biannual avoided cost filings supporting their qualifying facility ("QF") rates and their biannual marginal cost studies supporting their Economic Development Rider ("EDR") filings were consistent with the Companies' avoided generating capacity costs and anticipated generating capacity needs over this time frame.

- The Companies' 2016 QF avoided cost filing showed only the Brown Solar facility as capacity to be added between 2016 and 2025,[36] which was a

[35] *Id.* at 21 (Ky. PSC May 8, 2020) (emphasis added).
[36] Tariff Filing ID TFS2016-00338, KU 2016 Avoided Cost Filing Attachments (May 26, 2016), available at
https://psc.ky.gov/trf4/uploadedFiles/400_Kentucky_Utilities_Company/05262016010610/2016_Avoided_

facility the Companies had proposed in Case No. 2014-00002 as a fuel price and CO_2 emissions hedge, as well as to gain operational experience, not to obtain capacity benefits or because it was least cost.[37]

- The Companies' 2018 and 2020 QF avoided cost filings showed no capacity additions through 2029.[38]

- The Companies' EDR marginal cost analyses showed a marginal cost per kW of non-coincident peak demand of $2.54 in 2015, $1.59 in 2017, $0 in 2019, and $1.68 in 2021.[39] Notably, the 2017 analysis assumed *no* capacity additions through 2031. The 2017 non-zero capacity cost resulted from assuming a load addition of 450 MW or more, which advanced a large-frame SCCT by one year from 2032 to 2031.

Cost_Filing_Attachments.pdf; Tariff Filing ID TFS2016-00337, LG&E 2016 Avoided Cost Filing Attachments (May 26, 2016), available at https://psc.ky.gov/trf4/uploadedFiles/500_Louisville_Gas_and_Electric_Company/05262016010207/2016_Avoided_Cost_Filing_Attachments.pdf.

[37] *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Certificates of Public Convenience and Necessity for the Construction of a Combined Cycle Combustion Turbine at the Green River Generating Station and a Solar Photovoltaic Facility at the E.W. Brown Generating Station*, Case No. 2014-00002, Order at 7 (Ky. PSC Dec. 19, 2014).

[38] Tariff Filing ID TFS2018-00265, KU 2018 Avoided Cost Filing Attachments (May 29, 2018), available at https://psc.ky.gov/trf4/uploadedFiles/400_Kentucky_Utilities_Company/05292018030723/Avoided_Cost_Attachments.pdf; Tariff Filing ID TFS2018-00264, LG&E 2018 Avoided Cost Filing Attachments (May 29, 2018), available at https://psc.ky.gov/trf4/uploadedFiles/500_Louisville_Gas_and_Electric_Company/05292018030101/Avoided_Cost_Attachments.pdf; Tariff Filing ID TFS2020-00269, KU 2020 Avoided Cost Filing Attachments (May 28, 2020), available at https://psc.ky.gov/trf4/uploadedFiles/400_Kentucky_Utilities_Company/05282020122701/02_-_2020_Avoided_Cost_Filing_Attachments_KU.pdf; Tariff Filing ID TFS2020-00270, LG&E 2020 Avoided Cost Filing Attachments (May 28, 2020), available at https://psc.ky.gov/trf4/uploadedFiles/500_Louisville_Gas_and_Electric_Company/05282020123202/02_-_2020_Avoided_Cost_Filing_Attachments_LGE.pdf.

[39] *See* Tariff Filing TFS2016-00027, Louisville Gas & Electric Company Kentucky Utilities Company Marginal Cost of Service Study dated May 2015 at page 2 (filed Jan. 25, 2016), available at https://psc.ky.gov/trf4/uploadedFiles/400_Kentucky_Utilities_Company/02022016092356/KU_27_Marginal_Cost_Study.pdf; Tariff Filing TFS2018-00189, Louisville Gas & Electric Company Kentucky Utilities Company Marginal Cost of Service Study dated Aug. 2017 at page 2 (filed Apr. 26, 2018), available at https://psc.ky.gov/trf4/uploadedFiles/400_Kentucky_Utilities_Company/04262018011728/KU_189_Marginal_Cost_Study.pdf; Tariff Filing TFS2020-00386, Marginal Cost of Service Study, Kentucky Utilities Company and Louisville Gas and Electric Company, dated May 13, 2019 at page 2 (filed July 30, 2020), available at https://psc.ky.gov/trf4/uploadedFiles/400_Kentucky_Utilities_Company/08282020054744/KU_386_Support.pdf; Tariff Filing TFS2022-00368, Marginal Cost of Service Study, Kentucky Utilities Company and Louisville Gas and Electric Company, dated Oct. 26, 2021 at page 2 (filed July 18, 2022), available at https://psc.ky.gov/trf4/uploadedFiles/400_Kentucky_Utilities_Company/08122022090325/KU_368_Marginal_Cost_Study.pdf.

In sum, avoided generating capacity cost is a complex concept. Its value in a given context depends on a number of factors, including the timing of incremental generating capacity, the fundamentally different characteristics of different generating technologies, and the various ways of owning or contracting for capacity and energy. The Companies' history with calculating and applying avoided and marginal generating capacity cost shows the Companies have sought to account for these factors appropriately in accordance with the Commission's orders and the requirements of 807 KAR 5:054 (concerning qualifying facilities).

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated September 1, 2023

Case No. 2022-00402

Question No. 8

Responding Witness: Lonnie E. Bellar

Q-8. Refer to the August 22, 2023 hearing testimony of Lonnie Bellar. Provide a table showing the effect the loss of gas pressure arising from Winter Storm Elliot would have had on the equivalent forced outage rate for each affected unit if it had been reported to the North American Electric Reliability Corporation's (NERC) Generating Availability Data System (GADS).

A-8.

Unit	2022 Forced Outage Rate including Winter Storm Elliott low gas pressure event	2022 Forced Outage Rate excluding Winter Storm Elliott low gas pressure event
Cane Run 7	5.36	5.29
Trimble County 5	1.65	0.03
Trimble County 6	0.86	0.25
Trimble County 7	0.78	0.60
Trimble County 8	0.30	0.00
Trimble County 9	0.93	0.56
Trimble County 10	0.10	0.04

Note: Trimble County 5-10 outage rates use EFORd to better represent the peaking units' performance during periods of demand.

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Response to Commission Staff's Post-Hearing Request for Information
Dated September 1, 2023

Case No. 2022-00402

Question No. 9

Responding Witness: Lonnie E. Bellar

Q-9. Refer to LG&E/KU's response to Commission Staff's First Request for Information (Staff's First Request), Item 100. Provide an explanation for the increase in the forced outage rate for Ghent Unit 4 and Cane Run Unit 7, respectively, in 2022.

A-9. The increase in EFOR for both units was due to a specific equipment issue and was not due to any upward trend in EFOR. For Cane Run 7, the steam turbine generator experienced a grounding issue that accounted for over half the yearly EFOR. For Ghent 4, the unit required a turbine bearing repair that accounted for over 75% of the yearly EFOR. Without these atypical issues the EFOR on these units would have fallen within historical bounds.

Attached are the Root Cause Failure Analyses for each of these two events along with an excerpt from a presentation to Executive Leadership on the events.

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Response to Commission Staff's Post-Hearing Request for Information
Dated September 1, 2023

Case No. 2022-00402

Question No. 10

Responding Witness: Lonnie E. Bellar

Q-10. Refer to LG&E/KU's response to Staff's First Request, Item 100. Provide the equivalent forced outage rates for each thermal generation unit in LG&E/KU's fleet in 2018, 2019, 2020, 2021, and 2022.

A-10. The tables below contain EFOR values for coal and NGCC units and $EFOR_d$ values for large frame SCCTs and supporting information. For Table 2a and 2b, the supporting information is provided for any year in which a unit had an EFOR 4.0% or higher. Additionally, at the thermal fleet level the Companies' EFOR has been within the Top Decile of US Industry since 2018 and well within since 2020.

