COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

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

June 16, 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 operations. In addition, while at PGE, I was a workstream lead to advance bottom-up load and DER forecasting into PGE's Transmission & Distribution planning efforts. Part of my duties as a workstream lead included participating in internal working groups regarding the establishment of new policies and practices surrounding large load forecasting and planning. I have also served on a number of industry working groups and technical advisory committees related to DERs, Transportation Electrification, and Distribution Grid Impacts.

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

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

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

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

Q. What is the purpose of your testimony?

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

Q. How is your testimony organized?

A. In Section II, I present a summary of my findings and recommendations. In Section III, I summarize the Companies' modeling of demand-side resources in the 2025 CPCN Resource Assessment. In section IV, I discuss some of the fundamental flaws I encountered in the Companies' Potential Study used to inform the existing DSM programs, as well as the changes in the Companies' and the broader planning environment that render the existing programs too low as the Companies plan for additional investment in supply-side resources. In Sections V, VI, and VII, I further explain why the DSM-EE, dispatchable DSM, and distributed solar levels included in the 2025 Mid-Case CPCN load forecast are too low and do not reflect the Companies' true potential; I make recommendations on how these could be further enhanced, and estimate the additional DSM potential that the Companies should pursue. In the final section, I conclude and summarize my recommendations.

II. SUMMARY OF RECOMMENDATIONS

Q. Please summarize your findings.

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. The Companies' DSM and DER forecasts are low due to a number of reasons:

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

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,

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. Potential 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 can be

incorporated into future DSM-EE cost effectiveness modeling.

6. Order the Companies to improve their efforts at characterizing the most efficient energy savings opportunities in the market by:
    a. Instituting a process for refreshing measure characterization and efficiency assumptions on a rolling basis, and at minimum for each new potential study conducted for an IRP.
    b. Developing a formal emerging technology evaluation and planning framework, in collaboration with stakeholders, and filing for approval with the Commission during its next DSM-EE plan update or before the next IRP, whichever comes first.
7. Direct the Companies to conduct a process evaluation of current battery storage customers to understand barriers and motivations, and to inform evolutions in program design that are intended to balance between backup resilience use cases and leverage batteries for grid benefits.
    a. As part of this, Companies should evaluate different rate designs that consider how solar and storage interact with TOU (both current TOU structure and potential new structures based on grid needs assessments) and what incentives or price signals would be necessary to encourage more grid-friendly battery charge/discharge patterns, and to increase future enrollment potential.
8. Direct the Companies to modify their existing Bring your own device ("BYOD") Pilot concept to include a broader focus on gaining experience with dispatch coordination and communication of behind-the-meter ("BTM") battery aggregations with other controllable loads like water heaters, thermostats, and EV charging.

9. Direct the Companies to issue a Request for Information to gauge developer and aggregator interest in VPP deployment in Kentucky.
10. Direct the Companies to develop a scaling plan, in collaboration with stakeholders, for post-pilot implementation in order to maximize the potential benefits of this new resource type to contribute effectively and materially to the resilience and diversity of energy supply for its customers.
11. Order the Companies to adjust their Base Load Forecast in this CPCN by eliminating the use of the avoided cost-to-levelized cost of energy ("LCOE") methodology and instead incorporating the "NM Cumulative Capacity – High" solar forecast scenario developed for the 2024 IRP.[1]
12. Order the Companies to conduct an outside assessment of its solar PV forecasting modeling with a third-party consultant and in coordination with stakeholders, and implement changes and improvements based on the findings before the next IRP.
13. Investigate the potential benefits of forecasting locational solar adoption based on customer propensity modeling, with the capability to predict local solar adoption patterns based on differences in housing stock, customer demographics, localized incentives, and other factors.
14. Work with stakeholders to develop a roadmap and framework for a net energy metering ("NEM") successor program or tariff in anticipation of surpassing the statutory threshold of NEM installed capacity exceeding 1% of the previous year's peak load. The scope of

[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)")

this roadmap and framework should include evaluating possible program pairings of solar with storage, as was done with the Duke Energy Carolinas Power Pair program.

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

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I have prepared the following exhibits:

Exhibit AE-1: a copy of my résumé.

Exhibit AE-2: Maryland Public Service Commission - Case 9715 – Joint Exelon Utilities Energy Storage Proposal

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

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

A. In the instant application, the Companies request:

CPCNs to construct:

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

Q. Did the 2025 CPCN Resource Assessment evaluate the economics of incremental

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[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.

demand side resources as part of the "resource alternatives" analysis?

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

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

A. In terms of already approved programs, the 2025 CPCN Load Forecast includes "customer-initiated energy efficiency improvements, advanced metering infrastructure ("AMI") related conservation voltage reduction ("CVR") and ePortal savings, distributed 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.

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

Q. Do you find the Companies' evaluation of DSM resources in the 2025 CPCN Resource Assessment sufficient?

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

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

First, the Companies have historically missed opportunities to pursue additional cost-effective DSM programs, as the evaluation of such resources has been flawed. This 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.

and demand savings untapped. It also results in a higher capacity need in this CPCN (than if the Companies had pursued all cost-effective DSM from the time they were aware of the upcoming resource need). Thus, the "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"[9] are both more limited and sub-optimal to the position the Companies could have, had they pursued additional DSM resources up to now.

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

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

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

- Flaws in the cost-effectiveness methodology in the Potential Study that informed the 2022 CPCN, which are further exacerbated by recent developments in the Companies' planning, as well as the broader market environment, rendering the

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

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").

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

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

Then, the Companies conducted a DR potential assessment in 2021.[15] In 2022, the Companies filed a new plan to replace the 2019-2025 DSM-EE Program Plan providing a DSM portfolio through 2030, stating that avoided costs should be updated to reflect market conditions given the projected capacity shortfall in 2028.[16] However, despite the higher avoided capacity costs, the 2022 Study "did not entail a measure or fuel cost 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] Intervenors (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.

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

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

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

1. Missing avoided cost input values

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

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

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[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.

Project has become more prevalent.[19]

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

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

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

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

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

A. The Companies state that they have not evaluated a T&D avoided cost value but believe 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").

energy cost savings.[22] While T&D deferral values depend on the unique makeup of a utility and the costs of maintaining and upgrading its system, studies consistently show that these values can be significant. One national study on the national potential for load flexibility found 12% of the total avoided cost stack was attributable to T&D deferrals.[23] In a study conducted for the Pennsylvania Public Utility Commission, the calculated T&D value for PPL Electric was $153.54/kW-yr starting in 2026, and escalating to $185.82/kW-yr by 2035.[24]

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

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/pcdocs/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.

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

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

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

For example, the Companies' avoided cost methodology assumes an average marginal hourly energy cost in 2032 of [redacted] per MWh, with a max of [redacted] per MWh for a single hour on [redacted] at the [redacted] However, recent market experience during extreme weather events and other market irregularities accentuated price spikes in

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[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".

summer and winter months. Recent experience in the Southeast Energy Exchange Market, in which the Companies are a participant, shows 2024 max daily prices for January on-peak [redacted] The total cost for just these six hours was $232,774, for a weighted average of $141.59/MWh. Additionally, according to the Companies' market purchases data, purchases from the imbalance market are on an upward trend and the costs can exceed the marginal cost assumptions in the Companies' resource modeling. Figure 1 when themarket price is greater than $40/MWh.

[redacted]

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[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.

[redacted]

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.

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?

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 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.

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[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.

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

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

Q. Can you elaborate on your first concern?

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

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

A. Initial cost-effectiveness analysis for the 2024-2030 DSM-EE Plan (in the 2022 CPCN) was based on SCCT avoided capacity cost. According to the Companies' response to JI 2.44, additional cost-effectiveness testing was conducted in 2023, which used SCCT costs as the basis for avoided capacity for DR and NGCC costs for EE. Confidential Attachment 1 to Response to JI 1-93(e), however, [redacted]]

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

A. No. The Companies are currently applying for two NGCC units with capital costs that exceed $2,100/kW, significantly higher than the [redacted] SCCT[36] capital cost in the 2022 analysis, or even the [[redacted][37] Incremental DSM resources could now defer or 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.

Q. Why has the cost of gas turbines increased?

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

Q. What are the potential impacts of this backlog?

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

- Delays in Project Execution: Long backlogs can disrupt construction schedules and lead to cost overruns. Some gas turbine models now have leading times of up to 37 months, substantially affecting project planning and execution.
- Strain on Maintenance and Spare Parts Availability: Current gas turbine operators are increasingly concerned about slower turnaround times for scheduled maintenance. Customers are now experiencing lead overhaul times of around 350 days, a sharp increase from the 120 days that were previously standard.
- Rising Costs for End-Users: The high backlog demand has shifted pricing power to 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/.

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 SERVM 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]

[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").

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

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

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[42] LG&E-KU Resp. to JI 1-193(e), Confidential Attach. 1.
[43] *Id*.

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

Q. Can you elaborate on your third concern?

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

These resulting changes in load shape can have important implications on the 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.

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

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

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

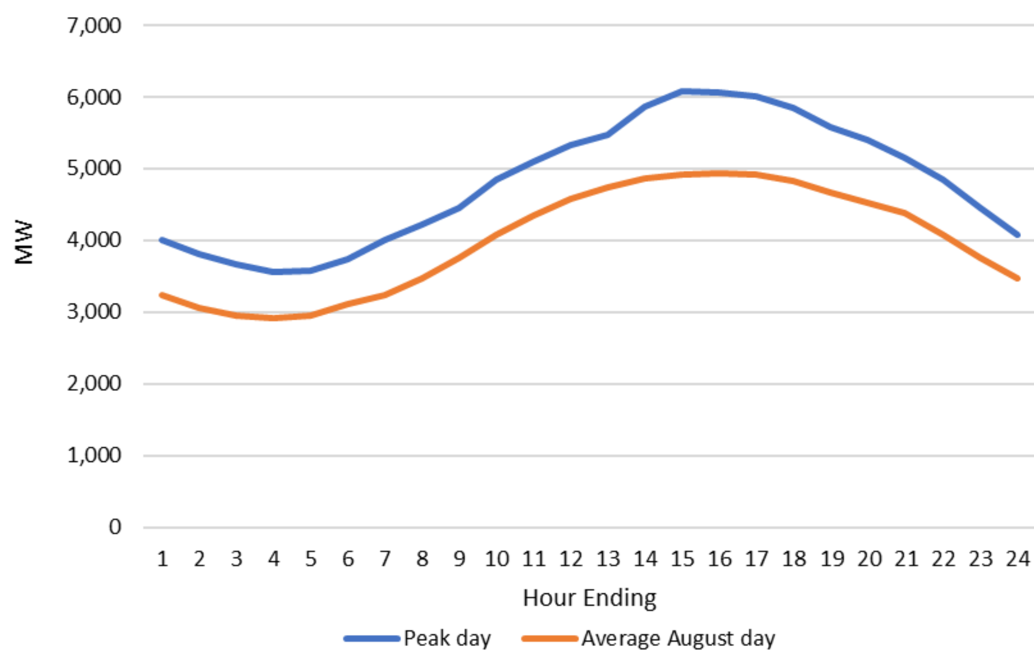
Q. Do you have concerns with this approach?

