COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

DIRECT TESTIMONY OF
TIM A. JONES
SENIOR MANAGER, SALES ANALYSIS AND FORECASTING
ON BEHALF OF
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: February 28, 2025

TABLE OF CONTENTS

Introduction ... 1

Highlights of the 2025 CPCN Load Forecast ... 3

The Companies' Load Forecasting Approach Is Reasonable ... 6

Relationship of the 2025 CPCN Load Forecast
to the 2024 IRP Load Forecasts ... 8

Economic Development Drives Nearly All Load Growth
in the 2025 CPCN Load Forecast ... 10

The Amount of Projected Economic Development Load
in the 2025 CPCN Load Forecast is Reasonable ... 14

The Companies' Forecast of Existing Load Remains Largely
Unchanged from the Forecast the Commission Found
Reasonable in the 2022 CPCN-DSM Case ... 21

All Customers, Not Just Data Centers and BOSK, Will Continue
to Require Significant Amounts of Energy in All Hours,
Seasons, and Daylight Conditions ... 22

Other Foundational Load Forecast Assumptions and Inputs:
Weather and Economic Assumptions ... 28

Other Foundational Load Forecast Assumptions and Inputs:
Energy Efficiency ... 29

Other Foundational Load Forecast Assumptions and Inputs:
Distributed Energy Resources ... 31

Other Foundational Load Forecast Assumptions and Inputs:
Electric Vehicles ... 40

Other Foundational Load Forecast Assumptions and Inputs:
Space Heating Electrification ... 42

Other Foundational Load Forecast Assumptions and Inputs:
AMI, Customer Growth, and Price Elasticity of Demand ... 43

The Companies Have Reasonably Accounted for Known Uncertainties in the
2025 CPCN Load Forecast ... 45

Conclusion ... 46

INTRODUCTION

Q. Please state your name, position, and business address.

A. My name is Tim A. Jones. I am the Senior Manager of Sales Analysis and Forecasting for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, "Companies") and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 2701 Eastpoint Parkway, Louisville, Kentucky 40223. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Please describe your job responsibilities.

A. The primary responsibility of the Sales Analysis and Forecasting team is to support decision-making within the Companies. This begins with an understanding of how the Companies' customers use electricity and gas in all hours, which we obtain through economic and statistical analysis and research into factors that could change future usage patterns. Though not a comprehensive list, this includes the following tasks:

- analyzing monthly sales and energy requirements variances;
- analyzing key factors that influence customers' energy consumption, such as the state of the economy, federal and state regulations, weather, demand-side programs, end-use appliance efficiencies and saturations, distributed generation, electrification, and rates and rate design;
- analyzing available interval data and using clustering algorithms to create hourly usage profiles by rate class;
- considering additional inputs that could aid in analysis or forecasting; and
- documenting our processes.

As Senior Manager of the Sales Analysis and Forecasting team, each year I am responsible for producing the Companies' 30-year electric load forecast and 10-year gas volumes forecast. I hold a bachelor's degree in mathematics from Bellarmine University, and I worked 11 years at Schneider Electric, primarily in a data analysis role, before joining the Companies more than eight years ago. I have spent my entire career with the Companies in the Sales Analysis and Forecasting group as an analyst or manager.

Q. Have you previously testified before this Commission?

A. Yes, I testified before this Commission in the Companies' most recent certificate of public convenience and necessity ("CPCN") and demand-side management and energy efficiency ("DSM-EE") plan proceeding, Case No. 2022-00402 ("2022 CPCN-DSM Case").[1] Also, I oversaw the preparation of the Companies' load forecast in the Companies' 2021 and 2024 Integrated Resource Plan ("IRP") proceedings,[2] and I have responded to numerous data requests in the Companies' ongoing 2024 IRP proceeding.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to discuss the Companies' electric load forecast and the process used to create it.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits:

---

[1] *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 Generation Unit Retirements*, Case No. 2022-00402, Direct Testimony of Tim A. Jones (December 15, 2022); Case No. 2022-00402, Rebuttal Testimony of Tim A. Jones (Aug. 9, 2023).

[2] *Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2021-00393; *Electronic 2024 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2024-00326.

- Exhibit TAJ-1: Electric Sales and Demand Forecast Process
- Exhibit TAJ-2: 2025 CPCN Load Forecast Workpapers

Note that Exhibit TAJ-2 consists of electronic workpapers concerning the load forecast that are being provided separately.

HIGHLIGHTS OF THE 2025 CPCN LOAD FORECAST

Q. Please summarize the key points of the 2025 CPCN Load Forecast.

A. The key points of the 2025 CPCN Load Forecast are:

1. Annual energy requirements climb sharply from 32,808 GWh in 2025 to a high of 48,129 GWh in 2032 due to economic development load growth and are flat to slightly declining through the mid-2030s as energy efficiency, distributed energy resources (assumed to be exclusively solar), and other energy-reducing measures outpace customer growth and increased penetrations of electric heating and electric vehicles ("EVs"). That trend reverses beginning in the late 2030s, ending at 49,045 GWh in 2054. Note that the Companies do not mean to suggest there will be zero economic development load growth beyond 2032. Rather, as Stuart A. Wilson notes in his testimony, because the Companies' application focuses on resource decisions that must be made now, i.e., those needed to ensure they can serve projected load increases through 2032, the Companies do not attempt to in this forecast to project possible economic load additions beyond 2032.
2. For the same reasons, seasonal system peak demands climb from 6,230 MW (summer) and 6,146 (winter) in 2025 to 8,034 MW (summer) and 7,930 (winter) in 2032. Thereafter, summer peaks slowly decline throughout the forecast period to 7,967 MW in 2054, whereas winter peaks slowly increase to 7,951 MW in 2054. This divergence

arises primarily from the effects of energy efficiency and distributed solar resources having their largest contributions near or at summer peaks, when EVs are less likely to be charging, all of which tends to decrease summer peaks, whereas increasing amounts of electric heating load with minimal contributions from distributed solar resources all tend to increase winter peaks, which typically occur during non-daylight hours.

3. Economic development load, i.e., data center load (1,750 MW) and BlueOval SK Battery Park ("BOSK") load (more than 250 MW summer, about 225 MW winter), is responsible for unprecedented load growth from 2025 through 2032. The very high load factors of this load (95% for data centers; 90% for BOSK) effectively shift the entire load curve up.

4. As Figure 2 shows, the Companies' system is now consistently dual-peaking, with winter peaks since 2014 being more volatile and often higher than summer peaks. This suggests the Companies' resource portfolio must be able to serve customers reliably at peak demands not just on hot, sunny summer afternoons but also during dark, frigid, ice-covered winter nights—and sometimes for days at a time at sub-freezing temperatures, which the Companies' service territories experienced during two separate periods in January 2025. In fact, during Winter Storm Enzo in January 2025 the Companies experienced 90 consecutive hours of system load above 5,000 MW and 18 consecutive hours of system load above 6,000 MW.

5. As shown most clearly in Figures 3 and 4 below, the 2025 CPCN Load Forecast for non-economic development load is largely unchanged from the Companies' 2021 IRP Load Forecast and the Companies' 2022 CPCN Load Forecast (minus BOSK load), the

reasonableness of the latter of which the Commission's Final Order in the 2022 CPCN-DSM Case supported.[3]

6. The 2025 CPCN Load Forecast includes significant amounts of customer-initiated energy efficiency improvements, AMI-related CVR and ePortal savings, distributed generation, and the energy efficiency effects of the Companies' 2024-2030 DSM-EE Program Plan, as well as the assumed impacts of DSM-EE programs and customer-initiated energy efficiency efforts beyond 2030. By 2032, those items result in nearly 1,500 GWh of annual energy reductions, summer peak demand reductions of 230 MW, and winter peak demand reductions of 171 MW.
7. Distributed generation capacity (including qualifying facilities ("QFs")) increases from the current level of about 67 MW to 150 MW in 2032 and 266 MW by 2054.
8. EVs increase in the Companies' Kentucky service territory from the current level of approximately 15,600 to 58,000 in 2032 and over 553,000 by 2054. This equates to about 190 GWh of annual energy and only about 5 MW added to seasonal peak demands in 2032.
9. By 2032, the forecast assumes electric space heating saturation increases from 2015 levels by 4% in KU's service territory (which is already highly saturated) and by 19% in LG&E's service territory.
10. Customers continue to have significant energy requirements in all hours and seasons, including in non-daylight hours. For example, minimum hourly demand in 2032 is 4,093 MW.

[3] Case No. 2022-00402, Order at 61-66 (Ky. PSC Nov. 6, 2023).

THE COMPANIES' LOAD FORECASTING APPROACH IS REASONABLE

Q. Please describe the Companies' electric load forecast process.

A. Each year from approximately March through July, the Companies prepare a 30-year demand and energy forecast, which involves:

- Using historical data to develop models that relate the Companies' electricity usage, demand, sales, and number of customers by rate classes to exogenous factors such as economic activity, appliance efficiencies and adaptation, demographic trends, and weather conditions;
- Using the models in combination with forecasts of the exogenous factors to forecast the Companies' electricity usage, demand, sales, and number of customers for the various rate classes; and
- Using historical load shapes for each of KU and LG&E to convert the monthly sales forecasts into a 30-year hourly forecast that can be used for generation planning purposes, including forecasting peak demands.

Q. How do the Companies ensure their electric load forecast is reasonable?

A. The Companies employ three practices to produce methodologically sound and reasonable forecasts:

1. Building and rigorously testing statistically and econometrically sound mathematical models of the load forecast variables;
2. Using high-quality forecasts of future macroeconomic events that influence the load forecast variables, both nationally and in the service territory; and

3. Thoroughly reviewing and analyzing model outputs to ensure the results are reasonable based on historical trends and the Companies' own experience and understanding of long-term trends in electricity and natural gas usage.

Q. What else supports the reasonableness of the Companies' load forecasting approach?

A. The Commission Staff Report in the Companies' 2021 IRP case stated, "LG&E/KU's assumptions and methodologies for load forecasting are generally reasonable,"[4] though the report did make a number of load forecasting recommendations.

As I discussed in my direct testimony in the 2022 CPCN-DSM Case, the Companies sought to address those recommendations in their 2022 CPCN-DSM load forecast.[5] The Commission explicitly found the Companies' 2022 CPCN-DSM load forecast to be reasonable in several respects when addressing intervenor criticisms;[6] nowhere did the Commission's Final Order state that the Companies' 2022 CPCN-DSM load forecast was unreasonable in any respect.

The Companies used the same processes and methodologies to create the 2024 IRP load forecasts that they used in the 2022 CPCN-DSM Case, and the Companies have used the same load forecasting processes and methodologies in this case. Therefore, the Commission can have confidence in the reasonableness of the 2025 CPCN Load Forecast.

