

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

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY)	
UTILITIES COMPANY AND LOUISVILLE GAS)	CASE NO.
AND ELECTRIC COMPANY FOR)	2025-00045
CERTIFICATES OF PUBLIC CONVENIENCE)	
AND NECESSITY AND SITE COMPATIBILITY)	
CERTIFICATES)	
)	
)	
)	

TESTIMONY OF ANDY EIDEN

**ON BEHALF OF JOINT INTERVENORS
KENTUCKIANS FOR THE COMMONWEALTH,
KENTUCKY SOLAR ENERGY SOCIETY,
METROPOLITAN HOUSING ASSOCIATION,
AND MOUNTAIN ASSOCIATION**

Public Version

August 1, 2025

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I. INTRODUCTIONS & QUALIFICATIONS

Q. Please state for the record your name and business address.

A. My name is Andy Eiden. My business address is 2900 E Broadway Blvd,
Suite 100 #780, Tucson, AZ 85716.

Q. By whom are you employed and in what position?

A. I am employed at Current Energy Group, LLC (“CEG”) as a Senior Manager of
Distribution System Planning and Distributed Energy Resource (“DER”) Integration.
CEG specializes in providing clients regulatory services in the areas of cost-of-service
modeling, regulatory innovation, performance-based regulation, DER, rate design,
renewable program development, grid modernization, new grid technologies, integrated
resource planning, and electric vehicles (“EVs”).

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Kentuckians for the Commonwealth, Kentucky Solar Energy
Society, Metropolitan Housing Association, and Mountain Association (collectively
“Joint Intervenors”).

Q. Please describe your professional background and education.

A. Before joining CEG, I was a Senior Principal Planning & Strategy Analyst in Portland
General Electric Company’s (“PGE”) Distributed Resource Planning team, where I led
company-wide DER forecasting and planning efforts, including for EVs and managed
charging, distributed solar and battery storage, building electrification, and demand
response (“DR”). As part of these job duties, I worked closely with Corporate Load
Forecasting, Integrated Resource Planning, Transmission and Distribution Planning, and
Power Operations teams surrounding all facets of DER integration into typical utility

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1 operations. In addition, while at PGE, I was a workstream lead to advance bottom-up
2 load and DER forecasting into PGE's Transmission & Distribution planning efforts. Part
3 of my duties as a workstream lead included participating in internal working groups
4 regarding the establishment of new policies and practices surrounding large load
5 forecasting and planning. I have also served on a number of industry working groups and
6 technical advisory committees related to DERs, Transportation Electrification, and
7 Distribution Grid Impacts.

8 Prior to joining PGE in 2019, I worked for five years at Energy Trust of Oregon, a
9 statewide non-profit implementer for energy efficiency ("EE") and renewable energy
10 programs, where I participated in or led multiple utility demand side management
11 ("DSM") potential studies. I held various roles at Energy Trust, most recently Sr. Project
12 Manager in the Planning department where I specialized in electric system avoided costs,
13 cost-effectiveness analysis of Energy Trust's \$200 Million DSM budget, and renewable
14 energy planning. Prior to Energy Trust, I was a consultant with Cadmus Group focusing
15 on third-party evaluations of utility EE programs, including many behavioral pricing and
16 time-of-use ("TOU") programs.

17 I have a Bachelor of Science dual degree from Portland State University in
18 Economics and Environmental Studies. I have taught two graduate-level courses related
19 to Smart Grid topics, one at Oregon State University in electrical engineering, and one at
20 Portland State University covering energy policy. My full qualifications are listed in my
21 résumé: Exhibit AE-1.

22 **Q. Have you previously filed expert witness testimony in other proceedings before this**
23 **Commission or before other regulatory commissions?**

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1 A. I have not testified before this Commission previously. I have testified before the
2 Massachusetts Department of Public Utilities (“D.P.U.”) in docket nos. D.P.U. 23-84
3 (“Eversource”) and D.P.U. 23-85 (“National Grid”) regarding EV TOU rate design and
4 policy, and before the Public Utilities Commission of Colorado in Proceeding No. 24A-
5 0442E regarding large load forecasting, DER potential, and electrification forecasts in
6 Public Service Company of Colorado’s 2024 Electric Resource Plan and solicitation.

7 **Q. What is the purpose of your testimony?**

8 A. The purpose of my testimony is to analyze the reasonableness of the Louisville Gas and
9 Energy Company (“LG&E”) and Kentucky Utilities Company’s (“KU”) (collectively
10 “LG&E-KU” or the “Companies”)² assessment of DSM resource potential, including the
11 2024-2030 DSM-EE Plan, the dispatchable DSM programs, and the distributed solar
12 photovoltaic (“PV”) forecasts included in the load forecast in the instant application. I
13 investigate whether incremental DSM resources could cost-effectively reduce the
14 projected capacity need for supply side resources, especially the approximately 1.3 GW
15 of natural gas combined cycle (“NGCC”) capacity for which the Companies request
16 Certificates of Public Convenience and Necessity (“CPCN”).

17 **Q. How is your testimony organized?**

18 A. In Section II, I present a summary of my findings and recommendations. In Section III, I
19 summarize the Companies’ modeling of demand-side resources in the 2025 CPCN
20 Resource Assessment. In section IV, I discuss some of the fundamental flaws I
21 encountered in the Companies’ Potential Study used to inform the existing DSM
22 programs, as well as the changes in the Companies’ and the broader planning
23 environment that render the existing programs too low as the Companies plan for

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1 additional investment in supply-side resources. In Sections V, VI, and VII, I further
2 explain why the DSM-EE, dispatchable DSM, and distributed solar levels included in the
3 2025 Mid-Case CPCN load forecast are too low and do not reflect the Companies' true
4 potential; I make recommendations on how these could be further enhanced, and estimate
5 the additional DSM potential that the Companies should pursue. In the final section, I
6 conclude and summarize my recommendations.

7 **II. SUMMARY OF RECOMMENDATIONS**

8 **Q. Please summarize your findings.**

9 A. Based on my review of the Companies' application, I find that the Companies miss
10 another opportunity to increase their DSM portfolio and are thus foregoing potential
11 energy and cost savings. Instead, they propose an increase to their supply side resource
12 portfolio, that is larger and more gas-reliant than would be required had cost-effective
13 DSM resources been pursued earlier and/or modeled accurately in the instant application.
14 The Companies' DSM and DER forecasts are low due to a number of reasons:

- 15 • The 2025 CPCN Resource Assessment fails to evaluate incremental DSM-EE or new
16 dispatchable DSM programs as selectable resources alongside proposed new gas
17 generation. Specifically, the Companies' dispatchable DSM forecast assumes less
18 than 2 MW of new customer-sited demand flexibility beyond the current portfolio,
19 despite rapid growth in technologies such as batteries and virtual power plant
20 ("VPP") platforms.
- 21 • The Companies' DSM forecasts are primarily based on existing programs that are
22 informed by outdated and flawed avoided cost and DSM potential analysis.
 - 23 ○ The forecasts and the cost effectiveness analysis were not updated to reflect

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current avoided costs or planning context.

- The avoided cost methodology omits key system benefits — such as avoided transmission and distribution (“T&D”) capacity costs and risk mitigation — leading to undervaluation of DSM-EE resources.
- The Companies’ DSM program design and potential study approach rely on outdated or incomplete assumptions, including low incentive levels and minimal bundling or segmentation to reach multifamily or manufactured housing customers.

Q. Please summarize your recommendations for the Kentucky Public Service Commission.

A. Based on my review, I recommend that the Commission:

1. Order the Companies to modernize their DSM-EE and Dispatchable DSM cost-effectiveness methods by:
 - a. Developing a T&D avoided cost value for incorporation into future DSM-EE cost-effectiveness analyses.
 - b. Conducting a study of non-energy benefits (“NEBs”) including value of resilience, health and safety, and environmental benefits.
2. Order the Companies to update their methodology for incorporating DSM-EE into any future Integrated Resource Plan (“IRP”) and related resource planning workflows by:
 - a. Developing a methodology to integrate measure-specific load shapes into resource planning.
 - b. Evaluating existing methodologies for attributing peak demand impacts to DSM-EE measures, especially for temperature-dependent measures like heating,

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ventilation, and air conditioning (“HVAC”) and water heating.

- c. Model DSM-EE as a selectable resource in the IRP framework, as opposed to a reduction in the load forecast. To accomplish this, the Companies should develop a supply curve in \$/MW that ranks the available potential from the potential study, along with any other related characteristics required by the Companies’ resource planning models. The outcomes of the study should be shared with stakeholders and the Commission before the next IRP to inform discussions about whether updating to the new methodology would be beneficial.

3. Order the Companies to recalculate the portfolio capacity need based on an updated assessment of dispatchable DSM’s contributions to resource adequacy. The Companies should account for each resource’s contributions compared to the new proxy capacity resource of a [REDACTED] as opposed to a Simple Cycle Combustion Turbine (“SCCT”).

4. Work with stakeholders to conduct a study seeking to identify and quantify additional benefits of DSM-EE that are outside of the current generation capacity deferral and marginal energy benefits assigned to them under the Companies’ avoided cost buildup. The study should identify and support methodologies needed to assess risk-mitigation impacts of DSM-EE by accounting for the following:

- a. An updated marginal price forecast that better accounts for market price extremes.

5. Identify pPotential unquantified system benefits associated with DSM-EE by running the portfolio analysis with and without DSM-EE in order to assess changes to present value revenue requirement (“PVRR”) or similar metric. The Commission should direct the Companies to take the results of this study and translate it into a \$/MWh framework that

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1 can be incorporated into future DSM-EE cost effectiveness modeling.

2 6. Order the Companies to improve their efforts at characterizing the most efficient energy
3 savings opportunities in the market by:

4 a. Instituting a process for refreshing measure characterization and efficiency
5 assumptions on a rolling basis, and at minimum for each new potential study
6 conducted for an IRP.

7 b. Developing a formal emerging technology evaluation and planning framework, in
8 collaboration with stakeholders, and filing for approval with the Commission
9 during its next DSM-EE plan update or before the next IRP, whichever comes
10 first.

11 7. Direct the Companies to conduct a process evaluation of current battery storage customers
12 to understand barriers and motivations, and to inform evolutions in program design that
13 are intended to balance between backup resilience use cases and leverage batteries for grid
14 benefits.

15 a. As part of this, Companies should evaluate different rate designs that consider
16 how solar and storage interact with TOU (both current TOU structure and
17 potential new structures based on grid needs assessments) and what incentives or
18 price signals would be necessary to encourage more grid-friendly battery
19 charge/discharge patterns, and to increase future enrollment potential.

20 8. Direct the Companies to modify their existing Bring your own device (“BYOD”) Pilot
21 concept to include a broader focus on gaining experience with dispatch coordination and
22 communication of behind-the-meter (“BTM”) battery aggregations with other controllable
23 loads like water heaters, thermostats, and EV charging.

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- 1 9. Direct the Companies to issue a Request for Information to gauge developer and
2 aggregator interest in VPP deployment in Kentucky.
- 3 10. Direct the Companies to develop a scaling plan for VPPs, in collaboration with
4 stakeholders, for post-pilot implementation in order to maximize the potential benefits of
5 this new resource type to contribute effectively and materially to the resilience and
6 diversity of energy supply for its customers.
- 7 11. Order the Companies to adjust their Base Load Forecast in this CPCN by eliminating the
8 use of the avoided cost-to-levelized cost of energy (“LCOE”) methodology and instead
9 incorporating the “NM Cumulative Capacity – High” solar forecast scenario developed for
10 the 2024 IRP.¹
- 11 12. Order the Companies to conduct an outside assessment of its solar PV forecasting
12 modeling with a third-party consultant and in coordination with stakeholders, and
13 implement changes and improvements based on the findings before the next IRP.
- 14 13. Investigate the potential benefits of forecasting locational solar adoption based on
15 customer propensity modeling, with the capability to predict local solar adoption patterns
16 based on differences in housing stock, customer demographics, localized incentives, and
17 other factors.
- 18 14. Work with stakeholders to develop a roadmap and framework for a net energy metering
19 (“NEM”) successor program or tariff in anticipation of surpassing the statutory threshold
20 beyond which the Companies may elect to stop offering NEM to new customers, which

¹ See Response of Kentucky Utilities Company and Louisville Gas and Electric Company to the Joint Motion of Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association’s Initial Request for Information Dated November 22, 2024, Case No. 2024-00326, Question 76 (b) (Dec. 18, 2024) (“LG&E-KU Resp. to JI 1-76(b)”).

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1 ~~occurs when~~ of NEM installed capacity ~~reaches~~~~exceeding~~ 1% of the previous year's peak
2 load. The scope of this roadmap and framework should include evaluating possible
3 program pairings of solar with storage, as was done with the Duke Energy Carolinas
4 Power Pair program.

5 I provide additional context for each of these recommendations in the respective sections
6 below.

7 **Q. Are you sponsoring any exhibits to your testimony?**

8 A. Yes. I have prepared the following exhibits:

9 Exhibit AE-1: a copy of my résumé.

10 Exhibit AE-2: Maryland Public Service Commission - Case 9715 – Joint Exelon

11 Utilities Energy Storage Proposal

12 **III. OVERVIEW OF DEMAND-SIDE RESOURCES INCLUDED IN THE 2025 CPCN**
13 **LOAD FORECAST**

14 **Q. Please summarize the Companies' requests in this CPCN application.**

15 A. In the instant application, the Companies request:

16 CPCNs to construct:

- 17 • a 645 MW NGCC at KU's E.W. Brown Generating Station ("Brown 12");
- 18 • a 645 MW NGCC at LG&E's Mill Creek Generating Station ("Mill Creek
19 6");
- 20 • a 400 MW, 4-hour (1,600 MWh) BESS facility at LG&E's Cane Run Station
21 ("Cane Run BESS");
- 22 • a selective catalytic reduction system at KU's Ghent Generating Station for

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Ghent 2;

- Site compatibility certificates for Brown 12, Mill Creek 6, and the Cane Run BESS;
- Approving regulatory asset treatment for certain expenses.²

Q. What analysis do the Companies present in support of their CPCN requests?

A. Witness Wilson presents the 2025 CPCN Resource Assessment. According to the witness, the assessment gathered and analyzed:

(1) updated load forecasting to understand customers' needs, (2) information about resource alternatives, and (3) information about the Companies' existing resources to inform resource decisions the Companies must make to address the load growth reflected in the 2025 CPCN Load Forecast.³

Witness Wilson states that the objective of the assessment was to:

fully inform resource decisions that must be made now to address issues that will affect the Companies' ability to reliably and economically serve customers in the 2028-2031 timeframe while also considering the possible future impacts of those resource decisions.⁴

The assessment used a series of different modeling tools to identify the resources needed to meet the large amounts of economic development load growth the Companies are anticipating by 2032.

² Joint Application, Case No. 2025-00045, at 1-2 (Feb. 28, 2025) ("Application").

³ Direct Testimony of Stuart A. Wilson, Director, Energy Planning, Analysis and Forecasting on Behalf of Kentucky Utilities Company and Louisville Gas and Electric Company, Case No. 2025-00045, at 9:6-10 (Feb. 28, 2025) ("Wilson Direct").

⁴ *Id.* at 9:10-14.

1 **Q. Did the 2025 CPCN Resource Assessment evaluate the economics of incremental**
2 **demand side resources as part of the “resource alternatives” analysis?**

3 A. Not really. The 2025 CPCN Load Forecast includes existing demand side resources as
4 approved in the 2022 DSM-CPCN. However, the 2025 CPCN Resource Assessment does
5 not evaluate incremental DSM-EE resources against the proposed (incremental) supply-
6 side resources. The only incremental DSM resources are dispatchable DSM options
7 representing increased participation in existing programs (but no new programs).⁵
8 Specifically, the three additional demand-response program measures the Companies
9 modeled were BYOD Energy Storage, BYOD Home generation, and expanding the
10 existing Business Demand Response program.⁶ The total assumed peak demand
11 reduction potential of these program measures in the model was less than 2 MW. The
12 Companies also modeled a 100 MW expansion of their Curtailable Service Rider
13 (“CSR”) CSR-2 program.

14 **Q. In terms of existing programs, what level of DSM-EE resources is included in the**
15 **2025 CPCN Load Forecast?**

16 A. In terms of already approved programs, the 2025 CPCN Load Forecast includes
17 “customer-initiated energy efficiency improvements, advanced metering infrastructure
18 (“AMI”) related conservation voltage reduction (“CVR”) and ePortal savings, distributed
19 generation, and the energy-efficiency effects of the Companies’ 2024-2030 DSM-EE

⁵ In response to SC 1-11(e)(i), , the Companies confirm that the new dispatchable DSM program measures and the expansion of the Companies’ Curtailable Service Rider program are the same as what was modeled in the 2024 IRP. Response of Kentucky Utilities Company and Louisville Gas and Electric Company to the Sierra Club's Initial Request for Information Dated March 28, 2025, Case No. 2025-00045, Question 11(e)(i) (Apr. 17, 2025) (“LG&E-KU Resp. to SC 1-11(e)(i)”).

⁶ See Wilson Direct, Ex. SAW-1 at 18-20.

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1 Program Plan and the assumed impacts of DSM-EE programs beyond 2030.”⁷ Thus, with
2 regards to DSM and distributed generation, the 2025 CPCN Load Forecast includes the
3 same assumptions as the 2024 IRP Mid load forecast: 150 MW of distributed generation
4 by 2032, annual energy reductions of 1,500 GWh by 2032 from EE and other energy
5 reductions, and summer and winter peak demand reductions in 2032 of 230 MW and 171
6 MW, respectively, resulting from EE.⁸

7 **Q. Do you find the Companies’ evaluation of DSM resources in the 2025 CPCN**
8 **Resource Assessment sufficient?**

9 A. No. Incremental DSM resources should have been assessed in parallel with the supply
10 side resources to evaluate which combination of resources would meet the projected
11 energy and capacity need at least cost. By failing to do so, the Companies are missing an
12 opportunity to increase their DSM portfolio and are thus foregoing potential energy and
13 cost savings, while they propose to increase their reliance on gas-fired resources and
14 ratepayers’ exposure to the associated risks.

15 As I explain in detail in later sections of my testimony, the demand-side forecasts
16 included in the 2025 CPCN Load Forecast and the overall Resource Assessment do not
17 adequately represent the true potential of these resources:

18 First, the Companies have historically missed opportunities to pursue additional
19 cost-effective DSM programs, as the evaluation of such resources has been flawed. This
20 has resulted in an existing DSM portfolio that leaves achievable and cost-effective energy

⁷ Wilson Direct at 12, n.11.

⁸ 2024 IRP Vol. I at 5-13 to 5-16. The two forecasts however differ in other aspects as the Companies’ 2025 CPCN Load Forecast is the 2024 IRP Mid load forecast adjusted to include the 2024 IRP High load forecast’s economic development load. Wilson Direct at 12.

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1 and demand savings untapped. It also results in a higher capacity need in this CPCN (than
2 if the Companies had pursued all cost-effective DSM from the time they were aware of
3 the upcoming resource need). Thus, the “decisions that must be made *now* to address
4 issues that will affect the Companies’ ability to reliably and economically serve
5 customers in the 2028-2031 timeframe”⁹ are both more limited and sub-optimal to the
6 position the Companies could have, had they pursued additional DSM resources up to
7 now.

