COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

In the Matter of:	
Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan	**Kentucky Public Service Commission Case No. 2022-00402**

EXPERT TESTIMONY OF

ANDREW LEVITT

ON BEHALF OF

Sierra Club, The Lexington-Fayette Urban County Government, and The Louisville/Jefferson County Metro Government

FILED: JULY 14, 2023

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC JOINT APPLICATION OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND SITE COMPATIBILITY CERTIFICATES AND APPROVAL OF A DEMAND SIDE MANAGEMENT PLAN AND APPROVAL OF FOSSIL FUEL-FIRED GENERATING UNIT RETIREMENTS	))))))))	**Case No. 2022-00402**

AFFIDAVIT OF ANDREW LEVITT
IN SUPPORT OF DIRECT TESTIMONY ON BEHALF OF SIERRA CLUB

Commonwealth of)
Pennsylvania)

Affiant Andrew Levitt, states the following: The prepared Direct Testimony and associated exhibits filed herewith on Friday, July 14, 2023, constitute the direct testimony of Affiant in the above-captioned case. Affiant states that he would give the answers set forth in his Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct.

Andrew Levitt

SUBSCRIBED, ACKNOWLEDGED, AND SWORN to before me by Andrew Levitt this 14th day of July, 2023.

Danny Serrano
Notary Public

Notary ID No.: 1432280

My Commission expires: 03/06/2027

Commonwealth of Pennsylvania - Notary Seal
Danny Xavier Serrano, Notary Public
Philadelphia County
My Commission Expires 03/06/2027
Commission Number 1432280

My name is Andrew Levitt. I am employed by The Brattle Group as a Senior Consultant. I have been retained by the Sierra Club, the Lexington-Fayette Urban County Government, and the Louisville/Jefferson County Metro Government (collectively, "Urban Intervenors and Sierra Club"). On behalf of the foregoing, I have prepared an independent assessment of prospective membership of Louisville Gas and Electric Company and Kentucky Utilities Company (LG&E-KU) in the PJM Interconnection, LLC (PJM) Regional Transmission Operator (RTO) with respect to the following questions:

1. Would joining PJM reduce or delay the need for new capacity to serve LG&E-KU customers? If so, by how much?
2. What are the potential resource investment cost savings of PJM membership for LG&E-KU customers, if any?
3. What are other potential benefits of PJM membership for LG&E-KU customers, if any?

In conducting my assessment, I have relied on LG&E-KU's joint application for certificates of public convenience and necessity and site compatibility certificates ("CPCN Application"), the direct testimonies of Stuart A. Wilson ("Wilson Testimony") and Tim A. Jones ("Jones Testimony") therein, the peak demand and resource plan submitted in discovery in that docket ("CPCN Plan"), LG&E-KU's RTO Study (as corrected in May, 2023), and associated workpapers ("RTO Study"), and LGE&E-KU's 2021 Integrated Resource Plan ("2021 IRP").[1]

I am sponsoring the following exhibits:

- Exhibit ACL-1: a copy of my curriculum vitae

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[1] LGE&E-KU, Electronic Joint Application for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan, Case No. 2022-00402, filed December 15, 2022.

Ibid., Direct Testimony of Stuart A. Wilson.

Ibid., Direct Testimony of Tim A. Jones.

Peak Demand and Resource Summary, Louisville Gas and Electric Company's and Kentucky Utilities Company's Responses to the Commission Staff's First Request for Information, Attachment to Question 53(f), filed March 10, 2023.

LG&E-KU, 2021 Integrated Resource Plan, October 2021.

LG&E-KU, 2022 RTO Membership Analysis, initially published April 2022, updated May 2023.

- Exhibit ACL-2: the 2021 IRP
- Exhibit ACL-3: LG&E-KU's Responses to Discovery Requests
- Exhibit ACL-4: PJM Hourly Load Forecast[2]
- Exhibit ACL-5: RTO Study Production Costs and Capacity Additions[3]
- Exhibit ACL-6: the RTO Study
- Exhibit ACL-7: EKPC's 2022 IRP[4]
- Exhibit ACL-8: South Carolina Market Reform Study[5]
- Exhibit ACL-9: Western Energy Imbalance Service and SPP Western RTO Participation Benefits[6]
- Exhibit ACL-10: 2028 LG&E-KU Hourly Demand Forecast[7]

I am an economic consultant with expertise in wholesale electricity markets in RTOs and Independent System Operators, including market design, reliability planning, operational integration of renewables and storage, and transmission policy. I earned an M.M.P. degree from the University of Delaware, and a B.S. in physics from the University of Toronto. Prior to joining Brattle, I was Senior Lead Market Design Specialist at PJM Interconnection, LLC. In that role, I developed PJM's Effective Load Carrying Capability (ELCC) method to set the capacity value of renewables and storage the PJM capacity market; I contributed to other policies and protocols to integrate growing resource types such as wind, solar and storage into markets, operations, and planning; and I contributed to the initial stages of an ongoing reform to the capacity market and its resource adequacy analysis framework.

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2 PJM, RTO Hourly Shape spreadsheet, April 4, 2023, accessible at p. "PJM – Load Forecast Development Process."

3 Included as part of the RTO Study, published in Louisville Gas and Electric Company's and Kentucky Utilities Company's Responses to the Sierra Club's Supplemental Requests for Information, Attachment 2 in Response to Question 26(b), May 4, 2023.

4 East Kentucky Power Cooperative, Integrated Resource Plan, 2022.

5 J. Tsoukalis, et al., South Carolina Electricity Market Reform Measures Study, The Brattle Group, May 1, 2023.

6 J. Tsoukalis, et al., Western Energy Imbalance Service and SPP Western RTO Participation Benefits, The Brattle Group, December 2, 2020.

7 Jones Testimony, Exhibit TAJ-3, Volume 12 (ZIP file) containing the spreadsheet "2028_weather_years_final_peak_adjusted_mean_10282022.xlsx."

CONTENTS

I. Executive Summary

On December 15, 2022, LG&E-KU filed a CPCN Application to request that the Kentucky Public Service Commission ("Commission") approve two new 621 MW natural gas combined cycle generators (NGCCs), among other resources, as necessary to meet energy supply and resource adequacy needs. LG&E-KU plans to retire three existing steam generators totalling approximately 1,500 MW. In light of forecasts of energy consumption, forecasts of peak demand requirements, and reserve margin requirements, LG&E-KU's proposal aims "to ensure that customers' remaining demand and energy requirements are met at the lowest reasonable cost."[8]

As an alternative or supplementary approach to meeting resource adequacy needs, LG&E-KU could join a Regional Transmission Organization (RTO) such as the PJM Interconnection, LLC (PJM). RTOs provide benefits to customers by jointly planning and operating the combined utilities as one system. This "pooling" is applied in resource adequacy planning (which leverages diversity across members to lower resource needs) and in operations (which schedules and dispatches the most cost-effective resources across all members). These functions enable each other: joint operations through an independent third party (the RTO) makes it easier for members to rely on one another for resource adequacy, since they know that shortage emergencies will be navigated impartially. Such power sharing requires financial arrangements to compensate members producing above their demand, and RTOs in the United States all feature energy markets with marginal pricing. Some RTOs (such as PJM and MISO) also have a market for capacity. Utilities representing over two-thirds of electricity demand across the US have joined such RTOs, including several utilities in Kentucky in the footprints of PJM and MISO (see Figure 1 below).[9]

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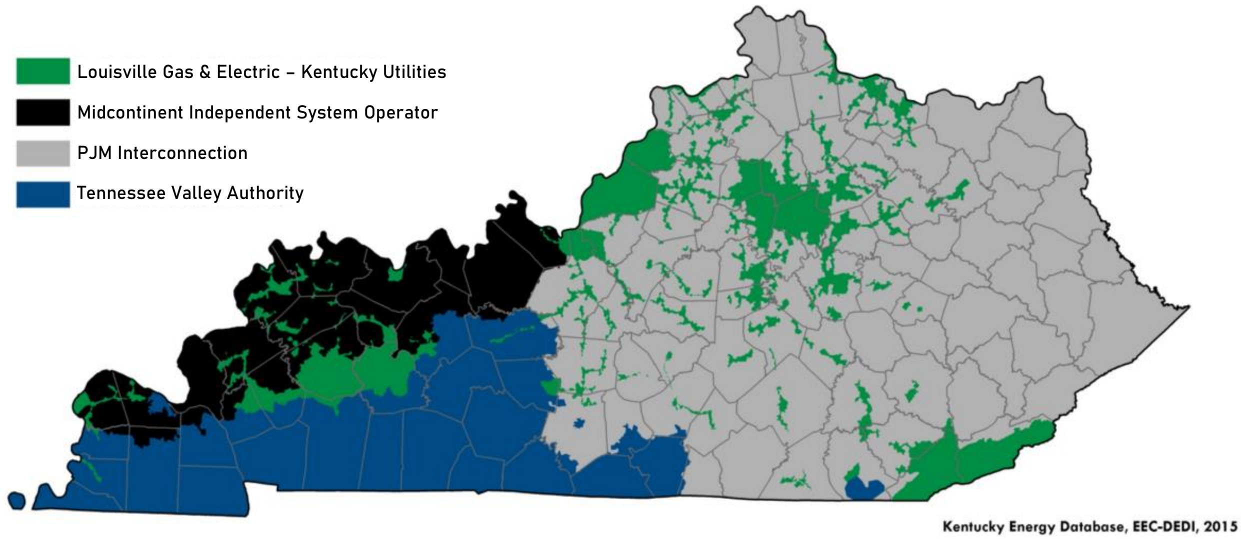
8 CPCN Application, p. 7.

9 The transmission systems of East Kentucky Power Cooperative, Kentucky Power, and Duke Energy Kentucky are part of PJM, and Big Rivers Electric Corporation and Henderson Municipal Power & Light form part of MISO.

FIGURE 1. KENTUCKY BALANCING AUTHORITY AREAS



Source/Notes: Kentucky Energy and Environment Cabinet Office of Energy Policy, Kentucky Energy Profile, 7th Ed., 2019. Legend adapted for consistency.

I analyze the PJM membership alternative and find that joining PJM would meet LG&E-KU's stated energy and demand requirements with lower investment costs for consumers relative to LG&E-KU's proposal to build two new power plants. This savings would be accomplished through the benefits of resource adequacy pooling across the many utilities in PJM, together with the relatively higher value of LG&E-KU solar in the PJM reliability context. By joining PJM, I find that LG&E-KU could meet its resource needs and meet standard reliability targets through 2029 without building the two proposed new NGCC facilities, and thereafter with only modest capacity market purchases for several years.

This capacity savings allows LG&E-KU to avoid the cost of resource investment. I find that LG&E-KU customers would save approximately $125 - $140 million annually in resource investment costs each year after 2027.[10]

I further find additional quantitative and qualitative benefits to PJM membership with respect to reliable and efficient operations of a system with a changing resource mix. Other RTO membership studies find that utilities realize operational production cost savings in the 4%–8% range by participating in regionally optimized dispatch that maximizes use of the regional

[10] Consistent with values used in the CPCN Application, I use nominal dollar values denominated in $2028.

transmission system.[11] Similar savings would translate to approximately $30-$70 million per year in savings in LG&E-KU's system. Production cost savings would be in addition to the resource investment savings mentioned above.

TABLE 1. SELECT BENEFITS OF PJM MEMBERSHIP FROM 2028+

Capacity Savings of PJM Membership	900-1,300 MW
Cost Savings of Reduced Capacity Needs (annualized)	$125-$140 million/yr
Potential Scale of Production Cost Benefits	Up to $70 million/yr

My conclusion that PJM membership is an advantageous solution to looming supply needs stands in contrast to LG&E-KU's RTO Study (as updated in May 2023), which identified net costs based on LG&E-KU's analysis of results from their consultant Guidehouse. In that analysis, LG&E-KU used annual projections from consultant Guidehouse to conclude that, relative to the status quo standalone arrangement, joining PJM would result in greater costs to customers totaling $421 million on a net present value basis. LG&E-KU revised this value downward by approximately 30% from an initial result of $620 million, following correction of a transposition error revealed during discovery. The error occurred in the transfer of data from the Guidehouse results to the supplemental analysis that LG&E-KU performed.[12]

My preliminary assessment is that the RTO Study result does not reflect any counterproductive capacity or operational pooling features of LG&E-KU in PJM, and therefore does not provide evidence to contradict my findings. The RTO Study finding is an outlier among several dozen studies that find net benefits from RTO membership across many other differently-situated utilities.[13] While the RTO Study's anomalous finding is not sufficiently explained to clarify the reason for the discrepancy, it may be due at least in part to use of inconsistent

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[11] J. Tsoukalis, et al., Western Energy Imbalance Service and SPP Western RTO Participation Benefits, The Brattle Group, December 2, 2020; J. Chang, et al., Joint Dispatch Agreement Energy Imbalance Market Participation Benefits Study, The Brattle Group, January 14, 2020; J. Chang, et al., Senate Bill 350 Study: The Impacts of a Regional ISO-Operated Power Market on California, prepared for California ISO (CAISO), The Brattle Group, July 8, 2016; J. Chang, et al., Production Cost Savings Offered by Regional Transmission and a Regional Market in the Mountain West Transmission Group Footprint, The Brattle Group, December 1, 2016.