---

[4] *Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2021-00393, Order Appx. "Commission Staff's Report on the 2021 Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company" at 51 (Ky. PSC Sept. 16, 2022).
[5] Case No. 2022-00402, Direct Testimony of Tim A. Jones at 5 (December 15, 2022).
[6] Case No. 2022-00402, Order at 61-66 (Ky. PSC Nov. 6, 2023).

RELATIONSHIP OF THE 2025 CPCN LOAD FORECAST TO THE 2024 IRP LOAD FORECASTS

Q. How does the 2025 CPCN Load Forecast relate to the load forecasts presented in the Companies' 2024 IRP?

A. Simply stated, the 2025 CPCN Load Forecast *is* the 2024 IRP Mid load forecast extended to 2054 and adjusted to include the 2024 IRP High load forecast's economic development load, i.e., the 2025 CPCN Load Forecast includes 1,750 MW of data center load by 2032 and the 120 MW BOSK Phase Two load, whereas the 2024 Mid Load Forecast includes only 1,050 MW of data center load and excludes BOSK Phase Two.[7]

The 2025 CPCN Load Forecast is in all other respects identical to the 2024 Mid load forecast, including 150 MW of distributed generation by 2032, annual energy reductions of 1,500 GWh by 2032 from energy efficiency and other energy reductions,[8] and summer and winter peak demand reductions in 2032 of 230 MW and 171 MW, respectively, resulting from energy efficiency (compared to a forecast with flat energy efficiency assumptions).[9]

Figure 1 below shows the 2025 CPCN Load Forecast for energy, and Figures 2 and 3 below show winter and summer seasonal peak demands, respectively, comparing them to the 2024 IRP Mid and High load forecasts:[10]

---

[7] *See, e.g.,* Case No. 2024-00326, IRP Vol. I at 5-13 to 5-16 (Oct. 18, 2024).

[8] Includes energy reductions from customer-initiated energy efficiency improvements, advanced metering infrastructure ("AMI") related conservation voltage reduction ("CVR") and ePortal savings, distributed generation, and the energy-efficiency effects of the Companies' 2024-2030 DSM-EE Program Plan and the assumed impacts of DSM-EE programs beyond 2030.

[9] Case No. 2024-00326, IRP Vol. I at 7-20 (Oct. 18, 2024).

[10] Note that this historical data in Figures 1 – 5 excludes departed municipal load.

Figure 1: Annual Energy Requirements Compared to 2024 IRP Mid and High Forecasts

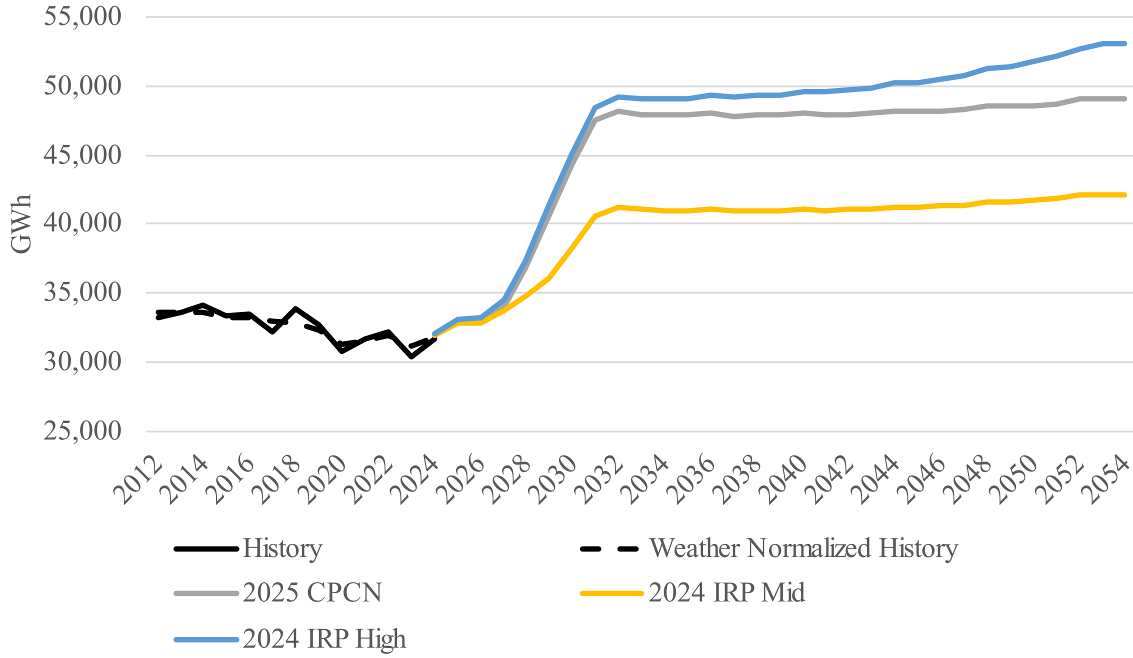


Figure 2: Winter Peaks Compared to 2024 IRP Mid and High Forecasts

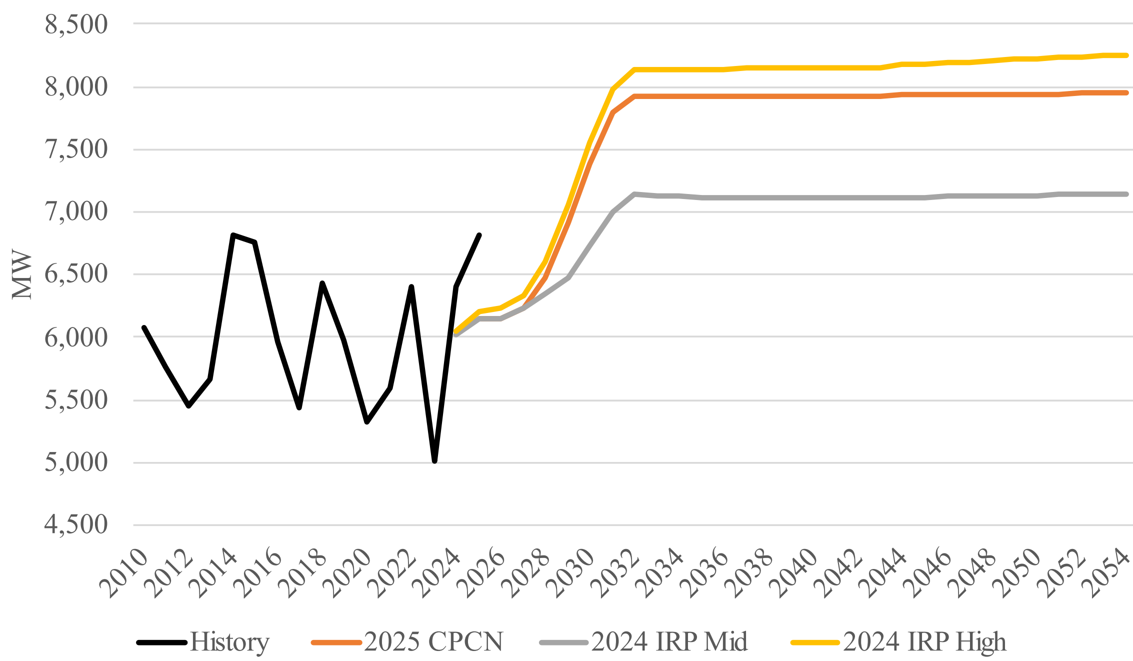
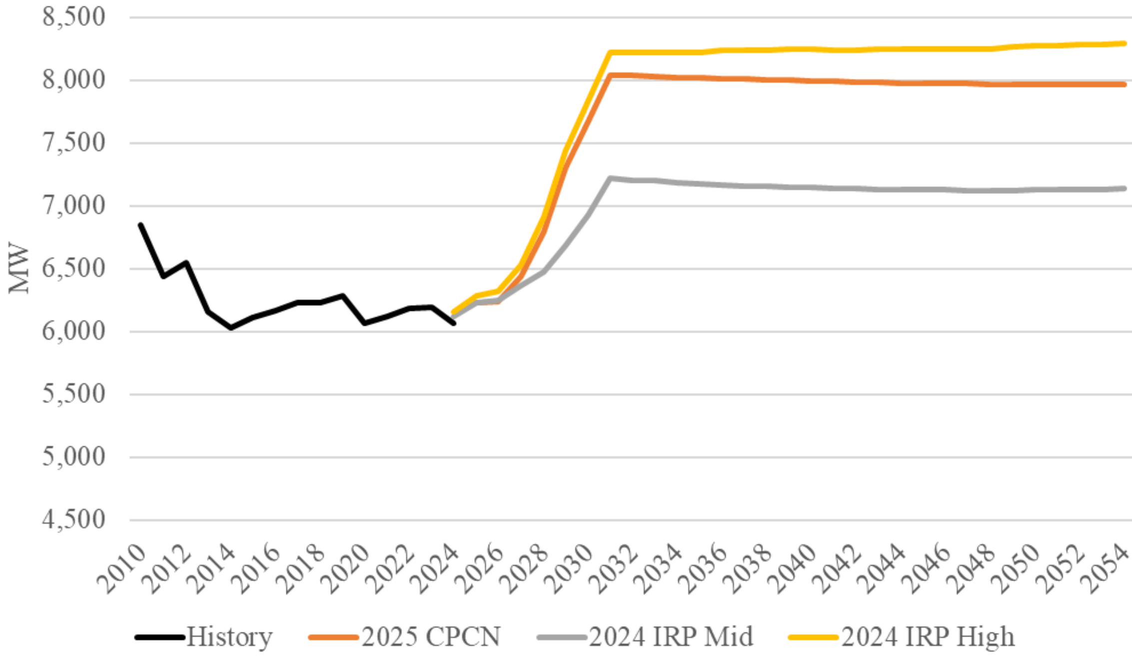


Figure 3: Summer Peaks Compared to 2024 IRP Mid and High Forecasts



<u>ECONOMIC DEVELOPMENT DRIVES NEARLY ALL LOAD GROWTH IN THE 2025 CPCN LOAD FORECAST</u>

Q. What is the key driver of load growth in the 2025 CPCN Load Forecast?

A. Economic development load, which includes BOSK load, is by far the largest driver of load growth in the 2025 CPCN Load Forecast, just as it is in the Companies' 2024 IRP load forecasts and was in the 2022 CPCN-DSM Load Forecast. To see this most clearly, it is helpful to divide the Companies' 2025 CPCN Load Forecast between all load except economic development load ("existing load") and economic development load, consisting of projected data center load, BOSK load, and other recent economic development activity likely to result in additional load. Dividing the load forecast in this way shows the 2025 CPCN Load Forecast of existing load is largely unchanged from the Companies' other recent load forecasts, with existing load projected to decline slightly in the near-to-medium term and a small amount of net growth beginning in the late 2030s as electricity consumption resulting from increasing heating electrification and electric vehicle ("EV") penetration exceeds energy savings associated with energy efficiency and other energy-reducing measures. In contrast, economic development load exclusively drives an unprecedented amount of load growth (for the Companies' service territories) in the near-to-medium term. Figure 4 below shows this graphically regarding annual energy requirements:

Figure 4: Forecasts Excluding Economic Development

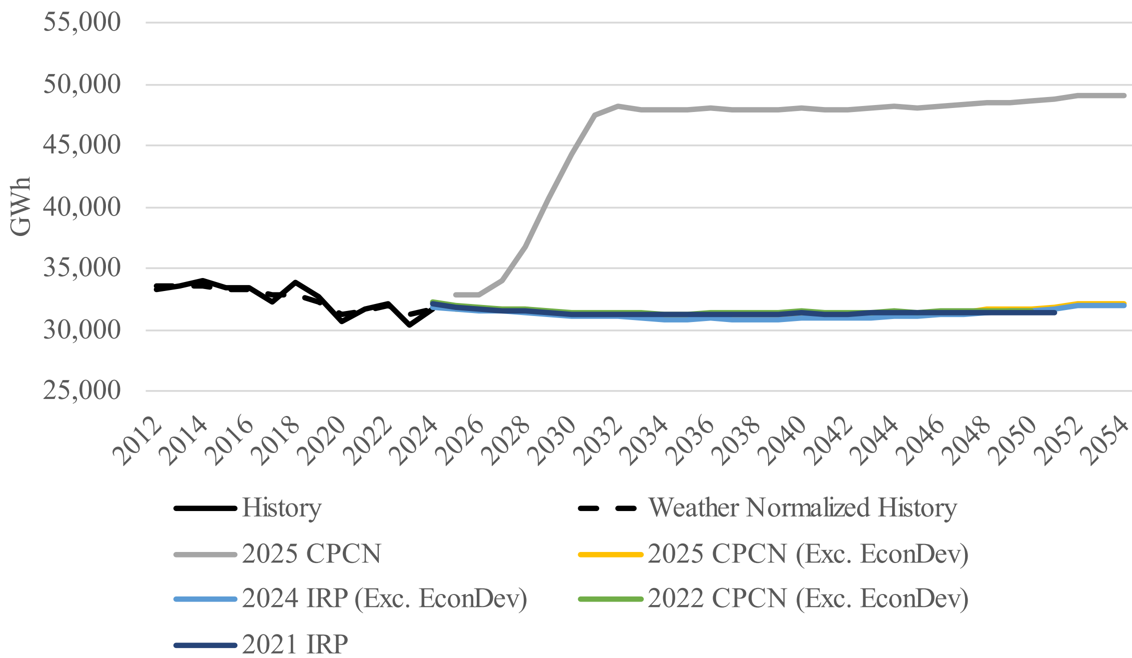


Figure 4 also demonstrates that the Companies' 2025 CPCN Load Forecast of existing load is essentially unchanged from the load forecast the Commission found reasonable in the Companies' 2022 CPCN-DSM Case and from the 2021 IRP Load Forecast formulated using assumptions and methodologies the Commission Staff found to be "generally reasonable."[11] Finally, Figure 4 demonstrates the magnitude of the impact

[11] Case No. 2022-00402, Order at 63-65 (Ky. PSC Nov. 6, 2023) ("The Commission finds that LG&E/KU's treatment of economic growth in this load forecast is reasonable despite certain risks acknowledged by LG&E/KU. … Thus, while the Commission does ultimately agree with Kentucky Coal Association that there is a high-side "risk" to the load associated with unexpected economic growth, the Commission finds that such a risk does not render LG&E/KU's load forecast unreasonable. … However, the Commission does not conclude that

of projected economic development load on the Companies' 2025 CPCN Load Forecast.

Q. How does the projected economic development load differ from other customer loads?

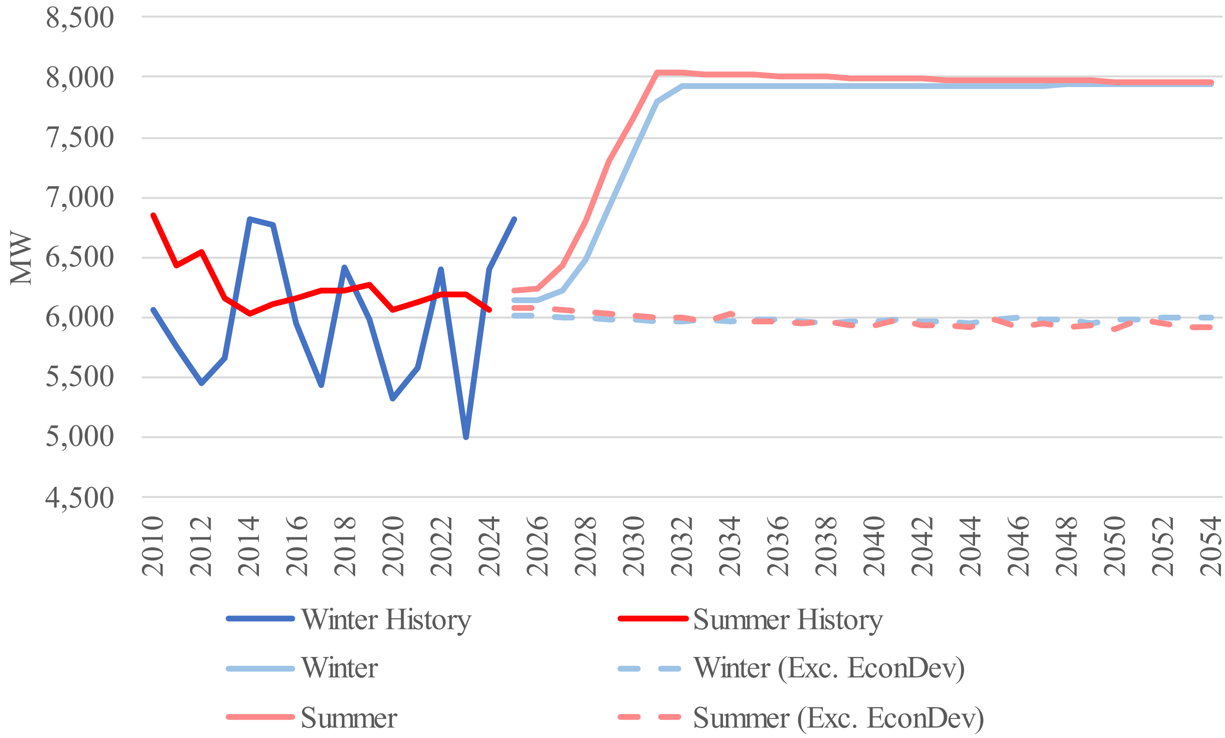
A. In addition to its size, the projected economic development load, particularly BOSK and data center load, is unlike nearly all other customer loads because it has a high load factor (assumed to be 95% for data centers and 90% for BOSK),[12] much higher than the Companies' current average system load factor (about 56% in 2024). These projected loads therefore have a large impact on energy requirements and demands in all hours, including system seasonal peak demands. Indeed, as shown in Figure 4 above and Figure 5 below, the projected economic development load essentially shifts the entire load curve up.

---

the low-side risks raised with respect to LG&E/KU's load forecast or its minimum reserve margin analysis materially affected LG&E/KU's need in this matter."); *Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2021-00393, Order Appx. "Commission Staff's Report on the 2021 Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company" at 51 (Ky. PSC Sept. 16, 2022).

[12] An electric consuming facility's load factor is the ratio of the facility's actual or projected energy consumption to the facility's theoretical maximum consumption over the same time period. Therefore, for a 100 MW facility to have a load factor of 95% would require the facility to have an average instantaneous demand of 95 MW at all times during the measurement period.

Figure 5: Seasonal Peaks With and Without Economic Development



Q. Is there reason to expect these customers' electric requirements or demands could be reduced through DSM-EE programs or curtailable service offerings?

A. No. John Bevington observes in his testimony that the data center developers with whom the Companies have interacted have expressed no interest in either DSM-EE programs or curtailable service. Moreover, such customers already have a strong financial incentive to be as energy-efficient as reasonably possible, making it unlikely the Companies could develop and offer cost-effective energy-efficiency programs for such customers. Therefore, the Companies reasonably did not forecast a load factor lower than 95% for data center loads (90% for BOSK) or assume that such customers' energy consumption or demand could be reduced by DSM-EE programs or curtailable service offerings.

THE AMOUNT OF PROJECTED ECONOMIC DEVELOPMENT LOAD IN THE 2025 CPCN LOAD FORECAST IS REASONABLE

Q. Is the Companies' projected economic development load reasonable?

A. Yes. The Companies' projection of significant economic development load in the 2025 CPCN Load Forecast is reasonable.

First, as Robert M. Conroy and Mr. Bevington address at greater length, the Kentucky General Assembly has stated that "the inducement of the location of data center projects within the Commonwealth is of paramount importance to the economic well-being of the Commonwealth,"[13] and it has specifically provided tax incentives for data centers to locate in Jefferson County, which is in LG&E's electric service territory.[14] This further supports the reasonableness of the Companies' projection that data center load will locate in their Kentucky service territories.

Second, as Mr. Bevington discusses, Kentucky's efforts to attract data centers are working: PowerHouse Data Centers and the Poe Companies recently announced their plans for a 402 MW hyperscale data center campus in Louisville, the first 130 MW of which will be available in October 2026.[15] State and local officials have expressed strong support for the announced data center, future data centers, and the statutes that are helping attract data centers to Kentucky.[16] As reported by WDRB:

[13] KRS 154.20-222(3).

[14] KRS 134.499; KRS 154.20-220(17)(c).

[15] "PowerHouse Data Centers and Poe Companies Partner to Develop Kentucky's First Hyperscale Data Center Campus" (Jan. 16, 2025), available at https://www.powerhousedata.com/news/powerhouse-data-centers-and-poe-companies-partner-to-develop-kentuckys-first-hyperscale-data-center-campus (accessed Jan. 16, 2025).

[16] *See, e.g.,* "Stivers on Tax Incentive for Kentucky's First Data Center: Incentive will attract major business to Louisville" (Jan. 16, 2025) ("'I worked closely with Secretary Jeff Noel from the Kentucky Cabinet for Economic Development and top private sector leaders to craft and pass groundbreaking legislation that will spark job creation and expand the tax base, which creates more revenue,' Stivers said. 'This project is a game-changer, driving long-term economic growth in our major metropolitan center and boosting Kentucky as a regional business hub.'"), available at https://kysenaterepublicans.com/press-releases (accessed Jan. 16, 2025).