8 Second, on a forward-looking basis, by investing in incremental cost-effective
9 DSM resources, the Companies can reduce or defer the need for supply side resources,
10 such as the proposed gas-fired units, that are subject to market, policy, and even load
11 growth risks. Instead, the Companies chose to not evaluate incremental DSM-EE or new
12 dispatchable DSM programs.

13 **Q. You mentioned that the Companies’ evaluation of DSM resources has historically**
14 **been flawed, resulting in existing DSM portfolios that leave cost-effective and**
15 **achievable energy and demand savings untapped. What are the analytical flaws in**
16 **the Companies’ DSM studies?**

17 A. There are a number of factors that have resulted in a DSM forecast that underestimates
18 the potential of DSM resources and consequently leads to a suboptimal resource buildout.
19 These factors include:

- 20 • Flaws in the cost-effectiveness methodology in the Potential Study that informed
21 the 2022 CPCN, which are further exacerbated by recent developments in the

⁹ Wilson Direct at 9:11-13 (emphasis original).

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Companies' planning, as well as the broader market environment, rendering the Potential Study even less relevant, and the 2022 CPCN DSM program insufficient. I provide details in Section IV;

- Omissions in program design that, if corrected, could significantly and cost-effectively increase the projected energy savings. I provide details in Section V;
- Failure to evaluate more aggressive adoption and procurement mechanisms for scaling distributed storage, such as pairing storage with other DERs to form an aggregated, dispatchable resource. I provide details in Section VI.
- Incorrect analysis of the customer value of solar and associated distributed solar PV forecasts, resulting in an overly conservative view of likely solar adoption. I provide details in Section VII.

IV. THE COMPANIES' AVOIDED COST ANALYSIS IS FLAWED; IT DOES NOT RECOGNIZE THE FULL SYSTEM VALUE OF DSM-EE AND SHOULD BE MODIFIED.

Q. Can you provide a timeline of the Companies' evaluation of DSM resources?

A. The Companies proposed and were granted approval for DSM-EE offerings in 1996, 1998, 2001, 2008, 2011, 2014, 2018, and 2022.¹⁰

The 2019-2025 DSM-EE Program Plan was approved in an Order dated October 5, 2018

¹⁰ Ex. JB-1, Louisville Gas and Electric Company and Kentucky Utilities Company 2024-2030 Demand-Side Management and Energy Efficiency Program Plan, at 3 (Dec. 15, 2022) ("Case No. 2022-00402, Ex. JB-1"), attached to Direct Testimony of John Bevington, Director, Business and Economic Development on Behalf of Kentucky Utilities Company and Louisville Gas and Electric Company, *In the Matter of Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan*, Case No. 2022-00402 (Dec. 15, 2022) ("Case No. 2022-00402, Bevington Direct").

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1 in Case No. 2017-00441,¹¹ and was later replaced in Case No. 2022-00402 by the 2024-
2 2030 DSM Plan.

3 The 2019-2025 DSM plan was based on a residential and commercial potential study
4 conducted in 2017,¹² and an industrial potential assessment conducted in 2016,¹³ but only
5 offered a limited DSM portfolio due to LG&E/KU's assumptions of zero avoided
6 capacity cost that reduced the cost-effectiveness of DSM programs.¹⁴

7 Then, the Companies conducted a DR potential assessment in 2021.¹⁵ In 2022, the
8 Companies filed a new plan to replace the 2019-2025 DSM-EE Program Plan providing a
9 DSM portfolio through 2030, stating that avoided costs should be updated to reflect
10 market conditions given the projected capacity shortfall in 2028.¹⁶ However, despite the
11 higher avoided capacity costs, the 2022 Study "did not entail a measure or fuel cost
12 update or cost-effectiveness model re-run"¹⁷ leading to proposed programs that were still

¹¹ Order, In the Matter of Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs, Case No. 2017-00441, at 34-35 (Oct. 5, 2018).

¹² Case No. 2017-00441, Ex. GSL-3, Cadmus, *Demand Side Management Potential Study 2019-2038* (Mar. 2017), attached to Direct Testimony of Gary S. Lawson, Manager, Energy Efficiency Planning & Development, LG& KU Services Company (Dec. 6, 2017), ("2017-00441 Lawson Direct").

¹³ Cadmus, *Industrial Sector DSM Potential Assessment for 2016-2035*. (Apr. 2016), filed in Case No. 2014-00003, May 26, 2016.

¹⁴ Intervenor (including the Attorney General) challenged 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 Advanced Metering Systems. Case No. 2017-00441, Oct. 5, 2018 Order at 27.

¹⁵ Cadmus, *2023 LG&E and KU Demand Response Assessment* (Apr. 2021), attached as Ex. LI-2, to the Direct Testimony of Lana Isaacson, Manager, Emerging Business Planning and Development Kentucky Utilities Company and Louisville Gas and Electric Company, Case No. 2022-00404 (Dec. 15, 2022) ("Isaacson Direct").

¹⁶ 2022-00402, Ex. JB-1 at 3.

¹⁷ *Id.*, Appendix D at 2.

1 not capturing all cost-effective savings. The values were then updated in May 2023. It is,
2 however, my understanding that those updates are not used to assess new DSM potential
3 levels or program design. Thus, any changes are not meaningfully informing resource
4 selection. The Companies are currently updating their DSM-EE Potential Study.

5 **Q. Do you have any concerns about the avoided cost methodology that informed the**
6 **design of the existing DSM plan?**

7 A. Yes. The methodology for calculating avoided costs has several shortcomings that reduce
8 the cost-effectiveness of DSM and limit the cost-effective resource potential. These
9 shortcomings fall under three main areas of 1) missing avoided cost input values
10 compared to national best practices in quantifying avoided costs of DSM-EE programs,
11 2) use of outdated cost inputs that are out of step with current market realities, and 3)
12 methodological errors and overly conservative assumptions. In the following subsections,
13 I provide greater detail about each of these shortcomings.

14 **1. Missing avoided cost input values**

15 **Q. What resources are there to inform best practices regarding avoided costs and cost-**
16 **effectiveness for evaluating DSM-EE programs?**

17 A. Historically, DSM programs were evaluated for cost-effectiveness according to the
18 California Standard Practice Manual (“CA SPM”).¹⁸ But more recently, the National
19 Standard Practice Manual (“NSPM”) developed by the National Energy Screening

¹⁸ *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects*, (Oct. 2001), https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/utilities_and_industries/energy_-_electricity_and_natural_gas/cpuc-standard-practice-manual.pdf.

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1 Project has become more prevalent.¹⁹

2 **Q. What are the avoided cost inputs that the NSPM recommends?**

3 A. The NSPM specifies various levels of system impacts that should be quantified when
4 developing assessments of avoided costs, including Generation, Transmission,
5 Distribution, and General categories such as impacts to bad debt, risk, and resilience.²⁰

6 **Q. Do the Companies' avoided cost inputs used to screen DSM-EE investments that**
7 **impact this CPCN align with the best practice recommendations of CA SPM or the**
8 **NSPM?**

9 A. No. Based on my review of the Companies' avoided cost inputs, there are significant
10 avoided cost input values missing. The most significant of these are the lack of a T&D
11 capacity deferral credit,²¹ and the lack of a risk reduction value or other means to capture
12 the impact of market price extremes.

13 **Q. How significant is the T&D capacity deferral credit?**

14 A. The Companies state that they have not evaluated a T&D avoided cost value but believe
15 that the benefits of such a credit would be minimal in relation to generation capacity and

¹⁹ National Energy Screening Project, National Standard Practice Manual: For Benefit-Cost Analysis of Distributed Energy Resources (Aug. 2020), https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf ("NSPM").

²⁰ *Id.* at 4-2.

²¹ Response of Kentucky Utilities Company and Louisville Gas and Electric Company to the Joint Motion of Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association's Second Request for Information Dated May 27, 2025, Case No. 2025-00045, Question 41 (June 6, 2025) ("LG&E-KU Resp. to JI 2-41").

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1 energy cost savings.²² While T&D deferral values depend on the unique makeup of a
2 utility and the costs of maintaining and upgrading its system, studies consistently show
3 that these values can be significant. One national study on the national potential for load
4 flexibility found 12% of the total avoided cost stack was attributable to T&D deferrals.²³
5 In a study conducted for the Pennsylvania Public Utility Commission, the calculated
6 T&D value for PPL Electric was \$153.54/kW-yr starting in 2026, and escalating to
7 \$185.82/kW-yr by 2035.²⁴

8 This value can be even higher when evaluating specific deferral opportunities. For
9 example, PGE in Oregon found instances of between \$283.39/kW-yr to \$650.53/kW-yr
10 for specific infrastructure deferral opportunities in its 2023 Distribution System Plan.²⁵
11 Likewise, across the California utilities, previous estimates following the state's
12 locational net benefits analysis method have resulted in several projects in the \$0-
13 100/kW-yr range, two in the \$100-500/kW-yr, and one greater than \$500/kW-yr range.²⁶

14 Identifying locational value of DER through strategic asset deferral is of growing

²² Response of Kentucky Utilities Company and Louisville Gas and Electric Company to the Joint Motion of Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association's Third Request for Information Dated May 27, 2025, Case No. 2025-00045, Question 16 (June 6, 2025) ("LG&E-KU Resp. to JI 3-16").

²³ Ryan Hledik et al., *The National Potential for Load Flexibility: Value and market potential through 2030*, Brattle Group, at 20 (June 2019), https://www.brattle.com/wp-content/uploads/2021/05/16639_national_potential_for_load_flexibility_-_final.pdf.

²⁴ Demand Side Analytics, *Avoided Cost of Transmission and Distribution Capacity Study*, at 65. (July 2024), <https://www.puc.pa.gov/pdocs/1842599.pdf>.

²⁵ Portland General Electric, *Distribution System Plan Part 2*, at 116, 129, (Aug. 15, 2022), https://downloads.ctfassets.net/416ywc1laqmd/2Fr2nVc4FKONetiVZ8aLWM/b209013acfedf1125ceb7ba2940bac71/DSP_Part_2_-_Full_report.pdf.

²⁶ Natalie Mims Frick et al., *Locational Value of Distributed Energy Resources*, Lawrence Berkeley Nat'l Lab'y, at 38 (Feb. 2021), https://eta-publications.lbl.gov/sites/default/files/lbnl_locational_value_der_2021_02_08.pdf.

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1 importance, as recent data shows distribution system investments now represent the
2 largest share of capital expenditures among U.S. investor-owned utilities, and the trend is
3 increasing.²⁷ Properly assessing and assigning T&D avoided costs to the value of DSM-
4 EE programs is therefore critical to ensuring a cost-effective system.

5 **Q. Can you explain the risk reduction benefit, and what relationship it has to market**
6 **price extremes?**

7 A. The risk reduction benefit reflects the value of DSM-EE as a hedge against future price
8 extremes due to market tightening, or other unforeseen factors that impact the cost of
9 delivering reliable electric supply to customers. Whereas the avoided energy portion of
10 the avoided cost value stack is typically modeled based on forecasted marginal energy
11 prices, the risk reduction factor incorporates the tendency of electricity markets to deviate
12 from forecasts, especially under contingency scenarios or under extreme weather.

13 For example, the Companies' avoided cost methodology assumes an average
14 marginal hourly energy cost in 2032 of [REDACTED]
15 per MWh, with a max of [REDACTED] per MWh for a
16 single hour on [REDACTED] at the hour
17 beginning [REDACTED]²⁸ However, recent market
18 experience during extreme weather events and other market irregularities accentuated

²⁷ *Id.* at 1.

²⁸ See Response of Kentucky Utilities Company and Louisville Gas and Electric Company to the Joint Motion of Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association's Initial Request for Information Dated March 28, 2025, Case No. 2025-00045, Question 93(e) (Apr. 17, 2025) ("LG&E-KU Resp. to JI 1-93(e)"), provided as Confidential Attachment 2 "20241021_LAK_2025BP_IRPUpdate_MarginalCost_2025-2050.xlsx".

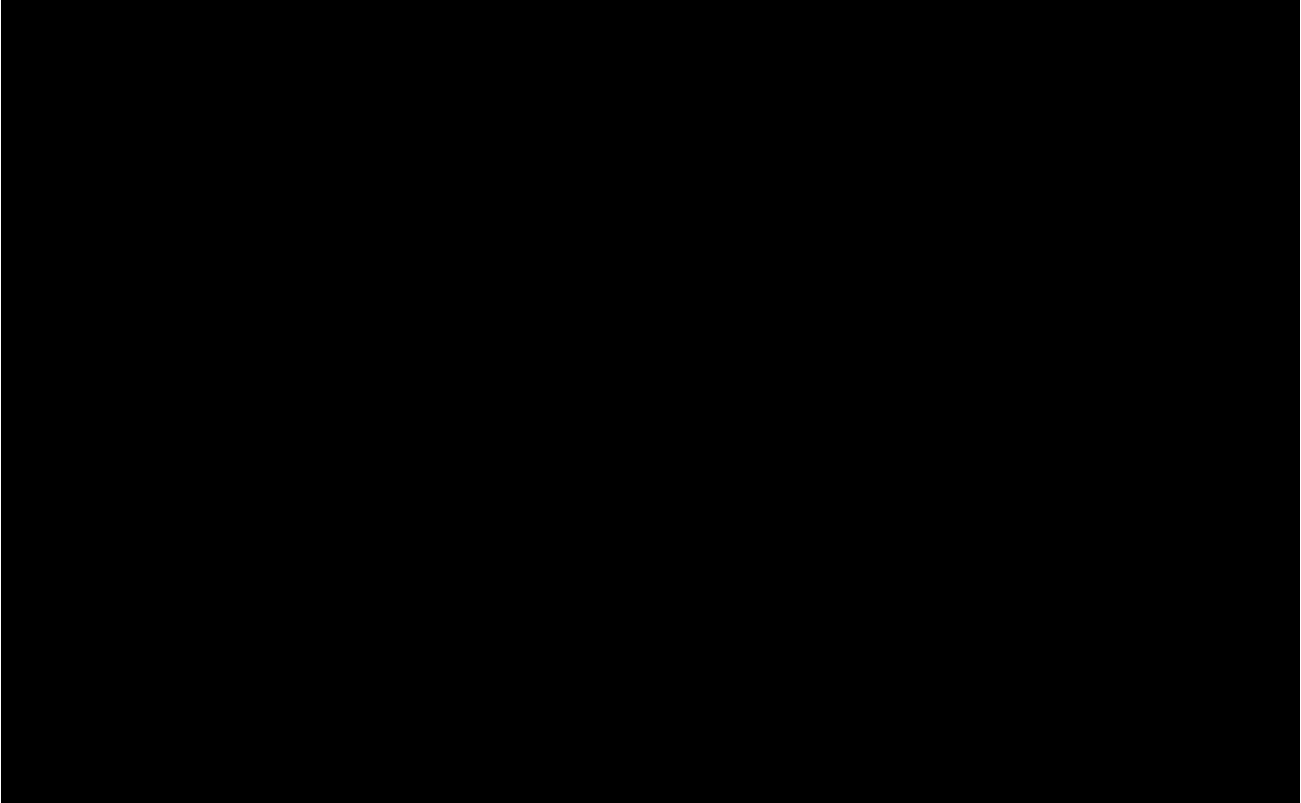
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1 price spikes in summer and winter months. Recent experience in the Southeast Energy
2 Exchange Market, in which the Companies are a participant, shows 2024 max daily
3 prices for January on-peak²⁹ exceeded \$60 per MWh on a daily average. Just this year,
4 the Companies went to the market to purchase ~~1,644-1,244~~ MWh
5 across six different hours over two winter days when the price was \$133/MWh on
6 average with a maximum of \$279/MWh.³⁰ ~~CONFIDENTIAL~~. The total cost for just
7 these six hours was \$232,774, for a weighted average of \$141.59/MWh. Additionally,
8 according to the Companies' market purchases data, purchases from the imbalance
9 market are on an upward trend and the costs can exceed the marginal cost assumptions in
10 the Companies' resource modeling. Figure 1 shows the total MWh and costs of
11 imbalance market purchases -when the market price is greater than \$40/MWh.

²⁹ See slide 11, Potomac Economics Independent Market Auditor, *2024 Annual Audit Report on the Southeast Energy Exchange Market*, SEEM (May 6, 2025), https://southeastenergymarket.com/wp-content/uploads/2024-Annual-Report_Final.pdf.

³⁰ See Response of Kentucky Utilities Company and Louisville Gas and Electric Company to the Joint Motion of Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association's Third Request for Information Dated May 27, 2025, Case No. 2025-00045, Question 10 (June 6, 2025) ("LG&E-KU Resp. to JI 3-10"), provided as Confidential Attachment 2.

³¹ *Id.*



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Note that the 2025 totals are only current through the end of April. Given the indications that actual market purchase activity deviates from the assumed marginal costs utilized in the Companies' avoided cost analysis and resource selection modeling, it will be important to monitor these assumptions going forward.

7

Q. Are there any other benefits attributable to DSM-EE called out by the CA SPM or the NSPM that the Companies are not including?

8

9

A. Yes. Both the CA SPM and the NSPM identify NEBs that may be important to consider, depending on the perspective taken by a specific jurisdiction when evaluating the cost-effectiveness of DSM investments. Typically, these are included in either a total resource cost ("TRC") or the societal cost test ("SCT") perspective. The NSPM lists a variety of NEBs that represent different potential benefits, such as increased comfort from having

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adequate heating and cooling,³² resilience to power outages provided by weatherization upgrades and battery storage, health and safety benefits,³³ and various other categories.³⁴

2. The application of avoided costs has methodological errors and uses overly conservative assumptions

Q. Are there any other concerns you have with the approach the Companies are using to apply avoided costs and evaluate cost-effective DSM-EE levels?

A. Yes, I have three additional concerns. First, the Companies include in this CPCN load forecast levels of DSM-EE from the 2024-2030 DSM-EE Plan, approved under Case 2022-0042. The avoided costs, especially the avoided capacity costs, have changed significantly compared to the avoided costs informing the 2022 programs. With new and updated avoided costs, there could be higher levels of cost-effective and achievable DSM-EE, either through new channels (e.g., Pay As You Save (“PAYS”) or increases to incentives to encourage greater participation.

³² NSPM at p. 3-7, 3-9. Note that this benefit can be either from having a more functional HVAC system, as in the case of equipment tune-ups or upgrades, or, by adding cooling benefits through installation of a heat pump, where previously there was only heating and no air conditioning. In some cases therefore, adding summer cooling increases system demand but achieves potentially significant health benefits for severe weather, especially for vulnerable populations.

³³ *Id.* at p. 4-17. Health and safety benefits of efficiency programs can be especially important for low-income programs, as the housing stock is typically older and has a higher risk of indoor air pollutants. Increasing the mechanical ventilation through tune-up or upgrade programs can provide significant benefits. Recently, the industry has caught on to these important dual benefits stemming from efficiency improvements to homes and has identified mechanisms to co-fund programs using a combination of utility incentives and healthcare dollars. *See* Sara Hayes & Christine Gerbode, *Braiding Energy and Health Funding for In-Home Programs: Federal Funding Opportunities*, ACEEE (July 2020), <https://www.aceee.org/sites/default/files/pdfs/h2002.pdf>.