[12] See the RTO Study, Table 9, p. 27; Sierra Club supplemental discovery request, Q2.26(b), and LG&E-KU's response on p. 50, explaining the transposition error.

[13] For example, Exhibits ACL-8 and ACL-9.

depreciation/annualization methods and inconsistent study timeframes between (a) the capacity expansion model and (b) the supplementary net present value analysis on which the final result was based.

II. Joining PJM Would Reduce LG&E-KU Capacity Requirements by 900 - 1,300 MW

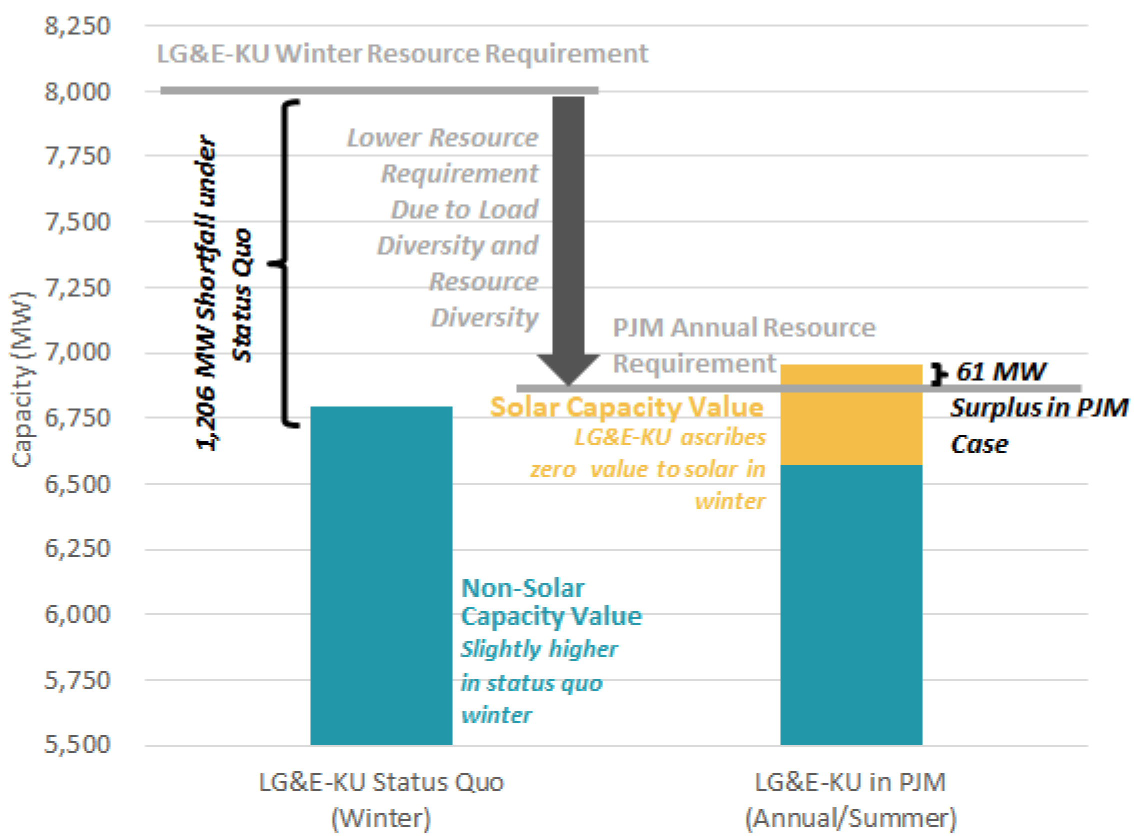
There are three main drivers for capacity savings from RTO membership: first, diversity in hourly patterns of demand between a utility and the RTO; second, reduced reserve margins; third, in some circumstances, increased capacity value of renewables. I chose to study these drivers as applied to LG&E-KU membership in PJM following the choice made in LG&E-KU's RTO Study, supported by LGE&E-KU's current position as a Balancing Authority that is largely embedded inside PJM (see Figure 1). The first two drivers would be expected to obtain with membership in any RTO (such as MISO), while the third is more dependent on circumstances (but could still apply in MISO).

I find that all three drivers are significant for LG&E-KU in PJM. First, as explained below in Section II.A, joining PJM would result in greater diversity in hourly patterns of demand, resulting in lower capacity requirements, largely as a result of the fact that PJM and LG&E-KU have differing seasonal peak demand patterns. Second, in Section II.B, I explain that joining PJM allows LG&E-KU to use a lower installed reserve margin while still meeting reliability standards. Third, the relevant capacity value of LG&E-KU's planned solar resources is higher under PJM membership, as explained in Section II.C.

I calculate the net effect of these three drivers in Section II.D (and as illustrated below in Figure 2), in which I find net capacity savings of approximately 1,300 MW relative to the winter-driven planning scenario in the status quo.

Finally, in Section II.E, I conclude that qualitatively similar capacity benefits would persist under PJM's recently proposed seasonal capacity approach.

FIGURE 2. NO NEW CAPACITY NEEDED IN 2028 (AFTER RETIREMENTS) IF LG&E-KU JOINS PJM



Source/Notes: comparison of projected capacity balance in 2028 in the status quo vs. the join PJM case, after retirements but before new NGCC additions. Analysis of and citations for CPCN Plan, resource requirements, and capacity values as detailed in the following subsections.

Figure 2 illustrates how PJM membership converts a capacity shortfall in 2028 under the status quo into a slight surplus. On the left side of the figure, the black bracket illustrates the retirement-driven capacity shortfall by showing the gap between the winter resource requirement (the upper gray horizontal line) and the winter capacity value of the planned fleet (after retirements, but before new NGCC plants). The right side of the chart shows that the resource requirement in PJM would be lower (due to load diversity and a lower reserve margin for equivalent reliability), and would be slightly exceeded by the higher capacity value of the fleet in the PJM context (due to higher solar value in the PJM context).

II.A. Regional Diversity in Customer Demand Patterns Reduces Capacity Requirements in PJM

All utilities benefit to some extent from the sharing of diverse resource adequacy needs.[14] This is because peak demands of utilities tend to occur at slightly different times, and therefore a utility that is experiencing shortage due to peak demand may have neighbors that are not experiencing a peak at the same moment, and therefore have excess supply available. A formal resource adequacy pooling arrangement, such as exists in an RTO, maximizes this sharing and the commensurate benefit by conducting resource adequacy planning and operations jointly across all member utilities. The RTO procures resources to meet the common simultaneous peak demand of all members, which (due to demand diversity) is necessarily lower than the sum of each member's individual peak demand. Put another way, each member's share of the pool-wide coincident peak demand is lower than its own non-coincident peak demand.[15] This effect is pronounced for a member that peaks in different seasons from its RTO.

Neighboring utility East Kentucky Power Cooperative (EKPC) provides a particularly striking example of a utility that has captured these diversity benefits. EKPC peaked in 2022 at 3,309 MW (in winter), but its consumption during PJM's peak (in summer) was only 2,030 MW. Because summer demand also features significant diversity, EKPC's total resource requirement in PJM of approximately 2,200 MW (including reserve margin) is below even EKPC's forecasted non-coincident 2022 summer peak (2,500 MW).[16] The ratio of EKPC's demand

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[14] E.g., see discussion of capacity benefit margin at P26 in Federal Energy Regulatory Commission, Order No. 729, "Final Rule on Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the Bulk-Power System", 74 FERC ¶ 64,883, Docket No. RM08-19-000, et al., issued November 24, 2009.

[15] The term "non-coincident peak" is used here to refer to the maximum annual demand of any one member of a resource adequacy pool (e.g., an RTO). The term "coincident peak" refers to the member's consumption during the time of peak demand of the entire resource adequacy pool.

R. Billinton, and R. Allan, "Reliability Evaluation of Power Systems", 2d ed., 1996, Plenum Press, New York and London, p. 117, "The adequacy of the generating capacity in a power system is normally improved by interconnecting the system to another power system. Each interconnected system can then operate at a given risk level with a lower reserve than would be required without the interconnection. This condition is brought about by the diversity in the probabilistic occurrence of load and capacity outages in the different systems."

[16] East Kentucky Power Cooperative, Integrated Resource Plan, 2022, Table 1-2, p. 21; PJM Interconnection, LLC, PJM Load Forecast Report, Table B10, January 2022, p. 58.

during the PJM system peak (2,030 MW) to EKPC's own peak demand (3,309 MW) yields a metric called the "coincidence factor" of just 61%. By joining PJM, EKPC therefore has reduced its own capacity planning requirement by well over 1,000 MW within its 3,300 MW system, achieving a capacity savings to its customers on the order of $100 million per year.[17] Utilities in the West are increasingly committing to joining pooling arrangements to capture similar benefits, including most recently almost two dozen utilities in ten states.[18]

In the present case, LG&E-KU sees a mix of winter-peaking years and summer-peaking years versus PJM's summer peaking system.[19] Moreover, as discussed further in Section II.C below, LG&E-KU expects more solar resource build in coming years, which provides significant summer value and typically less winter value. LG&E-KU expects winter constraints to grow in prominence in future years, and to the extent that LG&E-KU's capacity needs are driven by peak winter demand, they would present pronounced diversity effects when pooled with PJM, whose

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[17] PJM used a value of $256/MW-day for the Net Cost of Net Entry (Net CONE) in the 2025/2026 capacity market base residual auction, yielding an annual savings of $93 million for 1,000 MW of capacity.

[18] The new FERC-approved Western Resource Adequacy Program (WRAP) pools the resource adequacy needs of utility participants across ten states and one Canadian province to take advantage of regional load diversity and the trading of well-defined capacity products. 22 utilities have signed up, ranging from Arizona Public Service to PacifiCorp and Bonneville Power Administration to Chelan Public Utility District, including in New Mexico, Arizona, Utah, Nevada, Wyoming, Idaho, Montana, California, Oregon, Washington, and British Columbia. See M. McNichol, "WPP Announces FERC Approval of WRAP Tariff," Western Power Pool, February 10, 2023; Western Power Pool, WRAP: Western Resource Adequacy Program, accessed June 26, 2023; and Southwest Power Pool, Western Energy Services, Markets + Webinar, November 17, 2021.

The rapidly expanding Western Energy Imbalance Market (WEIM) and Western Energy Imbalance Service (WEIS) markets in the West provide pooling in the operational timeframe that leverages regional demand diversity for efficiencies in operating costs. Both entities are in talks with members to add additional pooling functionality. For example, see American Public Power Association, "PacifiCorp Agrees to Join California ISO's Extended Day-Ahead Market," December 13, 2022; Mountain West Transmission Group, "Frequently Asked Questions," updated January 5, 2017; J. Tsoukalis, et al., Western Energy Imbalance Service and SPP Western RTO Participation Benefits, The Brattle Group, December 2, 2020; SPP, "WEIS – Southwest Power Pool," accessed February 16, 2023; J. Tsoukalis, E. Bennett, Benefits of the SPP RTO Expansion into the WEIS Footprint, The Brattle Group, September 20, 2022; SPP, "RTO West—Southwest Power Pool," accessed February 16, 2023; SPP, "Markets+ – Southwest Power Pool," accessed February 16, 2023; CAISO, "EDAM: Extended Day-Ahead Market," accessed February 16, 2023.

[19] 2021 IRP Reserve Margin Analysis, p. 5: "Because of the potential for cold winter temperatures and the increasing penetration of electric heating, the Companies are somewhat unique in the fact that annual peak demands can occur in summer and winter months. The Companies' highest hourly demand occurred in the summer of 2010 (7,175 MW in August 2010). Since then, the Companies have experienced two annual peak demands in excess of 7,000 MW and both occurred during winter months (7,114 MW in January 2014 and 7,079 MW in February 2015)."

capacity needs are currently driven by a system-wide summer peak.[20] This diversity in the timing of peak demand could offer substantial economic benefits to LG&E-KU customers if the utility joined PJM, because capacity supply is relatively abundant and unused by other customers in winter when LG&E-KU customers need it. A similar effect occurs at a smaller scale even within seasons, since the hour and day of LG&E-KU's seasonal peak is generally distinct from that of PJM's peak in the same season. Within a given season, LG&E-KU would be able to export supply to other customers when its supply exceeds the utility's own demand, and import supply when LG&E-KU demand is relatively high compared to other utilities' customers. By pooling capacity reserves across a large geographic footprint, LG&E-KU can reduce the total MW quantity of capacity that it needs to build in order to reliably serve its customers.