Table 1: Thermal Fleet EFOR					
	2018	**2019**	**2020**	**2021**	**2022**
Fleet	2.63	2.51	1.52	1.82	2.78
Industry Top Quartile	4.66	4.71	5.38	4.23	6.30
Industry Top Decile	2.80	2.69	2.80	2.80	3.67
Industry Top Quartile/Decile data from NERC GADS PC_GAR software data reports					

Table 2a: Thermal Fleet EFOR					
	2018	2019	2020	2021	2022
BR3	12.46	6.35	3.24	3.16	5.17
GH1	1.56	1.56	1.20	2.41	1.20
GH2	1.90	0.68	0.60	0.30	0.76
GH3	4.86	0.87	1.12	0.98	0.25
GH4	1.11	0.10	1.97	0.54	5.25
MC1	1.16	2.93	1.19	2.57	1.17
MC2	2.31	1.80	0.45	4.17	6.69
MC3	1.21	3.89	1.19	1.03	0.70
MC4	2.41	0.75	1.69	2.84	0.02
TC1	1.88	3.25	1.26	2.59	3.93
TC2	2.73	7.53	2.03	3.01	2.21
CR7	0.74	1.04	1.60	0.34	5.38

Table 2b: EFOR Contributing Information		
Unit	Year	Primary Contributor
BR3	2018	Mulitple outages/derates due to wind damage to both cooling towers
	2019	Extraction steam line leak at Deaerator and EHC fluid leak at turbine intercept valves
	2022	Extended outage due to boiler pluggage
GH3	2018	Multiple outages due to superheater tube leaks
GH4	2022	Answer provided separately for PSC Q9
MC2	2021	Multiple outages/derates due to pulverizer issues and turbine vibration
	2022	Separate extended outages due to unit controls issues and loss of cooling tower pumps
TC2	2019	Multiple outages after PO for turbine/generator vibration, subsequent boiler feed pump issues
CR7	2022	Answer provided separately for PSC Q9

Table 3: Primary CT Starting Reliability					
	2018	**2019**	**2020**	**2021**	**2022**
BR5	95.24%	92.86%	90.00%	97.14%	97.73%
BR6	90.91%	94.68%	92.11%	94.64%	100.00%
BR7	97.78%	100.00%	86.67%	94.00%	95.95%
BR8	94.74%	100.00%	76.92%	88.89%	95.83%
BR9	93.10%	90.74%	96.30%	95.83%	92.86%
BR10	92.50%	92.68%	95.00%	95.65%	96.43%
BR11	100.00%	100.00%	90.00%	93.75%	96.15%
TC5	97.94%	98.73%	100.00%	97.47%	100.00%
TC6	99.07%	98.46%	100.00%	100.00%	100.00%
TC7	98.34%	100.00%	100.00%	98.77%	100.00%
TC8	99.24%	98.04%	98.31%	98.73%	100.00%
TC9	98.13%	98.59%	100.00%	100.00%	99.18%
TC10	97.67%	100.00%	100.00%	93.94%	100.00%
PR13	100.00%	96.67%	96.97%	98.00%	97.18%
Primary CT Fleet	97.53%	96.50%	96.40%	97.29%	98.74%
NERC Average	98.35%	98.35%	98.34%	98.52%	98.60%
Note					
NERC Average is based on most recent 5 year industry average for CTs > 50 GMW available at start of calendar year					

Table 4: Primary Combustion Turbine EFORd					
	2018	2019	2020	2021	2022
BR5	11.03	1.33	11.77	9.92	6.13
BR6	6.75	6.75	12.30	5.73	1.92
BR7	2.07	13.28	5.45	5.32	4.64
BR8	1.18	12.90	3.95	6.51	1.26
BR9	2.54	6.66	2.03	2.21	3.70
BR10	1.97	6.67	5.80	11.46	10.33
BR11	12.04	0.42	4.85	1.12	5.05
TC5	1.31	1.51	0.12	0.33	1.65
TC6	1.73	1.35	1.01	0.09	0.86
TC7	3.43	0.41	0.00	0.53	0.78
TC8	1.29	1.51	0.55	1.15	0.30
TC9	4.05	0.57	0.22	1.99	0.93
TC10	5.19	1.39	0.31	5.55	0.10
PR13	0.32	11.58	6.14	6.57	6.10
Primary CT Fleet	4.36	5.94	4.06	3.54	2.80
NERC Average	9.29	9.86	9.65	9.40	9.27
Note					
NERC Average is based on most recent 5 year industry average for CTs > 50 GMW available at start of calendar year					

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated September 1, 2023

Case No. 2022-00402

Question No. 11

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

Q-11. Refer to the May 10, 2023 Direct Testimony of Stuart A. Wilson (Wilson May 10, 2023 Direct Testimony), Exhibit SB4-1, Table 11: Total Stay-Open Costs (Table 11). Also refer to Bellar August 23, 2023 Hearing Testimony. Provide a schedule itemizing the type and amount of avoided costs that are included in ongoing costs in the stay-open cost analysis contained in Table 11 for each of the referenced generation facilities.

A-11. As stated in Section 7.4 of Exhibit SAW-1, stay-open costs reflect the costs required to continue operating a unit and are avoided if a unit is retired. Ongoing costs for each of the units in Table 11 reflect only the avoidable costs associated with each unit. Itemized detail for each station and the secondary CTs is available in the files below. See also the response to Question No. 12(b).

"\FinancialModel\Support\20230328_StayOpenSummary_0314.xlsx" in Exhibit SB4-2.

"\04_FinancialModel\Support\StayOpenCosts\20221021_StayOpenDetail_BR_0308.xlsx" in Exhibit SAW-2.

"\04_FinancialModel\Support\StayOpenCosts\20221021_StayOpenDetail_GH_0308.xlsx" in Exhibit SAW-2.

"\04_FinancialModel\Support\StayOpenCosts\20221021_StayOpenDetail_MC_0308.xlsx" in Exhibit SAW-2.

"\FinancialModel\Support\20230328_StayOpenDetail_SmallFrameCTs_0314.xlsx" in Exhibit SB4-2.

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Question No. 12

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

Q-12. Refer to the Wilson May 10, 2023 Direct Testimony, Exhibit SB4-1, Table 11. Also refer to Case No. 2020-00061,[40] Direct Testimony of Stuart A. Wilson (Wilson Direct Testimony), Exhibit SAW-1, Table 4: Stay-Open Costs. Finally, refer to Case No. 2020-00350,[41] Direct Testimony of Lonnie E. Bellar (Bellar Direct Testimony), Exhibit LEB2, Table 8: Stay Open Costs (Table 8).

a. Describe the categories of costs included in each of the three tables, including whether "ongoing maintenance" stay open costs as used in Table 11 refers to the same costs as "annual" stay open costs as used in Table 8.

b. Provide a table or spreadsheet with an itemized breakdown of the type and amount of costs for each generating unit for each year included in each table.

c. Explain any differences in the total or itemized costs in each table for each generating unit in each year.

A-12.

a. Each of these tables reflects the units' avoidable ongoing capital and fixed operating and maintenance ("O&M") costs, including routine annual maintenance and major overhaul maintenance. 'Annual' costs in Table 8 are synonymous with 'ongoing costs' in Table 11, and 'major maintenance' costs in Table 8 are synonymous with 'overhaul costs (standard)' in Table 11. These tables also include the forecasted share of common station costs that would be avoided if a unit were retired; this cost is included in 'annual' costs in Table 8 and in 'ongoing costs' in Table 11.

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[40] Case No. 2020-00061, *Electric Application of Louisville Gas and Electric Company for Approval of an Amended Environmental Compliance Plan and a Revised Environmental Surcharge* (filed Mar. 31, 2020), Application, Direct Testimony of Stuart A. Wilson.
[41] Case No. 2020-00350, *Electronic Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates, A certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit* (filed Nov. 25, 2020), Application, Direct Testimony of Lonnie E. Bellar.

Table 4 (from Case No. 2020-00061) aggregates these costs into a single value by unit by year. Table 8 (from Case No. 2020-00350) breaks these costs into two categories. Table 11 (from Exhibit SB4-1) includes these categories but also adds capital costs needed to operate the units beyond the end of their current depreciable book lives, reflected as 'overhaul costs (life extension)', and incremental costs associated with environmental compliance.

b. See attachment being provided in a separate file.

c. The most significant difference between the assumptions underlying the three tables is the change to common cost allocation. In Table 4 (from Case No. 2020-00061) and Table 8 (from Case No. 2020-00350), the Companies assumed common costs for Mill Creek would be reduced 10 percent after the retirement of Mill Creek 1 and an additional 20 percent after the retirement of Mill Creek 2, while the common costs for Ghent would be reduced 25 percent after the retirement of Ghent 2. After those analyses, the Companies developed stay-open costs for the 2021 IRP and CPCN using a more detailed process, which resulted in common cost allocations of approximately zero percent and 10.5 percent of Mill Creek station costs for Mill Creek 1 and 2, respectively, and approximately 7 percent of Ghent station costs for Ghent 2. For Mill Creek 1 and 2, the operation of only one of those units during the ozone season provided experience regarding the potential impact on maintenance expenses for the plant common systems. After accounting for the change in common cost allocation and because Table 11 (from Exhibit SB4-1) is the only table that includes life extension and incremental environmental compliance costs, total stay-open costs for the three tables are generally consistent. A summary of significant differences is provided below for each unit that contained data in more than one of the referenced tables.

Brown 3:

Focusing on 2026 through 2034 (the period for which data exists for Table 8 and Table 11; Brown 3 was not included in Table 4), Brown 3 ongoing capital averaged $7M per year in both tables. Overhaul capital (standard) was $23M across 2026 and 2027 in the Table 8 and was $17M consolidated into 2027 in Table 11, with the decrease attributable to deferring two major boiler projects. Brown 3 ongoing O&M averaged $25M per year in Table 8 compared to $21M per year in Table 11, with the decrease attributable to updated post-retirement costs (i.e., the preliminary estimates for post-retirement costs of Brown 3 developed for its assessment in Table 8 were refined through a more thorough process in the CPCN data to better assess the effect of Brown 3 retiring). Brown 3 overhaul O&M (standard) was $8M in both tables. Fixed coal transport (rail costs) for Brown station averaged $6M per year in Table 8 compared to $7M per year in Table 11.