³⁴ *Id.*, tbl.4-5 at p. 4-18. Particular NEBs, such as improvements in asset value (such as increasing home value after adding solar PV), or increased productivity (as in the case of improved office ventilation or lighting) can prove particularly beneficial in motivating customers to adopt a given DER.

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1 My second concern is that the Companies' capacity contribution methodology for
2 assessing contributions of Dispatchable DSM, including customer-sited energy storage,
3 to resource adequacy is incorrect and based on outdated proxy capacity resources. The
4 result is an overly conservative view of the contributions such resources bring to the
5 portfolio, and subsequent increase in supply side resource needs.

6 My third concern is that the Companies are simplifying the DSM-EE resource
7 shape in their modeling and applying a static avoided cost value to pre-screen DSM-EE
8 levels. This approach undervalues the benefits of DSM-EE to an optimal resource
9 portfolio and leads to an overreliance on supply side resources. In addition, the static
10 method of developing and applying capacity contribution factors for battery storage do
11 not account for potential synergistic effects with distributed solar, leading to a
12 conservative view of the full resource potential when these resources are coordinated and
13 used in tandem.

14 **Q. Can you elaborate on your first concern?**

15 A. Yes. As Witness Grevatt noted in the 2022 CPCN, the 2022 CPCN was based on a cost-
16 effectiveness analysis using a \$0.00 avoided capacity cost, whereas the Companies'
17 estimated avoided capacity cost in that case was \$136.20. The avoided capacity cost for
18 EE programs with peaking energy reductions in 2028 (as provided in response to JI
19 1.93(e)) ranges between \$178 and \$182. Despite the updates in the avoided costs, the new
20 values have not been used for re-assessing the cost-effectiveness of different DSM
21 programs and levels.

22 **Q. What is the basis for the avoided capacity cost?**

23 A. Initial cost-effectiveness analysis for the 2024-2030 DSM-EE Plan (in the 2022 CPCN)

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1 was based on SCCT avoided capacity cost. According to the Companies' response to JI
2 2.44, additional cost-effectiveness testing was conducted in 2023, which used SCCT
3 costs as the basis for avoided capacity for DR and NGCC costs for EE. Confidential
4 Attachment 1 to Response to JI 1-93(e), however, [REDACTED]

5 [REDACTED]

6 [REDACTED]

7 [REDACTED]

8 [REDACTED]

9 [REDACTED]

10 [REDACTED]

11 **Q. Do you find that the use of SCCT costs as the basis for the avoided capacity costs in**
12 **the 2022 CPCN (which led to the approval of the existing DSM programs)**
13 **sufficiently captures the costs that incremental DSM resources could now avoid?**

14 A. No. The Companies are currently applying for two NGCC units with capital costs that
15 exceed \$2,100/kW, significantly higher than the [REDACTED]

16 [REDACTED] SCCT³⁶ capital cost in the 2022 analysis, or even the

17 [REDACTED]

18 [REDACTED]

19 [REDACTED]³⁷ Incremental DSM resources could now defer or

20 reduce the need for the proposed NGCCs and should be evaluated based on these costs.

³⁵ LG&E-KU Resp. to JI 1-93(e), Confidential Attach. 1.

³⁶ LG&E-KU Resp. to JI 1-93(e), Confidential Attach. 5.

³⁷ LG&E-KU Resp. to JI 1-93(e), Confidential Attach. 1.

1 **Q. Why has the cost of gas turbines increased?**

2 A. As has been widely reported, the gas turbine market is experiencing a significant backlog
3 due to the increased demand resulting in both higher costs, as well as longer timelines for
4 the delivery of turbines. A recent newsletter summarizes information about this growing
5 backlog of gas turbine orders from the major manufacturers:³⁸ “The global gas turbine
6 market is experiencing a significant surge in orders, with major players like Siemens
7 Energy, GE Vernova, and Mitsubishi Power reporting record-breaking backlogs in
8 2024.”

9 **Q. What are the potential impacts of this backlog?**

10 A. The newsletter identifies some critical impacts for potential customers and eventually
11 electricity consumers. According to that newsletter, those include:

- 12 • Delays in Project Execution: Long backlogs can disrupt construction schedules and
13 lead to cost overruns. Some gas turbine models now have leading times of up to 37
14 months, substantially affecting project planning and execution.
- 15 • Strain on Maintenance and Spare Parts Availability: Current gas turbine operators are
16 increasingly concerned about slower turnaround times for scheduled maintenance.
17 Customers are now experiencing lead overhaul times of around 350 days, a sharp
18 increase from the 120 days that were previously standard.
- 19 • Rising Costs for End-Users: The high backlog demand has shifted pricing power to
20 original equipment manufacturers, meaning customers may pay more for both new

³⁸ *The Growing Backlog of Gas Turbine Orders: Implications for Customers* (Jan. 3, 2025), <https://gasturbinehub.com/the-growing-backlog-of-gas-turbine-orders-implications-for-customers/>.

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turbines and service agreements. Additionally, inflationary pressures on raw materials and supply chain constraints are further driving up capital and operational costs for gas turbine buyers.

- Uncertainty in Decarbonization Strategies: Many power producers are investing in hydrogen-compatible gas turbines as part of their long-term net-zero strategies.

However, backlog-induced delays may slow the transition to cleaner gas power.

Q. Can you elaborate on your second concern?

A. The Companies apply a 39% capacity contribution factor to Dispatchable DSM, including DR and energy storage in its BYOD program, to assess contributions of these resources to meeting resource adequacy needs in its preferred portfolio analysis under the Resource Assessment.³⁹ This is based on their modeling within SERVIM to compare an individual resource's contribution to reducing the loss of load expectation (LOLE) as compared to a SCCT.⁴⁰

The Companies' capacity contribution for Dispatchable DSM of 39% used in this CPCN reflects a comparison of these resources to a SCCT.⁴¹ However, the Companies elsewhere state that the new lowest cost proxy capacity resource is [REDACTED]

[REDACTED]

[REDACTED]

³⁹ Wilson Direct, Ex. SAW-1 at 20, tbl.5.

⁴⁰ Case No. 2024-00326, 2024 IRP. Vol. III Resource Adequacy Study, at 18 (Oct. 18, 2024).

⁴¹ See Response of Kentucky Utilities Company and Louisville Gas and Electric Company to the Joint Motion of Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association's Supplemental Requests for Information Dated May 2, 2025, Case No. 2025-00045, Question 44 (May 16, 2025) ("LG&E-KU Resp. to JI 2-44").

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1 [REDACTED]
2 [REDACTED]⁴² The forced outage rates are
3 much lower for SCCT compared to the “availability factor” for [REDACTED]
4 [REDACTED] within the Companies’ resource modeling, leading to a much
5 different calculation of capacity contribution when evaluating distributed storage and
6 dispatchable DSM against SCCT versus a [REDACTED]
7 [REDACTED]. If compared to the updated [REDACTED]
8 [REDACTED] capacity resource proxy instead of the SCCT, the capacity
9 contribution of Dispatchable DSM and distributed storage would increase, thus lowering
10 the need for supply side resources. The Companies stated that computing capacity
11 contributions of distributed storage and other Dispatchable DSM measures against a
12 [REDACTED] proxy capacity resource is
13 inappropriate. The Companies do not provide any supporting citation or precedent for
14 this justification, and simply state, “[f]or resource planning, capacity contributions for
15 limited-duration resources must be computed by comparing their reliability benefits to a
16 fully dispatchable resource.”⁴³

17 In addition, the Companies’ methodology of evaluating Dispatchable DSM,
18 including distributed storage, as individual resources ignores potential synergistic effects
19 on resource adequacy contributions that these resources can have when considered
20 together with other complementary resources, such as distributed solar and passive DSM-
21 EE. Moreover, the Companies evaluate capacity contribution by removing utility-owned

⁴² LG&E-KU Resp. to JI 1-193(e), Confidential Attach. 1.

⁴³ *Id.*

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1 and purchased solar PV from the Reference Case load forecast to which their capacity
2 contribution analysis assesses relative resource performance in reducing LOLE.⁴⁴ There
3 is a synergistic effect between solar and storage wherein more solar PV on the system
4 creates more value potential for storage due to solar's -impact to shorten the net-load
5 peak hours that storage must cover, as well as increasing the difference between high and
6 low power prices, which translates to greater economic arbitrage for storage.⁴⁵

7 **Q. Can you elaborate on your third concern?**

8 A. My third concern relates to the Companies' modeling approach for evaluating the time-
9 based impacts of DSM-EE on the load forecast, and how that impacts the resultant
10 resource need. The EE resource has a shape that corresponds to how much energy is
11 saved compared to baseline usage patterns. This shape may be relatively flat across all
12 hours of the year, for example when more efficient lighting is installed in a factory that is
13 open 24 hours a day, 365 days a year. In other cases, the kWh savings from a given
14 measure or program may be more coincident with heavy system load periods, such as
15 heating and cooling measures, or water heating.

16 These resulting changes in load shape can have important implications on the
17 resulting value of the DSM-EE resource. One key study by the Lawrence Berkeley

⁴⁴ See Response of Kentucky Utilities Company and Louisville Gas and Electric Company to the Joint Motion of Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association's Supplemental Requests for Information Dated May 2, 2025, Case No. 2025-00045, Question 56 (May 16, 2025) ("LG&E-KU Resp. to JI 2-56").

⁴⁵ See Nathaniel Gates et al., *Evaluating the Interactions Between Variable Renewable Energy and Diurnal Storage*, Nat'l Renewable Energy Lab'y, at 20 (Oct. 2021), <https://doi.org/10.2172/1827634>.

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1 National Lab demonstrated the importance of accurately modeling the time-varying
2 nature of different DSM-EE programs by calculating the avoided costs of various EE
3 measures using both a traditional (i.e., non-time varying) approach and one that correctly
4 reflected EE's contribution to electric system benefits at different times.⁴⁶ For example,
5 the study found a total electric system benefit of central air conditioning efficiency
6 measures under the time-varying approach being 1.4 to 3.1 times more valuable than
7 more traditional approaches.⁴⁷

8 **Q. How do the Companies currently develop the shape for the DSM-EE resource in**
9 **their plan?**

10 A. Currently, the Companies do not include an hourly shape for DSM-EE in their
11 assessment of resource need.⁴⁸ Instead, the Companies adjust monthly sales and energy
12 requirements before creating the system hourly load forecast, meaning that the DSM-EE
13 hourly 8760 shape effectively takes the shape of the overall system hourly shape prior to
14 being adjusted for distributed generation, EVs, and economic development loads.⁴⁹

15 **Q. Do you have concerns with this approach?**

16 A. Yes. The method of shaping DSM-EE contributions within the IRP to mirror the overall
17 system load shape does not reflect the relatively higher contributions of certain DSM-EE

⁴⁶ Natalie Mims Frick et al., *Time-varying value of electric energy efficiency*, Lawrence Berkeley Nat'l Lab'y, at xii, xiii (June 2017), https://eta-publications.lbl.gov/sites/default/files/lbnl_bto_time_varying_ee_final_070317.pdf.

⁴⁷ *Id.* See table ES-1. Note for the comparison above, I have left out the Pacific Northwest example from the table, which shows a 1.0 factor indicating no time varying difference for central air conditioner efficiency, because the region has since implemented new methodologies which place much greater emphasis on peak-reducing efficiency like air conditioning and heating measures.

⁴⁸ LG&E/KU Resp. to JI 2-39(c).

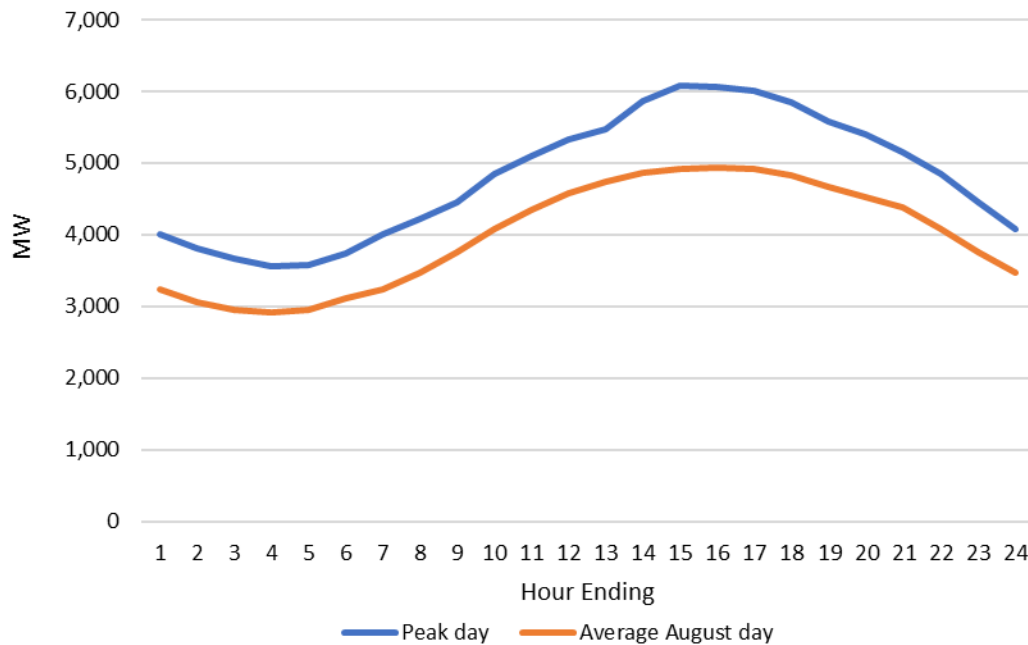
⁴⁹ *Id.*

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resources for reducing peak demand, such as heating and cooling efficiency measures.

This is especially important given the summer and winter capacity needs under the Companies' future load growth projections. Figure 2 below illustrates the unadjusted⁵⁰ total system load profile on a peak day in 2032, versus an average day.

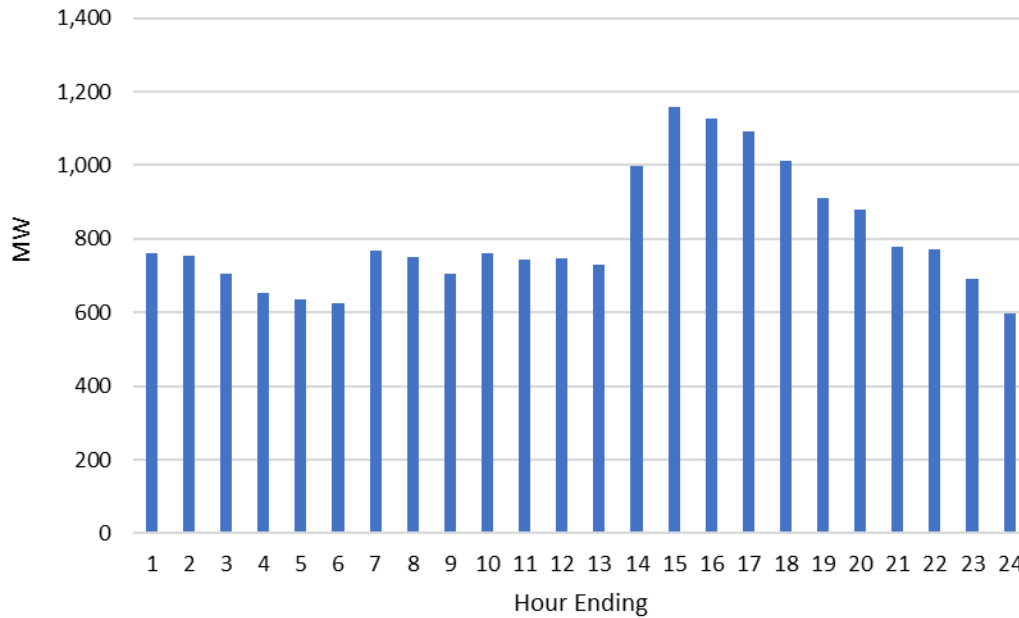
Figure 2: 2032 Peak Unadjusted Demand Hourly Profile Versus Average August Day



As shown in Figure 2, the peak demand day hourly system load profile is significantly higher than the average day, and takes on a different shape as well. Figure 3 below shows more clearly the hourly differences between the average day and the peak day.

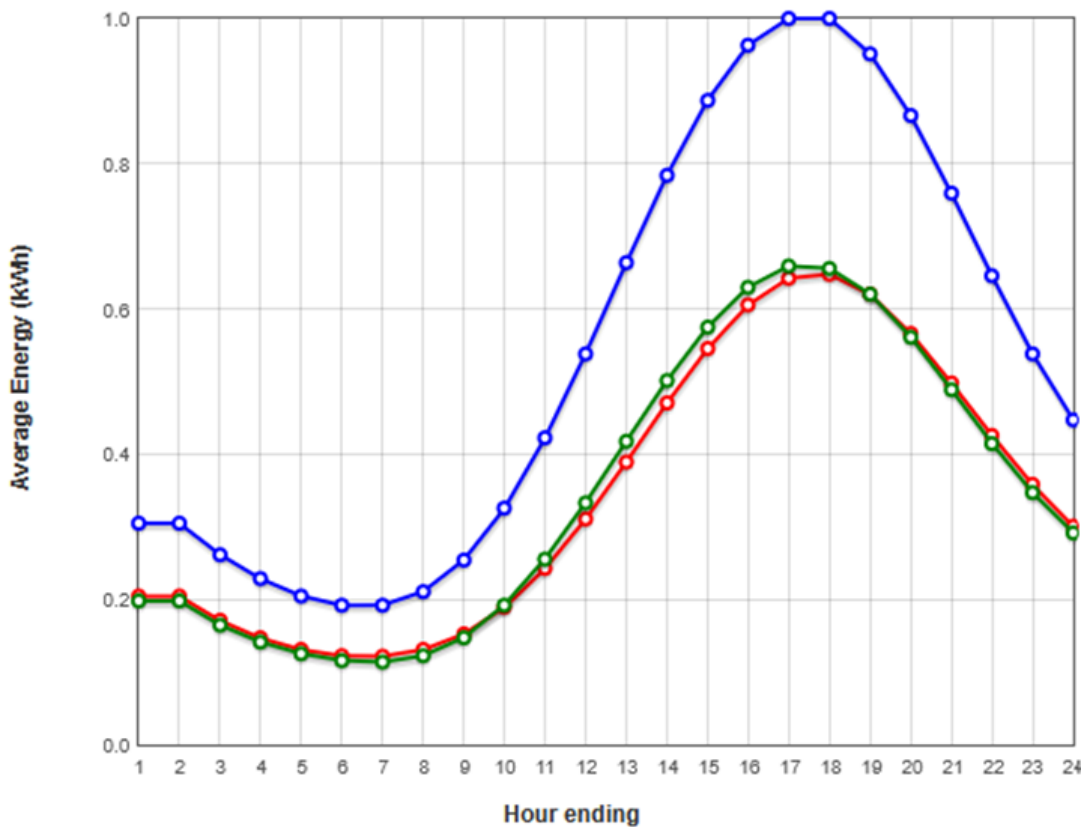
⁵⁰ The “unadjusted” forecast depicted here reflects the system load forecast before adjustments for distributed solar PV, electric vehicles, and economic development large loads, in order to align with the Companies’ current DSM-EE allocation methodology.