> Kentucky Senate President Robert Stivers, R-Manchester, credited Jeff Noel, secretary of Gov. Andy Beshear's economic development cabinet, and Katie Smith, the agency's deputy secretary, with helping craft the legislation with lawmakers. He called the effort "a really good example of how the system can work."
>
> …
>
> Attracting businesses in emerging tech industries is a plank in the economic development plan championed by Louisville's Mayor Craig Greenberg, a Democrat. In an interview, Greenberg said the data center project is forward-looking and helps raise the city's profile.
>
> "It sends a signal that we are a great place for technology businesses of today and tomorrow to locate, that we are going to be a city where we support software engineers, coders, tech businesses, businesses that are driven by AI."[17]

In addition, PowerHouse's press release reports:

> "This new data center will create thousands of good-paying jobs here in Louisville," said Louisville Mayor Craig Greenberg. "As the need for data centers grows, Louisville is perfectly positioned to meet the demands of the tech sector."
>
> …
>
> Senate President Robert Stivers, R-Manchester, agreed. "This project is a game-changer, driving long-term economic growth in our major metropolitan center and boosting Kentucky as a regional business driver."
>
> "Attracting hyperscale operators to any location requires a different set of tools than most other industries," said Jeff Noel, Secretary for Economic Development. "This announcement is a critical milestone from great leadership to assure all elements needed to begin successful operations are available."[18]

[17] Green, Marcus, "Developers unveil plans for large tech data center in Louisville, the 1st of its kind in Kentucky," WDRB (Jan. 16, 2025), available at https://www.wdrb.com/in-depth/developers-unveil-plans-for-large-tech-data-center-in-louisville-the-1st-of-its-kind/article_e7adef68-c92f-11ef-b262-bf1780db36c6.html (accessed Jan. 16, 2025).

[18] PowerHouse Data Centers, "PowerHouse Data Centers and Poe Companies Partner to Develop Kentucky's First Hyperscale Data Center Campus" (Jan. 16, 2025), available at https://www.powerhousedata.com/news/powerhouse-data-centers-and-poe-companies-partner-to-develop-kentuckys-first-hyperscale-data-center-campus (accessed Jan. 16, 2025).

Thus, Kentucky's efforts to attract data centers are yielding results, and the recent statements of state and local leaders give reason to believe that those efforts will continue for the foreseeable future.

Third, as Mr. Bevington explains, the Companies have over 8,000 MW of total economic development load potential based upon the current list of prospective customers, over 6,000 MW of which is related to data centers.[19] Although the Companies do not expect that all of this potential economic development load will materialize, it is reasonable to project that a part of that potential load will become actual for the reasons stated above and those Mr. Bevington discusses, including what the developers of the PowerHouse data center said according to their recent press release:

> "Louisville offers everything hyperscale users need – immediate and reliable power at very attractive rates, water, connectivity and a business environment that encourages more hyperscale growth in the region," said Doug Fleit, Co-founder and CEO of PowerHouse, "The experience of working with Louisville Gas and Electric (LG&E), the utility serving the site, has been a model for other utilities in the country to follow …."[20]

As Mr. Conroy explains, the Companies have an obligation to be ready to serve such load, again supporting its inclusion in the 2025 CPCN Load Forecast.

Q. How does the Companies' projected data center load compare to national projections of data center load growth?

[19] Case No. 2024-00326, Companies' Response to KCA 1-15 (Dec. 18, 2024).

[20] PowerHouse Data Centers, "PowerHouse Data Centers and Poe Companies Partner to Develop Kentucky's First Hyperscale Data Center Campus" (Jan. 16, 2025), available at https://www.powerhousedata.com/news/powerhouse-data-centers-and-poe-companies-partner-to-develop-kentuckys-first-hyperscale-data-center-campus (accessed Jan. 16, 2025).

A. There is a clear surge in current and projected data center demand in the U.S., and the Companies' projected 1,750 MW of such load is just a fraction of the projected national demand:

- The U.S. Department of Energy's Lawrence Berkeley National Laboratory ("Berkeley Lab") reports that U.S. data center electricity consumption more than doubled between 2018 and 2023, rising from 1.9% to 4.4% of total U.S. electricity use.[21] Berkeley Lab projects that by 2028 this energy use could grow between 85% and 230%, resulting in an increase in power demand for data centers between 34 and 92 GW.[22]
- According to the North American Electric Reliability Corporation's "2024 Long-Term Reliability Assessment" ("LTRA"), "The size and speed with which data centers (including crypto and AI) can be constructed and connect to the grid presents unique challenges for demand forecasting and planning for system behavior. … The aggregated assessment area winter peak demand forecast is expected to rise over almost 18% for the 10-year period: 149 GW this LTRA up from almost 92 GW in the *2023 LTRA*."[23]

[21] Berkeley Lab, "2024 United States Data Center Energy Usage Report" at 5 (Dec. 2024), available at https://eta-publications.lbl.gov/sites/default/files/2024-12/lbnl-2024-united-states-data-center-energy-usage-report.pdf (accessed Jan. 10, 2025).

[22] *See id.* at 6 ("Together, the scenario variations provide a range of total data center energy estimates, with the low and high end of roughly 325 and 580 TWh in 2028, as shown in Figure ES-1. Assuming an average capacity utilization rate of 50%, this annual energy use range would translate to a total power demand for data centers between 74 and 132 GW. This annual energy use also represents 6.7% to 12.0% of total U.S. electricity consumption forecasted for 2028."). The power demand increases shown in the body text derive from the values in the quote.

[23] NERC, "2024 Long-Term Reliability Assessment" at 8-9 (Dec. 2024), available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf (accessed Jan. 17, 2025) (emphasis original).

- The Electric Power Research Institute ("EPRI") projects annual data center energy use could more than double by 2030.[24]
- PJM projects its winter and summer peaks will climb nearly 50% by 2039, which it attributes to rapidly increasing demand from data centers, heating and vehicle electrification, and manufacturing.[25]

This enormous projected growth in data center load nationally, coupled with Kentucky's efforts to attract data centers to locate here, the announcement of the first hyperscale data center in Kentucky locating in Jefferson County, and having more than 6,000 MW of data center projects in the Companies' economic development queue, supports the reasonableness of the Companies' data center load projection.

Q. Are there additional reasons to anticipate a continuing surge in data center growth?

A. Yes. In addition to the projections of ongoing data center growth and development in the U.S. I discussed above, as well as recent data center location announcements,[26] the tech companies driving this growth have publicly stated their intentions to continue making enormous and increasing investments in data centers in the U.S.:

---

[24] EPRI, "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption" at 2 (May 2024), available at https://restservice.epri.com/publicdownload/000000003002028905/0/Product (accessed Feb. 19, 2025).

[25] PJM Inside Lines, "2025 Long-Term Load Forecast Report Predicts Significant Increase in Electricity Demand" (Jan. 30, 2025), available at https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/ (accessed Feb. 19, 2025).

[26] *See, e.g.,* https://datacenters.atmeta.com/wp-content/uploads/2024/12/Metas-Jeffersonville-Data-Center.pdf (accessed Jan. 4, 2025) (announcing a Meta data center in Jeffersonville, Indiana); https://iedc.in.gov/events/news/details/2024/04/26/gov.-holcomb-announces-google-is-building-a-2b-data-center-in-northeast-indiana (accessed Jan. 4, 2025) (announcing a $2 billion Google data center in Fort Wayne, Indiana); https://datacenters.atmeta.com/wp-content/uploads/2024/12/Metas-Richland-Parish-Data-Center.pdf (accessed Jan. 4, 2025) (announcing a 2 GW Meta data center in Richland Parish, Louisiana).

- On February 6, 2025, The Wall Street Journal reported in an article titled, "Tech Giants Double Down on Their Massive AI Spending: Amazon, Google, Microsoft and Meta pour billions into artificial intelligence, undeterred by DeepSeek's rise":

> Tech giants projected tens of billions of dollars in increased investment this year and sent a stark message about their plans for AI: We're just getting started.
>
> The four biggest spenders on the data centers that power artificial-intelligence systems all said in recent days that they would jack up investments further in 2025 after record outlays last year. Microsoft, Google and Meta Platforms have projected combined capital expenditures of at least $215 billion for their current fiscal years, an annual increase of more than 45%.
>
> Amazon.com didn't provide a full-year estimate but indicated on Thursday that total capex across its businesses is on course to grow to more than $100 billion, and said most of the increase will be for AI.[27]

- On January 21, 2025, OpenAI announced, "The Stargate Project is a new company which intends to invest $500 billion over the next four years building new AI infrastructure for OpenAI in the United States. We will begin deploying $100 billion immediately."[28]

- Microsoft recently stated, "In FY 2025, Microsoft is on track to invest approximately $80 billion to build out AI-enabled datacenters to train AI

[27] Nate Rattner and Jason Dean, "Tech Giants Double Down on Their Massive AI Spending," The Wall Street Journal (Feb. 6, 2025), available at https://www.wsj.com/tech/ai/tech-giants-double-down-on-their-massive-ai-spending-b3040b33?st=ZMvyQt (accessed Feb. 12, 2025).

[28] https://openai.com/index/announcing-the-stargate-project/ (accessed Jan. 21, 2025).

models and deploy AI and cloud-based applications around the world. More than half of this total investment will be in the United States ….”[29]

- Meta recently announced its plan to invest $65 billion in 2025 to expand AI infrastructure, and Amazon has said its 2025 data center investments would be higher than its estimated $75 billion in 2024.[30]

All of this points to unprecedented and ongoing growth in data center load for the foreseeable future across the U.S. Particularly considering the efforts Kentucky is making to attract such loads, as Mr. Bevington addresses in his testimony, it is reasonable to assume that a number of data centers will locate in the Companies' service territories.

Q. Are the Companies including BOSK Phase Two in the 2025 CPCN Load Forecast?

A. Yes. As Mr. Bevington explains, KU has a contract to serve the entirety of BOSK's load, including Phase Two load of 120 MW. It is my understanding that all of the electrical facilities necessary for BOSK to take service at the second building are in place, meaning that BOSK could relatively quickly begin taking service for the building at up to 120 MW if it decides to proceed. Thus, based on KU's contractual obligation to serve and the relatively short time in which BOSK could begin taking service after completing the second building, it is both reasonable and prudent to include both phases of BOSK in the 2025 CPCN Load Forecast.

[29] Smith, Brad, "The Golden Opportunity for American AI" (Jan. 3, 2025), available at https://blogs.microsoft.com/on-the-issues/2025/01/03/the-golden-opportunity-for-american-ai/ (accessed Jan. 4, 2025).

[30] Singh, Jaspreet, "Meta to spend up to $65 billion this year to power AI goals, Zuckerberg says," Reuters (Jan. 24, 2025), available at https://www.reuters.com/technology/meta-invest-up-65-bln-capital-expenditure-this-year-2025-01-24/ (accessed Jan. 30, 2025).