In PJM today, LG&E-KU's share of pool-wide capacity obligations would be allocated according to their consumption during the time of PJM's system-wide summer peak. To estimate this value, I used forecasted hourly demand for 2028 across 10 historical weather years developed separately by PJM and by LG&E-KU for their own systems.[21] Peak demand is a reflection of extreme weather, and a 10 year historical weather record captures important features of extreme weather that a shorter record would miss, including particularly cold weather in 2014 and 2015 and hot weather in 2012. Because load shapes are expected to evolve significantly, it is important to use forecasted hourly demand rather than historical actual demand. For both entities, the 2028 forecast year reflects evolving hourly consumption due to energy efficiency, customer-side solar, electric heat, and electric vehicle charging anticipated for that future year. The use of 10 historical weather years means that the load value for any hour in the dataset reflects the specific weather for that hour between 2012 and 2021, including temperature (e.g., for calculating electric heat needs) and solar insolation (for customer-side solar). For each of the 10 historical weather years, I identified the five summer days with the highest peak hourly demand on the standalone LG&E-KU system as well as on the combined PJM plus LG&E-KU system. I calculated the ratio of a) the average LG&E-KU demand during the five summer peak

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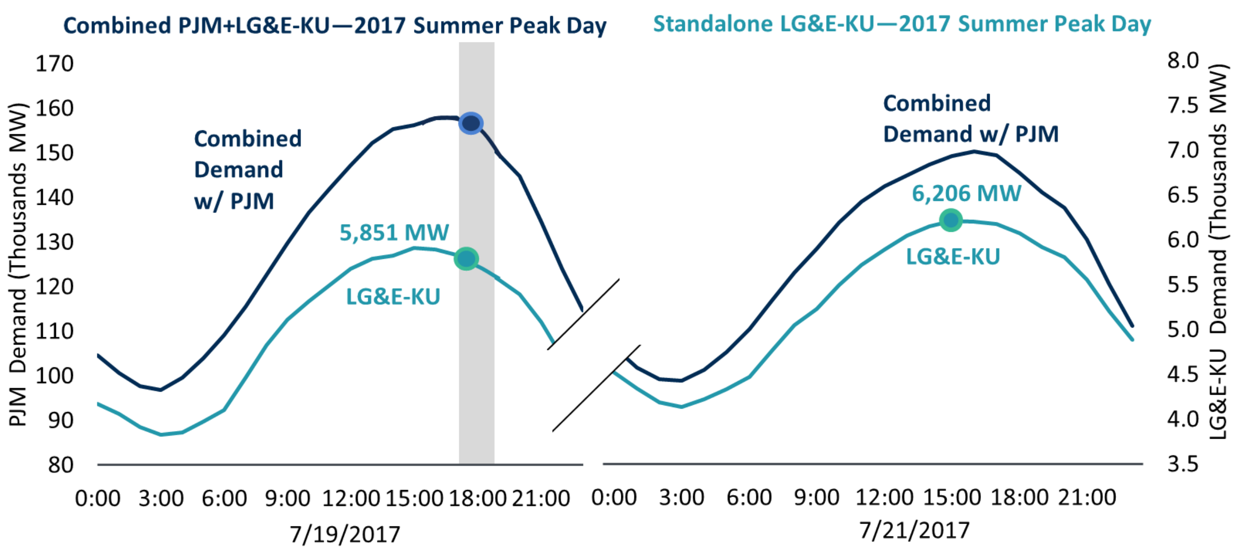
[20] 2021 IRP Reserve Margin Analysis, p. 3: "In past IRPs, the results of this analysis were communicated in the context of a summer peak reserve margin. However, as more solar generation is integrated into the Companies' generation portfolio and included in the calculation of summer reserve margin, a summer reserve margin will have less meaning as an indicator of the portfolio's ability to reliably serve customers in all hours."

[21] Exhibit ACL-10: 2028 LG&E-KU Hourly Demand Forecast, from the Jones Testimony. Exhibit ACL-4: PJM Hourly Load Forecast.

hours of the combined PJM system, to b) the average consumption during the five summer peak hours of the standalone LG&E-KU system. The result was a summer coincidence factor of 95%, showing that LG&E-KU consumes less during the combined system's summer peaks due to diversity effects.

An example of this effect for a typical summer is illustrated in Figure **3** below, which shows peak hourly demand on two weather days for the combined PJM+LG&E-KU system (dark blue curve, following the left axis) and LG&E-KU's standalone system (teal curve, right axis). The hourly load values represent the load composition expected in 2028 (e.g., with additional rooftop solar and energy efficiency), but reflecting historical weather from a typical summer: July 2017. The first weather day is July 19, 2017, showing that summer's peak for the combined PJM+LG&E-KU system at 18:00 hours. The second weather day is July 21, 2017, showing that summer's peak for LG&E-KU itself, at 16:00 hours. It is evident that both the two-day separation and the two-hour separation in the time of the two peaks contributes to a significant diversity effect.

FIGURE 3: 2028 FORECASTED HOURLY DEMAND OF LG&E-KU AND PJM ON PEAK DAYS



Sources and Notes: Exhibit ACL-10: LG&E-KU 2028 Hourly Forecast by Weather Years; Exhibit ACL-4: PJM Hourly Forecast.

For the purposes of a low-savings sensitivity described below, I also identified the average summer coincidence factor across all utilities in PJM today, equal to 97%.[22] This reflects a scenario in which the PJM and LG&E-KU systems exhibit more summer coincidence (i.e., less summer diversity) than expected, but more in line with other utilities in PJM. This could occur if PJM evolves into a system with greater relative winter peaks, or if LG&E-KU reverts to a more summer-peaking system.

II.B. Joining PJM Allows LG&E-KU to Utilize a Lower Installed Reserve Margin while Meeting Reliability Standards

Target reserve margins represent the additional resources needed for a planning area to reasonably match supply to demand under all conditions, even when demand exceeds the forecasted peak or significant shares of the resource fleet are unavailable. [23] Target reserve margins are often calculated using statistical models that account for the probability that peak loads are higher than in a typical year (i.e., forecast uncertainty) and that generators have lower availability than usual.[24] These models provide reliability metrics like "loss of load expectation" (LOLE) and others. Target reserve margins in the United States are commonly set to yield a modeled LOLE metric of 1-in-10 (that is, one expected shortage event per decade).[25] As described further in this section, when different regions target the same reliability metric, the resulting reserve margins can differ significantly depending on circumstances. In particular, reserve margins at 1-in-10 LOLE are lower in PJM than in LG&E-KU, yielding capacity savings from PJM membership while maintaining the same reliability target.

In order to determine the reserve margin necessary to meet the North American Electric Reliability Corporation (NERC) metric of an LOLE of 1-in-10, both PJM and LG&E-KU perform statistical analysis of load shapes, weather, and forced outage patterns. These analyses show that the LG&E-KU system requires a 23% summer reserve margin and a 31% winter

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[22] PJM Load Forecast Report, Tables B-1, B10, pp. 33-34, 58.

[23] J. Pfeifenberger, et al., "Resource Adequacy Requirements: Reliability and Economic Implications", The Brattle Group, Prepared for the Federal Energy Regulatory Commission, September, 2013, pp. 1-4.

[24] *Ibid.*, p. 4

[25] *Ibid.*, p. 1.

reserve margin to meet the 1-in-10 standard, while the PJM system requires a 14.7% annual installed reserve margin to meet that same reliability metric.[26] In order to compare the standalone vs. PJM membership scenarios at the same reliability level, I use these reserve margins in the capacity savings analysis (notwithstanding higher implied reserve margins in LG&E-KU's CPCN Plan and lower target reserve margins stated in the CPCN docket, both discussed further below). The remainder of this subsection explains the differences between the planning environment in the PJM RTO and the LG&E-KU system that are directionally consistent with the difference in their reserve margins.

In general, a geographically large system has more weather diversity and a greater variety in customer demand patterns, and therefore more load diversity. This tends to reduce reserve margins at a given target reliability level.[27] Likewise, a large system with more individual generation resources and a more diverse resource mix can provide the same estimated reliability level with a lower reserve margin because the probability that a large fraction of the fleet will be unavailable is proportionately lower.[28]

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[26] PJM has a resource adequacy framework that is primarily annual, using an annual reserve margin analysis and annual capacity values for renewables and storage. However, as a summer peaking system, it relies partly on summer-only metrics, for example using summer capacity values for thermal resources and allocating capacity obligations to utilities based on their coincident peak demand only in summer. This mix of annual and summer-based accounting is reflected in the method shown in Table 1 and Table 2. By contrast, LG&E-KU has introduced separate planning for summer and winter targets. In this seasonal context, LG&E-KU can meet the 1-in-10 LOLE standard while deviating from their target seasonal reserve margins, for example by trading off a lower reserve margin in the winter with a higher reserve margin in summer. Such a scenario is reflected in the low savings sensitivity.

Louisville Gas and Electric Company's and Kentucky Utilities Company's Responses to the Commission Staff's Fifth Request for Information, response to Question 4(a), July 7, 2023, p. 32.

PJM Interconnection, LLC, 2022 Reserve Requirement Study, October 4, 2022, p. 8.

[27] See Pfeifenberger, *et al*, *supra*, at page 29, describing analysis of four neighboring regions: "By using weather profiles from the same historical years for each of the modeled regions, we are able to capture the inter-regional correlation in loads and level of load diversity on high-demand days. Since weather patterns can differ substantially across the four regions on summer days, the timing of each region's highest peak loads will be different as well. If one region is at its system peak load but a neighboring region is not, the load diversity between the two systems will reduce their combined resource needs."

[28] Billinton R., and Allan, R., "Reliability Evaluation of Power Systems", 2d ed., 1996, Plenum Press, New York and London, p. 117. "The adequacy of the generating capacity in a power system is normally improved by interconnecting the system to another power system. Each interconnected system can then operate at a given risk level with a lower reserve than would be required without the interconnection. This condition is brought about by the diversity in the probabilistic occurrence of load and capacity outages in the different systems."

The entities that plan for resource adequacy in their territories ("planning areas" e.g. RTOs and many utilities) have a distribution of potential peak demands depending on the estimate of how extreme the hottest or coldest weather could be in any given year. In this distribution, the published "forecast peak demand" is near the median, while the right tail of the distribution is reflected in the reserve margin.[29] If there is a 10% chance of extreme weather that drives peak demands 8% higher than a typical year's peak, LOLE modeling of those weather patterns will identify the need for additional reserves to meet the 1-in-10 standard.[30] In a planning area the size of LG&E-KU, it is less uncommon for the entire area to experience extreme hot or cold weather simultaneously, and so system-wide demand can feature more pronounced extremes. In a larger planning area such as PJM, it is rarer for exceptionally hot or cold weather to affect the entire area at once, and so the extremes of system-wide demand are moderated.

For example, as shown in Figure 4 below, all of Kentucky was experiencing extraordinarily low temperature during Winter Storm Elliott, but only a minority of PJM experienced the most extreme exceptional cold during the event, and at all times there were a variety of absolute temperatures across the PJM footprint. Indeed, cold weather during the event drove high demand and high coincident forced outage rates in both regions, but LG&E-KU was forced to shed firm load while PJM (including several utilities in Kentucky) was not. This averaging of diverse weather across a single large system means the right tail of the distribution of peak demand can be less pronounced, and therefore lower reserve margins would be necessary to meet the same 1-in-10 LOLE standard.