Ghent 2:

Focusing on 2023 through 2030 (the period for which data exists for Table 4 and Table 11; Ghent 2 was not included in Table 8), Ghent 2 ongoing capital averaged $8M per year in Table 4 compared with $7M per year in Table 11, with fluctuations throughout the period due to changed project timing. Overhaul capital (standard) was $29M in 2026 in Table 4 compared to $27M that was deferred to 2027 in Table 11. Ghent 2 ongoing O&M averaged $21M per year in Table 4 compared to $10M per year in Table 11, with the decrease attributable to the aforementioned update to common station cost allocations. Ghent 2 overhaul O&M (standard) was $9M per year in both tables, with the costs shifting from 2026 in Table 4 to 2027 for Table 11 consistent with the deferral of the overhaul.

Mill Creek 1:

Focusing on 2023 through 2030 (the period for which data exists for Table 4 and Table 11; Mill Creek 1 was not included in Table 8), Mill Creek 1 ongoing capital averaged $4M per year in both tables. Overhaul capital (standard) was $4M in Table 4 compared to $9M in Table 11, but total capital within the overhaul year remained unchanged, so this can be attributed to categorization of costs rather than a change of costs. Mill Creek 1 ongoing O&M averaged $12M per year in Table 4 compared to $5M per year in Table 11, with the decrease attributable to the aforementioned update to common station cost allocations. Mill Creek 1 overhaul O&M (standard) was $5M in Table 4 compared with $2M in Table 11.

Mill Creek 2:

Focusing on 2026 through 2030 (the period for which data exists for all three tables; these comparisons are largely consistent with other overlaps of these tables), Mill Creek 2 ongoing capital averaged $6M per year in Table 4 and Table 8, compared to $5M per year in Table 11. Overhaul capital (standard) was $5M in Table 4 and Table 8, compared to $8M in Table 11, but total capital within the overhaul year remained unchanged, so this can be attributed to categorization of costs rather than a change of costs. Mill Creek 2 ongoing O&M averaged $18M per year in Table 4 and Table 8, compared to $12M per year in Table 11, with the decrease attributable to the aforementioned update to common station cost allocations. Mill Creek 2 overhaul O&M (standard) was $5M in Table 4 compared with $3M in Table 11.

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Question No. 13

Responding Witness: Lonnie E. Bellar

Q-13. Refer to Bellar August 23, 2023 Hearing Testimony regarding the Winter Storm Elliott root cause exercise conducted by LG&E/KU. Provide the documents that summarize the root cause exercise analysis and conclusions.

A-13. Attached are the 'After Action Review Recommendations' for Generation and Transmission following Winter Storm Elliott. Note that the Transmission document excludes Transmission Function Information.

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Question No. 14

Responding Witness: Charles R. Schram

Q-14. Provide a copy of the reserve sharing agreement between LG&E/KU and the Tennessee Valley Authority (TVA) that was in effect during Winter Storm Elliot and any amendments to that agreement since that time, including any agreement executed in June 2023. Explain any material changes to the agreement since Winter Storm Elliot.

A-14. See attachment being provided in a separate file. During 2022, including Winter Storm Elliott in December 2022, the Companies' contingency reserve requirement was 243 MW. The reserve calculation is updated annually; the Companies' current 2023 contingency reserve requirement is 238 MW. No changes have been made to the reserve sharing agreement since Winter Storm Elliott. The Companies did not execute a reserve sharing agreement or amendment in June 2023. The Companies did execute a Joint Reliability Coordination Agreement with TVA and PJM in June 2023, a copy of which the Companies provided in response to AG-KIUC 3-21.

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Question No. 15

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

Q-15. Refer to LG&E/KU's response to Commission Staff's Second Request for Information (Staff's Second Request), Item 53(b), which states that transmission upgrades would cost between $39 million and $52 million in the scenario in which Mill Creek Units 1 and 2, and Brown Unit 3 were retired; Ghent Unit 2 remained open with SCR; and only one NGCC was constructed, located at Mill Creek Station. Also refer to LG&E/KU's response to Joint Intervenors' Second Request for Information (Joint Intervenors' Second Request), Item 60(a), Exhibit SAW-1 (May 2023 Update), Table 35: Transmission System Upgrade Costs, which states that transmission upgrades would cost about $35 million in the same scenario. Reconcile the difference in the two responses and state the estimated transmission upgrade costs for that scenario.

A-15. The costs listed in Table 35 from Exhibit SAW-1 are listed in 2022 dollars and reflect scenarios where Brown Unit 3 and Mill Creek Units 1 and 2 are retired and replaced with either an NGCC at Mill Creek (resulting in a cost of $35,035,000 in 2022 dollars) or SCCTs at Mill Creek (resulting in a cost of $46,034,824 in 2022 dollars). As stated in the response to PSC 2-53(b), the capital costs for projects identified in the document responding to PSC 2-53(a) were escalated to 2028 dollars. When escalated at a two percent annual rate from 2022 to 2028, the costs of $35,035,000 and $46,034,824 from Table 35 become $39,455,100 and $51,842,689, respectively. Given that the replacement technology is NGCC, the appropriate cost in that scenario would be $39,455,100 in 2028 dollars.

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Question No. 16

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

Q-16. Refer to LG&E/KU's November 18, 2022 transmission impact analysis titled Generation Replacement & Retirement Scenarios–Expected Impacts filed as part of Exhibit SAW-2.

a. State whether the scenarios analyzed in that analysis included any retirements or additions other than those specifically mentioned in the Executive Summary, including specifically whether the scenarios included the retirement of Paddy's Run Unit 12 or Haefling Units 1-2, or the addition of the utility owned solar, the Purchase Power Agreements (PPAs), or the Brown battery energy storage system (Brown BESS) proposed in this case. If a scenario included any retirement or addition other than those specifically mentioned, identify and describe the retirement or addition included.

b. State whether the retirement of Paddy's Run Unit 12 and Haefling Units 1-2 would have an effect the cost of necessary transmission upgrades in any scenario discussed, and if so, identify and describe those effects.

c. State whether the addition of the utility owned solar, PPAs, or Brown BESS would eliminate the need for any transmission upgrades identified in Scenarios 1, 2, 3 or 4, and if so, identify the resource additions that would eliminate the need for the transmission upgrades, in whole or in part, and identify and describe the effects of the relevant additions on the need for transmission upgrades.

d. Describe and provide the cost of any transmission upgrades that would be necessary to operate Mill Creek Unit 2 and Mill Creek Unit 5 at the same time.

e. Describe and provide the cost of any transmission upgrades that would be necessary to operate Brown Unit 3 and Brown Unit 12 at the same time.

A-16.

a. The scenarios mentioned in the Executive Summary of the Generation Replacement & Retirement Scenarios–Expected Impacts report did include the retirements of Paddy's Run Unit 12 and Haefling Units 1-2. The retirement of these three generators is not expected to have any impact on the transmission system.

   With regard to the evaluation of the utility owned solar, the PPAs, or Brown BESS, please see the Companies' response to PSC 2-54.

b. The retirement of these three generators is not expected to have any impact on the transmission system.

c. The addition of the utility owned solar, PPAs, or Brown BESS would not be expected to eliminate any of the transmission upgrades identified in the Executive Summary of the Generation Replacement & Retirement Scenarios–Expected Impacts report.

d. Transmission has studied this scenario, assuming that the remaining generation portfolio is as proposed in the CPCN filing, and it is not expected that any additional transmission upgrades not already identified would be necessary to operate Mill Creek Unit 2 and Mill Creek Unit 5 at the same time.

e. Transmission has studied this scenario, assuming that the remaining generation portfolio is as proposed in the CPCN filing, and it is not expected that any additional transmission upgrades not already identified would be necessary to operate Brown Unit 3 and Brown Unit 12 at the same time, assuming Brown Unit 12 is connected to the 345kV at Brown.

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Question No. 17

Responding Witness: Stuart A. Wilson

Q-17. Refer to the August 24, 2023 hearing testimony of Stuart A. Wilson (Wilson August 24, 2023 Hearing Testimony). Also refer to LG&E/KU's response to Joint Intervenors' Second Request, Item 60(a), Exhibit SAW-1 (May 2023 Update), page E-2 referring to LG&E's use of gas price forecasts based on the U.S. Energy Information Administration's (EIA) forecasts in its 2022 Annual Energy Outlook ("AEO2022").

a. Provide the projection tables in Excel spreadsheet format for Coal Supply, Disposition, and Price and Coal Production and Minemouth Prices by Region for EIA's AEO2022 Reference Case, Low Oil and Gas Supply Case, and High Oil and Gas Supply Case.

b. Provide the projection tables in Excel spreadsheet format for Natural Gas Supply, Disposition, and Price for EIA's AEO2022 Reference Case, Low Oil and Gas Supply Case, and High Oil and Gas Supply Case.