Q. How have the Companies addressed other economic development load in the 2025 CPCN Load Forecast?

A. In addition to data center and BOSK load, the Companies included 20 MW from an economic development prospect in the auto industry and 19.4 MW from an existing customer's expansion as economic development load. Additional manufacturing or other economic development loads could locate in the Companies' service territories over the forecast period, but the Companies have not included any such additional loads in the 2025 CPCN Load Forecast.

THE COMPANIES' FORECAST OF EXISTING LOAD REMAINS LARGELY UNCHANGED FROM THE FORECAST THE COMMISSION FOUND REASONABLE IN THE 2022 CPCN-DSM CASE

Q. Is the Companies' 2025 CPCN Load Forecast of non-economic-development load materially unchanged from the Companies' other recent load forecasts of such load?

A. Yes. As I mentioned above and as is clear in Figure 4 above, the Companies' 2025 CPCN Load Forecast of non-economic-development load is materially unchanged from the Companies' 2021 IRP Load Forecast and the 2022 CPCN-DSM Load Forecast of such load, and it is identical to the 2024 IRP Mid Load Forecast of such load. The Commission explicitly found the Companies' 2022 CPCN-DSM Load Forecast to be reasonable in several respects,[31] and it did not find the load forecast to be unreasonable in any respect. Moreover, weather-normalized variances from the Companies' recent load forecasts have been low, and the forecasts have proven to be reasonable and reliable for resource planning. Therefore, as noted in the 2024 IRP concerning the

[31] Case No. 2022-00402, Order at 61-66 (Ky. PSC Nov. 6, 2023).

Companies' load forecasting, the Companies used the same processes and methodologies to create the 2024 IRP load forecasts they used in the 2022 CPCN-DSM Case, and the Companies have used the same load forecasting processes and methodologies in this case.

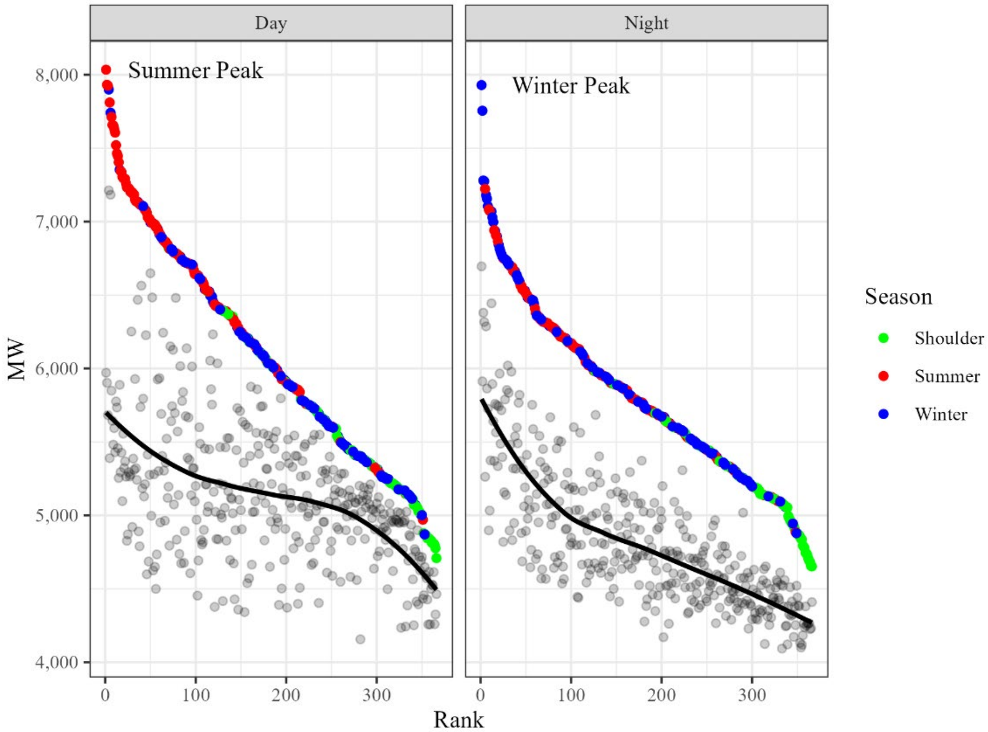
With that context in mind, the balance of my testimony addresses important observations, inputs, and assumptions for the 2025 CPCN Load Forecast to demonstrate its reasonableness in total, not just with respect to economic development load.

ALL CUSTOMERS, NOT JUST DATA CENTERS AND BOSK, WILL CONTINUE TO REQUIRE SIGNIFICANT AMOUNTS OF ENERGY IN ALL HOURS, SEASONS, AND DAYLIGHT CONDITIONS

Q. Please provide the support for your position in the "Highlights" section above that customers will have "significant energy requirements in all hours and seasons, including in non-daylight hours."

A. Given the very high load factors of data centers and BOSK, they will necessarily have virtually unchanging year-round, around-the-clock energy requirements. But the Companies' non-economic-development customers also have significant energy requirements in all hours, daylight conditions, and seasons. In that vein, Figure 6 below shows daily peak and minimum load values in both daylight and non-daylight hours for every day in calendar year 2032, ranked from highest to lowest by daily maximum (maximum values are in color; minimum values are gray):

Figure 6: 2032 Daily Maximum and Minimum Loads During Daylight and Non-Daylight Hours



Note that the values shown in Figure 6 include the effects of distributed generation and energy efficiency. Even accounting for those effects, there are about 2,137 non-daylight hourly demands above 5,000 MW, including a number of which occur in the summer, and more than 433 hourly demands above 6,000 MW, many of which occur in the winter.

Figure 7 below highlights the amount of energy customers use during non-daylight hours, again for calendar year 2032, with approximately 32.7% of summer electricity usage during non-daylight hours and over 53.1% of winter electricity usage during non-daylight hours:[32]

[32] Summer is defined here as the months of June, July, and August, and winter is defined here as the months of December, January, and February.

Figure 7: Proportion of Energy Consumed During Daylight and Non-Daylight Hours (2032)

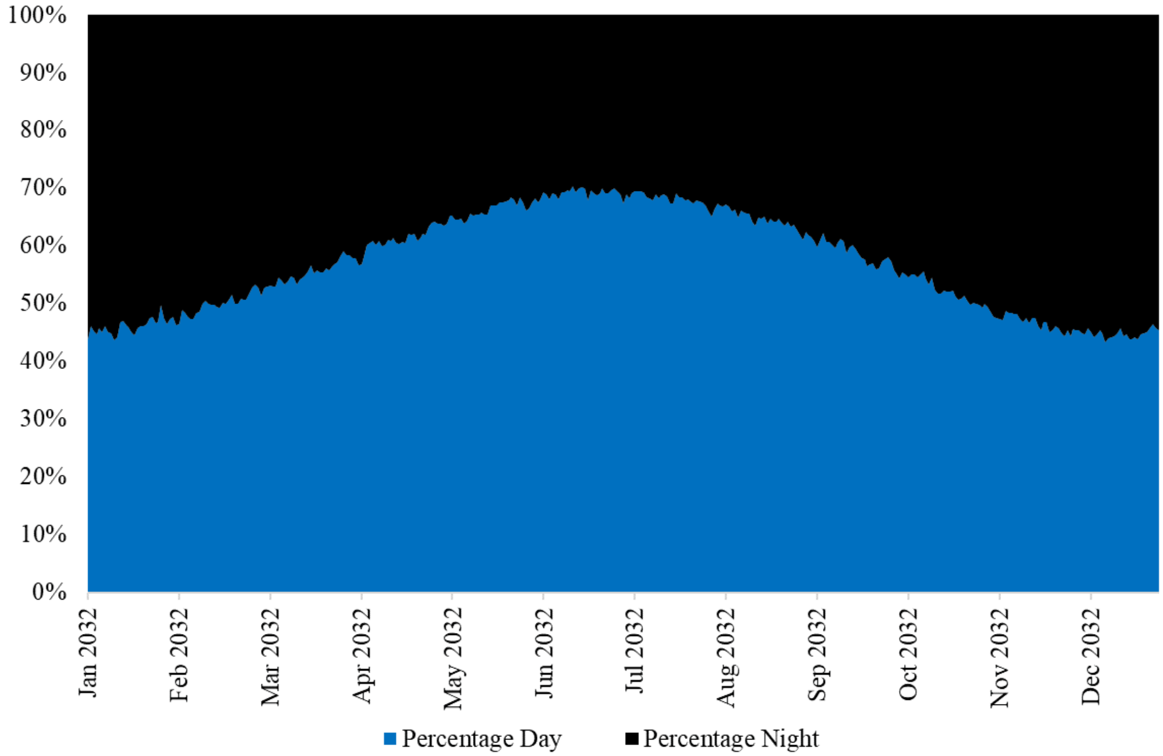


Figure 8 below shows projected hourly demand chronologically in 2032, and Figure **9**9 is a load duration curve of the same data. They show the Companies' combined system hourly peak is 8,034 in 2032, minimum hourly demand is 4,093 MW, and in 2032 there will be 917 hours with demand over 6,500 MW, 3,733 hours with demand over 5,500 MW, and all but 472 hours with demand over 4,500 MW.