Figure 3: Hourly Difference between Average 2032 August Day and Peak Day



The differences highlighted above reflect the underlying load drivers contributing to peak, in this case likely increased air conditioning usage. Using publicly-available end-use load shapes from the Electric Power Research Institute, we can see evidence for this assumption by noticing how residential central air conditioning hourly usage is much greater during a peak day as compared to the average day.

1 *Figure 4: Hourly load profile for residential central air conditioning during peak and off-peak*
2 *days for NERC Southeast Reliability Coordinator zone⁵¹*



3
4 **Q. Doesn't the fact that the Companies are applying the DSM-EE kWh savings**
5 **proportionally to the system load shape account for these differences?**

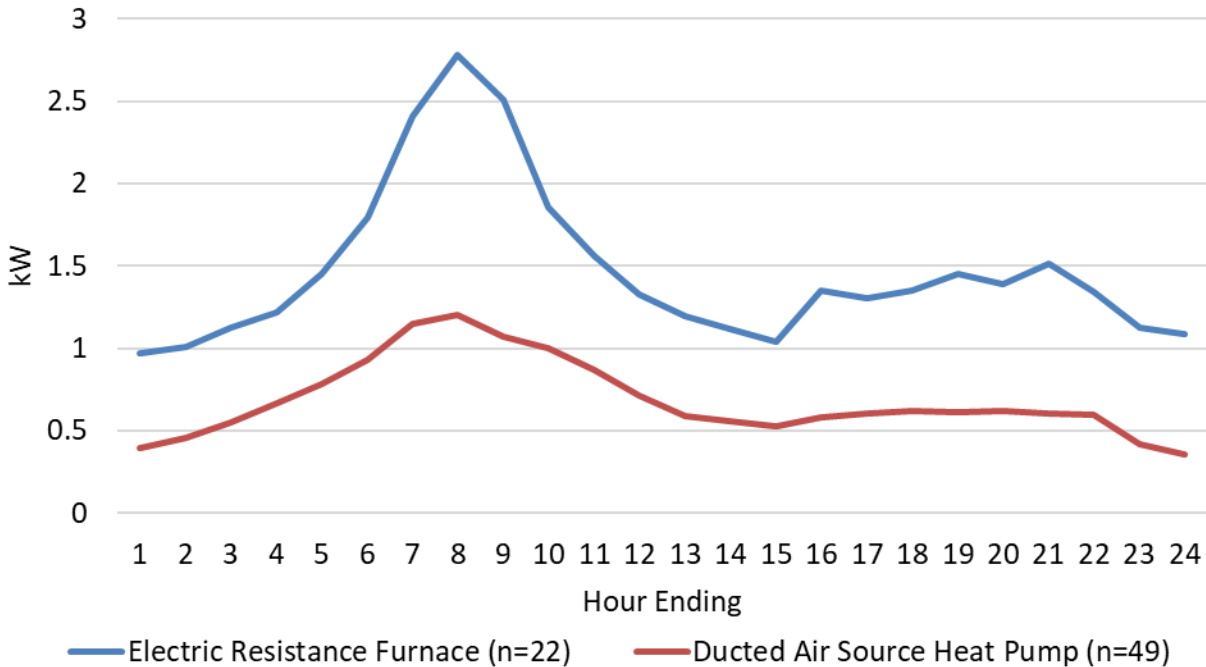
6 A. Not necessarily. In some cases, this approach may turn out to be a reasonable
7 approximation. But in cases where technologies are changing—as in the case of replacing
8 an electric resistance furnace with a heat pump—the shape of the electrical demand
9 profile for the two technologies is very different, therefore resulting in a more complex
10 time-varying savings shape.⁵² Figure 5 shows actual metered end use data for a sample of

⁵¹ Elec. Power Rsch. Inst., *End Use Load Shapes*, <https://loadshape.epri.com/enduse> (last accessed June 13, 2025).

⁵² See Regional Technical Forum, *Residential Air Source Heat Pumps*, at 1, <https://nwcouncil.app.box.com/v/ResASHPCapRecMemo> (last accessed June 13, 2025).

heat pumps and electric forced air furnaces in the Pacific Northwest.⁵³

Figure 5: Average February hourly load profile for electric resistance furnace and air source heat pumps in the Pacific Northwest⁵⁴



We can see from this chart how the magnitude of the efficiency savings changes dramatically over time. During the morning peak, the illustrative savings (calculated as the difference between the two curves) are two times the average savings. Following the Companies' approach to allocating DSM-EE savings evenly according to the un-adjusted system load profile will therefore substantially understate the effect of EE during peak

⁵³ While the sample is from the Pacific Northwest and not necessarily representative of the climate in Kentucky, the point I am making here is more about the relative differences between the technologies, as opposed to the likely impacts in Kentucky.

⁵⁴ The chart is based off of data collected from the Northwest Energy Efficiency Alliance's End Use Load Research project, which collected long-term end-use metering data for over 200 homes. The data in the chart was downloaded from the Regional Technical Forum, End-Use Load Shape ("EULR") Hourly Data, at <https://rtf.nwccouncil.org/end-use-load-shape-eulr-hourly-data/> (last accessed June 13, 2025).

1 demand periods for weather-sensitive measures.

2 **Q. What other methodology improvements do you recommend related to how the**
3 **Companies are modeling DSM-EE?**

4 A. The Companies should explore the possibility to include DSM-EE as a selectable
5 resource to allow a capacity expansion model to select the optimal amount of DSM-EE
6 based on the program or portfolio-level DSM-EE load profile (or availability parameters
7 as in the case of Dispatchable DSM), the levelized cost, and the amount of resource
8 available for each time step of the planning horizon. Doing so would allow demand- and
9 supply-side resources to be evaluated on a more comparable basis, thus potentially
10 leading to better outcomes and lower system costs.

11 **Q. What are the benefits of doing this?**

12 A. The main benefit and motive for moving toward this method of assessing DSM-EE
13 contributions to system needs is that it introduces parity in planning, which can ensure
14 that all resources are evaluated on a consistent basis subject to the same resource
15 acquisition screening practices.⁵⁵ By directly modeling the DSM-EE resource as a
16 resource option in a portfolio optimization, you can achieve better alignment of the
17 resource selection with system needs. This can result in lower overall costs because the
18 type of DSM-EE deployed is providing a higher value. Perhaps most importantly,
19 modeling the DSM-EE resource in this way allows stakeholders to understand the relative
20 benefits and tradeoffs between all resource types within the same modeling framework.

⁵⁵ Natalie Mims Frick et al., *Methods to Incorporate Energy Efficiency in Electricity System Planning and Markets*, Lawrence Berkeley Nat'l Lab'y, at ii (Jan. 2021), https://eta-publications.lbl.gov/sites/default/files/lbnl_ee_resource_planning_1_27_21.pdf.

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For example, if future resource needs arise from a lowering of the reserve margin, and there is additional DSM-EE resource potential available at a higher cost than the traditionally-cost-effective amount already included, then the model may select it.

Q. Are there examples of utilities or other electricity system planning entities doing this today?

A. Yes. PacifiCorp, Indiana Michigan Power Company, and the Northwest Power and Conservation Council all consider DSM-EE in the manner I described.⁵⁶ Additionally, PGE began modeling of non-cost-effective DSM-EE in its most recent IRP following an Oregon PUC order,⁵⁷ which ultimately led to the economic selection within the model of an additional 182 average MW (“MWa”)⁵⁸ of resources over a three year procurement window, compared to the older method for assessing DSM-EE outside of the IRP modeling framework.⁵⁹

V. THE DSM-EE FORECASTS INCLUDED IN THE MID-CASE LOAD FORECAST ARE TOO LOW AND DO NOT ADEQUATELY REPRESENT THE TRUE POTENTIAL FOR EE TO OFFSET FUTURE RESOURCE NEEDS

Q. Please describe the Companies’ EE programs and the analysis used to develop the

⁵⁶ *Id.* at iii.

⁵⁷ See Portland General Electric, 2023 Clean Energy Plan and Integrated Resource Plan 2023, at 186, 187, (June 30, 2023), https://downloads.ctfassets.net/416ywc1laqmd/6B6HLox3jBzYLXOBgskor5/63f5c6a615c6f2bc9e5df78ca27472bd/PGE_2023_CEP-IRP_REVISED_2023-06-30.pdf.

⁵⁸ An “average megawatt” or MWa for short, is a commonly used shorthand notation in Pacific Northwest energy planning practice, and represents one MW operating continuously for all 8,760 hours of a year.

⁵⁹ Order 24-096, Oregon Public Utility Commission, at 6 (Apr. 18, 2024), <https://apps.puc.state.or.us/orders/2024ords/24-096.pdf>.

Companies' 2024-2030 DSM-EE plan.

A. The Companies develop an updated DSM plan, inclusive of EE and DR programs, roughly every four years.⁶⁰ The current DSM plan is for the years 2024-2030, and was approved in Docket 2022-00402. The targeted electricity savings of the plan, through 2030, total 875 GWh and 170 MW from its EE portfolio.⁶¹ The Companies state that the targeted savings “are consistent with the numbers identified as achievable from the most recent potential studies and updates by Cadmus.”⁶² The portfolio of EE programs includes Income Qualified Solutions, Appliance Recycling, Residential Online Audit, and Business Solutions.⁶³

Q. How do the Companies' DSM plan underachieve the potential to offset future resource needs?

A. The Companies' DSM plan and analysis have several flaws which result in lower DSM savings than could reasonably be achieved to offset resource needs. The flaws, which will be discussed in detail in the following subsections, include:

1. The benchmark for achievable potential is based on low customer incentives.
2. The plan did not update certain key measures and omits measures with potential to increase savings and bundling to improve cost-effectiveness.
3. The plan fails to adequately pursue whole-building opportunities for multi-family customers.

3.1. The benchmark for achievable potential is based on low customer incentives

⁶⁰ Case No. 2022-00402, Bevington Direct at 2.

⁶¹ Case No. 2022-00402, Ex. JB-1 at 20.

⁶² Case No. 2022-00402, Bevington Direct at 12.

⁶³ Case No. 2022-00402, Ex. JB-1 at 14, tbl.1-1.

1 **Q. What incentives do the Companies provide for customer participation in the DSM**
2 **programs?**

3 A. For the Residential Online Audit and Business Solutions programs, the Companies seem
4 to target an incentive of 50% of the measure incremental cost.⁶⁴ The Income Qualified
5 Solutions and Appliance Recycling programs are free programs and have no direct
6 incentive.

7 **Q. Why is the target incentive level low?**

8 A. The target incentive level is aligned with an achievable potential evaluated in the
9 potential study, which projects the rate of customer participation based on the incentive
10 provided. The achievable potential assumed by the Companies is based on the 50%
11 incentive level, which was the “medium” scenario in previous studies.⁶⁵ However, the
12 potential study demonstrates that a higher incentive level (unspecified as to the
13 percentage of incremental costs) increases savings of energy and demand by 21% and
14 19%, respectively, for the DSM portfolio.⁶⁶ This would be additional demand reduction
15 that decreases the Companies’ resource need in 2030.

16 The potential study does not provide cost test results for the high incentive
17 scenario, but higher incentives do not strictly mean lower net benefits. While increasing
18 participation and incentives raise the total program cost, other costs, such as
19 administrative, implementation, and miscellaneous costs, do not scale directly with

⁶⁴ The incremental measure cost means the cost difference between the higher-efficiency solution and the standard replacement solution. For example, if the efficient AC unit costs \$5000 and the standard unit costs \$4000, the incremental measure cost is \$1000. If the incentive level is 50% of incremental costs, then the rebate for that AC unit type would be \$500. *See* Case No. 2022-00402 Ex. JB-1, Appendix D at 6.

⁶⁵ *Id.*, Appendix D at 6, n.4.

⁶⁶ *Id.*, Appendix D at 11, tbl.6 & tbl.10.

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1 participation. The result can be lower total program costs per energy or demand saved,
2 leading to greater net benefits. For example, Virginia Electric and Power Company
3 (“Dominion Energy”) conducted a similar EE potential study with incentive levels of
4 50% and 75% that demonstrated greater cost-effectiveness (in the TRC test) with 75%
5 incentives, while delivering greater than 30% additional energy and demand savings.⁶⁷
6 LGE-KU’s DSM plan under-represents achievable EE savings at a time when load
7 growth is driving the need for new generation.

8 **Q. Does the Companies’ inclusion of customer-driven DSM-EE increase these levels?**

9 A. Yes, the Companies include DSM-EE in the CPCN load forecast from the 2024-2030
10 DSM-EE Plan (875 GWh by 2032) and from customer initiated DSM-EE (233 GWh by
11 2032), for a total of 1,108 GWh of DSM-EE by 2032.⁶⁸ Taken together, the combined
12 DSM-EE levels in the CPCN application are more in line with the 2022 Cadmus study.
13 Although not directly comparable for the 2032 year due to lack of available data, the
14 2043 combined cumulative DSM-EE included in this CPCN load forecast is 1,790
15 GWh,⁶⁹ whereas the 2022 Cadmus study shows 1,471 GWh in the Medium scenario and
16 1,777 GWh in the High scenario for the same time period.⁷⁰

17 **Q. Does this address your concerns about the incentive levels being too low to achieve**
18 **more DSM-EE as outlined in the Cadmus potential study?**

19 A. No. The Cadmus study notes that the 2022 study update identified lower efficiency

⁶⁷ DNV Energy Insights, *Virginia Energy Efficiency Potential Study 2024 to 2033*, at 5, tbl.1-1, (June 12, 2024), <https://www.dominionenergy.com/virginia/save-energy>.

⁶⁸ See Case No. 2022-000402, Response of Kentucky Utilities Company and Louisville Gas and Electric Company to the Sierra Club’s Initial Request for Information Dated February 17, 2023, Question 16(a) (Mar. 10, 2023) (“LG&E/KU Resp. to SC 1-16(a)”).

⁶⁹ Id.

⁷⁰ KY PSC Case 2022-00402, Direct Testimony of Lana Isaacson, Exhibit LI-1 at 10.

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1 potential compared to the previous study, due primarily to changes in federal equipment
2 standards and reductions in potential savings from lighting measures as that market is
3 saturated with efficient LEDs.⁷¹ Importantly, the Cadmus study notes that in order to
4 mitigate these reductions in long-term efficiency potential caused by increasing
5 standards, the Companies may need to consider monitoring emerging technologies and
6 conducting pilots as a way to fill this gap.⁷²

7 **Q. Did the Companies follow the recommendation in the Cadmus study to include**
8 **explicit treatment of emerging technologies?**

9 A. No, they did not.⁷³ The Companies stated that future emerging technologies may be
10 represented in the load forecast to the extent the Statistically Adjusted End-Use (“SAE”)
11 forecasting method employed by the Companies leverages U.S. Energy Information
12 Administration (“EIA”) data that includes assumptions about continued end-use
13 efficiency trends,⁷⁴ though the Companies do not provide any estimate of the potential
14 impact of these embedded assumptions.

15 **Q. How does the SAE method incorporate EE projections?**

16 A. SAE is a hybrid forecasting tool developed to model electricity consumption at the end-

⁷¹ *Id.* at 9.

⁷² *Id.*

⁷³ See Case No. 2022-000402, Response of Kentucky Utilities Company and Louisville Gas and Electric Company to the Sierra Club’s Initial Request for Information Dated February 17, 2023, Question 16(a) (Mar. 10, 2023) (“LG&E/KU Resp. to SC 1-16(a)”).

⁷⁴ See Response of Kentucky Utilities Company and Louisville Gas and Electric Company to the Joint Motion of Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association’s Supplemental Requests for Information Dated May 2, 2025, Case No. 2025-00045, Question 38(a) (May 16, 2025) (“LG&E-KU Resp. to JI 2-38(a)”).

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1 use level—such as for air conditioning, heating, lighting, and plug loads.⁷⁵ It modifies
2 historical usage based on an accounting of equipment saturation, efficiency trends, and
3 historical usage patterns.⁷⁶ A key input into this framework is the EIA’s *Annual Energy*
4 *Outlook*, which provides national-level forecasts for appliance efficiency trends, turnover,
5 and fuel mix.⁷⁷

6 The SAE model typically incorporates EIA’s forecasts of gradually improving
7 efficiency—for example, by increasing efficiency from codes and standards, and
8 declining costs—but does not include radical changes in end use consumption reflective
9 of technologies that do not have significant market share during the baseline period.⁷⁸

10 These assumptions reduce projected use-per-customer and, in turn, total and peak
11 demand in long-term forecasts.

12 **Q. Is this sufficient to reflect emerging technology potential the Companies could**
13 **achieve through future efficiency product development from EE?**

14 A. No, for two reasons. First, as I noted above, the EIA methodology does not account for
15 dramatic changes in end use efficiency, and therefore cannot accurately reflect potential
16 shifts in energy consumption which are often disruptive in their scale. This is especially
17 true because, as I discuss elsewhere in my testimony, the 2022 Cadmus study also did not
18 update measure assumptions to reflect the highest level of efficiency among even existing

⁷⁵ Shawn Enterline and Eric Fox, *Integrating Energy Efficiency into Utility Forecasts*, proceedings of the 2010 ACEEE Summer Study in Buildings, at 5-87 (2010), <https://www.aceee.org/files/proceedings/2010/data/papers/2067.pdf>.

⁷⁶ *Id.*

⁷⁷ *Id.*

⁷⁸ U.S. Energy Info. Admin., *Annual Energy Outlook 2024: Residential Sector Assumptions*, at 2 (Mar. 2022), <https://www.eia.gov/outlooks/aeo/assumptions/pdf/residential.pdf>.

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1 technologies. Second, it is important to have visibility into which technologies and
2 market sectors have the most promising potential, what stage the technology is at in terms
3 of commercial readiness, and for the utility to ensure there is sufficient lead time to
4 develop the delivery mechanisms and program administration capabilities to increase the
5 speed of these solutions to market. Therefore, having emerging technologies explicitly
6 modeled in future DSM-EE potential studies and program plans will be critical to
7 increase the amount of achievable EE in future plans.

8 A few examples illustrate this need further. It is widely known that the industrial
9 sector has been a difficult sector to reach with certain end use efficiency programs.
10 However, recent advances in Industrial Heat Pump technology are key to unlocking
11 significantly expanded EE potential for this market sector⁷⁹ that would not be reflected in
12 baseline efficiency trends. In Kentucky, for example, there are 233 food and beverage
13 manufacturers that could be good candidates for this technology, and just one site uses
14 the equivalent energy of 418 typical homes.⁸⁰ Similarly, the commercialization of low-
15 voltage heat pump water heaters is a significant advancement that could overcome a key
16 market barrier (high installation costs due to site electrical upgrades) for this
17 technology.⁸¹ Again, the step-change nature of some emerging tech highlights the
18 importance of taking a tailored approach to defining the potential, not only because the

⁷⁹ Andrew Hoffmeister and Paul Scheihing, *The Industrial Heat Pump (IHP) Opportunity and Electrification Momentum*, <https://www.southeastenergysummit.com/wp-content/uploads/2024/12/1B-Push-Pull-Toward-Clean-Heat.pdf>.

⁸⁰ *Id.*, at 7.