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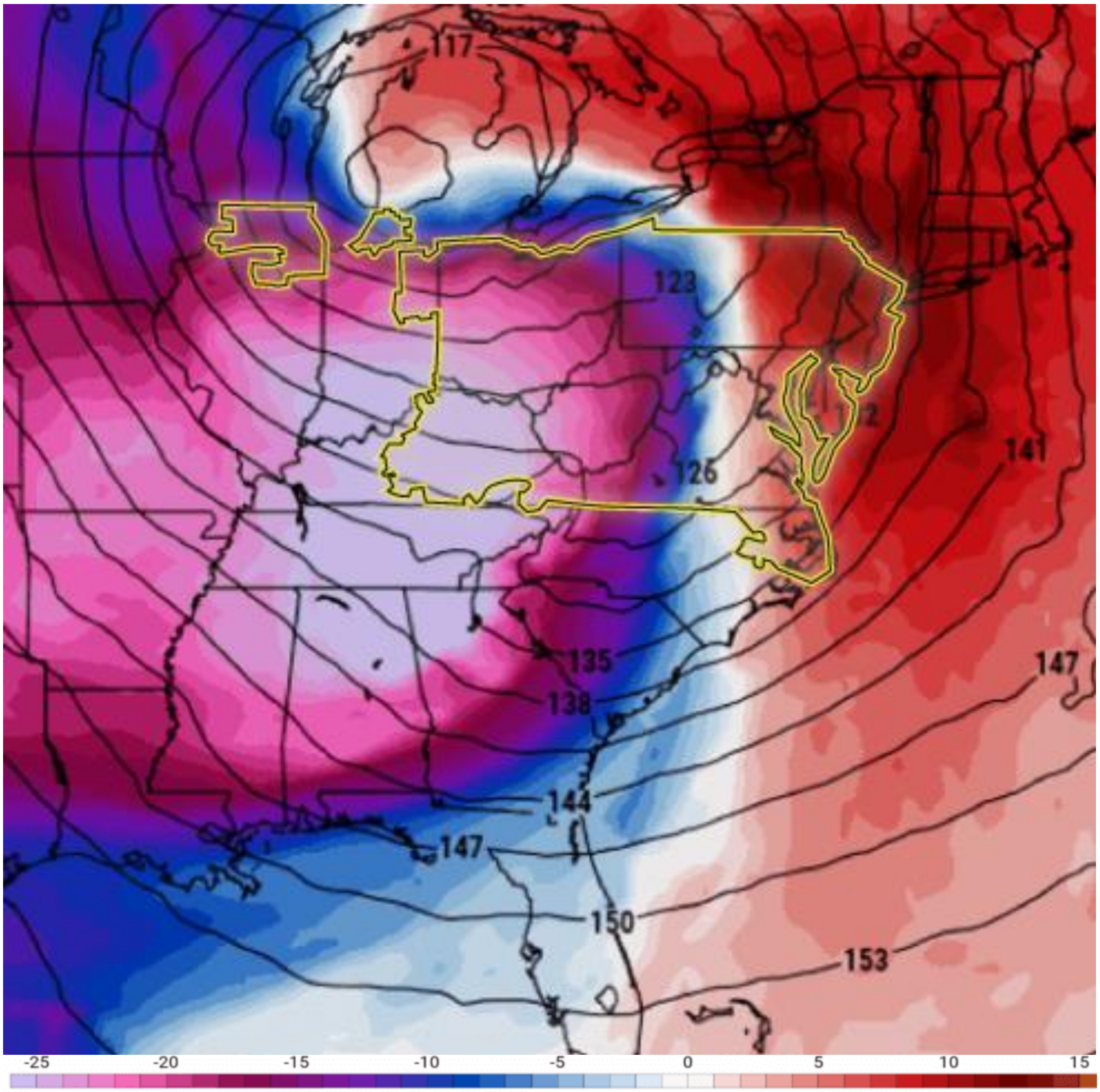
[29] See Pfeifenberger, et al, *supra* at p.15: "One of the most important factors driving resource adequacy is uncertainty in peak load, which is driven by both weather uncertainty and economic forecast uncertainty…For example, a recent LOLE study by ERCOT found differences in weighting the 2011 weather year, which some refer to as a 1-in-100 year heat wave. Depending on how likely such extreme weather is to recur, the resulting target reserve margins would range from a low of 13.7% (with zero probability) to a high of 18.9% (with a 5% probability)."

[30] For example, see 2021 IRP Reserve Margin Analysis, Figure 8, p. 19.

FIGURE 4. MAP SHOWING EXTENT OF ATYPICAL COLD TEMPERATURE DURING WINTER STORM ELLIOTT ON DECEMBER 23, 2022.



Source/Notes: PJM outlined in yellow. The coldest portion of the weather system (in lightest lavender) moderated slightly shortly after this snapshot. Global Forecast System model of temperature anomaly (in degrees Celsius) at a height corresponding to 850 millibar air pressure on December 23, 2022 at 15:00 UTC (10:00 EST). From Pivotal Weather.

Further, in a smaller system, each generator is proportionately larger compared to the size of the entire portfolio (for example, the three largest generator units in LG&E-KU comprise over 1,700 MW, compared to a total fleet size of approximately 7,500 MW). Therefore, with just two or three simultaneous unit forced outages, a significant portion of supply can be lost (in this example, 23% of the fleet is lost when the three largest units are unavailable), and replacement power during high-load periods can be more difficult to arrange. By contrast, a larger system requires coincident forced outages of many more units in order to reach high fleet-wide unavailability (in PJM's case, several dozen generators must be unavailable simultaneously in order for 23% of the fleet to be unavailable). In models that assume random forced outages, events with a larger number of generators facing simultaneous forced outages have a lower estimated probability than those with only a few simultaneous outages.

Other considerations can have offsetting effects or even reverse the trend. For example, smaller planning areas with relatively larger interties can show an improved reserve margin, to the extent they take full advantage of their neighboring systems in their resource adequacy planning.[31] LG&E-KU has significant interties with its neighbors (e.g., over 1,900 MW of total transfer capability just from PJM) and could theoretically offset the reserve margin pressures associated with its size by relying on substantial imports. However, the model LG&E-KU uses to select a target installed reserve margin model includes relatively little import capability (500 MW of import capability two thirds of the time, and 0 MW for the remainder), and so this potential offsetting effect is lost.[32] Similarly, the specific characteristics of neighboring systems, such as the relative load diversity and degree of resource adequacy, can have an important effect when imports are relied upon to play an important reliability role. Finally, the specific composition of customer loads (e.g., industrial vs. residential) and the geographic patterns of weather across a specific footprint can, in peculiar circumstances, produce relatively high diversity in a small footprint. Notwithstanding the potential for contrary trends in certain circumstances, the relatively higher reserve margins that LG&E-KU modeling shows for the companies to meet 1-in-10 as a standalone planning area are consistent with first principles expectations for a smaller system with less weather diversity and fewer generators.

By joining PJM, the target reserve margin needed for LG&E-KU to meet the standard 1-in-10 LOLE reliability target would drop by 16% percentage points, from 31% in winter (the most deficient season following retirements) to 14.7%. That said, LG&E-KU states that they plan to a

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31 See Pfeifenberger, et al., *supra* at p. 55.

32 2021 IRP Reserve Margin Analysis, p. 17; D. Souder, Interconnection Policy Workshop – Session 4, PJM Interconnection, LLC, August 27, 2021.

lower reliability level, one derived from an analysis of the trade-off between the cost of resource investment and the cost of shortage events. This lower target is 17% in the summer and 24% in the winter of 24%, and has an LOLE of more than 3.87 per decade, or over 3.87 times the number of shortage events relative to the 1-in-10 standard.[33] The lower economic target is not evident in the CPCN Plan, which has a summer reserve margin ranging from 36.4% to 40.7% and winter ranging from 29.4% to 36.0% in the years following 2027 (the first year of service of a new NGCC).[34] These three sets of reserve margins in LG&E-KU's planning are shown in Figure 5. In order to make a like comparison of the status quo to the PJM case, in my analysis I use the reserve margins corresponding to the 1-in-10 LOLE (which is PJM's target reliability). If LG&E-KU's planning intent were instead to target the reserve margins implied in the CPCN Plan, the savings from joining PJM would be higher; by contrast, if LG&E-KU's intent were to plan for their lower stated reserve margin targets based on economic analysis, notwithstanding the CPCN Plan's higher margin, the savings from joining PJM would be positive but lower (and reliability in PJM would be significantly higher, with offsetting benefits).

PJM uses a capacity market mechanism to fulfill most of the procurement needed to secure adequate resources to meet the target reserve margin. In many years, capacity costs are low enough that it makes sense for PJM to procure additional resources beyond the reserve margin (in fact, this has occurred in all years since the capacity market began). When there is more supply than necessary, the capacity market procurement mechanism is designed to reflect the low marginal cost of meeting the requirement. On the other hand, when supply is tight, prices rise to reflect the higher cost of capacity on the margin. This effect is also designed to modulate resource exit (which is accelerated when there are surplus resources and low prices, thus driving supply closer to the target) and entry (which is accelerated under the high prices caused by tighter conditions). In the event that the market mechanism fails to meet the target, PJM is empowered with broad discretion to conduct an emergency backstop procurement to ensure the target is met.[35]

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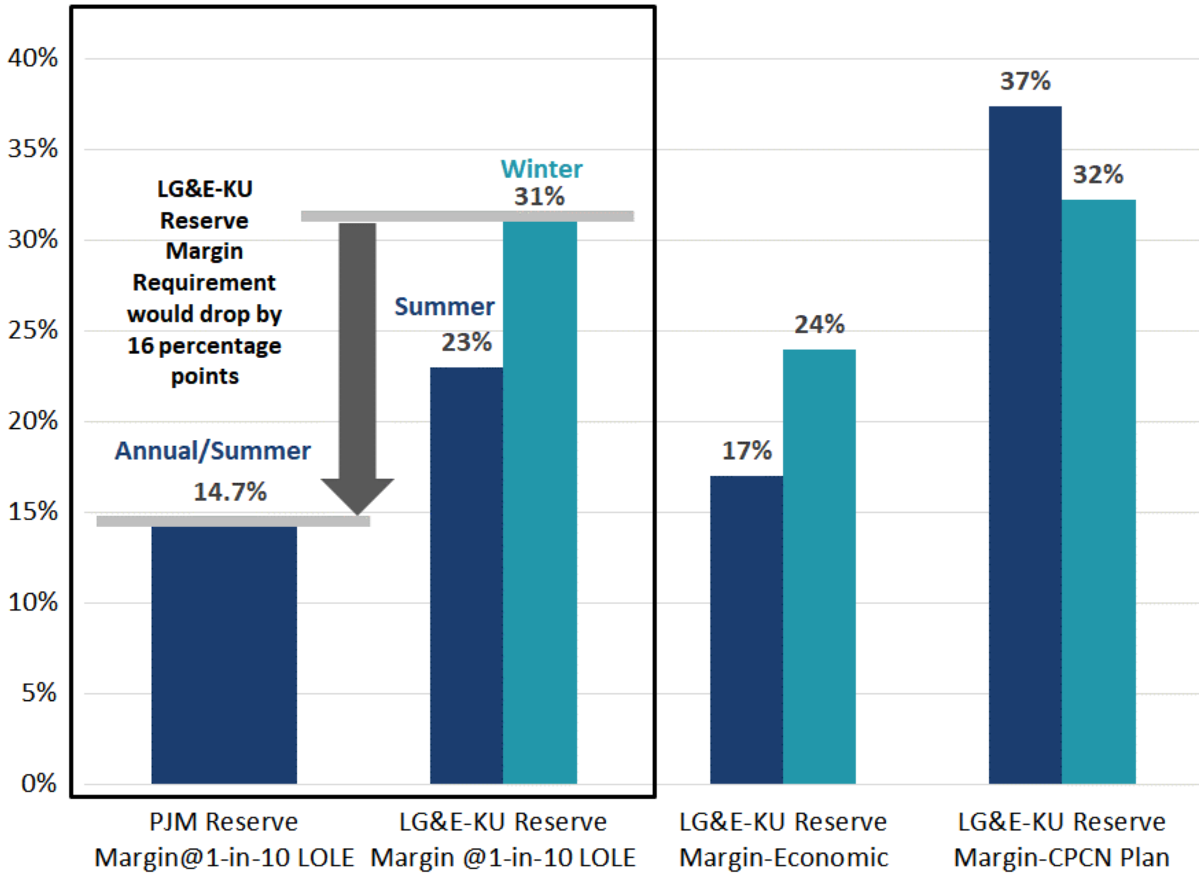
[33] Louisville Gas and Electric Company's and Kentucky Utilities Company's Responses to the Sierra Club's Supplemental Requests for Information, response to Question 2-30(b), May 4, 2023, p. 58.
Louisville Gas and Electric Company's and Kentucky Utilities Company's Responses to the Commission Staff's Fifth Request for Information, response to Question 4(a), July 7, 2023, p. 32.

[34] CPCN Plan.

[35] PJM Tariff Attachment DD Section 16.4,"Reliability Backstop Auction," Docket #: ER20-2799-000, p. 2.

FIGURE 5. 2028 LG&E-KU RESERVE MARGIN REQUIREMENT WOULD DROP BY 16%



Sources and Notes: All values reflect 2028. PJM 2022 Reserve Requirement Study; Wilson Testimony; Louisville Gas and Electric Company's and Kentucky Utilities Company's Responses to the Commission Staff's Fifth Request for Information, response to Question 4(a), July 7, 2023, p. 32.

II.C. Combining LG&E-KU and PJM Would Increase the Capacity Value of LG&E-KU's Solar Resources

LG&E-KU have proposed cumulative solar installations in 2028 of 1,127 MW nameplate.[36] In the standalone context, LG&E-KU assigns to this solar a capacity value of 866 MW summer and 0 MW winter.[37] PJM analysis estimates the value of this solar in the PJM context in 2028 is approximately 383 MW, based on an effective load carrying capability rating factor of 34%.[38] The capacity value of solar in PJM is expected to decline, as reflected in in Table 3, row 12,

[36] Wilson Testimony, p. 31.

[37] CPCN Plan.

[38] PJM Interconnection, LLC, Effective Load Carrying Capability (ELCC) Report, January 6, 2023, p. 10.

"Planned Solar (PJM Capacity Value)". I conservatively assume that PJM will assign zero capacity value to solar starting after 2032, the last year for which PJM provides projections of solar capacity values. For at least the next 7 years, PJM's solar accreditation means LG&E-KU customers derive higher value from the planned solar relative to the status quo, in large part because winter (as I show below) is the more restrictive seasonal requirement today.