Figure 8: LG&E and KU 2032 Hourly Load

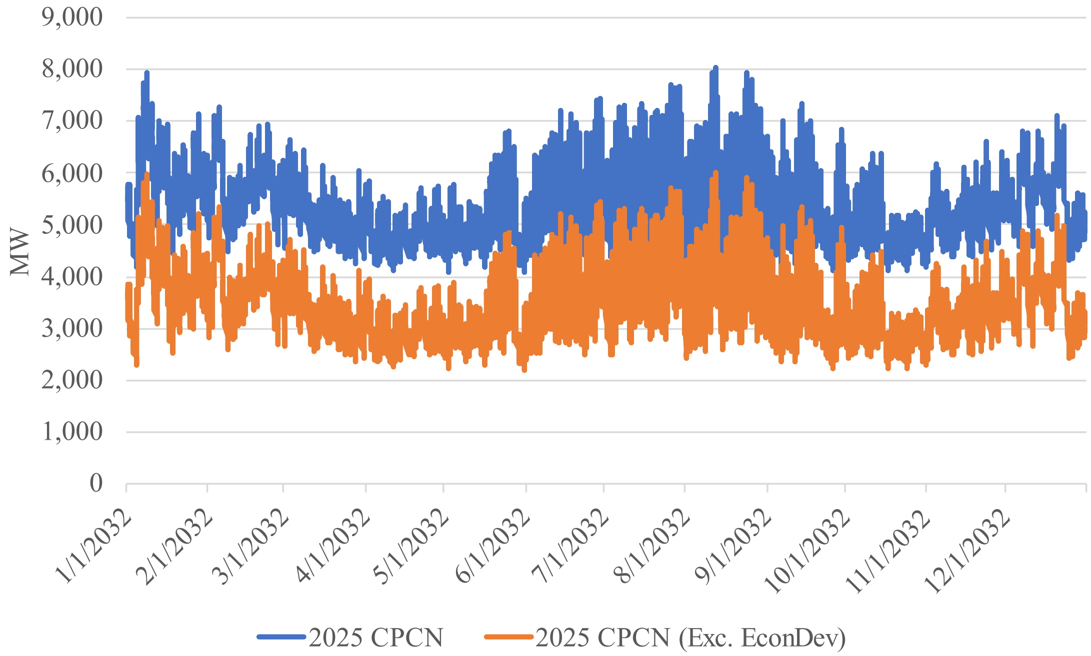
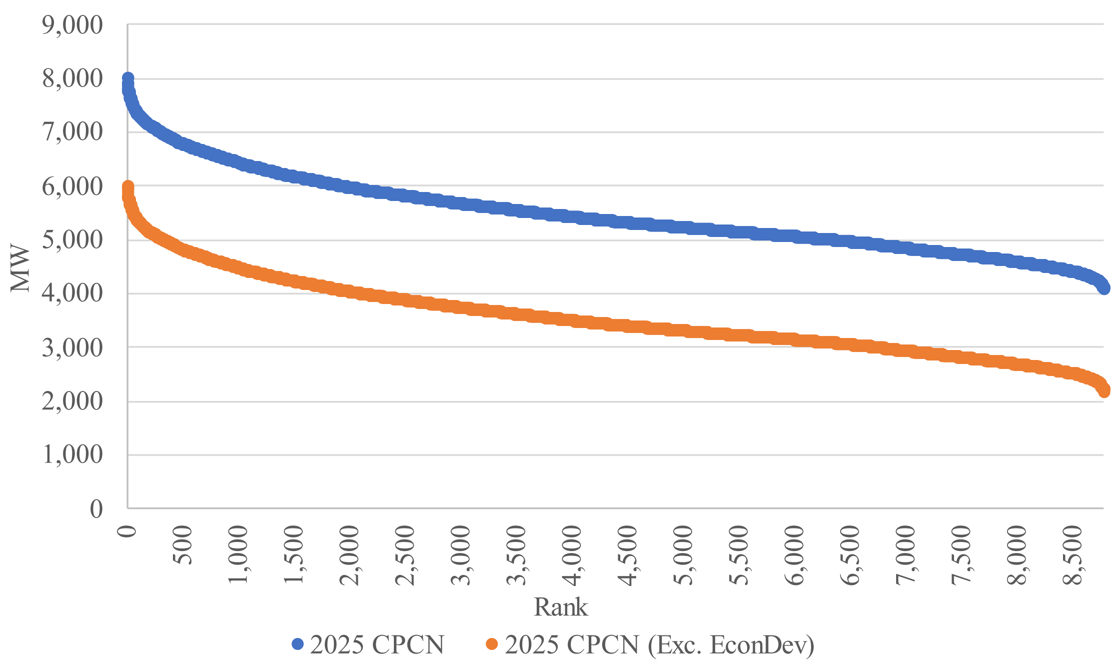


Figure 9: LG&E and KU 2032 Load Duration Curve



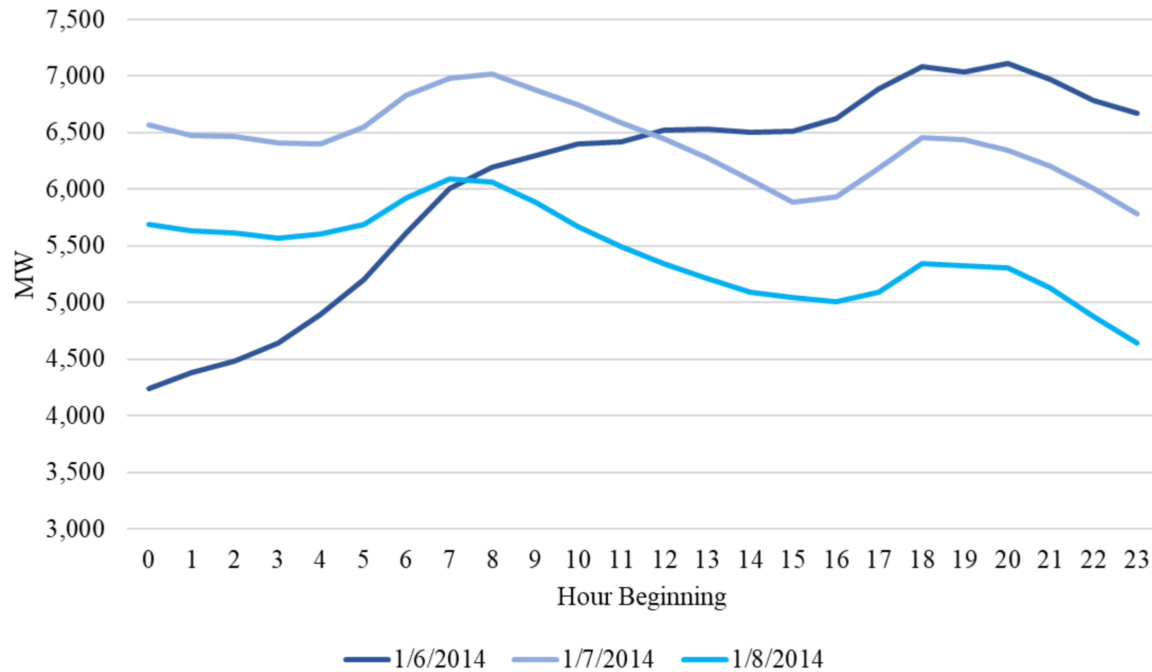
This data shows customers require large amounts of energy at all times, day and night, and in all seasons and weather conditions. It further shows system peak demands can occur in summer or winter and in daylight and non-daylight hours.

Notably, the hourly forecast and charts above assume normal weather and normal weather variability, but customers demand even greater load for a longer duration during extreme weather events. For example, Figure 10 below shows the hourly load profiles of three days during the Polar Vortex of January 2014.[33] During this period, hourly load remained above 6,000 MW for 32 consecutive hours and above 5,000 MW for 65 consecutive hours, and intra-hourly loads were as high as 7,300 MW.[34] The highest loads during this period were observed during non-daylight or very early morning hours.

[33] This includes load from the departed municipal customers. The lowest temperature recorded at the Muhammad Ali International Airport in Louisville during the Polar Vortex was -3 degrees Fahrenheit. On January 19, 1994 during a winter storm event that dumped over a foot of snow in Louisville, the recorded low temperature was -22 degrees Fahrenheit. See https://www.wlky.com/article/archives-unforgettable-snow-shut-down-louisville/30562805.

[34] As noted above, this includes load from the departed municipal customers.

Figure 10: Polar Vortex 2014 Hourly Load Profiles



Again, this demonstrates customers can and do have significant—and sometimes extreme—energy needs for entire days at a time, not just an hour or two.

Importantly, the 2014 Polar Vortex was not an historical aberration. As Charles R. Schram testifies, the Companies reached an hourly peak demand of 6,814 MW just after sunrise on the morning of January 22, 2025, during Winter Storm Enzo.[35] That hourly peak was roughly equivalent to the Companies' 2014 Polar Vortex hourly peak of 7,114 MW after adjusting for the departed KU municipal customers, and it was higher than the roughly 6,600 MW Winter Storm Elliott peak in December 2022 after accounting for the Companies' first-of-its-kind load shedding. Moreover, during Winter Storm Enzo the Companies experienced a stretch of 90 consecutive hours of system load above 5,000 MW (compared to 65 such hours during the 2014 Polar Vortex) and 18 consecutive hours of system load above 6,000 MW (compared to 32

[35] Peak load occurred during the 8:00 a.m. hour. Sunrise that day was 7:55 a.m.

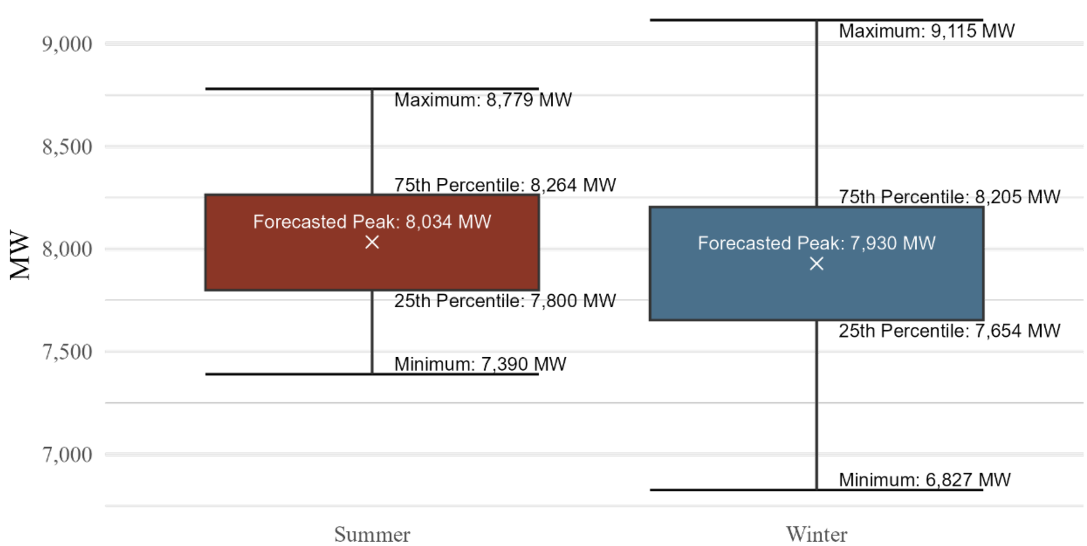
such hours during the 2014 Polar Vortex). Intra-hourly loads during Enzo reached 7,000 MW. Thus, such high winter demands, though not normal per se, are not rare, and the highest such demands tend to occur during non-daylight hours.