⁸¹ Josh Butzbaugh, *Demonstration of 120-volt Heat Pump Water Heaters in a Warm/Hot Climate (New Project)*, at 3 (July, 2023), <https://www.energy.gov/sites/default/files/2023-07/bto-peer-2023-141195-120v-hpwh-pnnl-butzbaugh.pdf#:~:text=Evaluate%20the%20energy%20efficiency%20and%20hot%20water%20delivery,Table%204.%20Residential%20Sector%20Key%20Indicators%20and%20Consumption>

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1 baseline trends likely understate the potential future savings, but because doing so will
2 allow the Companies to initiate early research and development and initiate the type of
3 pilot activities necessary to scale these technologies effectively.

4 **Q. Aside from not including emerging technology, did the 2022 Cadmus study**
5 **accurately reflect the energy savings potential for the existing measure and program**
6 **options?**

7 A. No. The 2022 Cadmus study had known limitations to the extent it did not include a
8 complete measure characterization update, meaning that some measures still reflected
9 technology performance at 2016/2017 levels at the time of the last study update.⁸² Below,
10 I quantify additional kWh savings resulting from the decision not to update with a full
11 measure characterization for the 2024-2030 DSM-EE Plan:

- 12 • Under the Residential Audit Online program, the central air conditioner and ducted
13 air-source heat pump kWh savings are too low. The 2022 Cadmus study updated the
14 baseline to match federal standards effective January 1, 2023, but did not increase the
15 efficient option to reflect higher efficiency tiers.⁸³ By utilizing the highest efficiency
16 tiers, this change would result in an increase of 1,047 MWh of cumulative electricity
17 savings by 2030 from just these two changes, which represents 4.5% of the
18 cumulative total program savings over the same period.

- 19 • Under the Residential Online Audit, the ductless heat pump (“DHP”) measure has 0

⁸² It is important to note that some of these measures may in turn have been based on previous vintages.

⁸³ For example, the new baseline of SEER2 14.3 rating reduces the savings potential from previous baseline comparisons, but Cadmus only modeled a SEER2 15.2 efficiency measure when there were models available or expected to be available that were 16 or 17 SEER2 compliant under the testing requirements under the new standard.

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1 kW savings attributed to it. While this does not directly impact the kWh that is
2 allocated to the load forecast,⁸⁴ it does potentially impact cost-effectiveness
3 screening, and should be updated in future rounds. One study of metered DHPs in
4 Rhode Island found 0.12-0.33 kW per unit of winter peak demand savings when
5 replacing electric resistance heat.⁸⁵

6 • Under the Business Rebate program, the electric chiller measure reflects outdated
7 efficiency levels,⁸⁶ and with updated assumptions that the baseline and efficient
8 options could increase per unit savings from between 1.3 times the current amount all
9 the way to seven times the current estimated savings level.⁸⁷ The top end of the range
10 is based on the Carrier 30XV model with VFD compressors and fans,⁸⁸ coupled with
11 longer chiller operating hours reflective of the lodging sector. Lastly, the chiller
12 measures do not reflect the ability of thermal energy storage (“TES”) technologies to
13 flexibly shift cooling load to overnight, when there is ample excess capacity.
14 Applications of TES to chillers operate by using electricity to make ice during off-
15 peak hours, and then melting the ice to provide cooling to the system during the day

⁸⁴ This is because, as I described above, the Companies are adjusting monthly sales and allocating savings according to the total system load shape, and not attributing any specific end-use measure savings shapes.

⁸⁵ Cadmus, *Ductless Mini-Split Heat Pump Impact Evaluation*, at 10 (Dec. 30, 2016), <https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/4755-TRM-DMSHP-Evaluation-Report-12-30-2016.pdf>.

⁸⁶ The baseline efficiency assumption is 12.5 EER, whereas the current standard from the Mid Atlantic TRM is 14 EER.

⁸⁷ Assuming a baseline of 14 EER and differing assumptions on the number of full load hours and the efficiency level of the replacement option.

⁸⁸ The assumptions currently used for the program are for a standard chiller, whereas adding a variable frequency drive (“VFD”) to the chiller can increase savings by 15-25% compared to standard models. See Florida Power & Light, *Air-Cooled Chillers: An FPL Technical Primer*, at 1, <https://www.fpl.com/content/dam/fplgp/us/en/business/save/programs/pdf/air-cooled-chillers-primer.pdf> (last accessed June 12, 2025).

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1 when cooling is required by the building, thereby significantly reducing peak
2 demand. Such systems help make significant commercial cooling loads grid-
3 interactive, and can be operated as part of a VPP, as I discuss later in my testimony.

4 **Q. What do you recommend to the Commission in light of these considerations?**

5 A. Given the out of date assumptions included in the measures identified above, as well as
6 others that I did not address in my testimony, the Commission should direct the
7 Companies to institute a process for refreshing measure characterization and efficiency
8 assumptions on a rolling basis, and at minimum for each new potential study conducted
9 for an IRP.

10 Recognizing the possibility that current SAE-based forecasts of future EE reductions
11 may understate the potential for peak demand mitigation from emerging technologies, I
12 recommend the Commission order the Companies to assess alternative scenarios or
13 sensitivities that reflect faster-than-expected adoption of these technologies and to
14 evaluate the corresponding impacts on their proposed resource plan. Further, I
15 recommend the Commission direct the Companies to develop a formal emerging
16 technology evaluation and planning framework, in collaboration with stakeholders, and
17 file for approval with the Commission during its next during its next DSM-EE plan
18 update or before the next IRP, whichever comes first. The framework should consist of
19 the following elements:

- 20 • Periodic market scans to assess emerging technologies from national labs, academic
21 research centers, and industry organizations.
- 22 • A planning step that identifies preliminary estimates of market potential, unit savings
23 (kWh and kW), and costs using a combination of literature reviews and engineering

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modeling. This step should clearly specify a research agenda for field testing (see the next step) in terms of dependent and independent variables.

- A specific process for pilot program development and approval that can quickly take the emerging technologies in the pipeline and deploy into field and lab test environments to collect necessary data to update the planning models. The pilot process should include a flexible evaluation, measurement, and verification (“EM&V”) plan to assess both customer acceptance and participation barriers, as well as technical and economic performance.

4.2. The plan omits measures with potential to increase savings and bundling to improve cost-effectiveness for residential programs.

Q. What EE programs does the DSM plan provide for residential customers?

A. For non-income qualified customers, the DSM Plan includes an Appliance Recycling program and Residential Online Audit. The online audit program, specifically, provides a self-guided assessment of a customer’s home and uses customer-specific interval data from the Companies’ AMI to assess the customer’s disaggregated energy use. After completing the online audit, customers receive feedback on their energy-use behavior, energy-saving tips, and recommendations, and are mailed a kit with EE measures for self-installation. In addition, customers who complete the audit gain access to prescriptive rebates for HVAC and water heating upgrades.⁸⁹ Non-income qualified residential customers have no option for in-person audits or direct-install measures from the Companies. Income qualified customers can receive more comprehensive measures including a direct-install weatherization and “turn-key” service for increasing EE for

⁸⁹ Case No. 2022-00402, Ex. JB-1 at 32.

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1 whole-building multi-family residences,⁹⁰ although as I discuss later, the WeCare
2 program has mostly been incentivizing low-cost energy saving kits, building shell and
3 related envelope upgrades, and energy efficient appliance rebates. This leaves significant
4 energy savings opportunities untapped by not pursuing more deep retrofits by targeting
5 HVAC and water heating upgrades.

6 **Q. How does the Companies' DSM plan omit potentially valuable EE programs?**

7 A. The residential online audit program does not include a range of residential measures
8 which would increase EE for single-family or multi-family participating customers,
9 including broader weatherization and air sealing.⁹¹ In a 2017 review of the Companies'
10 DSM plan, Cadmus identified that individual HVAC and weatherization measures (e.g.,
11 insulation, duct sealing, infiltration) were no longer proving cost-effective.⁹² This likely
12 explains why these measures are significantly limited for the non-income qualified
13 program. However, Cadmus' review concluded that bundled measure packages⁹³ and
14 performance-based incentives may allow the Companies to capture savings from
15 measures no longer deemed cost-effective. Cadmus then recommended that the

⁹⁰ *Id.* at 24-25.

⁹¹ *Id.* at 32.

⁹² Case No. 2017-00441, Ex. GSL-2 at 12, Direct Testimony of Gregory S. Lawson, Manager, Energy Efficiency Planning & Development, LG&E KU Services Company, *In the Matter of Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs*, Case 2017-00441 (Dec. 6, 2017).

⁹³ "Bundled measure packages" refers to the practice of promoting multiple EE measures into discrete packaged offerings, which can offer an attractive means to reduce transaction costs among participants (i.e., through easy to understand menu of options approach with tiered incentive systems to encourage deeper savings) and streamline delivery costs. *See* Matthew Socks et al., *The Energy Efficiency Extra Value Menu: Streamlining Energy Efficiency Delivery*, in Proceedings of the ACEEE 2016 Summer Study in Buildings conference, at 7-2 (2016), https://www.aceee.org/files/proceedings/2016/data/papers/7_801.pdf.

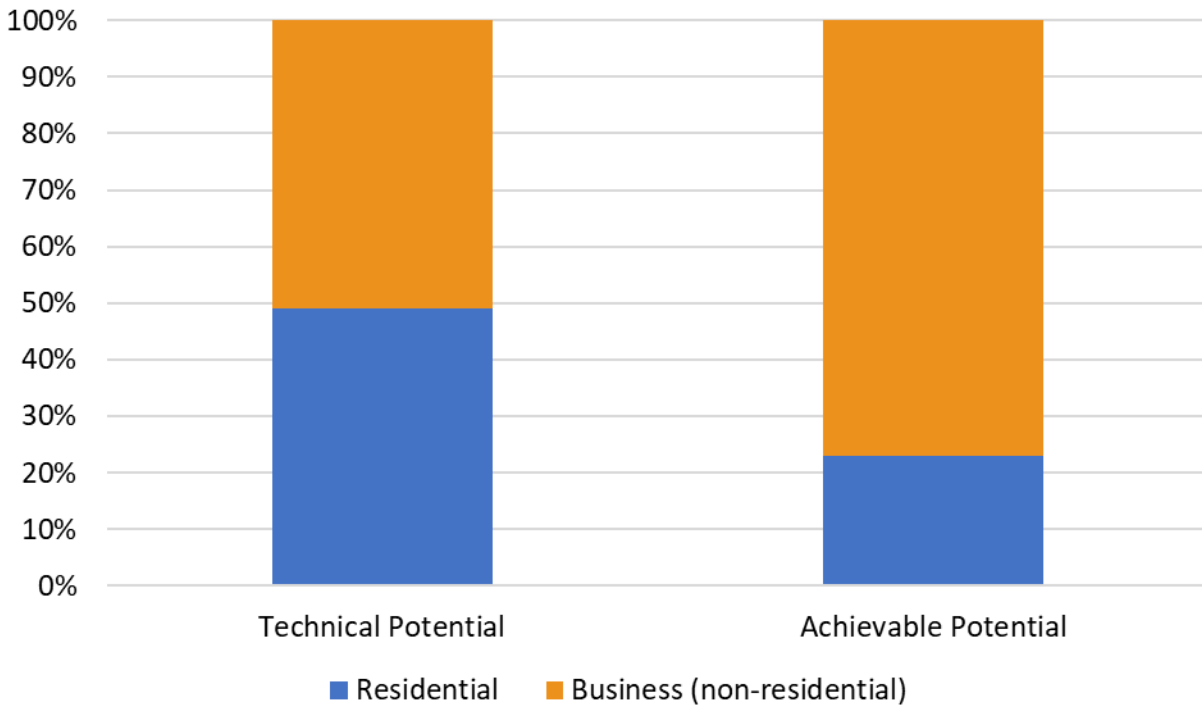
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1 Companies conduct additional analysis of bundled-measure scenarios and performance-
2 based incentives for customers who implement cost-effective EE projects.⁹⁴ I have found
3 no evidence in the Companies' DSM Plan that they have considered these
4 recommendations to provide more effective bundled and performance-based incentive
5 measures, opting instead to utilize a customer-directed self-assessment and installation.
6 The online residential audit program is likely significantly cheaper than a bundled direct-
7 install program, however, it also is likely to produce much lower savings. This is
8 evidenced by the residential online audit program contributing among the least amount of
9 energy or demand savings among the offered EE programs, with the business solutions
10 program contributing 3.5 times more cumulative savings over the 2024-2030 Plan
11 period.⁹⁵ Overall, the achievable potential from the 2022 Cadmus Study and the 2024-
12 2030 DSM-EE Plan includes far less residential efficiency compared to the technical
13 potential for this sector. Figure 6 illustrates this dramatic change.

⁹⁴ Case No. 2017-00441, Ex. GSL-2 at 12.

⁹⁵ Case No. 2022-00402, Ex. LI-6, "LGE KU Program Measure Inputs FINAL – Public.xlsx" from Direct Testimony of Lana Isaacson, Manager, Emerging Business Planning and Development Kentucky Utilities Company and Louisville Gas and Electric Company (Dec. 15, 2022).

Figure 6. Comparison of Residential and Business Sector's Contributions to Technical and Achievable EE Savings Potential by 2043



Looking at the sector composition of the savings from the 2024-2030 DSM-EE Plan over time, we see an even more dramatic trend in the savings makeup, where the steep drop off in commercial sector savings is not compensated for by sufficient increases in the residential sector.

1 *Figure 7. Final 2024-2030 DSM-EE Plan Savings Targets by Sector*⁹⁶



2
3 Based on these two figures, there appears to be significant remaining residential
4 efficiency potential that is underrepresented in both the achievable potential from the
5 2022 Cadmus study and the resulting 2024-2030 DSM-EE Plan. This is supported by a
6 recent benchmarking review across utilities from mostly Midwestern and Southern states
7 where it was found that the Companies' 2022 DSM Potential Study ranked last out of 10
8 publicly available IRP DSM Potential studies in terms of achievable potential as a share
9 of sales.⁹⁷ Clearly there is significant opportunity to accelerate residential EE to further
10 offset required supply side resources.

11 So far I have discussed the limitations resulting from not updating all of the key

⁹⁶ *Id.*

⁹⁷ GDS, *Ameren Missouri 2023 DSM Market Potential Study: Final Report*, at 85-86 (Apr. 2023), https://s21.q4cdn.com/448935352/files/doc_downloads/2023/09/25/chapter-8-appendix-a.pdf?utm_source=chatgpt.com.

1 engineering measure inputs to reflect the most efficient technology options, the potential
2 issues with ignoring the impact of emerging technology on future energy demand
3 reductions, and the lack of analysis around bundling and other mechanisms to improve
4 program cost-effectiveness. In the next subsection I will discuss the new whole building
5 multifamily subprogram offering and the need for deeper retrofit approaches.

6 **5.3.The plan fails to adequately pursue whole-building opportunities for multifamily**
7 **customers.**

8 **Q. Does the Companies' 2024-2030 DSM-EE plan forecast include programs aimed at**
9 **the low-income multifamily housing segment?**

10 A. Yes. The Companies included a subcomponent for Whole-Building Multifamily to their
11 existing Income-Qualified Solutions program as part of their proposal in Case No. 2022-
12 00402.⁹⁸ The Multifamily subcomponent will provide education regarding energy usage
13 and conservation, provide property managers and building owners with opportunities for
14 in-unit efficiency upgrades (such as free direct install of energy-saving devices), and
15 provide incentives for owners and managers making improvements to the whole building,
16 including shared common-areas.⁹⁹

17 **Q. What type of program delivery and design features do the Companies include in**
18 **their plan related to the Whole-Building Multifamily subcomponent?**

19 A. The Companies state that the new Multifamily subcomponent will provide owners and
20 property managers with a "turnkey service" to increasing EE savings, and that they will
21 propose to cap incentives at 50% of the project incremental costs for multifamily

⁹⁸ Case No. 2022-00402, Ex. JB-1 at 25.

⁹⁹ *Id.*

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properties.¹⁰⁰ In addition, the Companies state that their approach aims to encourage comprehensive energy improvements, and follows a whole-property approach that could benefit the entire complex (both in-unit and common areas).¹⁰¹ Lastly, the Companies define their target population for the Multifamily subcomponent as being property managers and owners serving low-income tenants, including those in Section 8 housing, and having buildings comprised of 4+ units.¹⁰²

Q. Are the savings and participation levels for the new Multifamily program reasonable?

A. No. The Companies' characterization of this program as a whole building offering is not supported by the underlying savings potential estimates. The Multifamily budget was developed by taking ~~half of~~ the single family WeCare budget of \$1,500 per home incentive, and dividing it by two in order to apply it to in-unit apartment savings.¹⁰³ The resultant kWh savings were also simply cut in half from the previous WeCare savings values.¹⁰⁴ However, the electric savings measures for WeCare in the DSM-EE Plan are only small appliance rebates, low-cost energy saver kits (such as efficient light bulbs, faucet aerators, and low-flow showerheads), and building shell measures.¹⁰⁵ This means that there are effectively no savings in the Multifamily subcomponent reflective of the significant potential to improve both in-unit HVAC and centralized HVAC and water heating systems.

¹⁰⁰ *Id.*

¹⁰¹ *Id.* at 26.

¹⁰² *Id.* at 26-27.

¹⁰³ Case No. 2022-00402, Ex. LI-6, workpaper titled "LGE KU Program Measure Inputs FINAL – Public.xlsx". See tab titled "LI Multifamily – Whole Building" cell E71.

¹⁰⁴ *Id.* See cell F71.

¹⁰⁵ See Case No. 2022-00402, LG&E/KU Resp. to JI 1-140, Attach. 5 at 24.

1 **Q. Do the Companies include any savings for common area measures that may address**
2 **this gap?**

3 A. No. Though the Companies do include a line item in the budget build up for “customer
4 retrofits” in common areas,¹⁰⁶ the savings for this line item only represent 6% of the
5 overall program savings and are not clearly supported.¹⁰⁷

6 **Q. Do the Companies provide a plan that will overcome the known market barriers for**
7 **achieving deep retrofit energy savings in Multifamily affordable housing?**

8 A. No. Although it is a new program offering, and therefore certainly will continue to grow
9 over time, there is insufficient detail regarding the plan for rolling out this program
10 subcomponent to judge whether it would effectively encourage deeper energy savings.
11 But, based on my review of the measure buildup informing the budget target, the overall
12 design appears insufficient to overcome the high hurdles needed to reach deeper market
13 penetration and realize greater savings, especially for low-income participants.
14 However, the barriers to multifamily deep retrofits have been well studied. The
15 Companies should work with stakeholders and customers to leverage best practices that
16 can support such whole-building deep energy savings that the Plan speaks to.

17 **Q. What are some of the main barriers that have been identified for reaching this**
18 **market segment with deep energy savings opportunities?**

¹⁰⁶ Case No. 2022-00402, Ex. LI-6, Workpaper titled “LGE KU Program Measure Inputs FINAL – Public.xlsx.” See tab “LI Multifamily – Whole Building”.

¹⁰⁷ For instance, the supporting data in the workpaper has notes of “MF Custom Project Benchmarking” showing two utilities’ custom project savings ranging from 26,167 kWh to 44,289 kWh, whereas the assumed custom common area savings per project used in the Companies’ budget plan was only 7,500 kWh for five projects. Elsewhere, the Companies note an even higher range of 4,500 to 167,000 kWh savings for these projects. It is unclear why the Company chose such a low level of savings.