A-17. Note that in each of the Low, Mid, and High natural gas price scenarios shown in Table 38 of SAW-1, the coal-to-gas ratio methodology always results in coal prices being lower than natural gas prices (on a $/mmBtu basis) throughout the study period. While this is a reasonable assumption on average over a long study period, this is not always the case. With the coal-to-gas ratio methodology, the only way for NGCC technology to reduce fuel costs related to a coal unit is via its lower heat rate (Btu/kWh). The table below demonstrates (using 2030 prices) that in only two of the six fuel price scenarios (both are "atypical") does the lower heat rate of Mill Creek Unit 5 and Brown Unit 12 – compared to the average heat rate of Mill Creek Units 1&2, Brown Unit 3, and Ghent Unit 2 – overcome the inherent price advantage assumed for coal. In all three of the expected CTG ratio (0.57) cases the proposed NGCC units are forecasted to have a higher fuel-only cost on a $/MWh basis. For the supporting workpaper, see the attachment being provided in a separate file.

2030 Prices	Low	Mid	High
Natural gas ($/mmBtu)	3.65	4.78	6.34
Coal price – Expected CTG ($/mmBtu)	2.08	2.72	3.61
Electricity Prices –Expected CTG ($/MWh)			
Natural gas @ 6,160 Btu/kWh	22.48	29.44	39.05
Coal @ 10,610 Btu/kWh	22.07	28.86	38.30
Natural gas over/(under) coal ($/MWh)	**0.42**	**0.59**	**0.75**
Coal price – Atypical CTG ($/mmBtu)			
Low Gas/High CTG Ratio	2.19		
High Gas/Low CTG Ratio			3.32
High Gas/Current CTG Ratio			5.30
Coal Electricity Prices – Atypical CTG ($/MWh)			
Low Gas/High CTG Ratio	23.24		
High Gas/Low CTG Ratio			35.23
High Gas/Current CTG Ratio			56.23
Natural gas over/(under) coal ($/MWh)			
Low Gas/High CTG Ratio	**(0.75)**		
High Gas/Low CTG Ratio			**3.83**
High Gas/Current CTG Ratio			**(17.18)**

a. See attachment being provided in a separate file. Note that EIA only provides minemouth coal prices collectively for all coals and delivered prices by major industrial sector. EIA does not provide prices at the production basin level (such as the Illinois Basin high-sulfur and Powder River Basin coals used by the Companies).

b. See attachment being provided in a separate file.

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Question No. 18

Responding Witness: Stuart A. Wilson

Q-18. Refer to the Wilson August 24, 2023 Hearing Testimony. Provide an Excel spreadsheet showing coal and gas price projections made for each scenario in LG&E/KU's 2021 Integrated Resource Plan and showing the calculation of the coal to gas price ratio from the projections in each scenario.

A-18. See attachment being provided in a separate file. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection. The implied average coal-to-gas ("CTG") price ratios are shown in the following table.

Fuel Price Scenario	CTG Price Ratio 2022-2036
Low	0.75
Base	0.58
High	0.49

The 2021 IRP's Base average CTG price ratio of 0.58 closely matches the 0.57 Mid CTG price ratio the Companies used in this proceeding. Beginning in 2027 when Mill Creek 5 is proposed to be commissioned, the 2021 IRP's Base average CTG price ratio is 0.57. The 2021 IRP's range of CTG price ratios of 0.49 to 0.75 are also comparable to the range of CTG price ratios the Companies used in this proceeding (0.52 to 0.84).

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Question No. 19

Responding Witness: Stuart A. Wilson

Q-19. Refer to the Wilson August 24, 2023 Hearing Testimony. Refer to the May 10, 2023 Direct Testimony of Stuart A. Wilson (Wilson May 10, 2023 Direct Testimony), Exhibit SB4-1, Table 5: 2028 Reliability Analysis (Table 5). Provide a version of Table 5 in which the summer loss of load expectations (LOLEs) for each portfolio reflect the months of March to November instead of June to August.

A-19. See the table below. For the supporting workpapers, see the attachment being provided in a separate file.[41]

[41] Note that the SERVM database .BAK file used for this response is the same as the one provided in the workpapers attached to Question No. 20 and is not being provided again here due to its very large file size.

	Portfolio	LOLE (days/10 years)		
		Summer (Mar-Nov)	**Winter (Jan-Feb, Dec)**	**Full Year**
0	No Retirements; Add DSM	0.24	0.21	**0.45**
Fossil retirements and dispatchable electric generating replacements:				
1	Ret MC1-2; Add DSM/MC5	0.24	0.17	**0.41**
2	Ret MC1-2/BR3; Add DSM/MC5/BR12	0.08	0.05	**0.13**
3	Ret MC1-2/BR3/PR12/HF1-2; Add DSM/MC5/BR12	0.07	0.08	**0.15**
4	Ret MC1-2/BR3/PR12/HF1-2; GH2 (Non-Ozone); Add DSM/MC5/BR12	0.86	0.06	**0.92**
5	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12	0.79	0.43	**1.22**
6	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar	0.35	0.42	**0.77**
Add dispatchable non-generating resources:				
7	Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar/ Brown BESS	0.20	0.25	**0.45**
Add non-dispatchable electric generating resources:				
8	**Final CPCN Portfolio:** Ret MC1-2/BR3/PR12/HF1-2/GH2; Add DSM/MC5/BR12/Owned Solar/ Brown BESS/Solar PPAs	0.03	0.25	**0.28**

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Question No. 20

Responding Witness: Philip A. Imber / Stuart A. Wilson

Q-20. Refer to the Wilson August 24, 2023 Hearing Testimony. Refer to the Wilson May 10, 2023 Direct Testimony, Exhibit SB4-1, Table 5. Using the same assumptions as used in Table 5, calculate the summer (March-November), winter (January-February, December), and total LOLE, LOLH and EUE, and the NPVRR (on and absolute and relative basis, compared to the proposed portfolio and retirements) for each of the following portfolios (do not include the "Add DSM," as that term is used in Table 5, in any portfolio):

a. No Retirements as that term is used in Table 5 (i.e. Portfolio 0 without the Add DSM).
b. Retire Mill Creek Unit 1, Haefling Unit 1 and Unit 2, and Paddy's Run Unit 12; Add Mill Creek Unit 5.
c. Retire Mill Creek Unit 1, Haefling Unit 1 and Unit 2, and Paddy's Run Unit 12; Add Brown Unit 12.
d. Retire Mill Creek Unit 1 and Unit 2, Haefling Unit 1 and Unit 2, and Paddy's Run Unit 12; Add Mill Creek Unit 5.
e. Retire Mill Creek Unit 1 and Unit 2, Haefling Unit 1 and Unit 2, and Paddy's Run Unit 12; Add Mill Creek Unit 5, and Owned Solar.
f. Retire Mill Creek Unit 1 and Unit 2, Haefling Unit 1 and Unit 2, and Paddy's Run Unit 12; Add Mill Creek Unit 5, Owned Solar, and Solar PPAs.
g. Retire Mill Creek Unit 1 and Unit 2, Haefling Unit 1 and Unit 2, and Paddy's Run Unit 12; Add Mill Creek Unit 5, Owned Solar, Brown BESS, and Solar PPAs.
h. Retire Mill Creek Unit 1, Brown Unit 3, Haefling Unit 1 and Unit 2, and Paddy's Run Unit 12; Add Brown Unit 12.
i. Retire Mill Creek Unit 1, Brown Unit 3, Haefling Unit 1 and Unit 2, and Paddy's Run Unit 12; Add Brown Unit 12, and Owned Solar.
j. Retire Mill Creek Unit 1, Brown Unit 3, Haefling Unit 1 and Unit 2, and Paddy's Run Unit 12; Add Brown Unit 12, Owned Solar, and Solar PPAs.
k. Retire Mill Creek Unit 1, Brown Unit 3, Haefling Unit 1 and Unit 2, and Paddy's Run Unit 12; Add Brown Unit 12, Owned Solar, Brown BESS, and Solar PPAs.