<u>OTHER FOUNDATIONAL LOAD FORECAST ASSUMPTIONS AND INPUTS: WEATHER AND ECONOMIC ASSUMPTIONS</u>

Q. What are the other foundational weather and economic assumptions the Companies used in the 2025 CPCN Load Forecast?

A. Consistent with longstanding prior practice, the Companies used 20 years of historical weather data to develop their long-term base energy requirements forecast, which assumes average or "normal" weather in all years. To account for weather variability and support the Companies' Reserve Margin Analysis, the Companies also produced 51 hourly energy requirement forecasts for 2032 based on weather in each of the last 51 years (1973–2023). Figure 1111 shows the resulting distribution of 2032 summer and winter peak demands, and in particular, it shows the variability of winter peak demand:

Figure 11: Distribution of 2032 Summer and Winter Peak Demands



For economic assumptions, the Companies used a reputable forecaster, S&P Global, in forecasting their base energy requirements.[36] For the U.S. overall, S&P Global projected real economic growth of 2.5 percent during 2024. This would result in a 7.1 percent larger economy in 2024 as compared to 2021, and 10.8 percent larger than pre-pandemic 2019 levels. For the 2025-2029 timeframe, real GDP is forecast to increase at an average annual rate of 1.7 percent, below the 2.3 percent rate experienced on average from 2010 to 2019 between the Great Recession and the COVID-19 pandemic.

Regarding Kentucky's economy, S&P Global projected real economic growth of 2.3 percent during 2024, comparable to the U.S. level. For the 2025-2029 period, the state's economy is expected to increase at an average pace of 1.2 percent, slightly below the between-recession average of 1.5 percent. Over the longer term from 2030-2039, S&P Global projects growth to average 1.5 percent.

OTHER FOUNDATIONAL LOAD FORECAST ASSUMPTIONS AND INPUTS: ENERGY EFFICIENCY

Q. Does the 2025 CPCN Load Forecast include significant amounts of energy efficiency?

A. Yes. As I noted above, the 2025 CPCN Load Forecast includes nearly 1,500 GWh of reductions by 2032 from customer-initiated energy efficiency improvements, AMI-related conservation load reduction and ePortal savings, distributed generation, and the energy efficiency effects of the Companies' 2024-2030 DSM-EE Program Plan and the

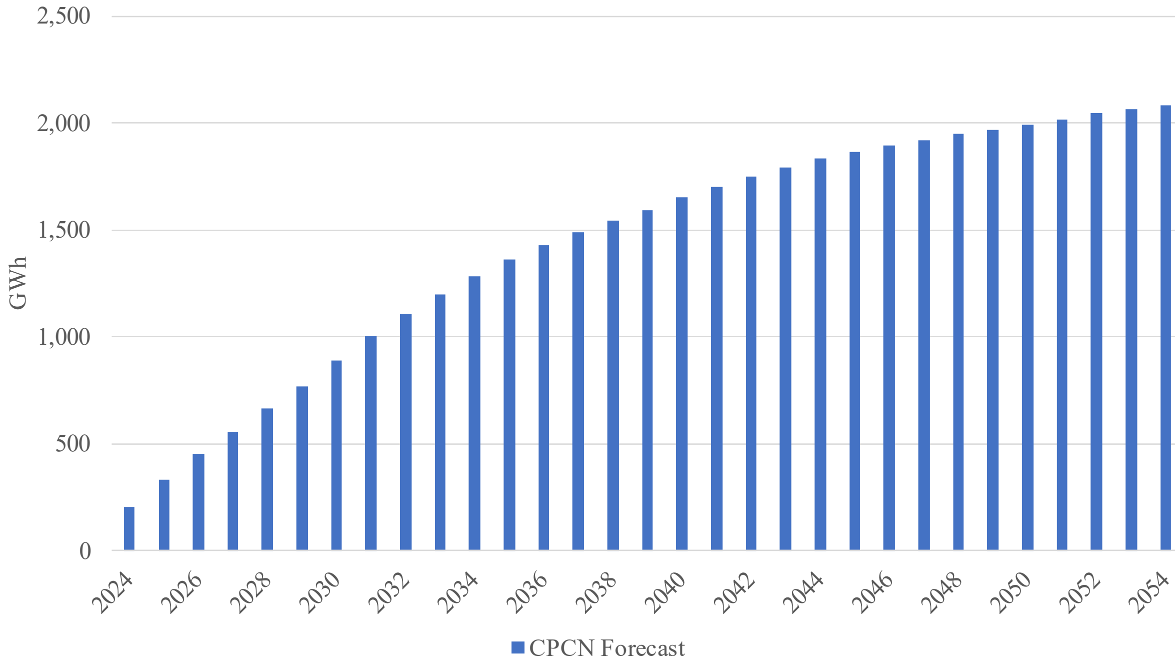
[36] All of the economic assumptions the Companies used are from S&P Global's May 2024 U.S. Economic Outlook. The spreadsheet containing those assumptions is included in the 2025 Load Forecast workpapers, Exhibit TAJ-2. Note that the S&P Global data contains many more assumptions than the Companies' load-forecasting models used.

assumed impacts of DSM-EE programs beyond 2030. These energy-reducing measures also reduce summer peak demand by 230 MW and winter peak demand by 171 MW in 2032. These reductions are in addition to significant reductions observed historically from customers' actions to use electricity more efficiently.

These energy efficiency improvements are not limited to the residential and commercial classes. Prior to 2020, when sales dropped significantly due to the COVID-19 pandemic, industrial sales were declining on average due in part to customer-initiated energy efficiency improvements. Customer-initiated energy efficiency improvements like these are implicitly projected to continue throughout the forecast period.

End-use efficiency improvements are explicitly incorporated in the Companies' residential and commercial forecasts through the statistically adjusted end-use modeling approach described in Exhibit TAJ-1. Figure 1212 below shows the impacts of energy efficiency improvements on the residential and commercial sales forecasts in the forecast scenarios, which improvements are assumed to increase throughout the CPCN planning period.

Figure 12: Impact of Energy Efficiency Improvements on Residential and Commercial Sales Forecast



OTHER FOUNDATIONAL LOAD FORECAST ASSUMPTIONS AND INPUTS: DISTRIBUTED ENERGY RESOURCES

Q. Does the 2025 CPCN Load Forecast reflect the impact of distributed energy resources?

A. Yes, a significant amount of analysis and consideration goes into the distributed generation forecast, which is included in the 2025 CPCN Load Forecast.

Q. How did the Companies determine which distributed energy resources to include in their 2025 CPCN Load Forecast modeling and analysis?

A. The most important single fact driving the Companies' decision to include only solar distributed energy resources in their 2025 CPCN Load Forecast modeling and analysis is this: About 99.8% of all distributed generation installations connected to the Companies' facilities in their service territory are solar. Of the Companies' more than 5,400 distributed generation customers, only 11 have non-solar distributed generation installations (one hydro and ten wind generators). Notably, the Companies' customers have informed the Companies of *zero* new non-solar distributed generation installations in over six years, the most recent being a wind installation in 2018.

Moreover, there is no reason to expect this nearly unanimous preference for solar to change in the foreseeable future. Solar has a superior return on investment ("ROI") compared to other distributed generation technologies. Solar is also often the most practical technology for distributed generation resources. For example, most residences do not have access to hydroelectric or biomass resources, and adding a windmill to a residence may be impracticable for a variety of reasons.

Regarding distributed energy storage, although batteries may be the most feasible of all options in terms of physical location, their ROI is not competitive when compared to solar under the Companies' current rate design.[37] Batteries can only increase total energy consumption for residential customers due to AC-to-DC losses when charging and DC-to-AC losses when discharging. Given that the vast majority of residential customers take service under Rate RS, which has a flat rate per kWh and no demand charge, this can only mean a more expensive energy proposition for the battery alone for most of the Companies' residential customers. For those on residential time-of-day energy rates or net metering, the disparity between the peak and

---

[37] *See, e.g.,* DNV and Z Federal, "Distributed Generation, Battery, and Combined Heat and Power Research – Final Report" at 43 (Mar. 22, 2024) (prepared for U.S. Department of Energy, U.S. Energy Information Administration, Office of Energy Analysis), available at https://www.eia.gov/analysis/studies/buildings/dg_storage_chp/pdf/dg_storage_chp.pdf (accessed Jan. 19, 2025):

> While solar PV benefits from being a familiar option to customers as method of procuring clean energy under favorable economic conditions, battery storage systems are typically not purchased solely on the basis of customer economics. Adoption of battery storage systems by customers is largely dependent on the value the customer places on accessing reliable backup power. Thus, battery storage adoption is more closely linked to the customer's perception and quantification of resiliency needs ….

off-peak rates or the tariff rate and the net metering sellback rate is unlikely to justify the up-front cost. Certainly, that rate difference has not proven to be an incentive for customers to date: Of the 17 customers on the Companies' residential time-of-day rates, 17 are net metering customers and *zero* have battery storage systems.

Putting aside economics, some customers may purchase battery storage as a backup power supply. But if a customer uses a battery solely as a backup power supply, i.e., it discharges only during power outages, by definition it can only increase demand; it can never help reduce demand. Thus, although such a battery can affect the Companies' load forecast, it would be minimal and could only increase the customer's demand and energy requirements.

Regardless, based on the data available to the Companies, batteries have not proven to be particularly attractive to the Companies' customers to date: The Companies' net metering customers had only 2,481 kW of distributed battery storage capacity across 323 installations at the end of 2024, which is only about 6% of the Companies' net metering customer base and less than 0.03% of all customers. The Companies' 6% rate of battery storage attachment to solar installations is neither uncommon nor surprising. According to Berkeley Lab, most states other than Hawaii and California have residential battery attachment rates between 4% and 10% and non-residential battery attachment rates below 2%.[38] That California has a higher than usual residential battery attachment rate (14%) is unsurprising due to state incentive programs to support behind-the-meter storage and because significant differences in

[38] Berkeley Lab, "Tracking the Sun: Pricing and Design Trends for Distributed Photovoltaic Systems in the United States, 2024 Edition" at 20 (Aug. 2024), available at https://emp.lbl.gov/sites/default/files/2024-10/Tracking%20the%20Sun%202024_Report.pdf (accessed Jan. 19, 2025).

time-of-use rates can create high time-arbitrage incentives (e.g., San Diego Gas and Electric Company's ("SDG&E") Schedule DR-SES currently creates an almost \$0.25/kWh difference between on-peak and off-peak summer rates and an almost \$0.32/kWh difference between summer on-peak and "super off-peak" rates).[39] In contrast, KU's residential time-of-day energy rate schedule (Rate RTOD-E) has on-peak and off-peak rates that differ by just over \$0.15/kWh,[40] and KU's standard residential rate (Rate RS) differs from its net metering compensation rate (Rate NMS-2) by about \$0.03/kWh.[41] (Note that KU's on-peak RTOD-E rate (\$0.22466/kWh) is lower than SDG&E's summer and winter "super off-peak" rates, both of which are over \$0.33/kWh.[42]) Thus, there is no reason to expect the Companies' penetration of battery storage would approach California's; rather, as I noted above, the Companies' battery storage attachment rates are in line with most other states.[43]

---

[39] *See* California Public Utilities Commission, "Self-Generation Incentive Program (SGIP): Energy Storage Rebates for Your Home Available NOW" available at https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/news_room/newsupdates/2020/sgip-factsheet-124020.pdf (accessed Jan. 19, 2025) ("The California Public Utilities Commission's (CPUC) Self-Generation Incentive Program (SGIP) offers rebates for installing energy storage technology at both households and non-residential facilities."); San Diego Gas and Electric, "Schedule DR-SES - DOMESTIC TIME-OF-USE FOR HOUSEHOLDS WITH A SOLAR ENERGY SYSTEM Effective 10/1/2024," available at https://www.sdge.com/sites/default/files/regulatory/10-1-24%20Schedule%20DR-SES%20Total%20Rates%20Table.pdf (accessed Jan. 19, 2024). Currently, summer on-peak times are 4:00 p.m. to 9:00 p.m., off-peak times are 6:00 a.m. to 4:00 p.m. and 9:00 p.m. to midnight, and super off-peak times are midnight to 6:00 a.m. https://www.sdge.com/total-electric-rates (accessed Jan. 19, 2025).