A. Yes. The method of shaping DSM-EE contributions within the IRP to mirror the overall 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.

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 unadjusted[50] total system load profile on a peak day in 2032, versus an average day.

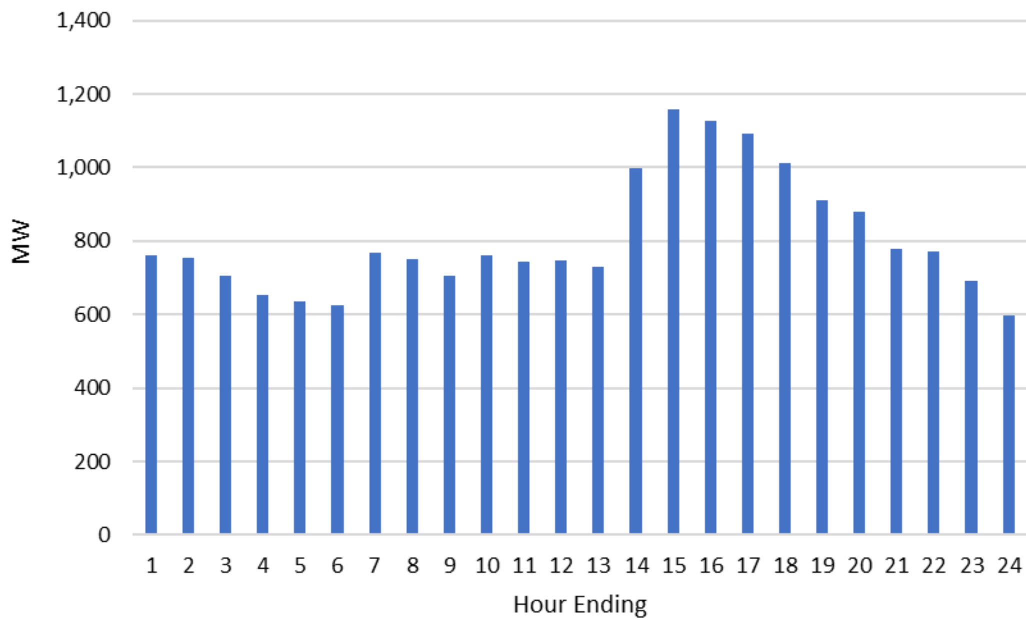
Figure 2: 2032 Peak Unadjusted Demand Hourly Profile Versus Average August Day



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.

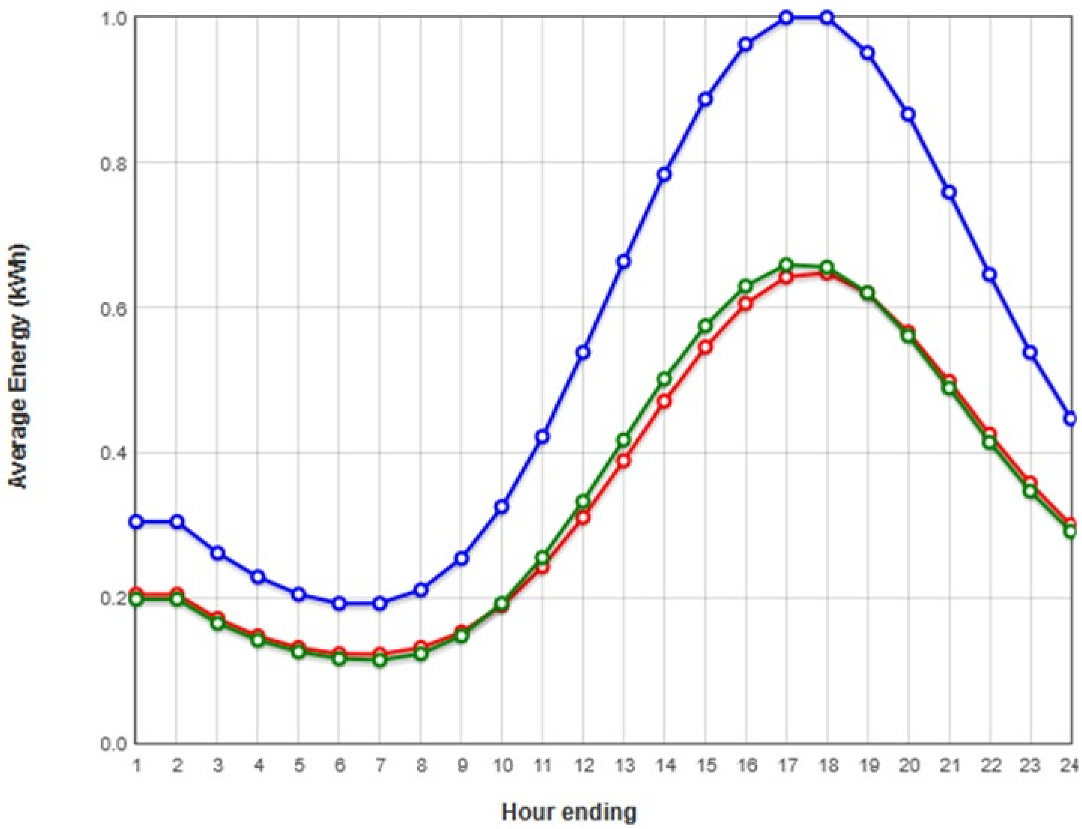
[50] The "unadjusted" forecast depicted here reflects the system load forecast before adjustments for distributed solar PV, electric vehicles, and economic development large loads, in order to align with the Companies' current DSM-EE allocation methodology.

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.

Figure 4: Hourly load profile for residential central air conditioning during peak and off-peak days for NERC Southeast Reliability Coordinator zone[51]



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

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

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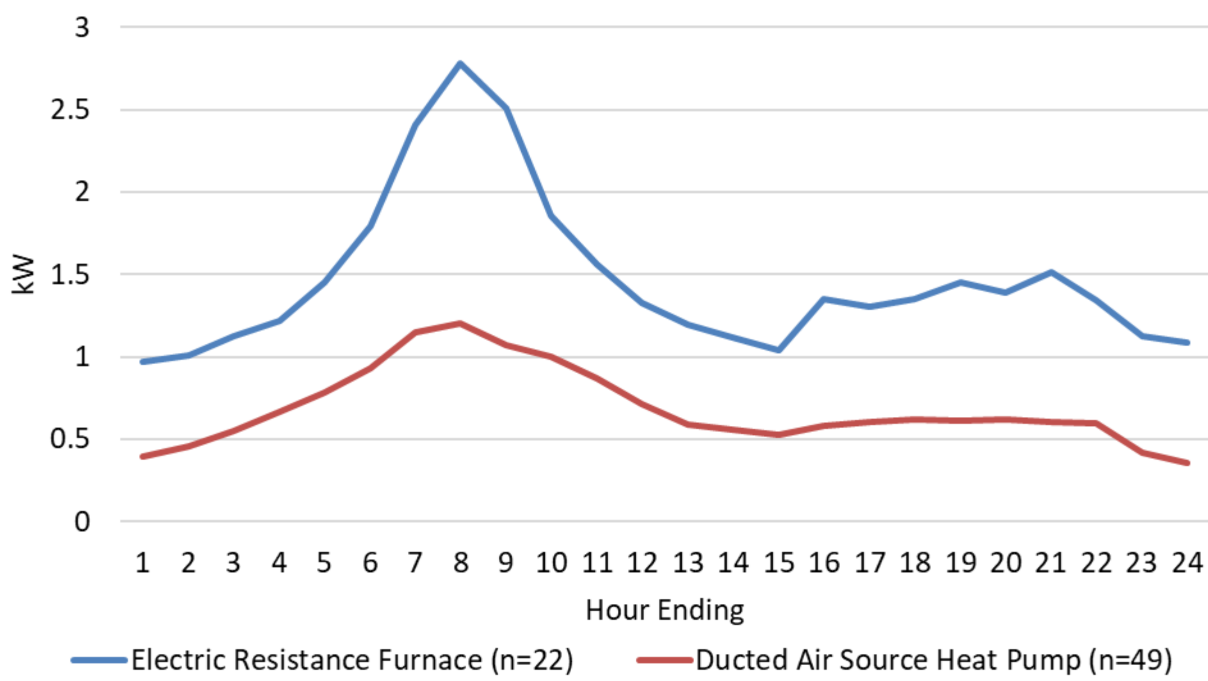
[51] Elec. Power Rsch. Inst., *End Use Load Shapes,* https://loadshape.epri.com/enduse (last accessed June 13, 2025).

[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 Northwest[54]



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.nwcouncil.org/end-use-load-shape-eulr-hourly-data/ (last accessed June 13, 2025).

demand periods for weather-sensitive measures.

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

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

Q. What are the benefits of doing this?

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

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. 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.

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

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

Q. Why is the target incentive level low?

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

The potential study does not provide cost test results for the high incentive scenario, but higher incentives do not strictly mean lower net benefits. While increasing participation and incentives raise the total program cost, other costs, such as 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.

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

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

A. Yes, the Companies include DSM-EE in the CPCN load forecast from the 2024-2030 DSM-EE Plan (875 GWh by 2032) and from customer initiated DSM-EE (233 GWh by 2032), for a total of 1,108 GWh of DSM-EE by 2032.[68] Taken together, the combined DSM-EE levels in the CPCN application are more in line with the 2022 Cadmus study. Although not directly comparable for the 2032 year due to lack of available data, the 2043 combined cumulative DSM-EE included in this CPCN load forecast is 1,790 GWh,[69] whereas the 2022 Cadmus study shows 1,471 GWh in the Medium scenario and 1,777 GWh in the High scenario for the same time period.[70]

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

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.

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

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

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

Q. How does the SAE method incorporate EE projections?

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)").

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

The SAE model typically incorporates EIA's forecasts of gradually improving efficiency—for example, by increasing efficiency from codes and standards, and declining costs—but does not include radical changes in end use consumption reflective of technologies that do not have significant market share during the baseline period.[78] These assumptions reduce projected use-per-customer and, in turn, total and peak demand in long-term forecasts.

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

A. No, for two reasons. First, as I noted above, the EIA methodology does not account for dramatic changes in end use efficiency, and therefore cannot accurately reflect potential shifts in energy consumption which are often disruptive in their scale. This is especially true because, as I discuss elsewhere in my testimony, the 2022 Cadmus study also did not 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]
[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.

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

A few examples illustrate this need further. It is widely known that the industrial sector has been a difficult sector to reach with certain end use efficiency programs. However, recent advances in Industrial Heat Pump technology are key to unlocking significantly expanded EE potential for this market sector[79] that would not be reflected in baseline efficiency trends. In Kentucky, for example, there are 233 food and beverage manufacturers that could be good candidates for this technology, and just one site uses the equivalent energy of 418 typical homes.[80] Similarly, the commercialization of low-voltage heat pump water heaters is a significant advancement that could overcome a key market barrier (high installation costs due to site electrical upgrades) for this technology.[81] Again, the step-change nature of some emerging tech highlights the importance of taking a tailored approach to defining the potential, not only because the

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[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

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

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

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

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

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

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

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[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).