l. Retire Mill Creek Unit 1 and Unit 2, Brown Unit 3, Haefling Unit 1 and Unit 2, and Paddy's Run Unit 12; Add Mill Creek 5.
m. Retire Mill Creek Unit 1 and Unit 2, Brown Unit 3, Haefling Unit 1 and Unit 2, and Paddy's Run Unit 12; Add Mill Creek 5, and Owned Solar.
n. Retire Mill Creek Unit 1 and Unit 2, Brown Unit 3, Haefling Unit 1 and Unit 2, and Paddy's Run Unit 12; Add Mill Creek 5, Owned Solar, and Solar PPAs.
o. Retire Mill Creek Unit 1 and Unit 2, Brown Unit 3, Haefling Unit 1 and Unit 2, and Paddy's Run Unit 12; Add Mill Creek 5, Owned Solar, Brown BESS, and Solar PPAs.
p. Retire Mill Creek Unit 1, Brown Unit 3, Haefling Unit 1 and Unit 2, and Paddy's Run Unit 12; Add Brown Unit 12; Operate Mill Creek Unit 2 and Ghent Unit 2 in Non-Ozone only.
q. Retire Mill Creek Unit 1, Brown Unit 3, Haefling Unit 1 and Unit 2, and Paddy's Run Unit 12; Add Brown Unit 12, and Owned Solar; Operate Mill Creek Unit 2 and Ghent Unit 2 in Non-Ozone only.
r. Retire Mill Creek Unit 1, Brown Unit 3, Haefling Unit 1 and Unit 2, and Paddy's Run Unit 12; Add Brown Unit 12, Owned Solar, and Solar PPAs; Operate Mill Creek Unit 2 and Ghent Unit 2 in Non-Ozone only.
s. Retire Mill Creek Unit 1, Brown Unit 3, Haefling Unit 1 and Unit 2, and Paddy's Run Unit 12; Add Brown Unit 12, Owned Solar, Brown BESS, and Solar PPAs; Operate Mill Creek Unit 2 and Ghent Unit 2 in Non-Ozone only.
t. Retire Mill Creek Unit 1 and Unit 2, Brown Unit 3, Haefling Unit 1 and Unit 2, and Paddy's Run Unit 12; Add Mill Creek Unit 5, Owned Solar, Brown BESS, and Solar PPAs; Operate Ghent Unit 2 in Non-Ozone only.
u. Retire Mill Creek Unit 1 and Unit 2, Brown Unit 3, Haefling Unit 1 and Unit 2, and Paddy's Run Unit 12; Add Brown Unit 12, Owned Solar, Brown BESS, and Solar PPAs; Operate Ghent Unit 2 in Non-Ozone only.

A-20. See attachments being provided in separate files. Attachment 1 presents comparisons to the proposed portfolio assuming no costs – ever – for CO_2 emissions. As discussed throughout these proceedings, the Brown BESS is included in the proposed portfolio to gain operating experience with battery storage at utility-scale and is not least-cost as modeled. As a result, the attached compares requested alternatives with Brown BESS to the recommended portfolio and compares requested alternatives without Brown BESS to the recommended portfolio without Brown BESS. These results are shown with the estimated capital costs in this proceeding and the initial bid data provided in response to JI PH 1-1. Attachment 2 contains the workpapers associated with the modeling for this question. Certain information in Attachments 1 and 2 is confidential and proprietary and is being provided under seal pursuant to a petition for confidential information.

Observations related to the PVRR results are included in the attachments. Observations related to reliability and permitting are noted below:

- Reliability:
  - The Companies' proposed portfolio has a lower LOLE than all but 5 of the alternative portfolios (portfolios b, c, f, g, and k), and each of those 5 alternative portfolios has a significantly higher PVRR.
  - Portfolios p and q have an LOLE that exceeds 3.57 and should not be considered viable alternatives.
  - Portfolios r through u have a total LOLE less than 3.57, but their summer reliability is significantly worse than the Companies' proposed portfolio or any of the portfolios evaluated in the Companies' SB4 analysis. The reliability of these portfolios would be unacceptable if the proposed solar PPAs (including the Rhudes Creek and Ragland PPAs) are not completed as assumed.
- Permitting:
  - Portfolio b, which proposes constructing an NGCC at Mill Creek while leaving Mill Creek 2 in service, is infeasible on the current project timelines for the environmental permitting issues identified in KIUC PH 1-3.
  - Portfolio c, which proposes constructing an NGCC at Brown while leaving Brown 3 in service, is infeasible on the current project timelines for the environmental permitting issues identified in KIUC PH 1-2.

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Question No. 21

Responding Witness: Stuart A. Wilson

Q-21. Refer to the May 10, 2023 Direct Testimony of Stuart A. Wilson (Wilson May 10, 2023 Direct Testimony), Exhibit SB4-1, Table 8: Incremental PVRR ($M) (Table 8).

a. Provide a table with the actual PVRRs used to calculate the incremental PVRRs reflected in Table 8 for each portfolio and scenario listed therein.

b. Using all of the same assumptions used to calculate the PVRRs in Table 8, unless a cost would be included twice (e.g. duplicate costs included in Mill Creek Unit 2 and Mill Creek Unit 5), provide PVRRs in each scenario listed in Table 8 for each of the following portfolios (do not include the "Add DSM," as that term is used in Table 8, in any portfolio):

(1) No Retirements, as that term is used in Table 8; Add Owned Solar.

(2) No Retirements, as that term is used in Table 8; Add Solar PPAs.

(3) Each of the portfolios listed in Item 20 of these Post-Hearing Requests for Information.

A-21. See attached being provided in a separate file. Certain information is confidential and proprietary and is being provided under seal pursuant to a petition for confidential information. Results are shown with the estimated capital costs in this proceeding and the initial bid data provided in response to JI PH 1-1. The estimated bid data reflects the September 8, 2023 Second Supplemental Errata Filing. Workpapers for these modeling runs are available as part of Attachment 2 to Question No. 20.

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Question No. 22

Responding Witness: Stuart A. Wilson

Q-22. Refer to the Wilson August 24, 2023 Hearing Testimony. Refer to LG&E/KU's response to Commission Staff's Fifth Request for Information (Staff's Fifth Request), Item 2, Table 2: PVRR Delta from Best, 50% NGCC CF Limit.

a. Provide the LOLEs for Portfolios 1 through 7 in Table 2 with Brown Unit 12 and Mill Creek Unit 5 limited to a 50% capacity factor.

b. Provide a version of Table 2 in which the only change is that Brown Unit 12 and Mill Creek 5 have a 20 year useful life.

A-22.

a. See the table below.

		LOLE (days/10 years) w/ 50% capacity factor		
	Portfolio Name	**Summer (Mar-Nov)**	**Winter (Jan-Feb, Dec)**	**Full Year**
1	MC5 & BR12	0.13	0.48	0.61
2	MC5/GH2 SCR	0.29	0.88	1.17
3	MC5; Non-Ozone GH2	0.46	0.21	0.67
4	MC5; Non-Ozone GH2; ret BR3	2.53	0.87	3.40
5	MC2/GH2 SCR	0.20	0.73	0.93
6	Non-Ozone MC2/GH2	6.86	0.74	7.60
7	Non-Ozone MC2/GH2; Ret BR3	6.19	0.92	7.11

The 50% capacity factor limit for Mill Creek 5 for Portfolios 1 through 4 is achieved by using a fuel cost multiplier to affect the generation unit's dispatch order. For comparison, the Companies also calculated LOLE for Portfolios 1 through 4 without the 50% capacity factor limit in the table below. Immaterial differences between the tables are due to random drawing of unit availability scenarios in SERVM and demonstrate that the capacity factor limit has no material impact on LOLE or reliability. For the supporting workpapers for parts (a) and (b), see the attachment being provided in a separate file.[42] Certain information is confidential and proprietary and is being provided under seal pursuant to a petition for confidential information.

	Portfolio Name	**LOLE (days/10 years) w/o 50% capacity factor**		
		Summer (Mar-Nov)	**Winter (Jan-Feb, Dec)**	**Full Year**
1	MC5 & BR12	0.17	0.53	0.70
2	MC5/GH2 SCR	0.27	0.84	1.11
3	MC5; Non-Ozone GH2	0.41	0.21	0.62
4	MC5; Non-Ozone GH2; ret BR3	2.70	0.83	3.53

b. Regarding the premise of this request:

The Companies are unaware of any physical constraint or regulation (existing or proposed) that would limit the useful life of the proposed NGCCs to 20 years. The Companies' analysis in PSC 5-2 shows that proposed NGCC units are always favorable except in a nonsensical scenario where future regulations add costs for CO_2 emissions to NGCC units but not to coal units. As demonstrated in the response to PSC 5-2, with a 50% NGCC capacity factor limit, the proposed portfolio is favorable in all \$15/ton and \$25/ton net CO_2 price cases but only one of the six \$0/ton net CO_2 price cases. The \$0/ton net CO_2 price scenario assumes a 50% capacity factor limit for NGCC but no net CO_2 costs – ever – for coal units. Specifically, this scenario assumes (1) 90% CCS can be added to coal units by 2030, (2) 45Q tax credits fully offset the cost of CCS and the cost of additional generating capacity needed to account for CCS auxiliary load requirements,[43] and (3) 45Q tax credits are extended indefinitely. The \$0/ton net CO_2 price scenario was modeled to demonstrate that the proposed portfolio is truly a "no regrets" portfolio (i.e., the unfavorability of the proposed portfolio even in this nonsensical scenario is less than the favorability of the proposed portfolio in the non-zero CO_2 price scenarios). The present request contemplates a more extreme scenario for stress-testing the proposed portfolio where NGCC units are further penalized by limiting their operating life to 20 years.