The higher resource adequacy benefit of solar in PJM is not primarily due to the effects of a large geographical pool, but rather reflects the greater prominence of summer reliability in the PJM planning environment relative to that in LG&E-KU, itself a function of the particular regional weather, the resulting hourly patterns of demand, as well as resource characteristics.[39]

LG&E-KU proposes relying on solar value to meet resource needs today, but the Companies suggest there are limits on the extent to which they will rely on solar value. For example, with respect to the "total reserve margin", which includes the resource adequacy value of solar and batteries, LG&E-KU Witness Wilson states in his direct testimony: "Total reserve margin will become less meaningful as a reliability metric as more intermittent and limited duration resources are added to the generation portfolio."[40] Wilson draws the contrast with the "dispatchable reserve margin", which does not include the capacity value of solar and storage, and states that a low dispatchable reserve margin is an indicator of reliability concerns, even if the total reserve margin meets requirements.[41] While it is not clear exactly how LG&E-KU intends to implement these concepts, the reluctance to rely on the full reliability value of solar and storage is plain. Any approach that does not count the appropriate capacity value of solar and

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[39] In principle, under high deployment of wind and solar, pooling resource adequacy across a wider area boosts the capacity values of wind and solar, holding all else equal. This is again due to geographical diversity, as follows. The capacity value of wind and solar declines as deployment increases, other resources are displaced, and reliability risks shift towards hours with lower wind or solar output. This effect is strongest when the temporal profiles of the output of the various wind and solar plants are similar, such as you would expect in a small geographical area. However, when there is a wider geographical area, the temporal profiles of wind and solar demonstrate more diversity. For example, PJM spans two time zones, and so solar in the West is still producing when solar in the East has reached the end of the day. Such diverse temporal profiles mean capacity values do not erode as quickly under high deployment.

[40] Louisville Gas and Electric Company and Kentucky Utilities Company Generation Planning and Analysis Group, 2022 Resource Assessment, Exhibit SAW-1, December 2022, p. D-4.

[41] *Ibid.*, at p. 10: "Therefore, any portfolio that achieves a total summer reserve margin of 17% but includes significantly less than a 12% reserve margin consisting of fully dispatchable resources raises reliability concerns."

storage resources towards resource requirements drives procurement of other resources to fill in the gap, thus unnecessarily increasing costs.

While LG&E-KU states that the reliability value of intermittent and limited duration resources is less meaningful at high deployment levels, PJM has effectively integrated wind and solar into its resource adequacy and operational frameworks in scalable fashion. For example, PJM counts all capacity towards its resource requirements, including capacity from wind and solar, even as deployment of such resources is expected to continue growing quickly.[42] PJM has taken steps to enhance operational and planning efficiency under growing deployment of such resources, in part to depend on the reliability value of these resources to the extent supported by prudent analysis and forecasting. These reforms include development of a statistical model to calculate the capacity value of wind and solar; requiring dispatchable control of utility-scale wind and solar; application of energy market and outage scheduling obligations for wind and solar; incorporation of wind and solar forecasts and meteorological telemetry into day-ahead and real-time operations; and statistical methods to incorporate wind and solar into transmission planning.[43]

II.D. The Combined Impact of PJM Membership Provides Capacity Savings of 900-1,300 MW

In summary, PJM membership yields capacity savings from demand diversity, reduced reserve margins, and increased solar value as follows:

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[42] PJM's capacity market works by procuring "Unforced Capacity" or "UCAP" in approximately the amount of the reliability requirement. PJM uses the term "Effective UCAP" to refer to the capacity value of renewables (such as wind and solar) and storage. The PJM governing documents define Effective UCAP as "a unit of measure that represents the capacity product transacted in the Reliability Pricing Model and included in FRR Capacity Plans. One megawatt of Effective UCAP has the same capacity value of one megawatt of Unforced Capacity." PJM, Reliability Assurance Agreement, effective May 8, 2023, p. 7.

[43] PJM, Effective Load Carrying Capability Measures Capacity Contribution of Renewables, Storage, 2022; PJM, Renewable Dispatchability Education, Operating Committee Special Session - Renewable Dispatch, February 22, 2022; PJM, Operational Practices for Intermittent Resources, Operating Committee Special Session - Renewable Dispatch, February 22, 2022; PJM, Energy Market Practices for Intermittent Resources, Operating Committee Special Session - Renewable Dispatch, February 22, 2022; PJM, Generator Deliverability Test Modifications: Light Load, Summer & Winter, January 10, 2023, p. 20, 38.

1. Diversity in hourly demand among pooled member utilities means that any one member's share of the pool-wide peak is lower than its standalone peak. This is because the peak demands of different utilities systematically occur at different times, so their combined peak is less than the sum of individual peaks.
2. Lower reserve margins are needed to meet the same resource adequacy reliability targets, because:
    a. Extreme hot or cold weather is less likely to occur throughout the larger footprint, and;
    b. Rare but credible risks of overlapping generator outages have a smaller impact on the pool.
3. Solar provides more value towards meeting PJM's pool-wide peak demand than it does towards meeting LG&E-KU's peak demand in the season that drives its resource planning (i.e., winter).

Through analysis of hourly load shapes in LG&E-KU and PJM, I find a large demand diversity effect, with a coincidence factor of 95%. Meanwhile, I find that PJM membership today would confer a 20 percentage point reduction in the relevant reserve margin, since comparable LOLE studies performed by LG&E-KU and PJM conclude that, in order to achieve the standard 1-in-10 LOLE reliability, a 31% winter reserve margin is needed in the standalone LGE&-KU scenario, whereas PJM requires only a 14.7% annual reserve margin throughout its footprint to achieve that same reliability level.

I further find that circumstances in PJM and LG&E-KU are such that solar resources provide more value towards meeting LG&E-KU's resource requirements in the PJM context than under the status quo in winter (but provide less value in PJM vs. the status quo in summer). Importantly, LG&E-KU's winter reserve requirement drives resource adequacy planning there, and solar provides less reliability value in winter (by L&E-KU's reckoning, zero value). By contrast, resource planning in PJM is currently performed on an annual basis, and historically has been largely determined by summer conditions. Solar provides significant value in that context.

Table 2 shows the surplus or deficiency balance of resources relative to requirements. It compares generation in LGE&E-KU's planned 2028 fleet (without the new build NGCCs, but with planned retirements and other planned additions) compared to the level required for adequate reliability in the standalone and PJM cases, calculating the capacity savings from PJM membership as the difference in surplus/deficiency balance relative to the status quo.

TABLE 2. NET CAPACITY SAVINGS IN 2028 FROM PJM MEMBERSHIP

	Status Quo: LG&E-KU Alone	Unit	Formula	Summer [s]	Winter [w]
[1]	LG&E-KU Forecasted Peak (2028)	*(MW)*		6,319	6,104
[2]	LG&E-KU Reserve Margin @ 1-in-10 LOLE	*(%)*		23%	31%
[3]	Resource Requirement under Status Quo (Seasonal)	*(MW)*	[1] x (1 + [2])	7,772	7,996
[4]	Planned Capacity (w/o Solar or New NGCC Builds)	*(MW)*		6,578	6,790
[5]	Capacity Value of Solar	*(MW)*		866	0
[6]	Total Planned Capacity (w/o NGCC Builds)	*(MW)*	[4] + [5]	7,444	6,790
[7]	Surplus (Deficit) vs. Seasonal Requirement (w/o NGCC Builds)	*(MW)*	[6] - [3]	(328)	(1,206)
[8]	**Winter Shortfall vs. Status Quo Requirements (w/o NGCC Builds)**	*(MW)*	MIN([7s],[7w])	**(1,206)**	
	Change Case: LG&E-KU Joins PJM			**Annual/Summer**	
[9]	Summer Coincidence Factor in Combined PJM+LG&E-KU	*(%)*		95%	
[10]	Peak Demand Coincident with PJM Peak	*(MW)*	[1] x [9]	6,007	
[11]	PJM 2028 Minimum Reserve Margin	*(%)*		14.7%	
[12]	Resource Requirement in PJM	*(MW)*	[10] x (1 + [11])	6,890	
[13]	Planned Capacity (w/o Solar or New NGCC Builds)	*(MW)*		6,568	
[14]	Capacity Value of Solar	*(MW)*		383	
[15]	Total Planned Capacity (w/o NGCC Builds)	*(MW)*	[14] + [13]	6,951	
[16]	**Capacity Surplus vs. PJM Requirement (w/o NGCC Builds)**	*(MW)*	[15] - [12]	**61**	
	Comparison of Status Quo vs. Join PJM			**Summer**	**Winter**
[17]	Savings from Lower Resource Requirement in PJM	*(MW)*	[3] - [12]	882	1,106
[18]	Lower Fleet Value in PJM (w/o NGCC Builds or Solar)	*(MW)*	[13]-[4]	(10)	(222)
[19]	Higher (Lower) Solar Value in PJM	*(MW)*	[14]-[5]	(483)	383
[20]	Capacity Savings of PJM Membership vs. Status Quo Seasonal Require	*(MW)*	[16] - [7]	389	1,267
[21]	**Capacity Savings of PJM Membership vs. Winter-Driven Status Quo**	*(MW)*	[16] - [8]	**1,267**	

Source and Notes:
All resource values are on an ICAP basis.
[1]: 2028 Peak Load (CPCN Plan)
[2]: Louisville Gas and Electric Company's and Kentucky Utilities Company's Responses to the Commission Staff's Fifth Request for Information, response to Question 4(a), July 7, 2023, p. 32
[4]: Total Supply - Solar - NGCC (CPCN Plan)
[5]: Solar (CPCN Plan)
[9]: From summer coincident peak analysis of 2028 hourly load forecasts, described in Section II.A below
[11]: PJM Reserve Requirement Report, p. 8
[13]: [4] with reduction of 125 MW battery storage to 92% capacity (PJM ELCC Report, p. 10)
[14]: 1,127 MW nameplate solar times 2028 ELCC rating for solar of 34% (PJM ELCC Report, p. 10)

Table 2 demonstrates how the three factors above impact the balance:

1. **Demand diversity**: the relevant peak demand in the PJM case (Table 2, row 10) is lower than in the standalone case (Table 2, row 1). This reflects the fact that LG&E-KU demand is lower

during PJM peaks than it is during its own peak periods, as captured in the "coincidence factor," which is the ratio of the former to the latter.

2. **Reserve margins**: the reserve margins for the PJM case (row 11) are lower than in the standalone case (row 2), making the resource requirement in the PJM case (row 12) lower still relative to those in the standalone case (row 3).

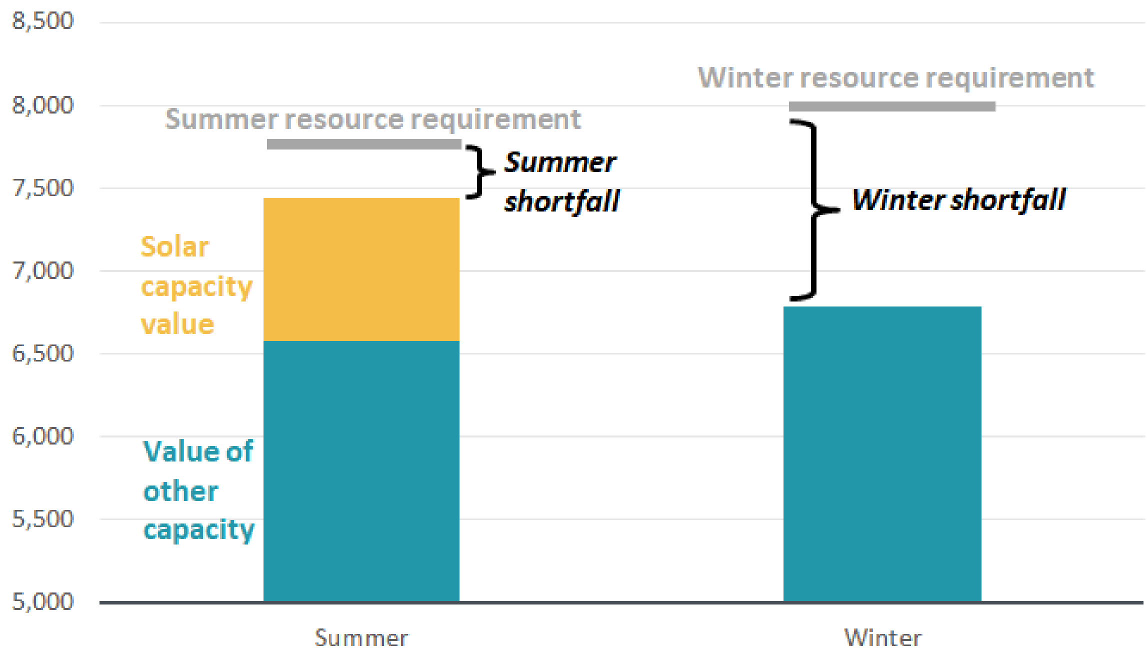
3. **Value of solar**: solar resources in PJM are worth more relative to the standalone LG&E-KU case in winter, but less relative to LG&E-KU's assessed summer value. Note that the lower winter solar value in LG&E-KU is partly offset by a higher winter value of non-solar resources, as evidenced by the value in row 4, column Winter [w] (which can be compared with the lower value for PJM in row 13).