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

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

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

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

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

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. 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.

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

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

A. The residential online audit program does not include a range of residential measures which would increase EE for single-family or multi-family participating customers, including broader weatherization and air sealing.[91] In a 2017 review of the Companies' DSM plan, Cadmus identified that individual HVAC and weatherization measures (e.g., insulation, duct sealing, infiltration) were no longer proving cost-effective.[92] This likely explains why these measures are significantly limited for the non-income qualified program. However, Cadmus' review concluded that bundled measure packages[93] and performance-based incentives may allow the Companies to capture savings from measures no longer deemed cost-effective. Cadmus then recommended that the

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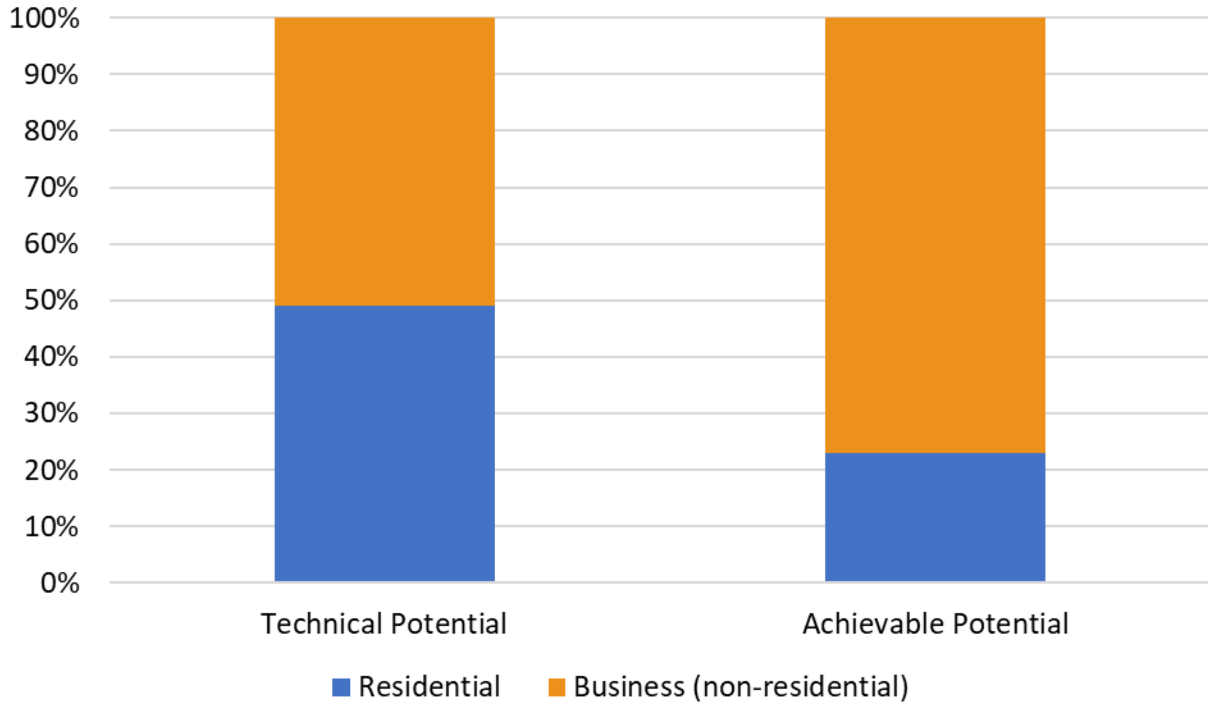
[90] *Id.* at 24-25.
[91] *Id.* at 32.
[92] Case No. 2017-00441, Ex. GSL-2 at 12, Direct Testimony of Gregory S. Lawson, Manager, Energy Efficiency Planning & Development, LG&E KU Services Company, *In the Matter of Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities 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.

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

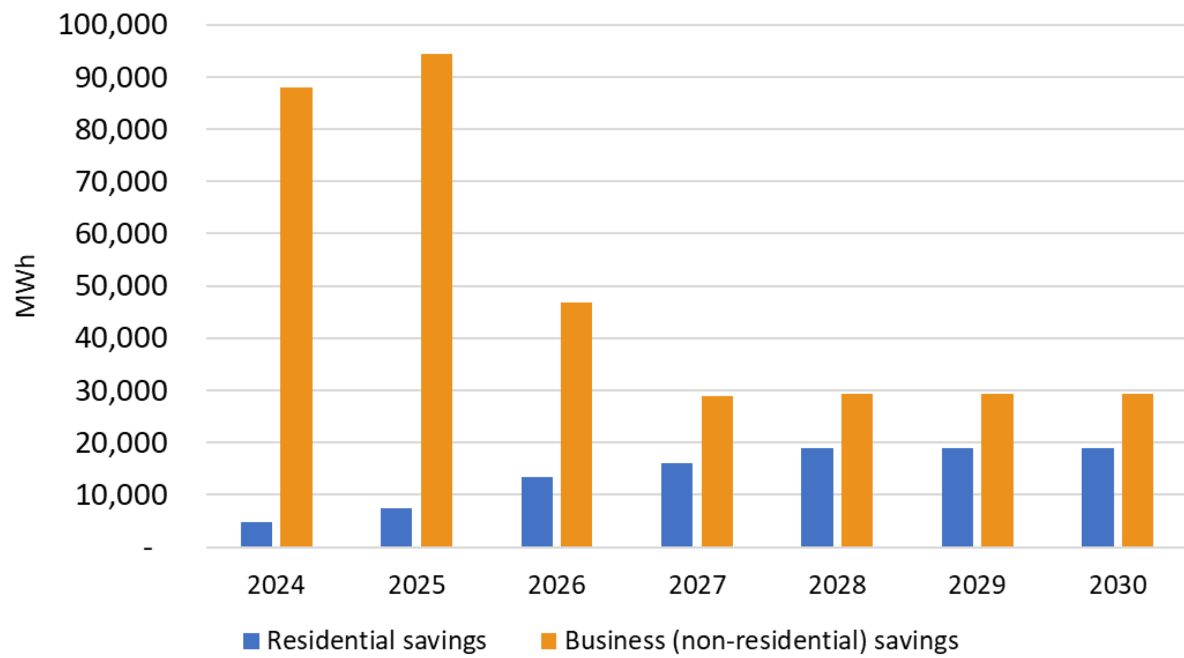
[94] Case No. 2017-00441, Ex. GSL-2 at 12.
[95] Case No. 2022-00402, Ex. LI-6, "LGE KU Program Measure Inputs FINAL – Public.xlsx" from Direct Testimony of Lana Isaacson, Manager, Emerging Business Planning and Development Kentucky Utilities Company and Louisville Gas and Electric Company (Dec. 15, 2022).

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.

Figure 7. Final 2024-2030 DSM-EE Plan Savings Targets by Sector[96]



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

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

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[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.

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

5. The plan fails to adequately pursue whole-building opportunities for multifamily customers.

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

A. Yes. The Companies included a subcomponent for Whole-Building Multifamily to their existing Income-Qualified Solutions program as part of their proposal in Case No. 2022-00402.[98] The Multifamily subcomponent will provide education regarding energy usage and conservation, provide property managers and building owners with opportunities for in-unit efficiency upgrades (such as free direct install of energy-saving devices), and provide incentives for owners and managers making improvements to the whole building, including shared common-areas.[99]

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

A. The Companies state that the new Multifamily subcomponent will provide owners and property managers with a "turnkey service" to increasing EE savings, and that they will 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*.

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.

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

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

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

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

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

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[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.

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

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

A. Yes. Especially in Louisville, given the focus of the Louisville Metropolitan Government ("LMG") to improve outcomes for low-income multifamily buildings. The LMG Housing Department offers up to $10,000 in funding per unit for landlords meeting certain geographic criteria to rehab their properties.[110] By working with local partners to align EE upgrades with these broader renovations, the Companies can begin 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/ntcn17ss1ow9/5lq94Fnz4padfRDcnYeBdZ/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.

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

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

This type of program is also not just the purview of small lenders and community nonprofits. Fannie Mae offers a Green Rewards program[114] that can unlock additional loan proceeds and provide a lower interest rate to market rate and affordable multifamily building owners, therefore offering enhanced benefits for implementing efficiency 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).

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

Q. What do you recommend?

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

- Order the Companies to conduct an update to the measure characterization and engineering assumptions factored into the current Whole-Building Multifamily subcomponent program in order to reflect true common area savings measures and whole building measures like central water heating and central HVAC system retrofits.
- Order the Companies to work with stakeholders to scope and conduct a market characterization study of the low-income multifamily market segment in its service area, including identification and evaluation of different program design options to address any identified market barriers. The study should evaluate opportunities and pathways for unlocking deep energy retrofits by providing tailored financial and pre-planning support for building owners during various phases of their project lifecycle (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]			
	CR BESS	GH BESS	BYOD Energy Storage	BYOD Home Generators	BDR 50-200 kW	CSR[27]
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.

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

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

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

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[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.

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

A. Yes.

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

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

For the sake of argument, even if it is taken as true that storage would be of sufficient volume in the historical baseline period to have a measurable effect on the load 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.

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

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

A. Yes. Although the Companies did not include growth in distributed storage as an explicit piece of their load forecast, they nevertheless included an additional 0.89 MW by 2030 in their Dispatchable DSM portfolio to reflect BYOD Energy Storage.[124] Assuming 4.5 kW per device, this amounts to 198 customers enrolled in the BYOD channel by 2030.[125]

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

A. Carrying forward the Companies' 6% percent attachment rate, and applying that to the forecasted solar adoption in the Base Case, I estimate 6.7 MW of distributed storage by 2032.[126] However, as I show in the next section, the solar PV forecast included in the

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[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.

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

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

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

provide continuous max rated output for approximately two hours, is therefore a very suitable resource to increase customer resilience to storm-related blackouts. Other notable utility programs are Rocky Mountain Power in Utah who had 28 MW of solar and storage enrolled in its Wattsmart program as of November 2024,[130] and Duke Energy Carolinas who is also piloting a 30 MW solar plus storage VPP.[131] Lastly, other models of pairing customer-sited energy storage with utility-scale storage interconnected at distribution voltage levels provides even broader opportunities to provide additional resilience through a VPP. Platte River Authority in Colorado is planning to add 20 MW of distribution-scale storage to its VPP plans, for a total VPP achievable capacity of 52 MW by 2030 and 113 MW by 2040.[132]

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

A. There is not yet a standard industry definition of a VPP, but they are broadly defined by Brattle as a "portfolio of distributed energy resources (DERs) that are actively controlled to provide benefits to the power system, consumers, and the environment."[133] The 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.

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.

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.

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.

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

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

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

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

Standardization across utility-aggregator interfaces, aggregator-to DER interfaces, and cybersecurity practices are essential to VPP deployment. VPP platform providers need to be able to send and receive information to and from a utility using an interface and data language compatible with varying utility IT systems. Recent efforts to address this need have moved rapidly, developing utility communication protocols, shared DER registries, and cybersecurity certification standards such as UL 2941.[143] Recently, the U.S. Department of Energy ("DOE") and industry partners have initiated platforms like EPRI's FlexIT and DOE's TSO-DSO-DER coordination framework to support VPP implementation through standardized operational platforms.[144]

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

[142] *Id.* at 4.
[143] *Id.* at 24.
[144] *Id.* at 23.

resources?