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1 A. There are many barriers to implementing programs targeting whole-building retrofits in
2 the Multifamily housing sector, especially for low-income building owners. Some of the
3 main barriers commonly found are split incentives, a lack of coordination among all the
4 various parties, and lack of capital.¹⁰⁸ The lack of capital issue is a major one, given that
5 low-income housing providers typically face the dual challenge of aging building stock in
6 need of significant repairs, and an inability to raise rents in order to cover the energy
7 upgrades which take time to repay the initial capital investment. Oftentimes, EE projects
8 end up being “value engineered” out of a property’s budget after reckoning with all of the
9 other pressing building improvements that are competing for cash.¹⁰⁹

10 **Q. Are there strategies to overcome these barriers that you believe the Companies**
11 **should be utilizing?**

12 A. Yes. Especially in Louisville, given the focus of the Louisville Metropolitan Government
13 (“LMG”) to improve outcomes for low-income multifamily buildings. The LMG
14 Housing Department offers up to \$10,000 in funding per unit for landlords meeting
15 certain geographic criteria to rehab their properties.¹¹⁰ By working with local partners to
16 align EE upgrades with these broader renovations, the Companies can begin
17 implementing the type of measure bundling I discussed earlier in my testimony, and

¹⁰⁸ Julia Friedman et al., *Multifamily Energy Efficiency Retrofits: Barriers and Opportunities for Deep Energy Savings*, Regional Energy Efficiency Organizations, at 1 (Dec. 2016), https://neep.org/sites/default/files/resources/REEO_MF_Report.pdf

¹⁰⁹ Peter Adamczyk et al., *Commercial PACE for Affordable Multifamily Housing*, VEIC at 4 (Jan. 2018), https://assets.ctfassets.net/ntcn17ss1ow9/51q94Fnz4padfRDcnYeBdZ/882f11ace128c243787109db23e76db1/Report_CPACE_for_Affordable_Multifamily_Housing.pdf.

¹¹⁰ U.S. Dept. of Energy, *Louisville Communities LEAP Engagement: Improving Energy Efficiency in Affordable Housing*, Nat’l Renewable Energy Lab’y, at 31 (Aug. 2024), <https://docs.nrel.gov/docs/fy24osti/90277.pdf>.

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1 developing key strategies to overcome the challenges of reaching the low-income
2 multifamily sector.

3 The lack of capital is another critical challenge where creative solutions have been
4 found to increase financing options to this sector. Working directly with the mortgage
5 lender and the building owner during the loan underwriting process can increase the
6 likelihood of capturing additional savings because it gives lenders the tools they need to
7 understand how efficiency can improve the borrowers loan performance.¹¹¹ By going
8 after simple upgrades, owners can achieve 1-5% bill savings.¹¹² However, medium
9 upgrades can yield 5-10%, whereas major upgrades—such as replacing windows,
10 installing rooftop PV, or upgrading the HVAC equipment—can yield upwards of 30%
11 savings.¹¹³ Given the LMG’s interest in this sector, this type of holistic approach may be
12 well suited to secure the interest of local lenders, especially Community Development
13 Finance Institutions.

14 This type of program is also not just the purview of small lenders and community
15 nonprofits. Fannie Mae offers a Green Rewards program¹¹⁴ that can unlock additional
16 loan proceeds and provide a lower interest rate to market rate and affordable multifamily
17 building owners, therefore offering enhanced benefits for implementing efficiency
18 measures. The Companies should explore additional ways to support these various

¹¹¹ Community Preservation Corporation, *Underwriting Efficiency: A mortgage lender’s handbook for realizing energy and water efficiency opportunities in multifamily housing*, at 3, (Apr. 22, 2017), https://nyceec.com/wp-content/uploads/2024/03/CPC_Underwriting_Efficiency_Handbook_Full_Interactive_FINAL.pdf.

¹¹² *Id.* at 9.

¹¹³ *Id.* at 13.

¹¹⁴ See Fannie Mae, *Specialty Financing: Green Rewards*, <https://multifamily.fanniemae.com/financing-options/specialty-financing/green-financing/green-rewards> (last accessed June 16, 2025).

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1 market actors through streamlined participation and enrollment channels, as well as clear
2 marketing that positions the program as a value add that can speak to the unique
3 challenges facing this sector.

4 **Q. What do you recommend?**

5 A. Based on the forgoing analysis about the Companies' assessment of EE potential, I
6 recommend the Commission:

- 7 • Order the Companies to conduct an update to the measure characterization and
8 engineering assumptions factored into the current Whole-Building Multifamily
9 subcomponent program in order to reflect true common area savings measures and
10 whole building measures like central water heating and central HVAC system
11 retrofits.
- 12 • Order the Companies to work with stakeholders to scope and conduct a market
13 characterization study of the low-income multifamily market segment in its service
14 area, including identification and evaluation of different program design options to
15 address any identified market barriers. The study should evaluate opportunities and
16 pathways for unlocking deep energy retrofits by providing tailored financial and pre-
17 planning support for building owners during various phases of their project lifecycle
18 (e.g., new construction, rehab, or refinance).¹¹⁵

¹¹⁵ For example, low-income properties that leverage the Low Income Housing Tax Credit ("LIHTC") have to complete a capital needs assessment every year or two and recertify their properties after year 15. Each of these presents unique opportunities to align the efficiency programs to meet the needs of the building owner and finance partners. *See* <https://www.energy.gov/scep/slsc/home-energy-rebates-program/serving-affordable-multifamily-buildings-home-energy-rebates>.

VI. THE NEW DISPATCHABLE DSM INCLUDED IN THE MID-CASE CPCN RESOURCE PLAN IS TOO LOW, AND DOES NOT REFLECT SIGNIFICANT POTENTIAL FOR BATTERIES AND VPP RESOURCES TO REDUCE THE NEED FOR SUPPLY-SIDE RESOURCES

Q. Please describe the additional types of Dispatchable DSM the Companies included in this CPCN application.

A. The Companies included three minor enhancements to existing Dispatchable DSM measures, represented by BYOD Energy Storage, BYOD Home Generators, and Behavioral Demand Response (BDR).¹¹⁶ Figure 8 shows the summer and winter capacity of these new additions, as well as the expansion of CSR to reflect an additional 100 MW.

Figure 8. Limited-Duration Resources (2030 Installation; 2030 Dollars)¹¹⁷

	4-Hour BESS		Dispatchable DSM ²⁶			CSR ²⁷
	CR BESS	GH BESS	BYOD Energy Storage	BYOD Home Generators	BDR 50-200 kW	
Summer Capacity (MW) ¹⁶	100+	100+	0.89	0.85	1.45	100
Winter Capacity (MW) ¹⁶	100+	100+	0.89	0.85	1.45	100
Capacity Contribution ²⁸	85%	85%	39%	39%	39%	39%
Round-Trip Efficiency	87%	87%	N/A	N/A	N/A	N/A
Capital Cost (\$/kW) ¹⁸	1,954	2,131	N/A	N/A	N/A	N/A
Fixed O&M (\$/kW-yr) ¹⁹	25	25	N/A	N/A	N/A	81
Investment Tax Credit ²⁹	50%	50%	N/A	N/A	N/A	N/A
Earliest In-Service Year ²⁵	2028	2028	2027	2027	2028	2028

Q. Do the Companies include an explicit forecast of distributed customer-sited battery storage for this CPCN?

A. No. The Companies state that they do not explicitly model growth in BTM energy storage for purposes of assessing resource planning relevant to this proceeding. They give

¹¹⁶ See Wilson Direct, Ex. SAW-1 at 20.

¹¹⁷ *Id.*

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1 several reasons for this, including: minimal amount of storage connected to the grid, lack
2 of reasons to expect an increase in storage sufficient to impact resource planning relevant
3 to this proceeding, the fact that current BTM storage adoption and subsequent use is
4 implicitly captured in the Companies' load forecast and the assumption that the level of
5 battery storage increases with customer growth.¹¹⁸

6 **Q. Do the Companies cite other reasons why they did not include a forecast of**
7 **customer-sited storage?**

8 A. Yes. In justifying their decision to only forecast distributed solar out of the different
9 options for DERs, the Companies put forth three additional points regarding customer-
10 sited battery storage. First, the Companies claim that the return on investment of batteries
11 is not competitive under the Companies' current rate design, compared to solar PV.¹¹⁹
12 Second, the Companies claim that some customers may install storage as a source of
13 backup power, and if the storage device is solely discharged during outages, then by
14 default the behavior of the storage device during normal grid operations will be to
15 increase load (i.e., to charge for eventual use during a power outage).¹²⁰ Third, the
16 Companies point to what they portray as a relatively low adoption rate of storage, with
17 2,481 kW of distributed storage capacity interconnected at the end of 2024, reflecting a
18 6% storage attachment rate.¹²¹

¹¹⁸ Direct Testimony of Tim A. Jones, Senior Manager, Sales Analysis and Forecasting on Behalf of Kentucky Utilities Company and Louisville Gas and Electric Company, Case No. 2025-00045, at 36:3-12 (Feb. 28, 2025) ("Jones Direct").

¹¹⁹ *Id.* at 32:10-12.

¹²⁰ *Id.* at 33:5-10.

¹²¹ *Id.* at 33:11-15. The attachment rate reflects the percentage of all solar customers who have "attached" storage to their home solar units.

1 **Q. Do you have concerns about the Companies’ reasoning to leave out explicit**
2 **treatment of customer-sited battery storage from the forecast of potential resources**
3 **in this CPCN?**

4 A. Yes.

5 **Q. Do you agree that the Companies’ current load forecasting methodology accurately**
6 **reflects the impact of BTM storage interconnected to the grid, and that this implicit**
7 **inclusion will grow with customer growth into the future?**

8 A. No. By the Companies’ own admission, they “do not have access to data concerning how
9 these customers use their batteries”,¹²² and so they could not have based their assessment
10 on data. Indeed, using their stated logic, some customers may use the battery as a backup
11 power supply, and therefore may only discharge sporadically, leading to ambiguous
12 impacts on storage customers’ overall load profile used to develop the residential usage
13 per customer forecast models. Lastly, with only 0.03% of customers currently adopting
14 storage,¹²³ it is highly unlikely that the storage charge and discharge pattern, even if it
15 were exclusively dispatched for grid benefits, would be detectable enough to influence
16 future load forecast trends. For these reasons, the Companies’ claim that the current and
17 future forecasted storage adoption is “implicitly” accounted for in the load profile is
18 misleading.

19 For the sake of argument, even if it is taken as true that storage would be of
20 sufficient volume in the historical baseline period to have a measurable effect on the load
21 forecast, only including storage as an implicit load modifier that charges and discharges

¹²² *Id.* at 36:3-4.

¹²³ *Id.* at 33:12-15.

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1 according to the customer's preference ignores the reality that storage is a highly flexible
2 resource that can provide grid benefits by coordinating charging and discharging across
3 hundreds or thousands of distributed customer locations, acting as a VPP. The 2,481 kW
4 of current battery capacity interconnected to the system would be perhaps disjointed and
5 uncoordinated, being more aligned with each customers' particular settings and
6 preferences, but as the resource grows, and as existing customers are potentially
7 motivated to join a utility-run program, the charge and discharge behavior can act
8 together to create a large and meaningful resource.

9 **Q. Does the Companies' inclusion of additional Dispatchable DSM include Energy**
10 **Storage as a resource?**

11 A. Yes. Although the Companies did not include growth in distributed storage as an explicit
12 piece of their load forecast, they nevertheless included an additional 0.89 MW by 2030 in
13 their Dispatchable DSM portfolio to reflect BYOD Energy Storage.¹²⁴ Assuming 4.5 kW
14 per device, this amounts to 198 customers enrolled in the BYOD channel by 2030.¹²⁵

15 **Q. How much distributed storage potential do you estimate is reasonable to plan for**
16 **under current tariff design and policies?**

17 A. Carrying forward the Companies' 6% percent attachment rate, and applying that to the
18 forecasted solar adoption in the Base Case, I estimate 6.7 MW of distributed storage by
19 2032.¹²⁶ However, as I show in the next section, the solar PV forecast included in the

¹²⁴ Ex. SAW-1, at 20.

¹²⁵ 4.5 kW is the most common size of the Companies' current storage installations. *See* Jones Direct at 35:3.

¹²⁶ 150 MW of rooftop solar PV in 2032 across 14,750 customers. Factoring a six percent attachment rate yields 885 storage adopters, with an average system size of 7.7 kW per storage device equals 6.7 MW of total distributed storage.

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1 Base Case forecast is overly conservative based on market trends and future PV
2 trajectories and electricity cost increases. For example, if 250 MW of distributed rooftop
3 solar is achieved by 2032, the associated distributed storage based on the 6% attachment
4 rate increases to 11.3 MW. It is important to view this figure as a conservative lower case
5 because it does not consider additional mechanisms to increase storage adoption.

6 **Q. Are there viable mechanisms to increase the amount of distributed storage that the**
7 **Companies can enroll in the Dispatchable DSM program, for example by developing**
8 **new program offerings?**

9 A. Yes. It is important to note that my estimates above are based on extensions of current
10 tariffs and policy, which in effect means no new utility incentives for encouraging new
11 customer adoption of storage. Many utilities offer incentives aimed at incentivizing new
12 customer adoption of battery storage, such as Green Mountain Power's battery leasing
13 program in Vermont.¹²⁷ The Vermont example is instructive because the utility there saw
14 dramatic increases in customer requests after increasing winter storms, causing them to
15 lift the initial pilot enrollment cap.¹²⁸ Likewise, in the case of the Companies, the total
16 duration of the rolling blackouts during Winter Storm Elliot that impacted over 50,000
17 customers was four hours and 12 minutes, with the average customer out for one hour.¹²⁹
18 Battery storage, which for a typical residential installation is around 5 kW and can

¹²⁷ Ethan Howland, *Vermont PUC lifts caps on Green Mountain Power battery storage programs with Tesla, others*, Utility Dive (Aug. 29, 2023), https://www.utilitydive.com/news/vermont-puc-green-mountain-power-gmp-battery-storage-programs-tesla/692052/?utm_source=chatgpt.com.

¹²⁸ *Id.*

¹²⁹ See Final Order, *In the Matter of Electronic Investigation of Louisville Gas and Electric Company and Kentucky Utilities Company Service Related to Winter Storm Elliott*, Case No. 2023-00422, at 5-6 (Jan. 7, 2023).

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1 provide continuous max rated output for approximately two hours, is therefore a very
2 suitable resource to increase customer resilience to storm-related blackouts. Other notable
3 utility programs are Rocky Mountain Power in Utah who had 28 MW of solar and
4 storage enrolled in its Wattsmart program as of November 2024,¹³⁰ and Duke Energy
5 Carolinas who is also piloting a 30 MW solar plus storage VPP.¹³¹ Lastly, other models
6 of pairing customer-sited energy storage with utility-scale storage interconnected at
7 distribution voltage levels provides even broader opportunities to provide additional
8 resilience through a VPP. Platte River Authority in Colorado is planning to add 20 MW
9 of distribution-scale storage to its VPP plans, for a total VPP achievable capacity of 52
10 MW by 2030 and 113 MW by 2040.¹³²

11 **Q. What is a VPP, and how does it relate to achieving resource adequacy and the goals**
12 **of this CPCN?**

13 A. There is not yet a standard industry definition of a VPP, but they are broadly defined by
14 Brattle as a “portfolio of distributed energy resources (DERs) that are actively controlled
15 to provide benefits to the power system, consumers, and the environment.”¹³³ The
16 Institute of Electrical and Electronics Engineers (“IEEE”) is actively developing VPP

¹³⁰ Sonali Razdan et al., *Pathways to Commercial Liftoff: Virtual Power Plants 2025 Update*, U.S Department of Energy, at 72 (Jan. 2025), https://www.smartenergydecisions.com/wp-content/uploads/2025/04/liftoff_doe_virtualpowerplants2025update.pdf.

¹³¹ North Carolina Clean Energy Technology Center, *New Duke Energy PowerPair Pilot Program Approved by NC Utilities Commission* (Feb. 27, 2024), <https://nccleantech.ncsu.edu/2024/02/27/new-powerpair-pilot-program-approved-by-nc-utilities-commission/>.

¹³² Platte River Power Authority, *2024 Integrated Resource Plan*, at 89 (Apr. 04, 2023), <https://prpa.org/wp-content/uploads/2023/04/2024-Integrated-Resource-Plan.pdf>.

¹³³ NARUC, *Regulators’ Financial Toolbox: Virtual Power Plants*, at 2 (June 21, 2023), <https://pubs.naruc.org/pub/F93C25D1-AD76-1A01-876D-E996D9522545>.

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standards to specify VPP functional requirements.¹³⁴ Common definitions emphasize the controllability or dispatchability of the DERs aggregated under a VPP, but as the IEEE notes, uncontrolled assets can still be aggregated for providing energy, similar to run-of-river hydro systems.¹³⁵

Studies have shown how VPPs can offset significant new generation resource needs and achieve cost savings and carbon reductions compared to natural gas alternatives. For example, Rocky Mountain Institute studied VPPs in a model of the Colorado electrical system using capacity expansion and production cost modeling tools, and found between 1 and 2 GW of potential SCCT reductions and billions of dollars in cost savings.¹³⁶ Similarly, Brattle recently concluded that a 400 MW VPP could provide resource adequacy on a lower net-cost basis compared to supply-side alternatives of a natural gas peaker plant and a utility-scale battery.¹³⁷

Q. What kind of resources typically comprise VPPs?

A. Based on a broad review of potential studies, Brattle's study methodology first developed a group of controllable DERs and realistic market potential and achievable customer participation rates to characterize the VPP (Figure 9). The RMI study assumed similar

¹³⁴ Robert W. Cummings, *Guide for Virtual Power Plant (VPP) Functional Specification for Alternate and Multi-Source Generation IEEE P2030.14*, IEEE, at 6 (June 5, 2024), https://www.energy.gov/sites/default/files/2024-06/Guide%20for%20VPP%20-%20IEEE%20Standards_optimized.pdf.

¹³⁵ *Id.* at 9.

¹³⁶ Jacob Becker et al., *Power Shift: How Virtual Power Plants Unlock Cleaner, More Affordable Electricity Systems: Technical Appendix*, RMI (Sept. 2024), https://rmi.org/wp-content/uploads/dlm_uploads/2024/10/power_shift_virtual_power_plants_appendix.pdf.

¹³⁷ Ryan Hledik & Kate Peters, *Real Reliability: The Value of Virtual Power, Vol. 1: Summary Report*, Brattle Group, at 24 (May 2023), <https://www.brattle.com/wp-content/uploads/2023/04/Real-Reliability-The-Value-of-Virtual-Power-Full-Report.pdf>.

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resources as the Brattle case.¹³⁸

Figure 9: Brattle 400 MW Resource Adequacy VPP Definition

	Smart Thermostat DR	Smart Water Heating	Home Managed EV Charging	BTM Battery DR
Eligibility (% of residential customer base)	67% summer; 35% winter	50%	15%	1%
Participation (% of eligible customers)	30%	30%	40%	20%
Total Controllable Demand at Peak (MW)	204 MW	114 MW	79 MW	26 MW
Participation Incentive (\$ per participant per year)	\$25 per season	\$30	\$100	\$500
Other Implementation Costs , including marketing and DERMS (\$ per participant per year)	\$43	\$55	\$80	\$140
VPP Operational Constraints	15 five-hour events per season, plus 100 hrs of minor setpoint adjustments per year	Daily load shifting of water heating load, ancillary services	Daily load shifting of vehicle charging load	15 demand response events per year

Q. How does a VPP differ from either of these resources viewed in isolation in terms of the contributions to resource adequacy, such as is conducted by the Companies in developing the case for this CPCN?