[42] Note that the SERVM database .BAK file used for this response is the same as the one provided in the workpapers attached to Question No. 20 and is not being provided again here due to its very large file size.
[43] The estimated auxiliary load requirement for coal CCS is approximately 30% of the unit's net capacity.

Regarding this request:

The Companies' analysis in PSC 5-2 focused on nine portfolios. The 20-year useful life assumption impacts portfolios 1 through 4; with a 20-year useful life, Mill Creek 5 and Brown 12 would be fully depreciated over 20 years and replaced at the end of 2046 and 2047, respectively. In portfolios 3 through 7 where Mill Creek 2, Ghent 2, and Brown 3 are not retired, these coal units would also be fully depreciated at the end of 2047, over 70 years old, and likely in need of replacement. Similarly, because Portfolio 8 ("All Renewables") and Portfolio 9 ("SCCT + Renewables") comprise shorter-lived resources (i.e., 20- and 25-year solar, wind, and battery storage PPAs as well as SCCTs with a 30-year lives), the full cost of most of these resources will be recovered through the end of 2047. In sum, with a 20-year useful life for NGCC units, the vast majority of investments for each portfolio are recovered through 2047. For this reason, to avoid speculation about replacement resources after 2047,[44] and to change only the NGCC useful life assumption, this response focuses only on revenue requirements for each portfolio through 2047.

The results of this analysis are summarized in the table below. An assumed 20-year useful life increases capital revenue requirements for the proposed NGCCs through 2047. With this penalty and the 50% capacity factor limit, the proposed NGCC units are higher cost in a scenario where there are no net CO_2 costs – ever – for coal units.[45] However, in the non-zero net CO_2 price scenarios, even with the additional penalty, the proposed portfolio is least-cost.

Workpapers for this request are provided in a separate attachment. Certain information is confidential and proprietary and is being provided under seal pursuant to a petition for confidential information.

[44] Because the 20-year useful life assumption better aligns the timing of the need for new resources in all portfolios, replacement resources for each portfolio would likely be very similar as they would depend on circumstances at that time.
[45] Again, the Companies stress that this is a nonsensical scenario. If 90% CCS is available for coal by 2030 at no net cost, there is no reason to believe it would not be available in 2035 for NGCC units.

		Difference from Best Case (PVRR, $M, 2023-2047, 2022 Dollars)								
		1	2	3	4	5	6	7	8	9
Fuel Price Scenario (Gas, CTG Price Ratio)	CO_2 Price	MC5 and BR12; 637 Solar	MC5 & GH2 SCR; 637 Solar	MC5; Non-Ozone GH2	MC5; Non-Ozone GH2; Ret BR3	MC2/ GH2 SCR	Non-Ozone MC2/ GH2	Non-Ozone MC2/ GH2 Ret BR3	All Renew	SCCT+ Renew
Low Gas, Mid CTG	0	189	18	259	0	118	74	478	1,598	629
Mid Gas, Mid CTG	0	193	0	239	8	93	82	354	1,407	620
High Gas, Mid CTG	0	210	0	202	47	36	88	98	1,074	605
Low Gas, High CTG	0	159	19	263	0	158	111	491	1,591	635
High Gas, Low CTG	0	371	75	259	140	0	77	109	1,081	677
High Gas, Curr CTG	0	0	328	597	293	1,061	967	601	1,307	905
Low Gas, Mid CTG	15	0	140	492	66	674	548	660	1,511	668
Mid Gas, Mid CTG	15	0	127	397	67	583	474	532	1,411	678
High Gas, Mid CTG	15	0	113	354	116	523	501	322	1,140	662
Low Gas, High CTG	15	0	166	528	75	759	604	685	1,493	678
High Gas, Low CTG	15	0	20	251	36	327	326	198	1,060	581
High Gas, Curr CTG	15	0	650	1,000	527	1,777	1,587	932	1,373	1,069
Low Gas, Mid CTG	25	0	347	734	180	1,130	880	835	1,408	628
Mid Gas, Mid CTG	25	0	353	702	204	1,113	902	720	1,372	750
High Gas, Mid CTG	25	0	313	585	264	973	886	528	1,222	799
Low Gas, High CTG	25	0	377	775	204	1,200	949	875	1,429	662
High Gas, Low CTG	25	0	231	492	204	785	724	429	1,181	736
High Gas, Curr CTG	25	0	839	1,231	617	2,228	1,912	1,100	1,323	1,082

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Question No. 23

Responding Witness: Stuart A. Wilson

Q-23. Refer to the Wilson August 24, 2023 Hearing Testimony regarding the expected capacity factor for Mill Creek Unit 5 and Brown Unit 12 without the 50 percent capacity factor limit. Refer to LG&E/KU's response to Staff's Fifth Request, Item 2, Table 1: PVRR Delta from Best, No NGCC CF Limit, Table 2: PVRR Delta from Best, 50% NGCC CF Limit.

a. Provide the capacity factor for Mill Creek Unit 5 and Brown Unit 12 that arose from each fuel price scenario modeled in Table 1 of LG&E/KU's response to Staff's Fifth Request, Item 2 assuming no 50 percent capacity factor limit.

b. Provide the capacity factor limit at which Portfolio 1 in Table 2 of LG&E/KU's response to Staff's Fifth Request, Item 2 is no longer economic in each fuel price scenario.

A-23.

a. See attachment being provided in a separate file. The annual capacity factors range between 64 and 84 percent in fuel price scenarios with zero CO_2 price and increase to between 80 and 84 percent in fuel price scenarios with a \$15/ton or \$25/ton CO_2 price.

b. Break-even capacity factor limits are not direct outputs of the model, so to provide a range of the capacity factors at which Portfolio 1 is no longer economic, the Companies evaluated Table 2 using 20 percent, 30 percent, and 40 percent capacity factor limits for the new NGCCs. The points at which Portfolio 1 is no longer economic varies by fuel and CO_2 price scenario and are shown in the table below. The Companies reiterate that it would be unlikely for a carbon-constrained world to favor coal-fired generation over gas-fired generation. Therefore, the most pertinent comparison is to Portfolio 8 (All renewables) and Portfolio 9 (SCCT + Renewables), which exclude coal and NGCC generation. Limiting the comparison solely to these portfolios yields a break-even capacity factor between 20 percent and 30 percent for most fuel and CO_2 price scenarios. Workpapers associated with these modeling runs are being provided in a separate attachment. The information in the attachment is confidential and proprietary and is being provided under seal pursuant to a petition for confidential information.

NGCC Break-even Capacity Factors

CO_2 Price Scenario	**Fuel Price Scenario**	**Break-even Capacity Factor vs. All Portfolios**	**Break-even Capacity Factor vs. Portfolio 8 (All Renewables) or Portfolio 9 (SCCT + Renewables)**
$0/ton	Low Gas, Mid CTG	Greater Than 50%	Less Than 20%
	Mid Gas, Mid CTG	Greater Than 50%	Less Than 20%
	High Gas, Mid CTG	Greater Than 50%	Between 20% and 30%
	Low Gas, High CTG	Greater Than 50%	Less Than 20%
	High Gas, Low CTG	N/A	Between 20% and 30%
	High Gas, Current CTG	Between 20% and 30%	Between 20% and 30%
$15/ton	Low Gas, Mid CTG	Between 30% and 40%	Less Than 20%
	Mid Gas, Mid CTG	Between 30% and 40%	Between 20% and 30%
	High Gas, Mid CTG	Between 30% and 40%	Between 20% and 30%
	Low Gas, High CTG	Between 30% and 40%	Less Than 20%
	High Gas, Low CTG	Between 40% and 50%	Between 20% and 30%
	High Gas, Current CTG	Between 20% and 30%	Between 20% and 30%
$25/ton	Low Gas, Mid CTG	Between 20% and 30%	Between 20% and 30%
	Mid Gas, Mid CTG	Between 20% and 30%	Between 20% and 30%
	High Gas, Mid CTG	Between 30% and 40%	Between 20% and 30%
	Low Gas, High CTG	Between 20% and 30%	Between 20% and 30%
	High Gas, Low CTG	Between 30% and 40%	Between 20% and 30%
	High Gas, Current CTG	Between 20% and 30%	Between 20% and 30%

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Question No. 24

Responding Witness: Stuart A. Wilson

Q-24. Refer to the Wilson August 24, 2023 Hearing Testimony. Refer to LG&E/KU's response to Commission Staff's Sixth Request for Information (Staff's Sixth Request), Item 2.

a. Explain in more detail how NGCC units with carbon capture and sequestration (CCS) were treated in the original response to this request, including specifically how carbon costs were assigned to the units.

b. Re-run the capacity expansion model conducted in response to Staff's Sixth Request, Item 2 using a 20 year useful life for new NGCC units without CCS but otherwise using the same assumptions. Using the optimal portfolio from the capacity expansion, provide the Selected Portfolio, Incremental PVRR, LOLE, Reserve Margin, Net Summer/Winter Capacity, and Dispatchable Summer/Winter Range.

c. Re-run the capacity expansion model conducted in response to Staff's Sixth Request, Item 2 using a 20 year useful life for all new gas units without CCS but otherwise using the same assumptions. Using the optimal portfolio from the capacity expansion, provide the Selected Portfolio, Incremental PVRR, LOLE, Reserve Margin, Net Summer/Winter Capacity, and Dispatchable Summer/Winter Range.