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

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

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

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

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

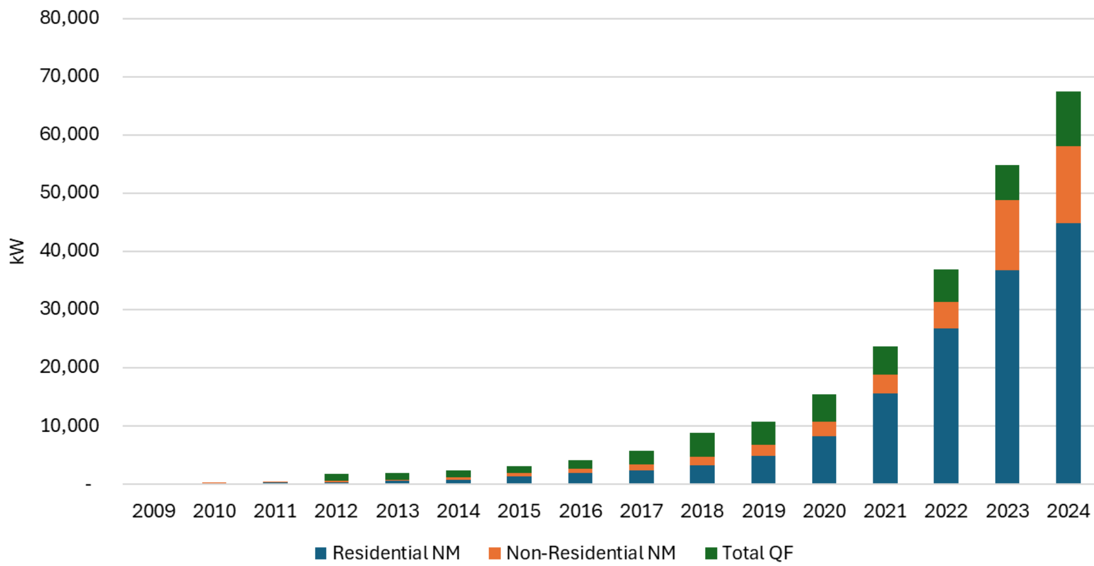
VII. THE DISTRIBUTED SOLAR MODELED IN THE CPCN MID-CASE FORECAST IS TOO CONSERVATIVE AND SHOULD BE INCREASED.

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)

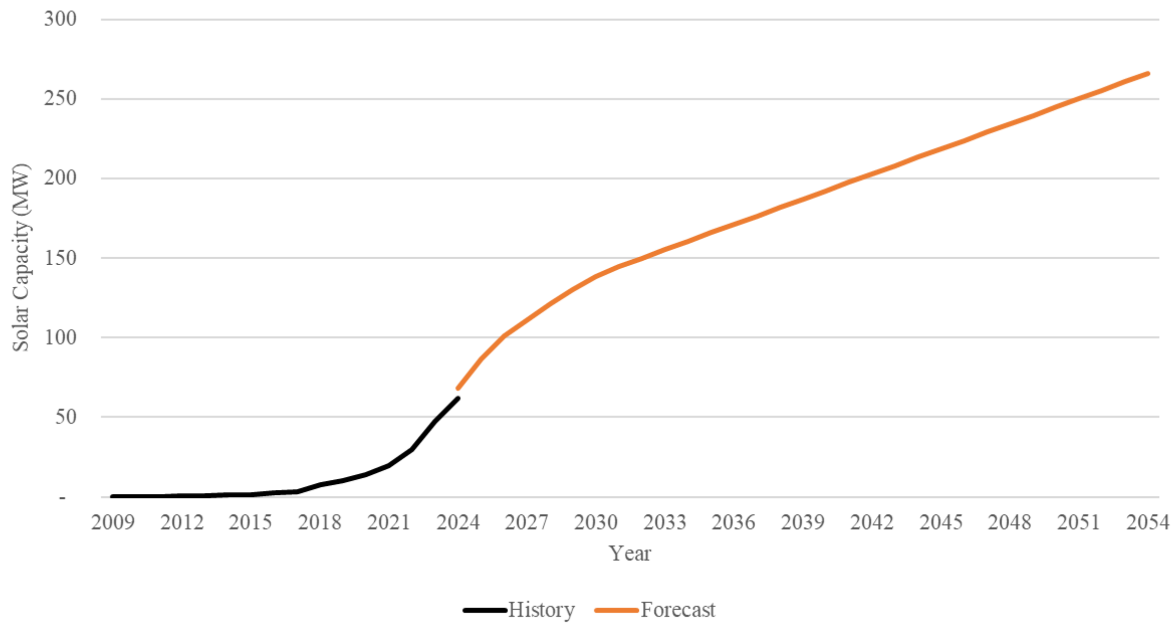


Q. Did the Companies forecast for future distributed solar adoption?

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.

Figure 11: History and Forecast of Distributed Generation[149]



Q. Please explain how the Companies developed their forecast for distributed generation.

A. The Companies forecasted future growth of distributed solar generation from increased adoption of net energy metered ("NEM") customer rooftop solar and from continued growth of small and large qualifying facilities ("QFs").[150] To forecast adoption of NEM growth, the Companies utilized an in-house statistical model that estimates future 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").

ratio[151] 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

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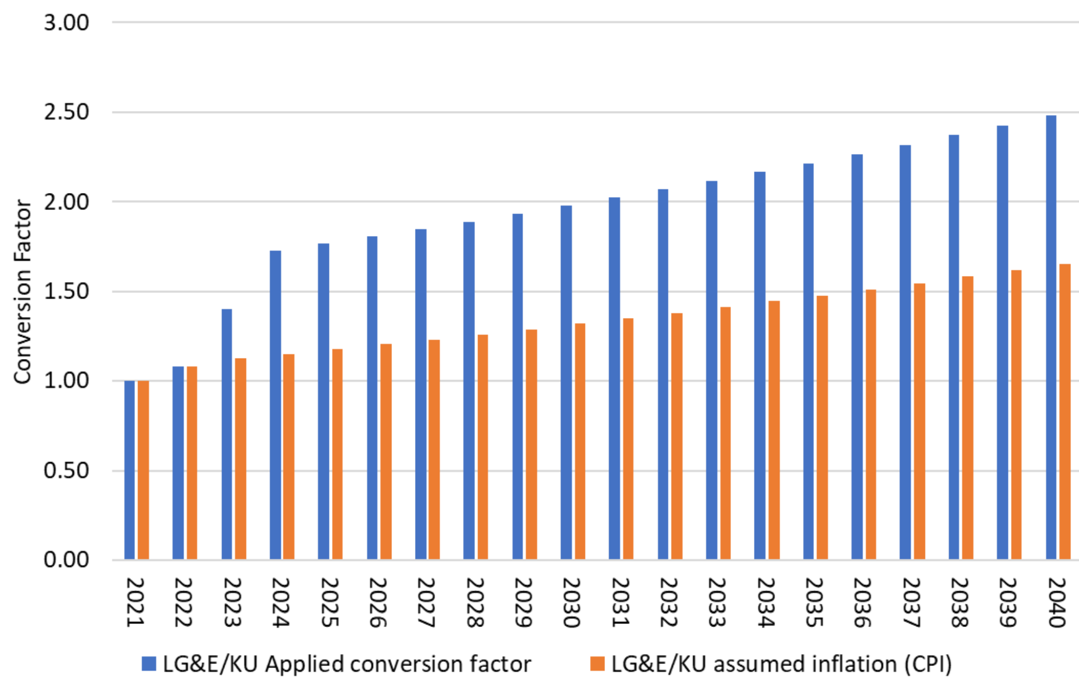
[151] This ratio is also called the "grid-to-LCOE" ratio in the supporting workpaper. The numerator is defined as the avoided costs (defined as the reductions in retail purchases from the self-consumed portion of the solar generation) plus the net exported amount that is compensated through the applicable 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". .

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

The calculations that lead to the pertinent input values, however, are based off of 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.

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

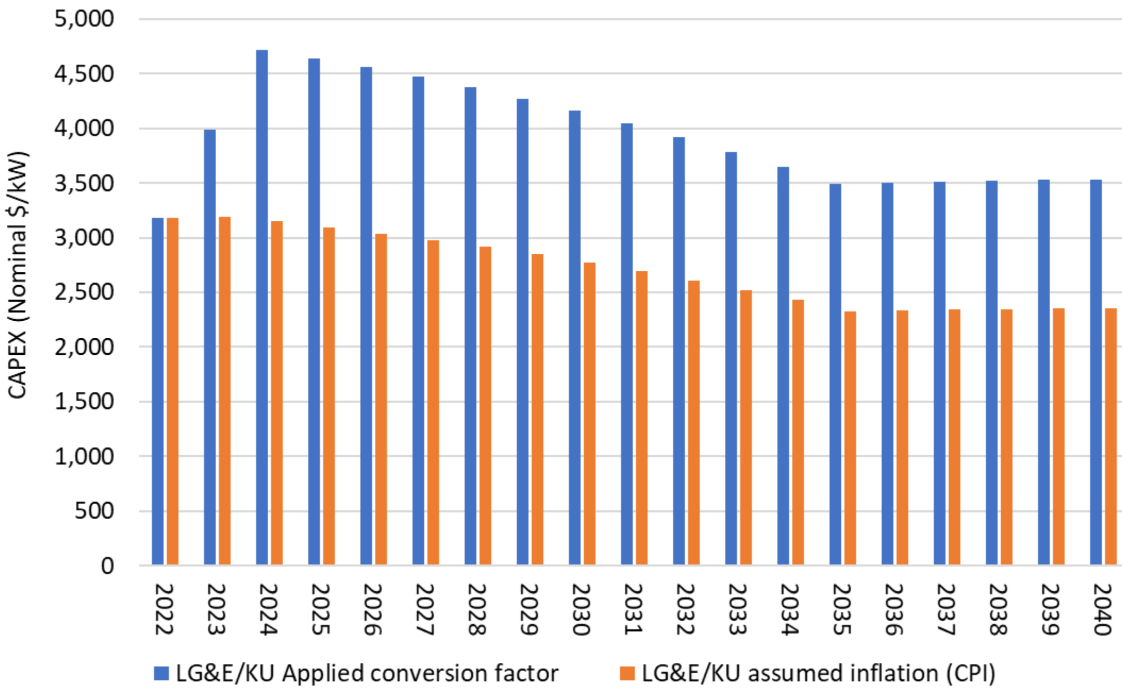


As you can see, the "LG&E/KU Applied conversion factor" is significantly higher beginning in 2023 and escalating throughout the 20-year period.

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

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

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



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

Q. Please describe the Companies' statistical model and methodology for forecasting 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.