A. While each of these resources can be included separately into resource planning, they will typically have lower performance when viewed in isolation as opposed to a contributor to an aggregated DER resource like a VPP. This is a classic situation of “the whole is

¹³⁸ Becker, supra note 136, at 7. Notably, the RMI example includes residential and commercial space and water heating control technologies, as well as medium- and heavy-duty EVs and e-buses. This illustrates the flexibility of configuring a VPP with different resource types to match the system and customer resources.

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greater than the sum of the parts” and reflects greater flexibility in the aggregated resources’ profile in terms of shape, dispatchability, and availability.

Q. What other mechanisms are there to increase deployment of VPPs and storage?

A. As recognition of the flexibility and scalability of VPPs has grown, there is a growing need for new procurement methods that are suited to the particular needs of the asset types. There are new procurement models, like SparkFund’s Distributed Capacity Procurement (“DCP”) mechanism, that are partnering with utilities to facilitate deployment of DERs and VPP resources at scale. Xcel Energy proposed a DCP in comments on its recent 2024-2040 Upper Midwest Resource Plan that would achieve between 400 MW and 1 GW from DERs,¹³⁹ and the Joint Exelon Utilities in Maryland discuss DCP within their proposal to procure 150 MW of distribution-connected storage, with 30 percent of the procurement reserved for third-party ownership.¹⁴⁰

Another viable financing mechanism to increase deployment of VPPs and storage are Inclusive Utility Investment models, such as the PAYS approach leveraged by Roanoke Cooperative in North Carolina.¹⁴¹ Under this model, the utility pays for upfront DER installations and recovers the cost through a fixed charge on the customer’s bill that is lower than the estimated energy savings. This approach enables broader participation,

¹³⁹ Autumn Proudlove et al., *50 States of Virtual Power Plants & Distributed Energy Resources: 2024 State Policy Snapshot*, at 13 (Feb. 2025), https://static1.squarespace.com/static/5ac5143f9d5abb8923a86849/t/67a68454ac578d0b39251fc1/1738966103047/2024-VPP-Report-Final.pdf?utm_source=chatgpt.com.

¹⁴⁰ Md. Pub. Serv. Comm’n, *Exelon MD Utilities’ Request for Approval under Case No. 9715 MD Energy Storage Program*, Case No. 9715 (ML 316129), at 7-9 (Feb. 21, 2024), provided as Exhibit AE-2.

¹⁴¹ Sonali Razdan et al., *Pathways to Commercial Liftoff: Virtual Power Plants 2025 Update*, U.S Department of Energy, at 51 (Jan. 2025), https://www.smartenergydecisions.com/wp-content/uploads/2025/04/liftoff_doe_virtualpowerplants2025update.pdf.

1 especially for low-income customers, and supports equitable expansion of VPP-enabling
2 technologies.

3 **Q. Are there technical requirements that need to be put in place before**
4 **operationalizing and investing in a VPP?**

5 A. Yes. While basic VPPs can be deployed in six months with less than \$1 million in
6 upfront investment,¹⁴² there remain technical requirements that must be established to
7 enable scalable and cost-effective VPP deployment.

8 Sophisticated VPP configurations require additional hardware and software to enable
9 high-resolution visibility into distribution grid conditions, and support localized, frequent
10 dispatch of DERs. This includes sensing, analytics, and communications infrastructure.

11 Standardization across utility-aggregator interfaces, aggregator-to DER interfaces, and
12 cybersecurity practices are essential to VPP deployment. VPP platform providers need to
13 be able to send and receive information to and from a utility using an interface and data
14 language compatible with varying utility IT systems. Recent efforts to address this need
15 have moved rapidly, developing utility communication protocols, shared DER registries,
16 and cybersecurity certification standards such as UL 2941.¹⁴³ Recently, the U.S.

17 Department of Energy (“DOE”) and industry partners have initiated platforms like
18 EPRI’s FlexIT and DOE’s TSO-DSO-DER coordination framework to support VPP
19 implementation through standardized operational platforms.¹⁴⁴

20 **Q. Should the Companies pursue more aggressive development of energy storage**

¹⁴² *Id.* at 4.

¹⁴³ *Id.* at 24.

¹⁴⁴ *Id.* at 23.

1 **resources?**

2 A. Yes. In a recent study by the Brattle Group and Lawrence Berkeley National Lab on
3 strategies to scale VPP deployment, the authors conclude that regulators should take an
4 active role in promoting future scaling of VPPs by requiring utilities to develop a plan for
5 how they will scale this important resource after successful implementation of a pilot
6 program.¹⁴⁵ Because of the supply chain issues related to natural gas turbines that I
7 discuss elsewhere in my testimony, a pluralistic approach to developing new, emerging
8 technologies like VPPs would increase energy security for Kentuckians.

9 **Q. What are your recommendations regarding Dispatchable DSM and distributed**
10 **storage with regard to this application?**

11 A. Based on the analysis discussed above, I recommend that the Commission:

- 12 • Direct the Companies to conduct a process evaluation of current battery storage
13 customers to understand barriers and motivations, and to inform evolutions in
14 program design that are intended to balance between backup resilience use cases and
15 leveraging batteries for grid benefits.
 - 16 ○ As part of this, Companies should evaluate different rate designs that consider
17 how solar and storage interact with TOU (both current TOU structure and
18 potential new structures based on grid needs assessments) and what incentives or
19 price signals would be necessary to encourage more grid-friendly battery
20 charge/discharge patterns, and to increase future enrollment potential.

¹⁴⁵ Ryan Hledik et al., *Distributed Energy, Utility Scale: 30 Proven Strategies to Increase VPP Enrollment*, at 58 (Dec. 2024), https://eta-publications.lbl.gov/sites/default/files/2024-12/30_strategies_to_increase_vpp_enrollment_12-19-2024.pdf.

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- 1 • Direct the Companies to modify their existing BYOD Pilot concept to include a
2 broader focus on gaining experience with dispatch coordination and communication
3 of BTM battery aggregations with other controllable loads like water heaters,
4 thermostats, and EV charging. This would allow the Companies to better understand
5 the contributions of each unique resource’s characteristics regarding charge/discharge
6 behavior and gain overall confidence in calling on this new type of resource for
7 system operations.
- 8 • Direct the Companies to issue a Request for Information to gauge developer and
9 aggregator interest in VPP deployment in Kentucky.
- 10 • Direct the Companies to develop a scaling plan, in collaboration with stakeholders,
11 for post-pilot implementation in order to maximize the potential benefits of this new
12 resource type to contribute effectively and materially to the resilience and diversity of
13 energy supply for its customers.

**VII. THE DISTRIBUTED SOLAR MODELED IN THE CPCN MID-CASE
FORECAST IS TOO CONSERVATIVE AND SHOULD BE INCREASED.**

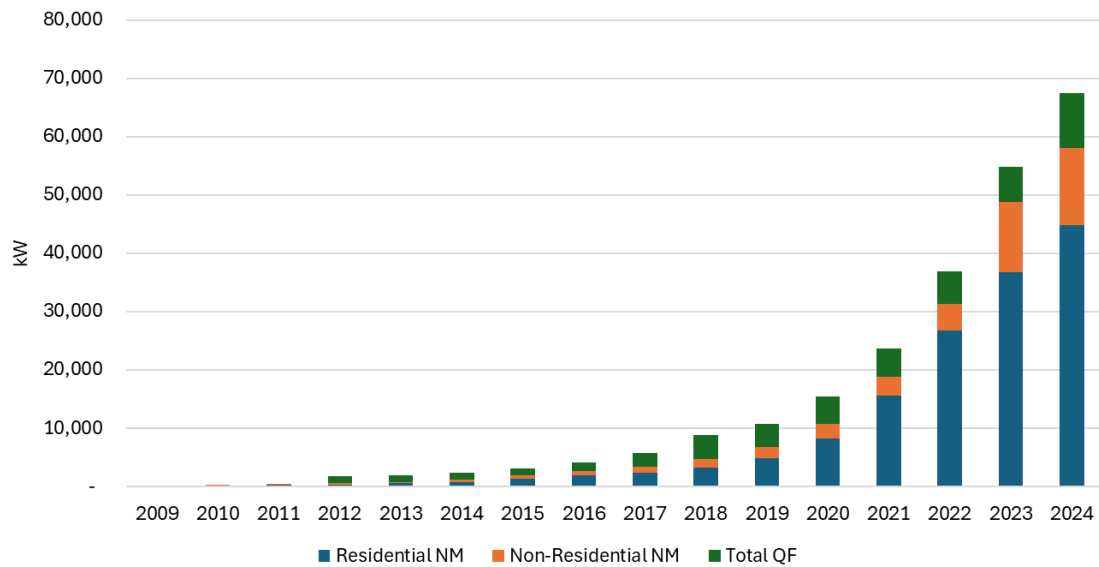
Q. How much distributed solar PV do the Companies have interconnected to its system today?

A. The Companies have approximately 67 MW of distributed PV installed as of 2024.¹⁴⁶
This amount consists of 58 MW of net metered customer solar installations as well as 9
MW of qualifying facilities (“QFs”). Figure 10 shows the historical annual growth of
distributed solar by each of these segments.¹⁴⁷

¹⁴⁶ Jones Direct at 37:3-4.

¹⁴⁷ LG&E/KU Resp. to JI 2-46(a)-(b).

Figure 10: Historical Distributed Solar PV Installed Capacity (Cumulative)

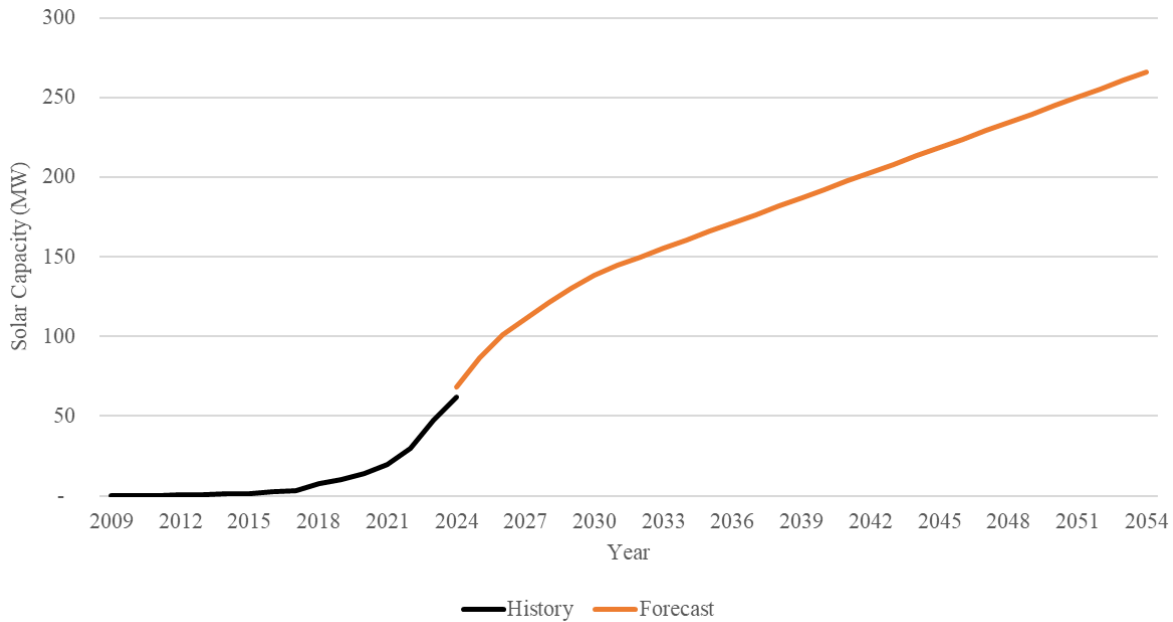


Q. Did the Companies forecast for future distributed solar adoption?

A. Yes. The Companies are including continued growth, albeit at a decreasing rate, growing from 67 MW in 2024 (base year) to 150 MW of installed capacity by 2032, and reaching 266 MW by 2054.¹⁴⁸ Figure 11 shows the forecast over the planning period.

¹⁴⁸ Jones Direct at 37:2-5.

1 *Figure 11: History and Forecast of Distributed Generation*¹⁴⁹



2
3 **Q. Please explain how the Companies developed their forecast for distributed**
4 **generation.**

5 A. The Companies forecasted future growth of distributed solar generation from increased
6 adoption of net energy metered (“NEM”) customer rooftop solar and from continued
7 growth of small and large qualifying facilities (“QFs”).¹⁵⁰ To forecast adoption of NEM
8 growth, the Companies utilized an in-house statistical model that estimates future
9 adoption based on various economic input variables, such as the avoided cost-to-LCOE

¹⁴⁹ *Id.* at 6. Also provided under Jones Direct, Ex. TAJ-2 (Public).

¹⁵⁰ 2024 IRP, Vol. I, Figs.5-6, 5-7, & p. 7-21 (Oct. 18, 2024) (“2024 IRP”).

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ratio¹⁵¹ and a measurement of disposable personal income.¹⁵² For QFs, the Companies assumed a continuation of the observed linear growth trend wherein future installed QF projects are the average size of the currently installed projects.¹⁵³

Q. Do you have concerns with the Companies' forecast of distributed solar PV growth that is used to modify the load forecast in this CPCN?

A. Yes, I have several concerns which I will elaborate on below. First, there are errant assumptions in the calculation of the key economic inputs to the avoided cost-to-LCOE metric, which is a key variable in the statistical adoption model utilized by the Companies. Second, the Companies' statistical model has notable shortcomings. And third, the Companies do not adjust for any locational considerations or additional incentives offered by local governments or other market actors.

Q. What are the errant assumptions that are impacting the avoided cost-to-LCOE metric?

A. The Companies calculated the LCOE of solar PV based on inputs derived from NREL's Annual Technology Baseline ("ATB") 2023 report,¹⁵⁴ which in turn used capital costs

¹⁵¹ This ratio is also called the "grid-to-LCOE" ratio in the supporting workpaper. The numerator is defined as the avoided costs (defined as the reductions in retail purchases from the self-consumed portion of the solar generation) plus the net exported amount that is compensated through the applicable NEM tariff. The denominator is the levelized cost of energy (LCOE) of the total kWh produced over the lifetime of the solar panel, accounting for capital and O&M costs, expected generation output, and solar system degradation. *See* Case No. 2024-00326, LG&E/KU Resp. to JI 1-45(b), "Price Needed for Energy Exported to Grid to Meet Total Project Costs_SAW_25BP_GP_IRP.xlsx", on 'Model' tab, cells D32:AT32.

¹⁵² LG&E/KU Resp. to JI 3-14(c).

¹⁵³ Jones Direct at 37:11 to 38:2.

¹⁵⁴ Case No. 2024-00326, LG&E/KU Resp. to JI 1-45(b), "Price Needed for Energy Exported to Grid to Meet Total Project Costs_SAW_25BP_GP_IRP.xlsx". .

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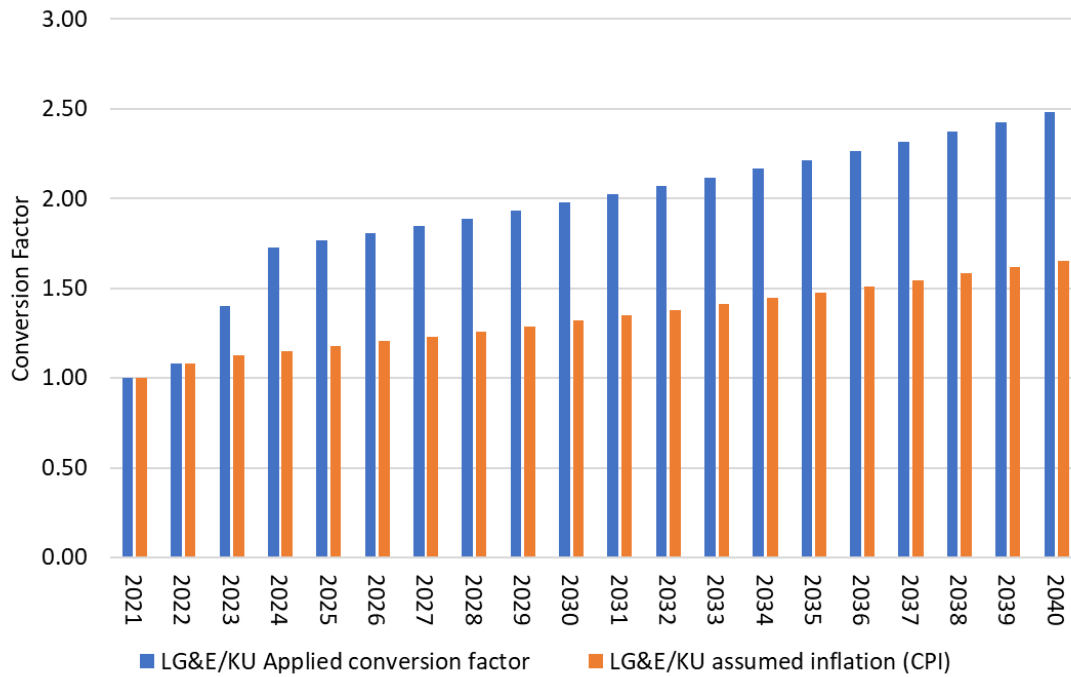
1 with a 2021 dollar year denominated in real dollars.¹⁵⁵ In order to convert the real dollars
2 into nominal,¹⁵⁶ the Companies used their own conversion factors that were dramatically
3 higher than inflation, and did not provide any documentation or justification for what
4 these conversion factors were meant to represent or where they were sourced from.
5 Confusingly, the cell column for these factors reads “Real-to-Nominal Conversion for
6 NREL ATB (Solar)”, even though nothing like this factor is found in the NREL source
7 documentation and the Companies also have a different conversion factor two rows
8 below this one called “Real-to-Nominal Conversion for NREL ATB (CPI)” that appears
9 to have values more closely aligned with expected inflation.

10 The calculations that lead to the pertinent input values, however, are based off of
11 the errant conversion factors. Figure 12 illustrates the large deviation.

¹⁵⁵ Case No. 2024-00326, “2023-ATB-Data_Master_v9.0.xlsx”.

¹⁵⁶ Real to nominal conversions are common when looking at time series data where price inflation is a key factor to consider.