As shown in row 21, the resulting capacity savings from PJM membership in 2028 is 1,267 MW.

Figure 6 demonstrates that LG&E-KU's resource planning is constrained by winter, and therefore the winter reserve margin is the relevant target for the purposes of comparison with the PJM membership case. For this reason, I have calculated capacity savings relative to the winter balance. Figure 6 compares the LG&E-KU resource plan balance for summer and winter in 2028, before new NGCC additions but after retirements and other additions such as solar and storage. It shows that planned summer capacity is closer to the target seasonal reserve margin than planned winter capacity. It is evident that the higher reserve margin target in winter widens the gap in that season, and a higher capacity value for solar in summer narrows the summer gap, notwithstanding a partial offset due to a lower capacity rating for other resources (i.e., thermal resources). Therefore, winter is the more constrained season, and the winter reserve margin is the relevant one for comparison with PJM.[44]

[44] While both summer and winter could theoretically be binding constraints (for example, if requirements were to be met with a mix of summer-dominant solar and wind with high winter values), in the context of the resources considered most viable in the CPCN Application (i.e., summer-dominant solar and annual NGCC), winter is clearly the determining factor for establishing resource adequacy investment needs.

FIGURE 6. LG&E-KU RESOURCE PLANS MUST ADDRESS A BIGGER CAPACITY SHORTFALL IN WINTER VS. SUMMER (2028 SCENARIO SHOWN)



Source/Notes: LG&E-KU capacity balance in 2028 (after retirements but before NGCC additions) relative to resource requirement necessary to meet 1-in-10 loss of load expectation. 2028 capacity values and seasonal peak demand from the CPCN Plan; resource requirement calculated as Peak × (1+PRM), where PRM is Planning Reserve Margin of 23% in summer and 31% in winter, from Louisville Gas and Electric Company's and Kentucky Utilities Company's Responses to the Commission Staff's Fifth Request for Information, response to Question 4(a), July 7, 2023, p. 32.

Table 3 shows a similar analysis to Table 2, calculated across the years of the CPCN Plan. It demonstrates that the capacity savings associated with PJM membership allow LG&E-KU to build fewer resources to replace retiring thermal generation while still meeting reliability standards. For example, considering current retirement plans, the proposed addition of 1,127 MW of solar, 125 MW of battery storage, and 102 MW of dispatchable DSM, as well as demand growth and current reserve margins, but without building any NGCC units, PJM membership means that LG&E-KU would meet capacity requirements through 2028 while retaining reliability levels above the current target. Succeeding years would have a modest capacity shortfall below 200 MW through 2032, and below 450 MW thereafter, which can be met with supplemental market purchases or with fewer new resource MWs.

TABLE 3. ANNUAL CAPACITY SAVINGS FROM JOINING PJM

(All values in MW)		2026	2027	2028	2029	2030	2035	2040	2045	2050
Status Quo: LG&E-KU Stand Alone (Winter Values)										
Resource Requirement	[1]	7,864	8,000	7,996	7,995	7,994	7,999	8,008	8,017	8,026
Capacity Before Retirements (w/o NGCC Builds or Sol	[2]	8,294	8,316	8,344	8,358	8,359	8,359	8,359	8,359	8,359
Planned Retirements	[3]	(355)	(652)	(1,554)	(1,554)	(1,554)	(1,554)	(1,712)	(1,712)	(1,712)
Capacity After Retirements (w/o NGCC Builds or Solar	[4]	7,939	7,664	6,790	6,804	6,805	6,805	6,647	6,647	6,647
Planned Solar	[5]	0	0	0	0	0	0	0	0	0
Total Planned Capacity (w/o New NGCC Builds)	[6]	7,939	7,664	6,790	6,804	6,805	6,805	6,647	6,647	6,647
Surplus (Deficit) vs. Requirement (w/o NGCC Builds)	[7]	**75**	**(336)**	**(1,206)**	**(1,191)**	**(1,189)**	**(1,194)**	**(1,361)**	**(1,370)**	**(1,379)**
Change Case: LG&E-KU Joins PJM (Annual/Summer Values)										
Resource Requirement	[8]	6,818	6,921	6,890	6,878	6,875	6,852	6,828	6,804	6,780
Capacity Before Retirements (w/o NGCC Builds, Solar	[9]	8,037	8,072	8,109	8,130	8,138	8,131	8,126	8,123	8,122
Planned Retirements	[10]	(347)	(644)	(1,541)	(1,541)	(1,541)	(1,541)	(1,693)	(1,693)	(1,693)
Capacity After Retirements (w/o NGCC Builds, Solar)	[11]	7,690	7,428	6,568	6,589	6,597	6,590	6,433	6,430	6,429
Planned Solar (PJM Capacity Value)	[12]	390	428	383	316	259	0	0	0	0
Total Planned Capacity (w/o New NGCC Builds)	[13]	8,080	7,856	6,951	6,905	6,856	6,590	6,433	6,430	6,429
Surplus (Deficit) vs. Requirement (w/o NGCC Builds)	[14]	**1,262**	**935**	**61**	**26**	**(19)**	**(262)**	**(395)**	**(374)**	**(351)**
Comparison of PJM vs. Status Quo										
Savings from Lower Resource Requirement in PJM	[15]	1,045	1,079	1,106	1,117	1,118	1,147	1,180	1,213	1,246
Lower Fleet Value in PJM (w/o NGCC Builds or Solar)	[16]	(249)	(237)	(222)	(215)	(208)	(228)	(214)	(217)	(218)
Higher Solar Value in PJM	[17]	390	428	383	316	259	0	0	0	0
Net Capacity Value Savings	**[18]**	**1,187**	**1,271**	**1,267**	**1,217**	**1,169**	**932**	**966**	**996**	**1,028**

Sources and Notes: All resource capacity data from CPCN Plan. All capacity accounting in ICAP terms (see Table 4 for UCAP adjustment).
[1]: Winter Peak Load x (1 + LG&E-KU Winter Reserve Margin for 1-in-10 Reliability); Reserve Margin from Louisville Gas and Electric Company's and Kentucky Utilities Company's Responses to the Commission Staff's Fifth Request for Information, response to Question 4(a), July 7, 2023, p. 32
[2]: Winter Totals of Existing Dispatchable Generation Resources + Intermittent/Limited-Duration Resources - Solar
[3]: Winter Totals of Retirements of Coal + Large-Frame SCCTs + Small-Frame SCCTs
[4]: [2] + [3]
[5]: Winter Total of Solar
[6]: [4] + [5]
[7]: [6] - [1]
[8]: Summer Peak Load x Summer Coincidence Factor x (1 + PJM Reserve Margin); Coincidence Factor from Section II.A; Reserve Margin from PJM Reserve Requirement Report, p. 8
[9]: Summer Totals of Existing Dispatchable Generation Resources + Intermittent/Limited-Duration Resources - Solar, with 125 MW battery capacity derated according to 2022 PJM ELCC Report
[10]: Summer Totals for Retirements of Coal + Large-Frame SCCTs + Small-Frame SCCTs
[11]: [9] + [10]
[12]: Total Solar Nameplate x Tracking Solar Rating Factor from 2022 PJM ELCC Report
[13]: [11] + [12]
[14]: [13] - [8]
[15]: [8] - [1]
[16]: [11] - [4]
[17]: [12] - [5]
[18]: [14] - [7]; alternately, [15] + [16] + [17]

Sensitivities

To understand a lower end of the range of potential savings reflecting the lower diversity factor discussed in II.A and the potential for a lower winter reserve margin, I provide a sensitivity analysis that yields capacity savings in 2028 of 883 MW.[45]

To understand how LG&E-KU's own assumptions would impact capacity savings, I evaluated the inputs used in the analysis conducted by LG&E-KU and Guidehouse in their RTO Study. The RTO Study found an even more diverse PJM coincidence factor of 92%, and used a winter reserve margin in the standalone case of 25% (and a summer margin of 16%).[46] With the same analysis shown in Table 2, use of these values yields capacity savings in the PJM case in 2028 of 1,123 MW.

LG&E-KU recently re-ran their analysis of the target reserve margin needed to meet 1-in-10 LOLE as part of their response to a discovery request.[47] The prior analysis had been conducted as part of the 2021 IRP ,and yielded a 35% winter reserve margin.[48] If I use that higher winter reserve margin, capacity savings in 2028 in PJM are 1,511 MW.

II.E. Capacity Benefits Would Persist under PJM's Recently Proposed Seasonal Capacity Approach

PJM has recently made an early stage proposal to its members for a seasonal capacity market construct together with a reformed resource adequacy modeling approach that indicates winter as the dominant risk season.[49] As of the date of this written testimony, PJM's initial proposal has many steps remaining before it is known what the precise quantitative effect will be: they must be finalized in the assigned stakeholder body, voted for endorsement by the RTO's members,

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[45] The sensitivity case uses a higher 97% coincidence factor in the PJM case and a lower 27% winter reserve margin in the standalone case.

[46] RTO Study, pp. 83, 85.

[47] Louisville Gas and Electric Company's and Kentucky Utilities Company's Responses to the Commission Staff's Fifth Request for Information, response to Question 4(a), July 7, 2023, p. 32.

[48] 2021 IRP, Vol III, p. 25.

[49] Resource Adequacy Senior Taskforce, Capacity Market Reform: PJM's Proposal, PJM Interconnection, LLC, June 14, 2023, p. 3.

approved by the PJM Board, filed with FERC, approved by FERC, and then implemented. Under these changes, winter planning considerations are likely to grow in prominence in PJM, which suggests a directional reduction in capacity benefits for LG&E-KU for the reasons described below.

Nonetheless, all else being equal, the categorical benefits associated with joining PJM are still likely to accrue under the new potential construct, for the same reasons described above:

a. Demand diversity will tend to reduce LG&E-KU's winter capacity requirement under PJM membership, because the winter diversity factor with PJM is 96.6%.

b. A larger and more diverse generation fleet together with less pronounced extremes in the weather distribution will tend to reduce the winter reserve margin at 1-in-10 LOLE.

c. To the extent that the new PJM model shows summer reliability risk, LG&E-KU's solar fleet is likely to be worth more for capacity planning purposes in the PJM context.

Based on stakeholder materials provided by PJM, the directional effects of a seasonal capacity construct if the proposal is adopted and approved are likely to include:

i. Winter capacity costs under PJM's current proposal would be allocated based on winter coincident peak.[50] LG&E-KU's winter coincidence factor with PJM is 96.6%.

ii. PJM's proposal is for distinct winter reserve margins and summer reserve margins. It is impossible to know at this early stage precisely what their relative or absolute values would be.

iii. PJM's proposal is for class-based derating factors to apply to the capacity value of certain thermal resources, including those gas generators without access to firm gas or dual fuel.

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[50] Resource Adequacy Senior Taskforce – Critical Issue Fast Path, Capacity Market Reform: PJM's Proposal, PJM Interconnection, LLC, June 14, 2023, p. 32.

iv. Resources such as wind and solar would have separate capacity values for winter vs. summer seasonal capacity markets. Relative to the status quo capacity ratings, the winter value of wind would be higher, while the winter value of solar would be lower.

The net effect of PJM's proposed changes may be to plan a system that is more robust to extreme weather in both winter and summer, though it is not possible at this time to estimate the net impacts on my estimated capacity savings if PJM's seasonal market should be finalized and implemented. Because the beneficial effects of load diversity and fleet size would continue to obtain, I conclude that PJM membership would offer savings relative to a scenario in which LG&E-KU plans an equivalently robust system. To the extent that LG&E-KU plans for lower reliability levels, or fails to capture certain phenomena in its modeling (such as coincident forced outages of thermal resources in extreme cold weather), such savings could be reduced or potentially reversed (at the operational cost of more frequent shortage events and load shed).

III. Avoided Capacity Builds Would Save LG&E-KU Customers Approximately $125 - $140 Million In Resource Investment Costs Per Year

I calculate the financial benefit associated with the capacity savings identified in Section II by identifying investments in new capacity and their cost (using LG&E-KU's annualized gross cost of new entry of an NGCC) and, in the PJM case, sale and purchase transactions associated with excess capacity and shortfalls. For the latter, I use the capacity price forecast that LG&E-KU used in the RTO Study. The results are shown in Table **4**.

While PJM members are not required to participate in the full capacity market, by doing so LG&E-KU would have the opportunity to easily sell excess capacity at the market price, and likewise fill any capacity shortfalls with market purchases (which provides consumer savings to the extent the market price is lower than the cost of new entry). This market dynamic provides additional consumer savings over and above that associated just with the capacity savings alone.