A. The Companies used a two-part modeling approach in the statistical software R to estimate how many residential customers will install solar panels under current NEM compensation structures.[158] First, they built a *short-term model* to estimate near-term monthly growth in solar customers. Then, they developed a *long-term model* to forecast how many total customers will have solar over a longer time horizon. The Companies state that using multiple models was necessary to correct for poor model performance beginning in 2020 due to COVID-19.[159]

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

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

Finally, of note is that the Companies segment the input data into time periods, creating a pre-2020 segment, a 2020 to April 2024 segment, and a future (forecasted) segment. While this is a useful way to structure data in a modeling exercise because it 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).

how the Companies appear to actually have executed this feature.

Q. What are your concerns with the Companies' modeling approach as you've described it?

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

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

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

A. The process of product diffusion does not simply follow narrow economic principles. In 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).

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

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

In a randomized study in Connecticut, researchers found that Solarize campaigns substantially influenced the rate of adoption of solar, primarily driven by word-of-mouth 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..

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

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[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.

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

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

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

- Adjust their Base load forecast in this CPCN by eliminating the use of the avoided cost-to-LCOE methodology and instead incorporating the "NM Cumulative Capacity – High" solar forecast scenario developed for the 2024 IRP.[167]
- Conduct an outside assessment of its solar PV forecasting modeling with a third-party consultant and in coordination with stakeholders, and implement changes and improvements based on the findings before the next IRP.
- Investigate the potential benefits of forecasting locational solar adoption based on customer propensity modeling, with the capability to predict local solar adoption patterns based on differences in housing stock, customer demographics, localized 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)")

- Work with stakeholders to develop a roadmap and framework for a NEM successor program or tariff in anticipation of surpassing the statutory threshold of NEM installed capacity exceeding 1% of the previous year's peak load. The scope of this work should include:
  - Evaluating possible program pairings of solar with storage, as was done with the Duke Energy Carolinas Power Pair program.
  - Understanding customer preferences and motivations to adopt solar and storage.
  - Alignment of interconnection application process, rebate frameworks, and alternative procurement mechanisms.
  - Development of a new community solar tariff structure that recognizes this resource as a grid asset that can provide environmental benefits, jobs, and local resilience, especially when paired with front-of-the-meter storage. This is in line with the Commission's findings that "QF's invest in technologies like solar, wind, or small-scale cogeneration, which offer significant environmental, and reliability benefits that LG&E/KU should take advantage of to reduce greenhouse gas emissions or diversify its energy supply to reduce market volatility to its customers."[168] In this vein, when coordinated with effective grid planning, Community Solar can provide strategic benefit to the grid and customers in terms 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. 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. 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.

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. 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. 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. Potential unquantified system benefits associated with DSM-EE by running the portfolio analysis with and without DSM-EE in order to assess changes to 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 can be incorporated to future DSM-EE cost effectiveness modeling.

19. Order the Companies to improve their efforts at characterizing the most efficient energy savings opportunities in the market by:
    a. Instituting a process for refreshing measure characterization and efficiency assumptions on a rolling basis, and at minimum for each new potential study conducted for an IRP.
    b. Developing a formal emerging technology evaluation and planning framework, in collaboration with stakeholders, and filing for approval with the Commission during its next DSM-EE plan update or before the next IRP, whichever comes first.
20. Direct the Companies to conduct a process evaluation of current battery storage customers to understand barriers and motivations, and to inform evolutions in program design that are intended to balance between backup resilience use cases and leverage batteries for grid benefits.
    a. As part of this, Companies should evaluate different rate designs that consider how solar and storage interact with TOU (both current TOU structure and potential new structures based on grid needs assessments) and what incentives or price signals would be necessary to encourage more grid-friendly battery charge/discharge patterns, and to increase future enrollment potential.
21. Direct the Companies to modify their existing BYOD Pilot concept to include a broader

focus on gaining experience with dispatch coordination and communication of BTM battery aggregations with other controllable loads like water heaters, thermostats, and EV charging.

22. Direct the Companies to issue a Request for Information to gauge developer and aggregator interest in VPP deployment in Kentucky.
23. Direct the Companies to develop a scaling plan, in collaboration with stakeholders, for post-pilot implementation in order to maximize the potential benefits of this new resource type to contribute effectively and materially to the resilience and diversity of energy supply for its customers.
24. Order the Companies to adjust their Base Load Forecast in this CPCN by eliminating the use of the avoided cost-to-LCOE methodology and instead incorporating the "NM Cumulative Capacity – High" solar forecast scenario developed for the 2024 IRP.[170]
25. Order the Companies to conduct an outside assessment of its solar PV forecasting modeling with a third-party consultant and in coordination with stakeholders, and implement changes and improvements based on the findings before the next IRP.
26. Investigate the potential benefits of forecasting locational solar adoption based on customer propensity modeling, with the capability to predict local solar adoption patterns based on differences in housing stock, customer demographics, localized incentives, and other factors.
27. Work with stakeholders to develop a roadmap and framework for a net energy metering

[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)")

("NEM") successor program or tariff in anticipation of surpassing the statutory threshold of NEM installed capacity exceeding 1% of the previous year's peak load. The scope of this roadmap and framework should include evaluating possible program pairings of solar with storage, as was done with the Duke Energy Carolinas Power Pair program.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

The undersigned, Andrew Eiden, being first duly sworn, deposes and says that he 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 Michael Eiden
____

Subscribed and sworn to before me by Andrew Eiden this 16th day of June, 2025.

Lashawndra Cunningham Lashawndra Cunningham
Notary Public

My commission expires: 08/15/2028

NOTARY PUBLIC • STATE OF FLORIDA •
LASHAWNDRA CUNNINGHAM
Notary Public - State of Florida
Commission # HH 583553
Expires on August 15, 2028

State of Florida

County of Seminole

Sworn to (or affirmed) and subscribed before me by means of online notarization,
this 06/16/2025 by Andrew Michael Eiden.

___ Personally Known OR ___ ✔ Produced Identification

Type of Identification Produced DRIVER LICENSE

EXHIBIT AE-1

Andy Eiden Résumé

CURRENT ENERGY GROUP

Andy Eiden

Sr. Manager, (971) 244-2063, aeiden@currentenergy.group

Education

Bachelor of Science, *magna cum laude,* Economics and Environmental Studies
Portland State University – Portland, OR (2011)

Master's Certificate in Energy Policy and Management
Portland State University – Portland, OR (expected fall 2025)

Work Experience

Sr. Manager, Current Energy Group, (January 2025 – Present)

- Subject matter expert in Distribution System Planning (DSP), electrification and DER forecasting, DSM potential studies, DER integration, advanced rate design, cost-effectiveness modeling, and locational value frameworks.
- Designing strategies to advance DSP processes and practices, DER adoption, and other decarbonization strategies before state public utility commissions.

Sr. Principal Planning & Strategy Analyst, Portland General Electric (2023-2024)
Principal Planning & Strategy Analyst (2022-2023)
Sr. Planning & Strategy Analyst (2020-2022)
Planning & Strategy Analyst (2019-2020)

- Led company-wide DER forecasting efforts to support DSP, IRP, finance, programs, and transmission planning. Responsible for all aspects of analysis and final reports.
- Represented PGE in regulatory proceedings, including DSP and TE dockets and related technical working groups.
- Designed Python-based DER forecasting tools for circuit-level DER adoption modeling.
- Led team of analysts to deliver sound planning studies to internal clients
- Managed multiple R&D partnerships with government, industry, and academia.
- Led valuation efforts and non-wire alternative evaluations for grid optimization.

Planning Project Manager, Energy Trust of Oregon (2015-2019)

- Managed electric avoided-cost dockets and targeted non-wire alternative pilots.
- Oversaw cost-effectiveness reporting for a $200M energy efficiency portfolio.
- Maintained TRM database and managed solar and multifamily program evaluations.

Research Analyst, The Cadmus Group (2012-2013)

- Conducted process and impact evaluations for utility clients across the U.S.
- Developed survey instruments to evaluate utility efficiency program offerings
- Delivered actionable recommendations through data-driven insights for client projects.

Publications

"Distribution Capacity Expansion: Current Practice, Opportunities, and Decision Support" (2022)

Co-authored a report looking at the future evolution of Distribution Planning to evolve toward a more holistic approach encompassing scenario planning, DER penetration, and economic optimization. Worked closely with lead authors to validate existing utility planning practices and identify areas for improvement.
Report

"KPF-AE-LSTM: A Deep Probabilistic Model for Net-Load Forecasting in High Solar Scenarios" (np., March 2022)

Co-authored a paper on net-load forecasting at the distribution level of aggregation that identified statistically-determined upper- and lower-error bounds for PV production while considering typical end use load patterns. Also presented on the paper topic at 2022 IEEE IGST conference in New Orleans regarding utility load forecasting from a system operations perspective.
Article

Industry Technical Advisory Committees

ESIG DER and Electrification Impacts Task Force Member (2023-current)

Invited to serve as Task Force member for Energy Systems Integration Group (ESIG) distribution impacts working group. Primary focus was identifying best practices in utility system planning and necessary regulatory evolution related to EV and DER growth.

NEEA End Use Load Research Steering Committee (2021-2024)

Utility representative for regional end-use metering study to update end use load profiles. Assisted steering committee with guidance around key study objectives and desired outcomes, guided workgroup with feedback about relevant research and analysis, and participated in quarterly meetings.

NREL Technical Advisory Group, Grid-Scale Metrics for GEBs (2022-2023)

Provided technical assistance to the NREL NOVA team related to development of metrics for assessing value of grid-interactive efficient buildings (GEBs) as part of DOE grant work. Participated in TAG meetings to review NREL staff concepts about possible metrics and advised on industry feasibility and usefulness. Reviewed draft study materials about TOU rate designs related to solar and storage, as well as provided data and input for a case study of buildings in the Pacific Northwest.

Industry Presentations

"Planning EV Impacts on the Grid" Presentation at ESIG Spring Technical Workshop (2023)

Presented on utility planning practices to accommodate EV load growth on the grid to conference of international attendees.

EV Load Forecasting and Planning, Western Energy Institute Fall conference (2022)

Gave presentation related to utility practices for forecasting EV load and integration of EV load forecasts with planning studies, with a particular focus on secondary distribution networks and common infrastructure sizing practices.

Expert Testimony

1. In the Matter of the Application of Public Service Company of Colorado for Approval of its 2024 Just Transition Solicitation. On Behalf of Western Resource Advocates and Southwest Energy Efficiency Partnership.
   Load and DER forecasting, Large Load forecasting, Interconnection policy
   Direct
2. Petition of NSTAR Electric Company d/b/a Eversource Energy for Approval to Offer Optional Electric Vehicle Time-of-Use Rates. Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid for Approval to offer Optional Electric Vehicle Time-of-Use Rates. On Behalf of the Massachusetts AGO (with Ron Nelson).
   EV TOU Rate Design, Submetering
   Direct

Other Industry Engagement

Smart Grid Graduate Policy Course, Portland State University, adjunct instructor (Spring 2024)
Teaching

Taught graduate-level Smart Grid course under the PSU Energy Policy and Management certificate. Course covered policy trends in Smart Grid topics for public administration and policy students, as well as professional development for industry practitioners.

Smart Grid Graduate Course in Electrical Engineering, Oregon State University, adjunct instructor (Spring 2023)
Teaching

Taught graduate-level Smart Grid course in electrical engineering consisting of weekly lectures and final essay topic in topic of student choice. Course covered distribution system basics, smart controls, demand-side technologies, transmission issues, climate change impacts, cybersecurity, wildfire mitigation and more.