1 *Figure 12: Companies' real to nominal conversion factors used for solar modeling*

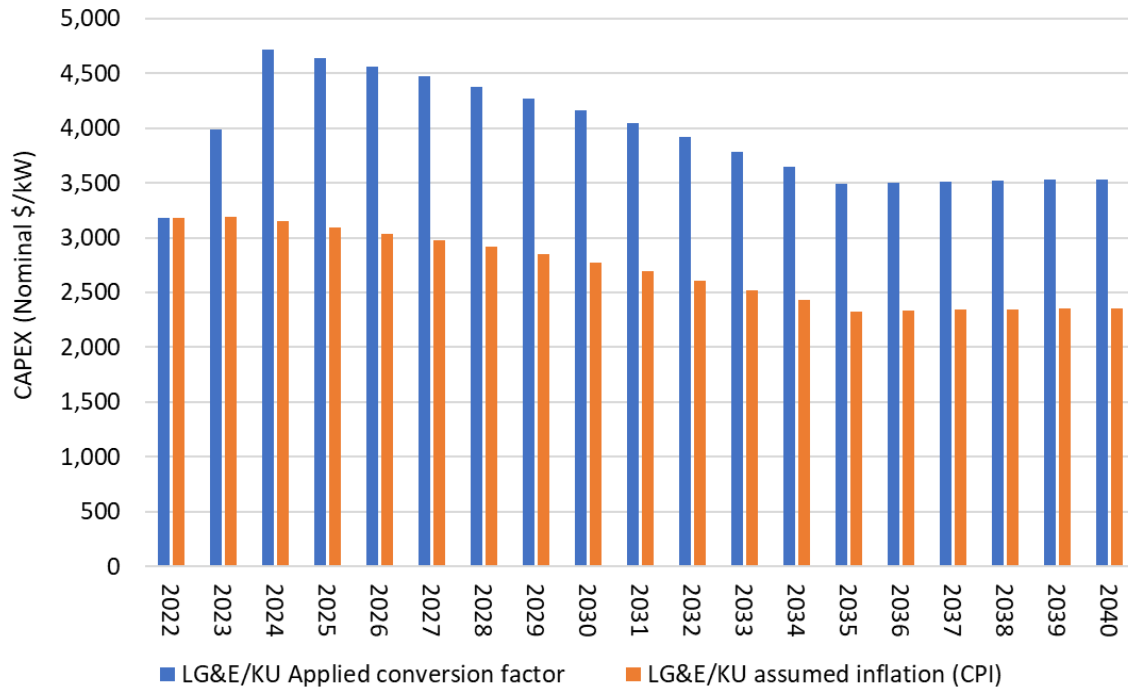


2
3 As you can see, the “LG&E/KU Applied conversion factor” is significantly higher
4 beginning in 2023 and escalating throughout the 20-year period.

5 **Q. Could there be some other justifiable reason to inflate the costs of solar this much?**

6 A. Although it is possible that the Companies intentionally applied this conversion factor,
7 Figure 13 shows the ultimate impacts on \$/kW of capex (installed cost) that results from
8 using the two different value streams, illustrating that it is unjustifiable compared to
9 recent market evidence.

1 *Figure 13: CAPEX (\$/kW) comparison utilized in avoided cost-to-LCOE metric*



2
3 Based on 2023 benchmark data from NREL, installed costs for residential solar were
4 between \$2,481/kW and \$2,849/kW,¹⁵⁷ which is much more in line with the adjusted
5 values based on the CPI index in Figure 13 as opposed to the higher system costs
6 assumed by the Companies in their modeling. The Companies' modeling of capital costs
7 leads to an additional \$13,155 for the average residential system size of 8.5 kW installed
8 in 2025.

9 **Q. Please describe the Companies' statistical model and methodology for forecasting**
10 **future distributed rooftop solar adoption that is the basis of your second concern.**

¹⁵⁷ Vignesh Ramasamy et al., *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2023*, Nat'l Renewable Energy Lab'y, at 20 (Sept. 2023), <https://docs.nrel.gov/docs/fy23osti/87303.pdf>. Note that to compare costs for a similar size PV system, the NREL benchmark solar costs were adjusted upward to match the 8.5 kW typical installation size assumed in the Companies' modeling. The unadjusted costs for an 8 kW system from NREL are \$2,335 and \$2,682 respectively.

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1 A. The Companies used a two-part modeling approach in the statistical software R to
2 estimate how many residential customers will install solar panels under current NEM
3 compensation structures.¹⁵⁸ First, they built a *short-term model* to estimate near-term
4 monthly growth in solar customers. Then, they developed a *long-term model* to forecast
5 how many total customers will have solar over a longer time horizon. The Companies
6 state that using multiple models was necessary to correct for poor model performance
7 beginning in 2020 due to COVID-19.¹⁵⁹

8 The short-term model attempts to predict how many new customers will sign up
9 for solar each month. Its key inputs are derived from the flawed avoided cost-to-LCOE
10 metric described above, as well as the retail price of electricity, historical seasonal
11 patterns in customer adoption trends, and finally a measure of economic purchasing
12 power (disposable personal income or “DPI”).

13 In contrast, the long-term model looks at the total cumulative number of
14 customers installing solar over time, and uses a simplified model structure consisting
15 solely of the avoided cost-to-LCOE ratio and DPI.

16 Finally, of note is that the Companies segment the input data into time periods,
17 creating a pre-2020 segment, a 2020 to April 2024 segment, and a future (forecasted)
18 segment. While this is a useful way to structure data in a modeling exercise because it
19 facilitates model training and forecast validation, as I discuss below there are issues with

¹⁵⁸ My description of the Companies’ modeling approach is based on a review of the R code found in confidential workpapers in Exhibit TAJ-2 at

“Load_Forecasting\Electric_Load_Forecast\Electric\Forecasts\PV\model and output.” See LG&E/KU Resp. to JI 3-14(a)(i).

¹⁵⁹ LG&E/KU Resp. to JI 3-14(d).

1 how the Companies appear to actually have executed this feature.

2 **Q. What are your concerns with the Companies’ modeling approach as you’ve**
3 **described it?**

4 A. The Companies claim that “[t]he overall model predictions are highly correlated to the
5 [historical PV adoption] used [to train] the model (R-square values of .92 and .94
6 for KU and LG&E, respectively)”,¹⁶⁰ implying that the model is robust and a good
7 predictor of future adoption. However, this correlation modeling uses total cumulative
8 customer counts over time—which naturally increases year after year—so it is easier for
9 the model to appear accurate just by following the trend. This doesn’t necessarily mean it
10 is good at predicting future changes.

11 The above findings indicate the potential for overfitting the model to conform to
12 past trends. The best way to test this is to construct a training dataset and a test dataset
13 consisting of a portion of the baseline historical period that is “withheld” from the model
14 to see how well it predicts actual known adoption. However, the Companies did not test
15 the model in this way, meaning that it is difficult to tell whether the model would be
16 reliable for future planning.

17 **Q. Please elaborate on your third concern that the Companies’ solar forecast does not**
18 **account for any locational considerations or additional incentives offered by local**
19 **governments.**

20 A. The process of product diffusion does not simply follow narrow economic principles. In
21 particular with the case of solar, customers are motivated by different factors such as a

¹⁶⁰ LG&E/KU Resp. to JI 3-14(c).

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1 desire to reduce their environmental impact and to gain energy independence or
2 resilience, and of course saving money is a primary consideration as well. The
3 Companies have not studied customer motivations for adopting solar,¹⁶¹ and so therefore
4 their forecasting ability is limited. This is because adoption behaviors change based on
5 the influence of our neighbors, such as by word-of-mouth, as well as traditional
6 marketing.

7 As more and more customers adopt solar, which is a highly visible consumer
8 good and a significant home purchase, more people throughout the community learn
9 about it and begin to consider purchasing themselves. This process of consumer product
10 diffusion (referred to as “market diffusion” or “S-curve” modeling) is a well-known and
11 extensively studied phenomenon in other product categories, and has been applied in
12 leading studies by researchers at NREL.¹⁶² Although the Companies state their model
13 accounts for customers’ decisions to adopt solar in the past based on non-economic
14 motivations, and projects those continuing trends forward,¹⁶³ this misses a critical piece
15 about social influence that is captured by the S-curve modeling approach.

16 In a randomized study in Connecticut, researchers found that Solarize campaigns
17 substantially influenced the rate of adoption of solar, primarily driven by word-of-mouth
18 influence, which could play just as meaningful a role in spurring adoption than the type

¹⁶¹ LG&E/KU Resp. to JI 3-13.

¹⁶² Ben Sigrin et al., *The Distributed Generation Market Demand Model (dGen): Documentation*, Nat’l Renewable Energy Lab’y, at 22 (Feb. 2016),
<https://docs.nrel.gov/docs/fy16osti/65231.pdf>.

¹⁶³ LG&E/KU Resp. to JI 3-13..

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of price discounts that customers received from bulk purchasing the solar panels.¹⁶⁴

Q. Are there any local examples of Solarize campaigns or other local incentives that might spur adoption to higher levels than just based on the retail NEM rate calculus?

A. Yes. Louisville Metropolitan Government has launched a Solarize campaign among other sustainability-related actions.¹⁶⁵

Q. Should the policies and goals set forth by the Louisville Metropolitan Government and related actors be incorporated into the Companies' planning?

A. Yes. The type of local clean energy goals such as the adoption of Clean Energy Resolution ("R-102-19") in February 2020 by the Louisville Metro Council to reach 100% clean electricity for government operations by 2030, and 100% clean energy community-wide by 2040, represent substantial and sizeable commitments that can impact utility planning needs.¹⁶⁶

Q. Based on your overall review of the Companies' approach to distributed solar forecasting, please summarize your findings.

A. Based on the significant flaws I found in the Companies' avoided cost-to-LCOE modeling, their limited approach to validating the solar forecast model's predictive power

¹⁶⁴ Bryan Bollinger et al., *The Effect of Group Pricing and Deal Duration on Word-of-Mouth and Durable Good Adoption: The Case of Solarize CT*, at 22-23 (2016), https://resources.environment.yale.edu/gillingham/BollingerGillinghamTsvetanov_SalesDurationGroupBuys.pdf.

¹⁶⁵ 100 Percent Louisville, 100% clean energy community-wide by 2040, <https://www.100percentlou.com/2040> (last accessed June 13, 2025).

¹⁶⁶ U.S. Dept. of Energy, *Louisville Communities LEAP Engagement: Improving Energy Efficiency in Affordable Housing*, Nat'l Renewable Energy Lab'y, at 2 (Aug. 2024), <https://docs.nrel.gov/docs/fy24osti/90277.pdf>.

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1 for future adoption trends, and the failure to incorporate additional incentives from a
2 large metropolitan area like Louisville Metropolitan Government, I conclude that the
3 Companies are in all likelihood significantly undercounting future rooftop solar additions
4 in its service area, and therefore overstating the need for new supply side resources to
5 meet future load growth.

6 **Q. What are your recommendations regarding the Companies' distributed solar**
7 **forecast?**

8 A. Based on the analysis described above, I recommend that the Commission direct the
9 Companies as follows:

- 10 • Adjust their Base load forecast in this CPCN by eliminating the use of the avoided
11 cost-to-LCOE methodology and instead incorporating the “NM Cumulative Capacity
12 – High” solar forecast scenario developed for the 2024 IRP.¹⁶⁷
- 13 • Conduct an outside assessment of its solar PV forecasting modeling with a third-party
14 consultant and in coordination with stakeholders, and implement changes and
15 improvements based on the findings before the next IRP.
- 16 • Investigate the potential benefits of forecasting locational solar adoption based on
17 customer propensity modeling, with the capability to predict local solar adoption
18 patterns based on differences in housing stock, customer demographics, localized
19 incentives, and other factors.

¹⁶⁷ See Response of Kentucky Utilities Company and Louisville Gas and Electric Company to the Joint Motion of Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association's Initial Request for Information Dated November 22, 2024, Case No. 2024-00326, Question 76 (b) (Dec. 18, 2024) (“LG&E-KU Resp. to JI 1-76(b)”).

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- 1 • Work with stakeholders to develop a roadmap and framework for a NEM successor
2 program or tariff in anticipation of surpassing the statutory threshold beyond which
3 the Companies may elect to stop offering NEM to new customers, which occurs when
4 of NEM installed capacity reaches exceeding 1% of the previous year's peak load.

5 The scope of this work should include:

- 6 • Evaluating possible program pairings of solar with storage, as was done with the
7 Duke Energy Carolinas Power Pair program.
- 8 • Understanding customer preferences and motivations to adopt solar and storage.
- 9 • Alignment of interconnection application process, rebate frameworks, and
10 alternative procurement mechanisms.
- 11 • Development of a new community solar tariff structure that recognizes this
12 resource as a grid asset that can provide environmental benefits, jobs, and local
13 resilience, especially when paired with front-of-the-meter storage. This is in line
14 with the Commission's findings that "QF's invest in technologies like solar, wind,
15 or small-scale cogeneration, which offer significant environmental, and reliability
16 benefits that LG&E/KU should take advantage of to reduce greenhouse gas
17 emissions or diversify its energy supply to reduce market volatility to its
18 customers."¹⁶⁸ In this vein, when coordinated with effective grid planning,
19 Community Solar can provide strategic benefit to the grid and customers in terms
20 of reducing interconnection costs, deferring distribution capital upgrades, and

¹⁶⁸ See Case No. 2023-00404, Final Order at 21 (Nov. 6, 2023).

reducing distribution line losses.¹⁶⁹

VIII. CONCLUSION & RECOMMENDATIONS

Q. Based on your analysis, what are your conclusions with regard to the Companies' requests in this application?

A. Based on my review of the Companies' application, I find that the Companies miss another opportunity to increase their DSM portfolio and are thus foregoing potential energy and cost savings. Instead, they propose an increase to their supply side resource portfolio, that is larger and more gas-reliant than would be required had cost-effective DSM resources been pursued earlier and/or modeled accurately in the instant application.

Q. What recommendations do you have for the Kentucky Public Service Commission?

A. Based on my review, I recommend that the Commission:

~~15-1.~~ Order the Companies to modernize their DSM-EE and Dispatchable DSM cost-effectiveness methods by:

- a. Developing a T&D avoided cost value for incorporation into future DSM-EE cost-effectiveness analyses.
- b. Conducting a study of NEBs including value of resilience, health and safety, and environmental benefits.

~~16-2.~~ Order the Companies to update their methodology for incorporating DSM-EE into any future IRP and related resource planning workflows by:

- a. Developing a methodology to integrate measure-specific load shapes into

¹⁶⁹ Miguel Heleno et al., *Distribution Grid Impacts of Community Solar*, Lawrence Berkeley Nat'l Lab'y, at -2 (Sept. 2023), https://eta-publications.lbl.gov/sites/default/files/lbl_cs_grid_impacts_final_09.01.23_v3.pdf.

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resource planning.

b. Evaluating existing methodologies for attributing peak demand impacts to DSM-EE measures, especially for temperature-dependent measures like HVAC and water heating.

c. Model DSM-EE as a selectable resource in the IRP framework, as opposed to a reduction in the load forecast. To accomplish this, the Companies should develop a supply curve in \$/MW that ranks the available potential from the potential study, along with any other related characteristics required by the Companies' resource planning models. The outcomes of the study should be shared with stakeholders and the Commission before the next IRP to inform discussions about whether updating to the new methodology would be beneficial.

17.3. Order the Companies to recalculate the portfolio capacity need based on an updated assessment of dispatchable DSM's contributions to resource adequacy. The Companies should account for each resource's contributions compared to the new proxy capacity resource of a [REDACTED] as opposed to a SCCT.

18.4. Work with stakeholders to conduct a study seeking to identify and quantify additional benefits of DSM-EE that are outside of the current generation capacity deferral and marginal energy benefits assigned to them under the Companies' avoided cost buildup. The study should identify and support methodologies needed to assess risk-mitigation impacts of DSM-EE by accounting for the following:

a. An updated marginal price forecast that better accounts for market price extremes.

b. Identify pP Potential unquantified system benefits associated with DSM-EE by

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1 running the portfolio analysis with and without DSM-EE in order to assess
2 changes to PVRR or similar metric. The Commission should direct the
3 Companies to take the results of this study and translate it into a \$/MWh
4 framework that can be incorporated to future DSM-EE cost effectiveness
5 modeling.

6 19.5. Order the Companies to improve their efforts at characterizing the most efficient
7 energy savings opportunities in the market by:

- 8 a. Instituting a process for refreshing measure characterization and efficiency
9 assumptions on a rolling basis, and at minimum for each new potential study
10 conducted for an IRP.
- 11 b. Developing a formal emerging technology evaluation and planning framework, in
12 collaboration with stakeholders, and filing for approval with the Commission
13 during its next DSM-EE plan update or before the next IRP, whichever comes
14 first.

15 20.6. Direct the Companies to conduct a process evaluation of current battery storage
16 customers to understand barriers and motivations, and to inform evolutions in program
17 design that are intended to balance between backup resilience use cases and leverage
18 batteries for grid benefits.

- 19 a. As part of this, Companies should evaluate different rate designs that consider
20 how solar and storage interact with TOU (both current TOU structure and
21 potential new structures based on grid needs assessments) and what incentives or
22 price signals would be necessary to encourage more grid-friendly battery
23 charge/discharge patterns, and to increase future enrollment potential.

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1 ~~21.7.~~ Direct the Companies to modify their existing BYOD Pilot concept to include a
2 broader focus on gaining experience with dispatch coordination and communication of
3 BTM battery aggregations with other controllable loads like water heaters, thermostats,
4 and EV charging.

5 ~~22.8.~~ Direct the Companies to issue a Request for Information to gauge developer and
6 aggregator interest in VPP deployment in Kentucky.

7 ~~23.9.~~ Direct the Companies to develop a scaling plan for VPPs, in collaboration with
8 stakeholders, for post-pilot implementation in order to maximize the potential benefits of
9 this new resource type to contribute effectively and materially to the resilience and
10 diversity of energy supply for its customers.

11 ~~24.10.~~ Order the Companies to adjust their Base Load Forecast in this CPCN by
12 eliminating the use of the avoided cost-to-LCOE methodology and instead incorporating
13 the “NM Cumulative Capacity – High” solar forecast scenario developed for the 2024
14 IRP.¹⁷⁰

15 ~~25.11.~~ Order the Companies to conduct an outside assessment of its solar PV forecasting
16 modeling with a third-party consultant and in coordination with stakeholders, and
17 implement changes and improvements based on the findings before the next IRP.

18 ~~26.12.~~ Investigate the potential benefits of forecasting locational solar adoption based on
19 customer propensity modeling, with the capability to predict local solar adoption patterns
20 based on differences in housing stock, customer demographics, localized incentives, and

¹⁷⁰ See Response of Kentucky Utilities Company and Louisville Gas and Electric Company to the Joint Motion of Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association’s Initial Request for Information Dated November 22, 2024, Case No. 2024-00326, Question 76 (b) (Dec. 18, 2024) (“LG&E-KU Resp. to JI 1-76(b)”)

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1 other factors.

2 27.13. Work with stakeholders to develop a roadmap and framework for a net energy
3 metering (“NEM”) successor program or tariff in anticipation of surpassing the statutory
4 threshold beyond which the Companies may elect to stop offering NEM to new customers,
5 which occurs when ~~of~~ NEM installed capacity reaches ~~exceeding~~ 1% of the previous year’s
6 peak load. The scope of this roadmap and framework should include evaluating possible
7 program pairings of solar with storage, as was done with the Duke Energy Carolinas
8 Power Pair program.

9 **Q. Does this conclude your testimony?**

10 A. Yes.

VERIFICATION

The undersigned, Andrew Eiden being first duly sworn, deposes and says that his has personal knowledge of the matters set forth in the foregoing testimony and that the information contained therein is true and correct to the best of his information, knowledge, and belief, after reasonable inquiry.

Andrew Eiden

Subscribed and sworn to before me by Andrew Eiden this 17th day of July, 2025.

Courtney Jones

Notary Public

State of Texas; County of Harris

My commission expires: 07/11/2027

Electronically signed and notarized online using the Proof platform.