TABLE 4. JOINING PJM YIELDS INVESTMENT SAVINGS OF APPROX. $130 – $140 MILLION ANNUALLY STARTING IN 2028

	(All capacity values are winter ratings)	Unit	2026	2027	2028	2029	2030	2035	2040	2045	2050
	Status Quo: LG&E-KU Stand Alone (Winter Values)										
[1]	Resource Requirement	*(MW)*	7,864	8,000	7,996	7,995	7,994	7,999	8,008	8,017	8,026
[2]	Existing and Planned Resources (w/o NGCC Builds)	*(MW)*	7,939	7,664	6,790	6,804	6,805	6,805	6,647	6,647	6,647
[3]	Planned NGCC Additions	*(MW)*	0	641	1,282	1,282	1,282	1,282	1,282	1,282	1,282
[4]	Other Additions Needed (Surplus)	*(MW)*	(75)	(305)	(76)	(91)	(93)	(88)	79	88	97
[5]	**Annualized Incremental Capacity Cost**	*($M/yr)*	**$0**	**$69**	**$139**	**$139**	**$139**	**$139**	**$144**	**$144**	**$145**
	Change Case: LG&E-KU Joins PJM (Annual/Summer Values)										
[6]	Resource Requirement	*(MW)*	6,818	6,921	6,890	6,878	6,875	6,852	6,828	6,804	6,780
[7]	Existing and Planned Resources (w/o NGCC Builds)	*(MW)*	8,080	7,856	6,951	6,905	6,856	6,590	6,433	6,430	6,429
[8]	New NGCC and Other Additions	*(MW)*	-	-	-	-	-	-	-	-	-
[9]	Conversion of ICAP Shortfall/Excess to UCAP	*(MW)*	(141)	(117)	(61)	(61)	(61)	(63)	(54)	(55)	(56)
[10]	Net Sale (Purchase) Qty from Market	*(UCAP MW)*	1,120	818	0	(35)	(81)	(325)	(449)	(429)	(407)
[11]	PJM Capacity Price	*($/UCAP MW/d)*	$55	$60	$81	$91	$93	$74	$59	$66	$72
[12]	**Annual Incremental Capacity Cost (Revenue)**	*($M/yr)*	**($23)**	**($18)**	**($0)**	**$1**	**$3**	**$9**	**$10**	**$10**	**$11**
	Comparison of PJM vs. Status Quo										
[13]	**Annualized Capacity Investment Savings in PJM**	*($M/yr)*	**$23**	**$87**	**$139**	**$138**	**$136**	**$130**	**$134**	**$134**	**$134**

Source and Notes: All resource capacity data from CPCN Plan

[1]: Winter Peak Load x (1 + LG&E-KU Winter PRM for 1-in-10); Reserve Margin from Responses to Q4(a) in the KYPSC Staff's 5th Discovery Request.

[2]: Winter Totals of Existing Dispatchable Resources + Intermittent/Limited-Duration Resources – Retirements + SCCTs

[3]: Winter NGCC Builds

[4]: [1] - [2] - [3]

[5]: (Min of [4] and 0) × CT Gross CONE / 1000 × Rating Adjustment + [3] × (Capital Recovery Factor × CC CAPEX + CC Firm Gas + CC FOM) /1000 × Rating Adjustment; CT Gross CONE from Wilson Testimony Exhibit SAW-1, D-18, p.133; CC Firm Gas, Discount Rate and Lifetime for Capital Recovery Factor from Wilson Testimony, CC CAPEX, CC FOM from RTO Study; Rating Adjustment = ratio of summer to winter ratings in CPCN Plan.

[6]: Summer Peak Load × Coincidence Factor × (1 + PRM); Coincidence Factor from Section II.A; PRM from PJM Reserve Requirement Report, p. 8

[7]: Summer Totals of Existing Dispatchable Resources + Intermittent/Limited-Duration Resources - Retirements + SCCTs; Battery and Tracking Solar capacity values based on relevant values from 2022 PJM ELCC Report

[8]: No new NGCC and other additions

[9]: Difference between supply balance in ICAP terms vs. UCAP terms. Supply balance is total capacity of existing and planned resources minus the resource requirement. Balance is calculated using ICAP([7]) and PRM ([6]) for the ICAP balance, vs. UCAP and Forecast Pool Requirement are used for the UCAP balance. Forecast Pool Requirement from PJM Reserve Requirement Report, p. 8
[10]: Total UCAP minus [6] × PRM / FPR. FPR from PJM Reserve Requirement Report, p. 8. Total UCAP is [7] + [8] – Avg EFORd × Dispatchable Resources
[11]: RTO Study, Case No. 2022-00402 Attachment 1 to Response to SC-2 Question No. 26(b) p. 101
[12]: [9] × [10] × 365 / 1,000,000
[13]: [5] – [11]

The low savings sensitivity case described in Section II.E produces slight lower results, ranging from $126 million to $136 million per year starting in 2028.

IV. Joining PJM will Offer Additional Economic and Reliability Benefits

Capacity pooling is one of several cost-reduction functions that RTOs such as PJM offer. Another major significant benefit comes from operational pooling of day-ahead resource schedules and real-time dispatch signals across all resources in the footprint. This operational pooling also serves to facilitate and ease the integration of variable resources such as wind and solar, because fluctuations in wind or sun in one part of their large footprints is more likely to be offset by effects elsewhere. The net effect of these benefits together with capacity savings represents the potential for significant customer savings, notwithstanding LG&E-KU's RTO Study which draws a conflicting conclusion.

IV.A. Dozens of Studies Suggest Annual Production Cost Benefits From Joining PJM Could Range Up to $66 Million per Year

Pooled energy markets such as those conducted by RTOs yield significant operational savings. These benefits stem from the seamless trade with neighboring utilities that is made possible by pooled scheduling and dispatch of generators across a wide area. When LG&E-KU generators are relatively cheap, they have the option to automatically sell energy at the market price, thereby earning an operating profit that may be refunded to customers (depending on Kentucky's jurisdictional cost recovery policies).[51] On the other hand, when the Companies' generators are relatively costly, cheaper power is available from the market, yielding savings by avoiding the higher cost of self supply. A similar dynamic is present in existing bilateral wholesale markets, but such trades are limited due to various frictions such as transmission booking, trading charges, and scheduling delays.

[51] For example, consider PJM member Duke Kentucky. Duke maintains a Commission-jurisdictional tariff rider called "Rider PSM – Profit Sharing Mechanism" (effective June 1, 2023), whereby 90% of net proceeds from off-system energy, renewable energy credit, and capacity transactions are refunded to customers.

Dozens of studies have been performed to evaluate the net effect of such benefits (called "adjusted production cost" savings). These commonly show savings in the range of 4% - 8% relative to total adjusted production costs (see Table 5 below), with some results above and below that range. These studies include those performed to: validate the benefit of proposed RTO integrations of utilities into existing RTOs;[52] explore prospective RTO formation or membership;[53] support integration of utilities in a related pooling arrangement called an Energy Imbalance Market (EIM), currently growing in the West (see Table 5 below);[54] and periodic retrospective production cost studies performed by many RTOs and both EIMs, as shown in Table 6 below.

According to its RTO Study, LG&E-KU's standalone annual production cost in 2028 is $971 million.[55] Extrapolating the high end of the typical range of other studies to the LG&E-KU context suggests that annual production cost savings could be reasonably anticipated up to $66 million annually.

52 For example, EKPC, FirstEnergy, Virginia Electric and Power Company, AEP, and Entergy.

53 In the early aughts, a bevy of studies were performed supporting the early formation of RTOs, as summarized in: Joseph H. Eto, et al, A Review of Recent RTO Benefit-Cost Studies: Toward More Comprehensive Assessments of FERC Electricity Restructuring Policies, December 2005, Prepared for the Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy; United States Department of Energy, The Value Of Economic Dispatch: A Report To Congress Pursuant To Section 1234 of the Energy Policy Act Of 2005, November 7, 2005.

More recently, studies have assessed a Southeast RTO, RTO membership options for the utilities of South Carolina (Exhibit ACL-8), and a Western RTO.

54 Including PacifiCorp (for both WEIM and EDAM), NV Energy, Portland General Electric, Bonneville Power Administration, and many of the other 30+ members of the new Western energy imbalance markets run by CAISO and SPP.

55 Source data of $829 million escalated from $2020 for $2028; RTO Study, p. 119.

TABLE 5. PROSPECTIVE PRODUCTION COST BENEFIT STUDIES OF RTO AND EIM EXPANSIONS SHOW BENEFITS RANGING UP TO 9%

Study Name	Study Scenario	Year	Estimated Cost Savings
Western Energy Imbalance Service and SPP Western RTO[56]	SPP WEIS vs. RTO expansion in the Western United States	2020	Production cost savings of around 4% for new members joining the WEIS or SPP RTO.
WEIM vs. WEIS benefits study for Black Hills Energy, CSU, PRPA and PSCO[57]	WEIM vs. WEIS expansion in Colorado	2020	Production cost savings range from 0.3% to 3.6% for new members joining the WEIM or WEIS.
Mountain West Transmission Group[58]	RTO market formation in Colorado and Wyoming	2016	Production cost savings of 5%–9%. Did not study other benefits, such as improved long-term investment decisions, renewable integration, or reliability
California SB350[59]	RTO market formation in western U.S.	2016	Production cost savings of 4.5% - 5%
Basin/WAPA/ Heartlands[60]	Benefit from Joining SPP or MISO	2013	Production cost savings of 3%–4% Did not study other benefits, such as improved long-term investment decisions, renewable integration, or reliability

Source: See footnotes.

56 Exhibit ACL-9

57 J. Chang, et al., Joint Dispatch Agreement Energy Imbalance Market Participation Benefits Study, The Brattle Group, January 14, 2020.

58 J. Chang, et al., Production Cost Savings Offered by Regional Transmission and a Regional Market in the Mountain West Transmission Group Footprint, The Brattle Group, December 1, 2016.

59 The Brattle Group, Senate Bill 350 Study: The Impacts of a Regional ISO-Operated Power Market on California, prepared for California ISO (CAISO), July 8, 2016.

60 M. Celebi, et al., Integrated System Nodal Study: Costs and Revenues of ISO Membership, The Brattle Group, March 8, 2013.

TABLE 6. RETROSPECTIVE PRODUCTION COST BENEFIT STUDIES OF RTO AND EIM EXPANSIONS SHOW SIGNIFICANT BENEFITS

Study Area	Study Name	Year	Estimated Cost Savings
MISO[61]	2021 Value Proposition Study	2021	• $3.0–$3.8 billion annually
Western EIM[62]	Q4 Value Study	2022	• $739 million in savings in 2021 • $1.4 billion in savings in 2022 • $3.4 billion cumulative cost savings since 2014
PJM[63]	PJM Value Proposition	2019	• $3.2–$4.0 billion annually
SPP[64]	2021 Member Value Study	2021	• $2.1 billion annually
SPP, Western Energy Imbalance Service (WEIS)[65]	2022 Member Value Study	2022	• $31.7 million in net benefits in 2022 • $61.2 million in cumulative net benefits since 2021
PJM (Dominion Virginia Service Territory)[66]	2015 PUC filing on Benefits of PJM Membership	2015	• $109 million of production cost savings in 2014 • $75 million of production cost savings in 2013 • Cumulative 2005–2015 benefits filed with NC PUC, but not made public • Did not study other benefits, such as improved long-term investment decisions, renewable integration, or reliability

Source: See footnotes.

61 MISO, "2021 MISO Value Proposition," March 9, 2022.

62 California ISO, "Western EIM Benefits Report: Fourth Quarter 2022", January 31, 2023.

63 PJM, PJM Value Proposition accessed February 13, 2023.

64 SPP, 2021 Member Value Study, April 6, 2022.

65 SPP, Benefit of the Market Western Energy Imbalance Service (WEIS), March 27, 2023.

66 Direct Testimony of Alan Meekins on Behalf of Virginia Electric and Power Company, Before the State Corporation Commission of Virginia, Case No. PUE-2015-00022, February 27, 2015; and Direct Testimony of Alan Meekins on Behalf of Virginia Electric and Power Company, Before the State Corporation Commission of Virginia, Case No. PUE-2014-00033, May 2, 2014.