EXHIBIT AE-2

Maryland Public Service Commission

Case No. 9715 – Joint Exelon Utilities energy Storage Proposal

Crystal Barnett
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BGE Legal Department

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February 21, 2025

Andrew S. Johnston
Executive Secretary
Maryland Public Service Commission
6 St. Paul Street, 16th Floor
Baltimore, MD 21202

RE: Case No. 9715 MD Energy Storage Program
Exelon MD Utilities' Request for Approval

Dear Mr. Johnston:

Attached please find Baltimore Gas and Electric Company, Delmarva Power & Light Company, and Potomac Electric Power Company energy storage procurement proposal and request for approval filed in accordance with Order No. 91495 in the above captioned matter.

Pursuant to the Commission's July 12, 2021 Notice of Continued Waiver of Paper Filing Requirements, paper copies of this filing will not be provided.

Respectfully submitted,

/s/ Crystal Barnett
Crystal Barnett
Counsel for
Baltimore Gas and Electric Company

/s/ Andrea H. Harper
Andrea H. Harper
Counsel for
Delmarva Power & Light Company and
Potomac Electric Power Company

cc: All Parties of Record

BEFORE THE
PUBLIC SERVICE COMMISSION
OF MARYLAND

Maryland Energy Storage Program | Case No. 9715

EXELON MARYLAND UTILITIES' REQUEST FOR APPROVAL OF ENERGY STORAGE PROCUREMENT PROPOSAL

Maryland faces a substantial challenge to move boldly, deliberately, and quickly to meet important and ambitious decarbonization goals while also supporting its resource adequacy needs. Challenges, however, can be looked at as opportunities to design and deploy innovative solutions, which is how Baltimore Gas and Electric Company ("BGE"), Delmarva Power & Light Company ("Delmarva Power") and Potomac Electric Power Company ("Pepco") (together, the "Exelon MD Utilities" or "Companies") approach their response to the Maryland Public Service Commission's ("Commission") call for proposals pursuant to Order No. 91495 ("Procurement Order"). The Exelon MD Utilities' proposals set forth herein support the first Maryland Energy Storage Program ("MESP") goal of 750 MW of energy storage in the State by May 31, 2028.[1]

The Exelon MD Utilities appreciate and support the Commission's call for consideration of a broad array of battery energy storage system ("BESS") initiatives for a diverse set of customer types and sizes, while recognizing that it will require coordinated action by all participants to meet the stated goals. To that end, through the Exelon MD Utilities' and SEIA's Joint Distribution Procurement initiatives as well as the distribution and transmission procurement initiatives proposals herein ("Procurement Initiative Proposals"), the Exelon MD Utilities focus on deploying a varied and innovative portfolio of storage solutions that provide opportunities for all customer classes to participate and benefit. With respect to action by all participants, Maryland House Bill 910 of 2023 ("HB910") requires that initiatives include "competitive procurement

[1] Public Utilities, Md. Code Ann., §7-216.1 (b).

mechanisms to reach [its total statewide goal of] 3,000 megawatts of energy storage."[2] For this reason, the Procurement Initiative Proposals create robust opportunities for stakeholders to compete for and partner together to implement initiatives to deploy third-party and utility-owned storage in a rapid, scalable manner.

The Exelon MD Utilities provide herein further descriptions and background on the Procurement Initiative Proposals for both front-of-the-meter ("FTM") and behind-the-meter ("BTM") distribution-connected storage and transmission-connected storage, respectively:

Table 1: Distribution-Connected Storage Procurement Initiative Proposals

	Utility-Owned	3rd Party-Owned	Utility-Sited	Customer-Sited	FTM	BTM	Potential Battery Sizes
1. Utility Distribution-Connected	X		X		X		500kW
2. 3rd Party Distribution-Connected		X		X	X		1-3MWs
3. Commercial/Industrial Customer-sited	X			X	X	X	500kW-1MW
4. Residential Behind-the-Meter	X			X		X	10-15kW

Table 2: Transmission-Connected Storage Procurement Initiative Proposals

	Utility-Owned	3rd Party-Owned	Utility-Sited	Customer-Sited	FTM	BTM	Potential Battery Sizes
1. Utility Transmission-Connected	X		X		X		100MW+
2. 3rd party Transmission-Connected		X		X	X		100MW+

Earlier this year, at a briefing to the Maryland House Economic Matters Committee, PJM Interconnection, LLC provided a stark warning regarding the status of resource adequacy to meet Marylanders' energy needs.[3] Customers–both large and small–currently face economic challenges due to rising costs for

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[2] *An Act Concerning Energy Storage*, HB 910, 443d Md. Gen. Assembly ch. 570 (2023) (codified at Md. Ann. Code, Pub. Util. Art., § 7-216.1) at § 7–216.1.(c)3.

[3] PJM's Executive Director of State Government Policy stated, "[T]he bottom line is that the energy outlook in the state of Maryland is dire." *Maryland House Economic Matters Committee – Briefing* (Jan. 15, 2025) (*avail. at* https://www.youtube.com/watch?v=waZprMcZUS0 *at* 00:03:06) (*emph. added*).

home and business materials and needs, including their energy needs, due to underlying market conditions. Further exacerbating these challenges, federal support for clean energy technologies may not be as prevalent as it has been in the past. In the current environment, taking full advantage of the value that utilities provide as a primary *platform* through which the State can affordably fund, reliably execute, and transparently oversee the actions required to drive the energy transformation, including a diverse set of energy storage programs such as the Procurement Initiative Proposals herein, becomes increasingly important. Moreover, by correctly applying to utility investments in energy storage initiatives, systems and infrastructure cost recovery mechanisms similar to those used for investment in traditional distribution and transmission, utilities can spread out costs over time to benefit customers, promote competitive procurement to a broad range of businesses, grow Maryland's economy, and receive an appropriate, regulated return for approved Procurement Initiative Proposals. HB910 states:

> Energy storage systems provide benefits to the electric grid and utility customers by: enabling the transition to a clean grid with diversified renewable resources; creating system efficiencies that can reduce costs and save money for utilities and ratepayers; bolstering grid reliability and resilience; improving system capabilities to withstand shocks and stressors; and promoting economic development and job creation in Maryland communities.[4]

While any one of the Procurement Initiative Proposals would provide benefits to the State and Exelon MD Utilities' customers and communities, a comprehensive energy storage strategy that leverages *all* of the Procurement Initiative Proposals will best set Maryland on a path to meet its leading clean energy goals. Together the Procurement Initiative Proposals present an 'all-in' and diverse approach to more rapid and widespread energy storage growth that will drive, in part:

- Broad societal benefits by laying the foundation for faster, broader, more affordable electrification on Exelon MD Utilities' systems;

[4] HB910 at Preamble.

- A more flexible grid with greater ability to accommodate renewable generation, which results in cleaner air and a lower carbon grid;
- Solutions to support customer resilience; and
- A near-term part of the State's solutions to address resource adequacy by supporting more dispatchable, dynamic load that can manage and drive down system peaks to bolster reliability.

The Commission should offer flexibility to utilities regarding the types of initiatives that they offer. Each utility has unique electric systems, customer segments, counties and municipalities, and geography, all of which will inform the types of initiatives they can offer and the amount of storage that can be affordably and cost-effectively procured. Allowing flexibility between the utilities in target development and initiative design will enable the State to deploy storage most effectively.

The Exelon MD Utilities appreciate this opportunity to file the Procurement Initiative Proposals, which attempt to address each of the Commission's identified issues in its Procurement Order to the extent currently possible. Certain Procurement Initiative Proposals can be implemented in the near term, begin to address the 2028 target of 750 MW of energy storage deployed in Maryland, and initiate a significant investment of in-state storage resources that will provide long-term uses for Maryland.

The Companies support the Commission's direction on Phase II of the Maryland Energy Storage Program Work Group. In addition to lessons learned developed from the narrow-scope proceeding, the four directives described in the Procurement Order will inform the development of future initiatives that will lay the foundation for achieving the State's longer-term goal of 3,000 MW of energy storage deployed by end of delivery year 2033.

Given the expedited timeframe for responses directed in the Procurement Order and the important issues the Commission seeks to address for any storage proposal, the Companies ask that the Commission approve Exelon MD Utilities' and SEIA's proposed Joint Distribution Procurement initiative as well as the

Procurement Initiative Proposals subject to more fulsome utility filings that will provide further detail on each initiative.

I. Distribution System-Connected Procurement Initiative Proposals

The Exelon MD Utilities support and have experience with a variety of ownership models and technology configurations of distribution-connected energy storage projects. Through the Maryland Energy Storage Pilot Program,[5] BGE, Delmarva Power, and Pepco have deployed multiple energy storage projects and have gained significant experience and lessons learned with the deployment and operation of these projects. These projects include a mixture of utility-owned battery energy storage projects,[6] third-party-owned projects,[7] and a behind-the-meter residential virtual power plant[8] ("VPP"). BGE, Delmarva Power, and Pepco use their respective projects to provide peak shaving and other services as well as to operate in PJM markets. Additionally, there are other utilities nationwide—including Con Edison, SDG&E, Dominion Power, and Green Mountain Power—who have successfully deployed utility-owned storage for distribution benefits, wholesale market services, and residential back-up power.

Further, at the distribution level, a utility-implemented Distributed Energy Resource Management System ("DERMS") will enable the Exelon MD Utilities to efficiently manage and dispatch this growing fleet of energy storage resources by providing real-time visibility, advanced analytics, forecasting, scheduling, and automated control capabilities. By integrating with grid infrastructure, DERMS will facilitate seamless coordination between various distributed energy resource ("DER") assets—including assets from storage programs, solar, and demand response programs—to align their operations with grid conditions. DERMS will enhance grid resilience by enabling fast, intelligent dispatch of resources in response to outages, peak demand events, and other grid disturbances, ultimately improving reliability and operational efficiency.

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[5] See the Maryland Energy Storage Pilot Program, Case No. 9169.
[6] BGE's Chesapeake BESS and Delmarva Power's Ocean City BESS.
[7] BGE's Fairhaven BESS and Pepco's Brookville Bus Depot.
[8] Delmarva Power's Elk Neck VPP.

Finally, in response to the Procurement Order, the Exelon MD Utilities and SEIA have updated and re-filed their Joint Energy Storage Procurement proposal, which includes a 150 MW statewide distribution procurement allotment between third-party and utility-owned storage. The Joint Energy Storage Procurement proposal contains certain structural details that would apply to the Procurement Initiative Proposals—such as targets, how those targets are allocated, and cost recovery—so those details are not repeated in the Procurement Initiative Proposals.

The following sections describe several utility-owned energy storage deployments that the Exelon MD Utilities are currently implementing or, with Commission approval, could implement either to fulfill their utility-owned storage allotment within the Joint Energy Storage Procurement proposal or independently should the Joint Energy Storage Procurement proposal not be approved.