A-24.

a. NGCC units with CCS were modeled with the same characteristics as the proposed Mill Creek 5 NGCC unit, but with no capacity factor limitation and with the addition of CCS in 2035. For example, if a "NGCC with CCS" unit was constructed in 2030, it would be constructed initially without CCS, undergo a CCS retrofit in 2035, and never have a capacity factor limitation.

The CCS cost is reflected by three levels of CO_2 emissions prices net of 45Q tax credits starting in 2035: $0 per short ton ("ST"), $15 per ST, and $25 per ST. The 45Q tax credits of $85 per metric ton ("MT") are assumed to expire after twelve years in all three cases at the end of 2046. This is modeled by increasing the CO_2 costs by $85 per metric ton for all three cases.

b. For this scenario, the Companies developed 18 portfolios covering all combinations of the three CO_2 price scenarios ($0, $15, and $25 per ST) and the six fuel price scenarios the Companies have used throughout this proceeding. All of the portfolios include the retirement of Mill Creek 2, Ghent 2, and Brown 3 by 2029 and in all but one portfolio, the addition of at least two and up to seven NGCC units (with and without future CO_2 reduction) by 2030.[46] In these results, at least one NGCC unit with future CO_2 reduction was selected in all portfolios, which is considerably more than the one portfolio including NGCC with future CO_2 reduction provided in the response to PSC 6-2(b). Consistent with the results provided in response to PSC 6-2(b), these results continue to support the Companies' no-regrets proposal to retire Brown 3, Mill Creek 2, and Ghent 2 and to construct the proposed Mill Creek and Brown NGCC units.

Given these conclusions, the Companies' proposed portfolio in this case is unchanged. Therefore, the 2028 LOLE, Reserve Margin, Net Summer/Winter Capacity, and Dispatchable Summer/Winter Range are unchanged from the metrics presented in Exhibit SB4-1. The Companies' SB4 analysis compared the PVRR for the proposed portfolio to a portfolio with no retirements and assumed in both cases no portfolio changes beyond 2028. With a non-zero compliance cost per ton of CO_2, the proposed EPA carbon regulations (or any variants of the rule) would only exacerbate the incremental PVRR presented in Exhibit SB4-1 (versus a case with no coal retirements). As discussed in the responses to PSC 5-2 and PSC 6-2(b), the Companies do not have cost estimates for the proposed CO_2 reduction activities (e.g., CCS or gas co-firing for coal units) and cannot estimate the incremental PVRR more specifically.

See attachments being provided in separate files. Attachment 1 summarizes the resulting portfolios from part (b). Attachment 2 contains the workpapers associated with the modeling for parts (b) and (c). Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

c. For this scenario, the Companies again developed 18 portfolios using the same fuel price and CO_2 price assumptions discussed in part (b). All of the portfolios include the retirement of Mill Creek 2, Ghent 2, and Brown 3 by 2029 and the addition of at least two and up to seven NGCC units (with and without future CO_2 reduction) by 2030. In these results, at least two NGCC units with future CO_2 reduction were selected in all portfolios. As with the

[46] The scenario with high gas prices/low coal-to-gas price ratio and $0/ST CO_2 resulted in a portfolio with one NGCC with CO_2 reduction and two SCCTs.

results in part (b), these results continue to support the Companies' no-regrets proposal to retire Brown 3, Mill Creek 2, and Ghent 2 and to construct the proposed Mill Creek and Brown NGCC units. See attachment being provided in a separate file, which summarizes the resulting portfolios from part (c).

Regarding the requested metrics for the optimal portfolio, see the response to part (b).

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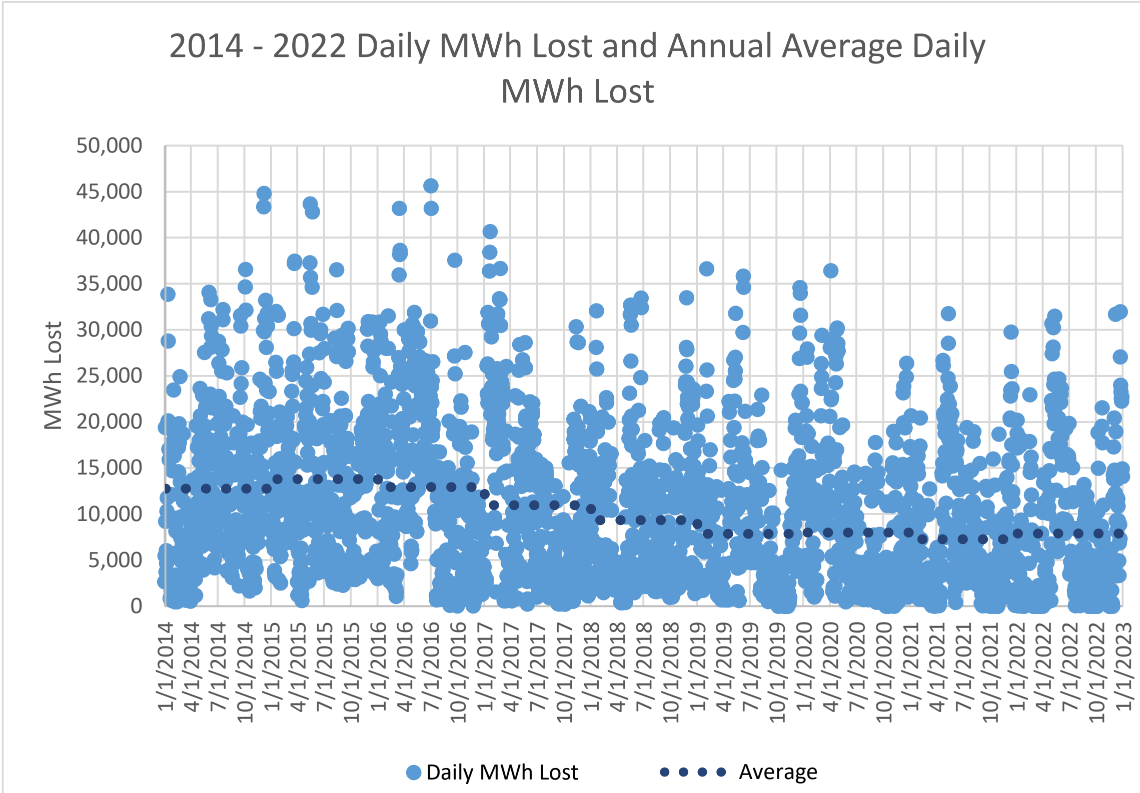
Question No. 25

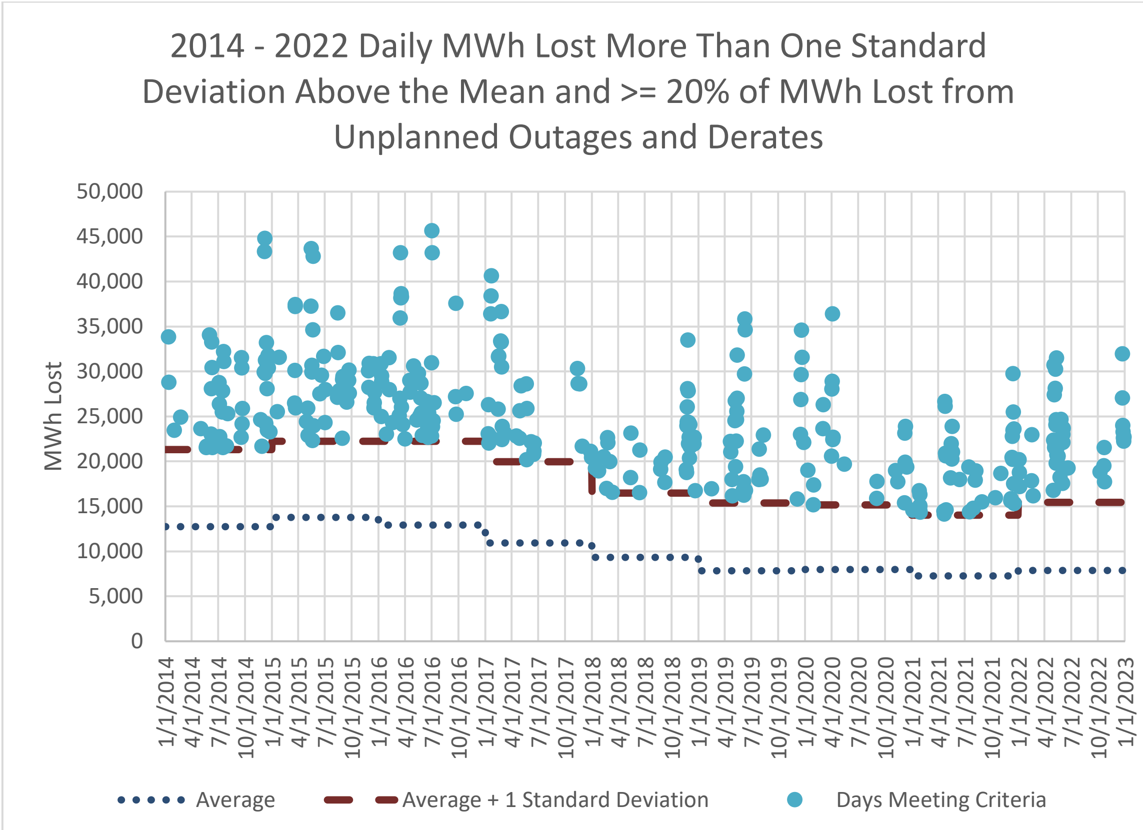
Responding Witness: David S. Sinclair / Stuart A. Wilson