IV.B. RTOs Such as PJM Improve Integration of and Access to Low-Cost Wind and Solar and Reduce Curtailments

RTOs facilitate integration of and access to wind and solar:

- By balancing operations across a wide area with diverse wind and solar patterns, the impact of variability of such resources on operations is mitigated. To give a simple example, the sun sets across the entirety of a single utility's territory over the course of only a few minutes, causing a rapid drop-off in output of all solar within the purview of those operators. By contrast, a large RTO such as PJM is balancing across two time zones, so that there is a full hour's difference between sunset on one end of the footprint (e.g., Newark, NJ) and the other (Chicago). This eases the challenges associated with obtaining adequate dispatch flexibility, allows for less ramping of thermal resources, reduces reserves procurement, and ultimately reduces the need for renewables curtailment under high wind/solar scenarios.
- A broad operating pool also mitigates reliability issues associated with overgeneration and eases curtailment due to excess renewables in a subregion.
- Regional transmission planning provides dependable access to low-cost wind and solar outside a member utility's footprint. This is especially useful for utilities with smaller geographical footprints or those that lack the best wind and solar resources internally.
- Access to more diverse resources allows for resource adequacy solutions that combine a variety of resource types for more flexibility, potentially lower cost, and more robust feasibility in achieving reliability with low-carbon resource mixes.

IV.C. LG&E-KU's RTO Study Conflicts with Industry Consensus Without Explanation

Joining a regional wholesale market such as an RTO lowers barriers to wholesale electricity trade and provides more options for beneficial buying and selling of both energy and capacity. It therefore is an advantageous option for the great majority of utilities. As LG&E-KU consultant Guidehouse says in the RTO Study: "Joining an RTO creates more opportunities for purchases and sales and allows generators to operate more efficiently, resulting in adjusted production cost savings, or dispatch benefits…"[67]

Dozens of utility RTO membership studies have demonstrated this point in diverse contexts, as shown in Table 5 and Table 6 above. Given the RTO Study's outlier finding, an explanation is warranted to credibly draw a conclusion which differs so greatly from the body of similar studies. A finding of net costs from joining an RTO would require LG&E-KU to be in a unique situation, but such a situation is not described in the study.

I performed a review of the base case (case 1) of the RTO Study to attempt to identify whether it provides evidence that such unique circumstances obtain. The study is divided into two pieces—first, Guidehouse ran a capacity expansion model with an integrated production cost model to identify the optimal quantity of new entry by type and year together with annual production costs; second, LG&E-KU performed a downstream net present value (NPV) analysis by assessing the capital cost of new entrants provided by the Guidehouse study, annualizing those capital costs according to various multi-decade schedules, and combining those annualized capital costs with fixed operations and maintenance costs and Guidehouse's annual production cost results. Of the various cost components assessed in the downstream NPV analysis, the difference in production cost between the standalone case and the RTO case was most significant.[68] In fact, at a 10% cost deterioration in the RTO case in 2030, the finding is an outlier relative to other RTO studies not only for showing increased production costs in the RTO case, but also for the magnitude of the change.

I assessed Guidehouse's production cost model for unusual circumstances that would explain a net deterioration in production cost when changing to PJM membership. One of the unusual scenarios in which a utility could lose by joining an RTO is when, in the non-RTO scenario, they can trade with a captive second utility at prices well above or below that of the prevailing regional wholesale market. When the captive utility and studied utility both gain market access, the latter loses their privileged market position, which can result in a net cost. However,

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[67] RTO Study, p. 51.

[68] RTO Study, p. 37, see Appendix 1, table titled "PJM Membership Cost Analysis - Case 1: Mid Fuel; No CO2 Reductions Regulations ($M)". In 2030, production cost is $97 million higher in the PJM case. The next largest cost that year is the PJM administrative fee, at $21 million.

Guidehouse's description of LG&E-KU's configuration suggests it is not possible for such a scenario to exist for the Companies in the Guidehouse model, since LG&E-KU has been set up to trade only with PJM in both the Standalone and RTO cases. Therefore, the only possible change in modeled trade patterns from introducing an RTO would be to increase LG&E-KU's own opportunity to access PJM markets, an increase in optionality that cannot increase costs. Put another way, the described study configuration is such that the RTO case cannot take away a valuable trading partner from LG&E-KU or otherwise affect profitable trade with regions other than PJM.[69]

Further, Guidehouse's production cost model provides evidence that, when all else is equal between the standalone and PJM cases (in particular the resource mix), PJM membership yields systematic production cost improvements. This is evinced in years in which the two cases have identical resource mixes (i.e., prior to 2027). In 2025 and 2026, the Guidehouse study shows a modest production cost savings in the RTO case of 0.2% and 1.0%.[70]

Thus lacking an explanation for the unexpected finding in the Guidehouse production cost model, I assessed the capacity expansion model and the relationship with the downstream NPV model. I identified a discrepancy between the NPV analysis and the capacity expansion analysis, which led LG&E-KU to revise down the NPV impact of RTO membership from a cost of $620 million to a cost of $421 million.[71] Based on my initial review of the Companies' updated modeling and limited supporting information on the capacity expansion model method, my best determination is that the drivers of the outlier result may include one or more of the following methodological issues:

i. **Inefficient resource mix in PJM case**. As shown in Figure 7, the lower production cost in the standalone case appears to be due to greater deployment of efficient solar and NGCC units relative to the PJM case (not due to shifting trading patterns with PJM). It is

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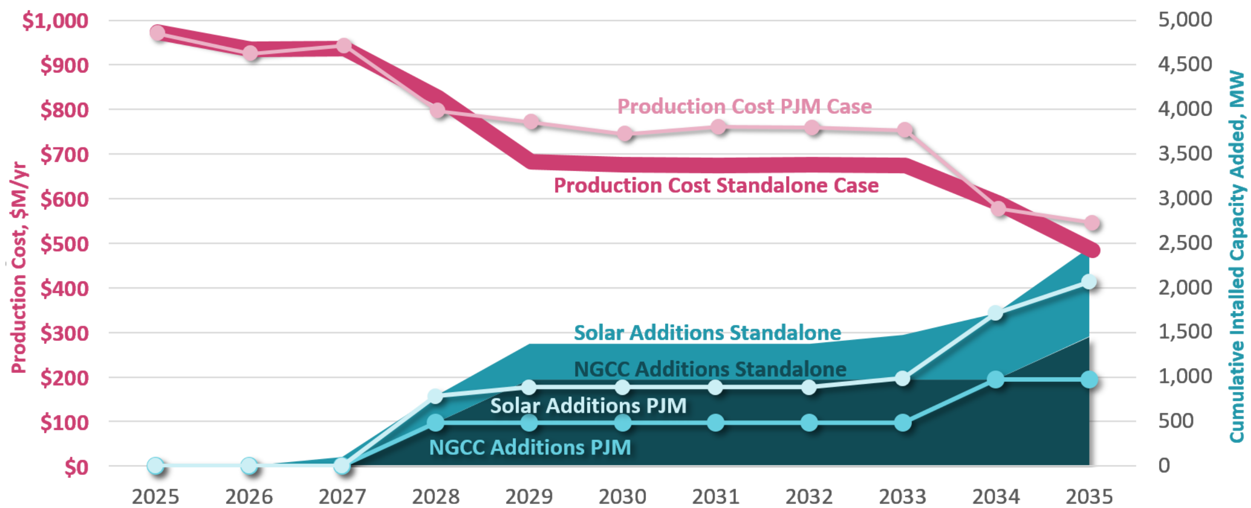
69 RTO Study, p. 80: "Interchanges between TVA, MISO, and EEI are disabled to simplify the analysis and to isolate the effects of PJM RTO participation."

70 Exhibit ACL-5: RTO Study Production Costs and Capacity Additions, comparison of Case 1 production costs between RTO and Standalone.

71 See Sierra Club supplemental discovery request, Q2.26(b), and LG&E-KU's response on p. 50: "This file includes an error in that the expansion plan data for the RTO cases were transposed among the storage, solar, and wind columns on the "RTO" worksheet."

unclear why the model does not pursue as much of these NGCC and solar investments in the PJM case. The effect is illustrated in Figure 7 immediately below, which shows that production costs (in magenta) decline commensurate with new investment in NGCC and solar units (teal), and that the base, standalone case has both more new solar and NGCC investment and lower production costs.

FIGURE 7. STANDALONE CASE SHOWS LOWER PRODUCTION COST LARGELY DUE TO GREATER ADDITIONS OF NEW, LOW-PRODUCTION-COST NGCC AND SOLAR



Source/Notes: Exhibit ACL-5: RTO Study Production Costs and Capacity Additions, from workpapers of RTO Study (updated).

ii. **Fixed retirements**. Retirement of existing generation was a fixed input to the capacity expansion model, identical between the standalone and PJM cases. The model was therefore not able to decide the optimum level of replacement of existing generation with efficient new solar and NGCC generation. Capacity expansion models reach the least cost resource mix by both adding and retiring resources, so this assumption limits the ability of the model to achieve least cost. This could conceivably have an effect on the issue described in (i) above.

iii. **Truncated capital cost modeling**. In the supplementary net present value analysis, the capital costs of new resource investments (including efficient new NGCC and solar plants) are spread across a lifetime of up to 40 years. With only 15 years represented in the NPV analysis, most of these annualized capital costs fall outside the analysis window and are thus omitted.[72] This skews analysis of the trade-off between production cost savings from NGCC investments and the corresponding capital cost burden.

iv. **Choice of experimental design which requires careful harmonisation of annualization schedules**. The NPV approach uses a specific set of annualization schedules with different terms for various resource types—following a supplemental discovery request, it remains unclear whether the capacity expansion model was programmed with consistent schedules.[73] The highly specific nature of these schedules (which vary by year and by generator type), the need to manually transfer the schedules from LG&E-KU to Guidehouse for consistent use in the capacity expansion model, the fact that an unrelated mistake occurred in transferring data between the Guidehouse stage and the NPV stage, and the lack of an explanation when asked about the schedule used in the capacity expansion model, all suggest these schedules could be discrepant between the NPV analysis and the capacity expansion model. Such a discrepancy could cause the effect seen in (i) above, by effectively resulting in a different assessment of the tradeoff between capital investment and lower production cost between the two analyses.

v. **Other potential discrepancies**. A paucity of detail on the workings of the capacity expansion model means it is also unclear whether other methodological assumptions were harmonized between the NPV analysis and the capacity expansion model, including discount rate, time horizon, etc. Such a discrepancy could similarly bias the capacity expansion model's assessment of the trade-off between higher capital costs of efficient

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[72] For example, in the workbook provided in Attachment 4 to Response to Question 26(b), column AE in table "Standalone" shows that only 13 years of annualized capital cost are accounted for from the NGCC MWs built in 2028, truncating the remaining 27 years of the 40 year life assumed in table RRProfiles. See Louisville Gas and Electric Company's and Kentucky Utilities Company's Responses to the Sierra Club's Supplemental Requests for Information, Attachment 4 in Response to Question 26(b), May 4, 2023.

[73] Sierra Club supplemental discovery request, question 2-18(c). "Please describe any methods and assumptions used in the capacity expansion model to adjust costs and benefits that occur in different years in order to optimize net benefits, such as calculations of present value, annualization or levelizing of capital costs, capital recovery factors, etc. Among the assumptions provided, please include the discount rate, whether the discount rate used reflects real vs. nominal, assumed useful life or depreciation schedule of capital investments if applicable, and any other assumed parameters used for these calculations. Please provide descriptions and citations to support the assumptions, together with any documents, analyses, or forecasts relied upon to calculate such parameters." LG&E-KU's reply does not include the discount rate, annualization method, depreciation schedules, etc used in the capacity expansion model.

NGCC investments vs. lower production costs relative to the NPV evaluation, yielding the issue described in (i) above.

While I have identified these issues and potential discrepancies as potential contributing factors to the study's outlier conclusion, there may be other methodological factors or market fundamentals that could contribute to these results but that have not been explained in the study.

If the above are the underlying factors causing an outlier result, they should be corrected in an updated and self-consistent analysis that integrates the capacity expansion model approach with the calculation of net present value benefits between the base and study cases. If there are other, more fundamental economic realities that exist in LG&E-KU but do not exist in the dozens of other utilities studied in a pooled energy market, these unique circumstances should be explained. Without either, it is not credible to draw the conclusion from the RTO Study that PJM membership entails costs that exceed the production cost benefits and capacity saving benefits.

The RTO Study tallies all those costs and benefits of PJM membership other than production cost or resource investment (e.g., PJM administrative fees, transmission cost allocation, etc.) and finds they represent a net cost of approximately \$20 – \$45 million per year through 2035.[74] Given my findings of capacity investment savings in the range of \$125 - \$140 million per year, and likely positive production cost benefits (potentially significantly so), PJM membership is expected to yield a significant overall net benefit.

V. Certification

I hereby certify that I have prepared the filing signed and know its contents are true as stated to the best of my knowledge and belief. I possess full power and authority to sign this filing.

[74] RTO Study, p. 37, see Appendix 1, table titled "PJM Membership Cost Analysis - Case 1: Mid Fuel; No CO2 Reductions Regulations (\$M)". Sum of all rows except PJM Energy Market Benefits, PJM Capacity Market Benefits, and Avoided Capacity Savings.

Date: July 14, 2023

Respectfully submitted,

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CERTIFICATE OF SERVICE

This is to certify that the foregoing copy of direct testimony in this action is being electronically transmitted to the Commission on July 14, 2023, and that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding.

/s/ Joe F. Childers
JOE F. CHILDERS