1. Utility-Owned FTM Distribution-Connected Energy Storage

Utility ownership of energy storage allows for a scalable, cost-effective approach to storage deployment by developing repeatable projects that minimize operational and maintenance expenses and project development efforts required over time. Utilities can deploy these projects rapidly to meet localized system constraints and defer the need for more expensive and time-consuming distribution system upgrades. This is especially valuable to meet the rapid growth in load caused by electrification, growth in data centers, electric vehicles, and other sources of electric growth. BGE is currently in the deployment stage of its Distributed Battery Energy Storage System ("DBESS") program (which was approved in BGE's last MYP) to deploy 500KW energy storage units to benefit its system and customers.

Recognizing utility expertise with the deployment of energy storage in 2024, the U.S. Department of Energy selected BGE's Infrastructure Reliability and Distribution Solutions ("BIRDS") application for $50 million in Grid Resilience and Innovation Partnerships ("GRIP") grant, which supports BGE's DBESS program. As the Exelon MD Utilities continue to develop programmatic energy storage deployment projects, these projects will be subject to normal rate case review and the possible development of PIMs. Due to the unique nature of utilities' obligation to serve customers, they are also uniquely situated to deploy energy storage projects in disadvantaged communities where the projects can provide additional resilience benefits to vulnerable communities. The Exelon MD Utilities will continue to pursue cost-effective utility-owned energy storage to meet system needs as they are identified. The Companies have no specific request of the Commission regarding utility-owned, front-of-the-meter, distribution-connected energy storage beyond the acknowledgment of the importance of these initiatives to modernize the distribution system and support the State energy deployment goals.

2. Third Party-Owned FTM Distribution-Connected Energy Storage

In response to the Procurement Order, the Exelon MD Utilities and SEIA have updated and re-filed their Joint Energy Storage Procurement proposal. This proposal includes a 150 MW statewide distribution procurement of third party-owned energy storage at no less than 30% of the utilities' allocated total procurement target. The details of this proposal are being filed concurrently under separate cover.

3. Utility-Owned Customer-Sited C&I Energy Storage

Utility-Owned Commercial and Industrial ("C&I") customer-sited BTM and FTM storage offers many benefits, including lower interconnection costs, reduced peak demand at the source, and faster deployment compared to larger FTM projects. Historically, distributed energy storage for C&I customers has been deployed through programs that provide direct value to participating customers, such as retail incentives. However, broad incentive programs in other jurisdictions—such as New York's Retail Storage incentive—have not resulted in significant BTM deployment. Tepid adoption is due to numerous factors, including customer interest, the complexities of structuring BTM contracts between developers and building owners, and competing incentives that are available to both FTM and BTM resources.

For these reasons, the Exelon MD Utilities propose a utility-owned, customer-sited procurement model for C&I energy storage assets. The Companies would provide storage assets to host customers and locate and dispatch these resources to maximize system benefits. This distributed capacity procurement ("DCP") framework will assess the need for energy storage from the standpoint of system planning (as opposed to retail need) and aim to strategically deploy capacity at parts of the system where the capacity provides the most grid value. Unlike a market-driven approach, this framework allows utilities to identify, procure, and manage storage assets efficiently.

Deploying energy storage via a DCP could secure system value for all customers by alleviating congestion, providing resiliency, and/or deferring expensive grid upgrades. Additionally, the local vendor network will benefit by gaining access to new, large solicitations of project installation opportunities, which should reduce their customer acquisition costs. Finally, this approach enables the Exelon MD Utilities to expand their operational experience with storage, further developing their expertise to scale future deployments and integrate storage as a core grid asset over the next decade.

To implement a DCP, the Companies will work with stakeholders and an implementation partner to design and implement a targeted storage procurement that maximizes grid and customer benefits. They will identify areas of need via a locational cost-benefit analysis to determine where it makes sense to site the batteries for cost-effective deployment. Underneath this framework, the Exelon MD Utilities would deploy initiatives that site storage for FTM or BTM applications depending on system needs and technical performance requirements of the batteries themselves. The DCP would provide benefits similar to demand response and provide additional distribution system support services and resilience benefits.

If the DCP is approved, the Exelon MD Utilities will issue an RFP for an implementation partner to support the utility with customer engagement, value chain management, data and analytics, and administration, safety, and compliance:

- Customer Engagement: A dedicated team will engage eligible customers to host energy storage assets on their respective properties at no cost or potentially receive a lease payment depending on the final initiative structure. This is not a sales process since the utility would own, operate, maintain, and dispatch the batteries.
- Value Chain Management: An implementation partner will be responsible for engaging the local workforce and issuing a cadence of competitive solicitations on which vendors and other contractors can bid. The utility will work with its implementation partner to employ cost-reduction strategies, such as bulk equipment purchasing and overhead fee reductions, to further drive down project costs and make the most efficient use of capital.
- Data and Analytics: Through a combination of in-house and third-party software tools, the utility will analyze where on the system energy storage can deliver the most grid value and determine what planned investments in the distribution system may be able to be deferred. An implementation partner will also provide operational tools to automate aspects of the project design and delivery process to enable speed and scale.
- Administration, Safety, and Compliance: Administration would include management of all metrics and initiative reporting requirements, including adherence to all utility requirements for participating vendors and third-party service providers.

Should the Commission seek additional information on how this initiative would fall within a utility's allocation of the 150 MW Distribution Procurement proposal, the Exelon MD Utilities can provide a more comprehensive DCP program description, including a competitive solicitation for an implementation partner, later this year.

4. BTM Distribution-Connected Residential Energy Storage

The Exelon MD Utilities propose a procurement initiative for residential customers that would allow eligible customers (“subscribers”) to have utility-owned and utility-controlled battery storage devices installed on their property. These batteries would be located at the customer's site, but the utility would own and manage them. Each BESS will be commissioned to provide, at minimum, load management through PJM’s demand response market to deliver distribution system support. Each BESS will have the ability to provide the customer with home backup power during service interruptions, and the utility will maintain access and control for the purpose of reducing power costs for the subscriber and other customers on a utility’s system. By providing BESS resources to residential customers, this Procurement Initiative Proposal would further enhance the resilience benefits provided by renewable DERS incentivized by the utility DRIVE Act program. In addition, it would enhance the capability of VPPs resulting from the DRIVE Act to provide substantial benefits from Distribution System Support Services, such as peak shaving at the system and feeder level. Utility-owned BESS provide a unique opportunity to showcase benefits to both single- and multi-family properties while also providing value through peak load reduction to all customers.

The multi-family space poses unique challenges, and the Exelon MD Utilities remain committed to designing and offering innovative and beneficial solutions to these customers. The Exelon MD Utilities will work with partners and industry experts to address the unique opportunities presented by the multi-family sector relating to BESS design, procurement, and installation.

The Exelon MD Utilities’ BTM Distribution-Connected Residential Energy proposal is based on conversations with Green Mountain Power (“GMP”) about the benefits their Home Energy Storage leasing program has provided to Vermont customers.[9] The GMP Home Energy Storage program has been operating

[9] See https://greenmountainpower.com/rebates-programs/home-energy-storage/energy-storage/#:~:text=Get%20two%20Powerwall%20batteries%20with%20a%20ten%20year,share%20access%20with%20GMP%20during%20peak%20energy%20times.

since 2017 and has deployed 6,000 batteries to 4,400 homes (approximately 2% of GMP's customers). Nearly fifty percent of GMP's Home Energy Storage customers have paired solar panels with their leased battery storage. The program allows GMP to draw residential batteries down to ten percent of their capacity but does not dispatch any battery energy during adverse weather to allow customers to run their batteries as generators during outages. The GMP program has been successful, providing peak reduction similar to a demand response program and reducing outages without resulting in increasing fees to customers. The Exelon MD Utilities will continue to engage with GMP if this Procurement Initiative Proposal is approved to bring additional learnings to the development of a Maryland residential energy storage subscription initiative.

Eligible customers may acquire from the utility at zero upfront cost an eligible BESS system, as defined by the utility, through a manufacturer-certified, utility-approved contractor. Each utility will maintain a list of qualified contractors for the initiative. After installation, customers will incur a monthly, on-bill subscriber fee based on the pre-determined total utility value of the BESS, amortized over a 10-year term. This monthly fee will be tied to the customer's premise meter and any new resident will take on continued monthly payments through the original term. After the subscription term is complete, subscription fees will be waived, and the customer will gain ownership of the equipment through the device's end of useful life. This subscription will include communication between the BESS and the utility via a dispatch platform utilizing the customer's home internet connection, auto-enrollment in applicable utility initiatives and will establish home back up generation when the utility does not need the BESS for distribution support services.

The Exelon MD Utilities prioritize safety and recognize the importance of addressing potential safety concerns associated with residential BESS systems. MESP regulations require that "[t]he energy storage device shall meet NFPA 855 standards, if applicable, in addition to any other applicable federal and state requirements and local codes and standards."[10] The National Fire Protection Association ("NFPA"), a trusted source of safety

[10] COMAR §20.50.14.05(A)(3).

knowledge, provides requirements for the installation of BESS in their NFPA 855 Standard for the Installation of Stationary Energy Storage Systems publication. The Exelon MD Utilities will comply with applicable regulations, which provide guidance on topics ranging from maximum storage limitation to location and location siting to fire detection measures and inverter UL listing requirements. The Exelon MD Utilities intend to further protect customers by requiring the customer to hold appropriate insurance coverage in case the BESS causes the customer's property to incur damage.

Should the Commission seek additional information on how this Procurement Initiative Proposal would fit within a utility's allocation of the 150 MW Distribution Procurement proposal, the Exelon MD Utilities can provide a more comprehensive description as they seek to move forward with the offering later this year.

II. Transmission System-Connected Procurement Initiative Proposals

The Exelon MD Utilities acknowledge the need for bulk-level resource adequacy and wholesale services within the State. They recognize that transmission-level energy storage will be crucial to the State achieving its near-term goal of 750 MW of energy storage capacity by May 31, 2028 as well as its longer-term goal of 3,000 MW of energy storage capacity by May 31, 2034. Therefore, the Exelon MD Utilities propose transmission-level energy storage procurements of up to 600MW that will support the State's near-term and longer-term energy storage goals. As MAREC Action discussed, there are currently seventeen active storage projects in the PJM queue with a total MW capacity equivalent to 1,627MW.[11] These projects likely will not go forward to construction and commissioning without State support for the purchase or tolling agreements to provide the necessary financing. To expedite placing these projects in-service to help meet Maryland's energy storage deployment goals and help address resource adequacy challenges, the Companies believe they are best positioned to provide the necessary support and propose both utility- and third-party-owned transmission-level procurements of energy storage projects.

[11] Comments of MAREC Action, Case No. 9715 (Nov. 5, 2024) at 3.

1. Utility-Owned Transmission-Connected Procurement Initiative Proposal

The 17GW of utility-owned transmission-connected energy storage (14GW of pumped storage and 3GW of battery storage) presently operating in the US demonstrates that utility-owned transmission-connected energy storage provides benefits to customers by meeting peak resource adequacy needs. In states with vertically integrated utilities, the costs for the utility-owned BESS resources that are constructed to support resource adequacy as their primary use case are generally recovered from customers in the same manner as generation and recorded under the "Production" category on FERC Form 1.[12] Further, California created a new cost allocation mechanism to track and recover the net cost of new capacity resources owned or contracted by regulated distribution utilities to support the resource adequacy needs of all delivery customers (those that do and do not buy energy from the utilities).