Q-25. Refer to the Wilson August 24, 2023 Hearing Testimony. Also refer to the Rebuttal Testimony of David Sinclair (Sinclair Rebuttal Testimony) at Page 80. Provide a version of the table on Page 80 of the Sinclair Rebuttal Testimony showing dates in which MW/h Lost is one standard deviation above the average and at least 20 percent of the MW/h Lost is attributable to forced outages.

A-25. The first chart below shows the MWh lost for each day in 2014-2022. When a unit is unavailable, MWh lost is computed as the product of its net capacity and the number of hours it is unavailable. Therefore, MWh lost is the maximum amount of MWh the unit could have produced during its outage and not necessarily the amount of MWh the unit would have produced had it been available. For the supporting workpapers, see the attachment being provided in a separate file.



The next chart below shows dates in 2014-2022 that have (1) MWh lost greater than one standard deviation above the mean; and (2) at least 20% of MWh lost from unplanned outage and derates (forced, not maintenance outages).



In 2014-2022, 351 (number of light blue dots in the chart) out of 3,287 days meet the two criteria. Those 351 days can be considered as having relatively high outages.

To determine if these outages are related to weather, the Companies calculated correlation coefficients between (1) ratios of daily MWh lost for unplanned outages to daily energy requirements and (2) average daily temperature for those 351 days by season. The Companies used the ratio of MWh lost to daily energy requirements instead of the absolute level of MWh lost to properly account for the scale of an unplanned outage. For example, a small unplanned outage may be because only a small number of generation units are online due to low energy requirement.

The Companies calculated the correlation coefficients as -0.14 for the winter and 0.08 for the summer. Those values are very close to zero, which indicate that there are almost no correlation between unplanned outage and temperature. Note that, statistically, it is very rare to have a calculated correlation coefficient exactly equal to zero. In general, a correlation coefficient less than -0.7 or greater than 0.7 is considered as a strong negative or positive correlation, which provides a good relationship for econometric modeling.

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Question No. 26

Responding Witness: Charles R. Schram

Q-26. Refer to the August 24, 2023 hearing testimony of Charles R. Schram (Schram August 24, 2023 Hearing Testimony). Also refer to LG&E/KU's response to Staff's First Request, Item 69. Provide a copy of LG&E/KU's communication with June 2022 request for proposal (RFP) respondents to update their proposals to reflect federal incentives that resulted from the Inflation Reduction Act (IRA).

A-26. See attachment being provided in a separate file.

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Question No. 27

Responding Witness: Lonnie E. Bellar / Charles R. Schram

Q-27. Refer to the Schram August 24, 2023 Hearing Testimony. State whether LG&E/KU specifically inputs ambient derates into GADS.

A-27. No. LG&E/KU uses seasonal (Winter, Spring, Summer, Fall) unit ratings, but does not track ambient derates in GADS.

The Companies follow the NERC guidelines for reporting GADS information into the NERC database. The instructions state that ambient related losses should not be reported. As such, the Companies do not enter ambient related derates into the database. However, if ambient conditions cause a specific issue with the generating unit that requires a derate, that derate is entered into the GADS database with the appropriate cause code related to the specific issue. See attachment being provided in a separate file for supplemental information on the Companies' tracking of ambient derates in GADS.

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Question No. 28

Responding Witness: Charles R. Schram

Q-28. Refer to the Schram August 24, 2023 Hearing Testimony. State whether LG&E/KU's Power Supply Commodity Policy – Natural Gas Fuel for Generation: Operating Policy for the Power Supply Group, effective January 1, 2020, is still in effective and, if not, provide a copy of the policy currently in effect.

A-28. The current policy, effective May 1, 2023 is attached. It contains immaterial updates to the signature page and document classification.

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Question No. 29

Responding Witness: Lonnie E. Bellar

Q-29. Refer to the Schram August 24, 2023 Hearing Testimony. Provide the median time that customers lost service during Winter Storm Elliot.

A-29. The table below shows the average and median length of time Transmission customers were impacted by load shed to address the capacity and energy emergency during Winter Storm Elliott.

Average duration of outage per Transmission customer impacted by load shed	59 minutes
Median duration of outage per Transmission customer impacted by load shed	49 minutes

While implementing the rotational load shed plan to mitigate the capacity and energy emergency during Winter Storm Elliott, there were a few breakers that could not be closed via supervisory control from the Transmission Control Center. Field personnel had to be dispatched to these locations to close the breakers manually, which increased the outage time for certain customers. The following table provides the estimated average and median length of time Transmission customers would have been impacted by load shed to address the capacity and energy emergency during Winter Storm Elliott had there not been any issues closing breakers back in during rotational load shed.

Average duration of outage per Transmission customer impacted by load shed	43 minutes
Median duration of outage per Transmission customer impacted by load shed	44 minutes

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Question No. 30

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

Q-30. Refer to LG&E/KU's response to KCA's Third Request for Information, Item 29. Provide a version of the table provided therein that includes the annual changes through the year used to determine the Full Analysis Period PVRR.

A-30. See the table below, which assumes no costs for CO_2 emissions. Workpapers for this request are provided in a separate attachment. Certain information is confidential and proprietary and is being provided under seal pursuant to a petition for confidential information. The Companies computed annual revenue requirements for each portfolio through 2050 and used a terminal value to estimate the present value of revenue requirements beyond 2050. A terminal value is needed to properly evaluate generating assets with different operating lives (e.g., 30 years for SCCTs, 40 years for NGCCs, 30 years for solar, etc.)[47] and is computed with the assumption that the portfolio operates in perpetuity. The Companies' PLEXOS model computes a terminal value for each portfolio with this assumption.[48] The PVRR difference ("NPVRR") for years 2051+ is the present value of the difference in terminal values between the two portfolios. This difference is greater for the "Portfolio 8 versus Portfolio 0" comparison because annual revenue requirements differences near the end of the analysis period between Portfolios 8 and 0 are greater than the differences between Portfolios 5 and 0. Portfolios 8 and 5 are lower cost than Portfolio 0 based on revenue requirements through 2050 and for the full analysis period.

[47] The unrealistic alternative for this analysis is to extend the analysis period to 120 years.
[48] Before PLEXOS, the Companies used Strategist for portfolio screening, and it also computed terminal value with the same assumption.

Year	RR Difference, Portfolio 8 less Portfolio 0 ($M)	RR Difference, Portfolio 5 less Portfolio 0 ($M)
2023	(0)	(1)
2024	4	(1)
2025	26	16
2026	54	23
2027	40	9
2028	45	22
2029	38	17
2030	7	(11)
2031	3	(9)
2032	(15)	(23)
2033	(25)	(32)
2034	(53)	(57)
2035	(82)	(82)
2036	(70)	(78)
2037	(48)	(55)
2038	(58)	(69)
2039	(46)	(54)
2040	(55)	(56)
2041	(67)	(55)
2042	(86)	(71)
2043	(98)	(81)
2044	(99)	(76)
2045	(101)	(83)
2046	(113)	(86)
2047	(100)	(79)
2048	(117)	(83)
2049	(100)	(67)
2050	(128)	(92)
Years 2023-2050 NPVRR ($M)	(259)	(336)
Years 2051+ NPVRR ($M)	(350)	(271)
Full Analysis Period NPVRR ($M)	(609)	(607)

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Question No. 31

Responding Witness: Lonnie E. Bellar

Q-31. Provide an estimated construction timeline for an SCR at Ghent Unit 2, and explain each basis for the assumptions in the timeline.

A-31. See attachment being provided in a separate file which details the estimated twenty-nine month construction timeline from detailed engineering through final completion. This timeline would follow successful completion of project development and then parallel completion of the ECR/CPCN filing, permitting, and EPC RFP process totaling between six and ten months depending on duration of the ECR/CPCN proceeding.