The Exelon MD Utilities support utility-owned transmission-connected energy storage as a method for addressing bulk-level resource adequacy challenges and wholesale services within the State to assist in meeting Maryland's goal of 3,000 MW of energy storage capacity by May 31, 2034. Upon Commission approval to pursue Utility-Owned Transmission-Connected Procurement Initiative Proposal, the Companies will collaborate with developers of energy storage projects in Maryland, focusing on projects poised for approval in the PJM interconnection queue to explore the cost-effective acquisition of projects to address Maryland's resource adequacy challenges.

2. Third-Party-Owned Transmission-Connected Tolling Procurement Initiative Proposal

Regarding utility procurement of third-party transmission-connected storage, the Exelon MD Utilities propose a Utility Dispatch Rights Procurement Initiative Proposal to competitively procure third-party-owned energy storage resources. This "full tolling" initiative offers developers long-term revenue certainty through a competitive bidding process, granting the utility the right to dispatch the asset.

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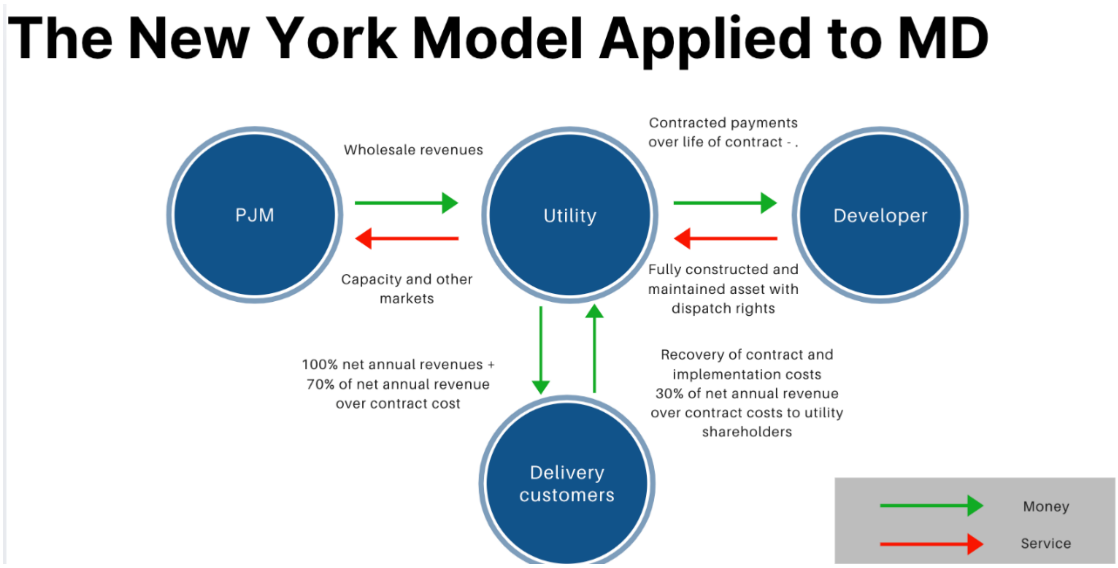
[12] In some cases these resources have been classified under the Distribution category of FERC Form 1 while under construction. See https://lf-puc.idaho.gov/WebLink/DocView.aspx?dbid=0&id=143622

To provide for quick execution, balanced risk/reward, and clear expectations for developers, this Procurement Initiative Proposal is modeled after New York State's tolling program. The general structure is outlined in Exhibit 1.

Exhibit 1: Utility Dispatch Rights



The proposal will generally operate as follows:

1. The utility will issue an RFP for 15-year tolling agreements with qualified developers.
2. The utility will seek authorization to procure transmission-connected storage, subject to a Utility Defined Bid Ceiling.
3. Contracts will include operational dates, performance commitments (availability, capacity maintenance, round-trip efficiency), and liquidated damages to protect customers.
4. The developer will be responsible for completing PJM interconnection requirements to enable PJM market participation coincident with the commercial operation of the resource.
5. Upon commercial operation, the utility will have full control of the BESS operation to participate in PJM markets and provide grid services. The utility, either directly or via a third-party vendor, will participate in the PJM markets for the contract term.

6. The utility will own the wholesale revenues that result from market operations.
7. The utility will return 100% of revenues to customers up to the annual levelized contract cost.
8. To incentivize strong PJM market participation, the utility will retain 30% of annual revenues exceeding the levelized contract cost, with the remaining 70% going to customers.
9. Each annual contract and implementation cost will be recovered from customers as a regulatory asset amortized over 5 years and included in rate base until it is fully recovered.
10. To mitigate against the potential for higher costs of borrowing that would negatively impact customers, if the Commission issues an order approving full tolling agreements, the Companies would then seek an assessment from a premier credit rating agency to ascertain if the structure and cost recovery provisions are likely to adversely impact the utility's credit rating. The Commission's order should explicitly provide for the utility to not enter into the tolling agreement if the credit assessment determines that the structure and terms of the order have an adverse impact to the utility's credit metrics and credit. This same standard would also apply to utility-owned transmission-connected BESS projects.

Similar programs have been successful in California and New York. The competitive procurement of tolling contracts provides developers with revenue certainty, enabling them to offer competitive prices, which is enabled by lower risk-adjusted return requirements due to the ability to obtain favorable financing for a tolling contract tied to an energy storage asset.

There are several other key aspects of the program design, including:

- Payment Structure: Utilities can offer flexible payment options, including either a larger upfront payment at commercial operation followed by levelized payments or purely levelized payments.
- Contract Approval and Oversight: The Commission will have oversight of the RFP process and provide approval before any contract is executed.

- Reporting: Utilities propose an annual reporting requirement to commence after a storage asset becomes operational to communicate confidential operating information that is not otherwise captured in MESP requirements. The expectation is that this confidential report will include:
  - confidential market revenues;
  - confidential annualized price; and
  - calculation of revenue share for utility, if applicable.

The utility-administered Third-Party-Owned Tolling Procurement Initiative Proposal described above to procure third-party transmission-connected storage would expedite placing many of the nearly 1,600 MW of the active projects in the PJM queue in-service in support of the State's energy storage deployment goals to help address resource adequacy challenges.

Upon Commission approval of this Procurement Initiative Proposal, the Exelon MD Utilities will issue a more comprehensive initiative description as they seek to move forward with the offering.

III. Project Interconnection and Timing Considerations

Meeting the May 2028 deadline for project interconnections presents several challenges. Key factors influencing project timelines include land acquisition, State and local approvals, community outreach, and the long lead times and supply chain issues associated with procuring lithium-chemistry energy storage and other key components, such as transformers and switchgear. Further, interconnection processes will impact both the timelines for placing energy storage projects in-service and for realizing the full benefits to customers from participation in PJM markets. Additionally, utilities will need to onboard appropriate levels of staffing to support initiative administration and increased interconnection requests that will result from these procurements. BESS that intend to participate in the wholesale markets are required to go through the process of obtaining a PJM Interconnection Service Agreement ("ISA") or a PJM Wholesale Market Participant

Agreement. [13] Finally, the Utility-Owned BTM Residential Energy Storage Procurement Initiative Proposal will be the most rapidly deployed storage, potentially contributing to achieving resource adequacy via demand response benefits.

IV. Benefit-Cost Analysis

As the Commission directed, the Companies will conduct separate Benefit-Cost Analyses ("BCAs") to evaluate the cost-effectiveness of each Procurement Initiative Proposal. Their BCA framework will be well-aligned with the recommendations outlined in the Maryland Unified BCA ("UBCA") Workgroup Final Report (Maryland UBCA Framework for DERS - Work Group Report), appropriately considering all key cost and benefit streams.

Pursuant to the Exelon MD Utilities' portfolio approach to energy storage, the BCAs will account for the Procurement Initiative Proposals' interconnection levels—BTM, FTM distribution-connected, and FTM transmission-connected—as well as their ownership and operating models, including utility-owned-and-operated storage, third-party-owned-and-operated storage, third-party-owned storage with utility operation, and other ownership structures.

The final net benefit ratio for each Procurement Initiative Proposal will be calculated based on Net Present Values using an appropriate discount rate aligned with the UBCA framework recommendations. By maintaining these alignments, the Exelon MD Utilities' BCA provides a structured and transparent approach for utilities to develop procurement proposals that comply with Commission requirements.

V. Bill Impact Analysis for Customer Affordability & Equity Assessment

As the Procurement Order directed, the Companies may conduct a separate customer bill impact analysis to assess the affordability and equity impacts of each proposed initiatives.[14] The bill impacts will

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13 While implementation details still must be determined, FERC Order No. 2222 may not require resources less than 5 MW and registered in a DER Aggregation to complete a PJM New Service Interconnection study. This will create a more timely path to PJM market participation.

14 Procurement Order at page 4, fn 18.

depend on the cost recovery mechanism allowed for the proposed initiatives and will be calculated for the entire service territory. Additionally, if deemed necessary to assess thoroughly both affordability and equity impacts, the analysis will include evaluations for different customer segments, *e.g.*, Disadvantaged Communities ("DAC") vs. non-DAC customers. This approach examines the equity impacts of each initiative on different customer populations, supporting a transparent and informed decision-making process.

VI. Conclusion

The Exelon MD Utilities are committed to supporting the State in developing the portfolio of energy storage initiative necessary to meet the established targets of cost-effective cumulative energy storage capacity. To begin implementation of the Maryland Energy Storage Program by July 1, 2025, the Parties request the Commission:

1. Approve Exelon MD Utilities' and SEIA's proposed Joint Distribution Procurement initiative, subject to more fulsome filings laying out answers to the Commission's identified Procurement Order issues, including but not limited to an appropriate benefits-cost analysis. This initiative is the creation of a utility-run procurement process for up to a total of 150 MW of the State's total MESP target for utility-owned and FTM third-party-owned distribution BESS to be procured through an annual, separate procurement processes.
2. Approve the Exelon MD Utilities' Distribution Procurement Initiative Proposals herein subject to more fulsome utility filings laying out answers to the Commission's identified Procurement Order issues, with flexibility for the Companies and other utilities to enhance and/or revise their respective program proposals in those additional filings.
3. Approve the Exelon MD Utilities' Transmission Procurement Initiative Proposals herein for up to 600MW of storage, subject to more fulsome utility filings laying out answers to the Commission's

identified Procurement Order issues, with flexibility for the Companies and other utilities to enhance and/or revise their respective program proposals in those additional filings.

Respectfully Submitted,

/Andrea H Harper/
Andrea H. Harper
Counsel for
Potomac Electric Power Company
and Delmarva Power and Light Company

/Crystal Barnett/
Crystal Barnett
Counsel for
Baltimore Gas and Electric Company

CERTIFICATE OF SERVICE

I hereby certify that on this 21st day of February 2025, I caused to be served via electronic mail the foregoing Exelon MD Utilities' energy storage procurement proposal and request for approval to each counsel of record in Case Nos. 9715.

/s/ *Andrea H. Harper*

Andrea H. Harper