[40] Kentucky Utilities Company, P.S.C. No. 20, Fourth Revision of Original Sheet No. 6.

[41] Kentucky Utilities Company, P.S.C. No. 20, Fifth Revision of Original Sheet No. 5; Kentucky Utilities Company, P.S.C. No. 20, Second Revision of Original Sheet No. 58

[42] *Id.*; San Diego Gas and Electric, "Schedule DR-SES - DOMESTIC TIME-OF-USE FOR HOUSEHOLDS WITH A SOLAR ENERGY SYSTEM Effective 10/1/2024," available at https://www.sdge.com/sites/default/files/regulatory/10-1-24%20Schedule%20DR-SES%20Total%20Rates%20Table.pdf (accessed Jan. 19, 2024).

[43] *See also* NREL, "Check the Storage Stack: Comparing Behind-the-Meter Energy Storage State Policy Stacks in the United States" at page v, Figure ES-1 (Aug. 2022) (indicating, according to the report's ranking methodology, Kentucky's behind-the-meter "policy stacking score" placed it almost exactly in the middle of the group of 50 states plus Washington, D.C.), available at https://www.nrel.gov/docs/fy22osti/83045.pdf (accessed Jan. 20, 2025).

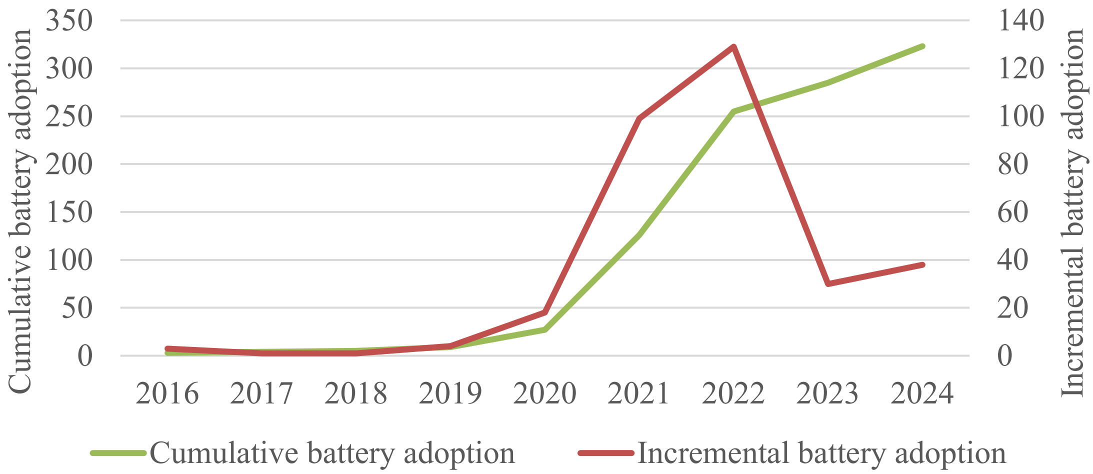
Regarding the customer battery storage systems of which the Companies are aware, the average battery installation size is about 7.7 kW, with sizes ranging from 0.4 to 81.6 kW. The most common installation size is 4.5 kW. Such systems typically have energy storage sufficient to supply about two hours of their maximum continuous output, which is half of the storage per kW the Companies are proposing for their Cane Run BESS (and the Commission-approved Brown BESS).[44] Thus, for the Companies' customers' distributed energy storage to reach the same level of storage capacity as a 100 MW, four-hour utility-scale BESS, such installations would need to increase more than *80 times* their end-of-year 2024 levels.[45]

Figure 1313 below shows the cumulative and incremental number of net metering solar customers with battery installations by year. Notably, after an uptick in 2021 and 2022, incremental battery storage adoption in 2023 significantly decreased. Incremental battery storage adoption was slightly higher in 2024 compared to 2023 but nowhere near the adoption levels seen in 2021 or 2022.

[44] *See, e.g.,* Tesla Powerwall 3 data sheet (showing "up to 11.5 kW of continuous power per unit" and "Nominal Battery Energy" of 13.5 kWh AC), available at https://energylibrary.tesla.com/docs/Public/EnergyStorage/Powerwall/3/Datasheet/en-us/Powerwall-3-Datasheet.pdf (accessed Jan. 20, 2025); Tesla Powerwall 2 data sheet (showing "Real Power, max continuous" of 5 kW and "Usable Energy" of 13.5 kWh AC), available at https://energylibrary.tesla.com/docs/Public/EnergyStorage/Powerwall/2/Datasheet/en-us/Powerwall-2-Datasheet.pdf (accessed Jan. 20, 2025).

[45] As noted above, the Companies are aware of 2,481 kW of distributed battery storage in their service territories. Assuming each such battery is designed to store sufficient energy for two hours of peak output, those batteries have an aggregate storage capacity of 4,962 kWh, i.e., just under 5 MWh. That is less than 1/80th of the 400 MWh of a 100 MW, four-hour utility-scale BESS, and it is less than 1/320th of the proposed 400 MW, four-hour (1,600 MWh) Cane Run BESS.

Figure 13: Incremental and Cumulative Battery Adoption by NM Customers



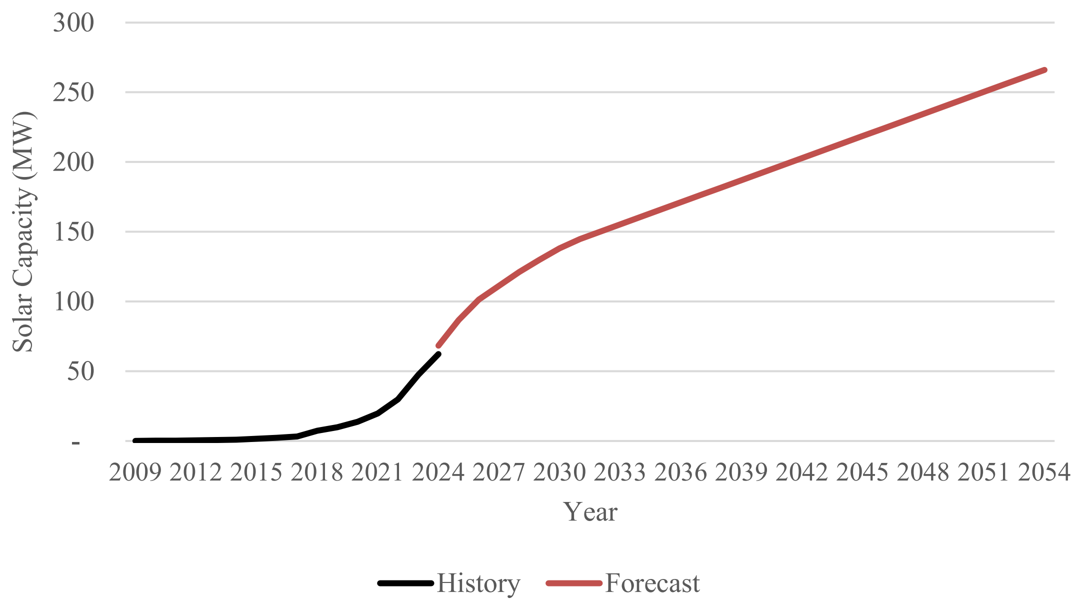
Currently, the Companies do not have access to data concerning how these customers use their batteries, and the Companies lack data as to what extent non-net metering customers have battery storage because there is no mechanism to obtain such data today. But due to the minimal amount of such storage connected to the Companies' grid and the lack of reasons to expect an increase in such storage that might affect load sufficiently to impact resource planning relevant to this proceeding, and because the Companies' load forecast implicitly captures customers' actual deployment and use of such battery storage and assumes the level of battery storage increases with customer growth, the Companies quite reasonably do not explicitly forecast distributed battery adoption, though they will continue to monitor it.

In sum, the Companies do not expect that resources other than distributed solar will materially affect load. Thus, the 2025 CPCN Load Forecast explicitly assumes all distributed generation additions will be solar.

Q. What is the Companies' forecast of distributed generation in the 2025 CPCN Load Forecast?

A. Figure 14Figure 14 below shows the Companies' forecast of distributed generation capacity (net metering and qualifying facilities ("QFs")) for this load forecast. Notably, the Companies project that such capacity will grow from the year-end 2024 level of 67 MW (5,812 customers) to 150 MW (about 14,750 customers) by 2032 and to 266 MW (about 27,000 customers) by 2054.

Figure 14: History and Forecast of Distributed Generation Capacity



The Companies created the net metering forecast reflected in using a consumer choice model in which the ratio of net-metering customers to total residential customers is predicted by the avoided cost-to-LCOE ratio, which is weighted by the potential universe of net-metering customers per company. The Companies forecast behind-the-meter QF customers separately from net metering customers (and net-metering-sized facilities, i.e., QFs not exceeding 45 kW). This includes only those customers served by the Companies, not independent or merchant generators. Historically, the Companies have projected that future numbers of QF customers will be consistent with the historically observed linear trend for the Companies' QF customers to date. The

Companies also typically assume that the forecasted capacity per new QF customer will be the average of current QF installations.

The distributed generation forecast assumes (1) customers receive the applicable retail rate for excess generation, (2) instantaneous netting of usage and generation, and (3) a continuation of the federal investment tax credit for residential customers. After 2025, the forecast shows a slower growth rate due to reaching the 1% cap of the Companies' single hour forecasted peak load, but the additional net metering growth from the "Solar for All" grant from 2025-2030 obscures this trend.[46] After reaching the 1% cap, the payment for excess generation drops to the QF compensation rate. The Companies' models indicate this change will result in a relatively small reduction in the number of customers who choose to install solar and will cause those customers who do install solar less to be likely to overbuild their solar installations relative to their own consumption. This is similar to the Companies' distributed generation forecast approach in the 2022 CPCN-DSM Case.

Q. Why is it reasonable to expect the number of distributed generation customers and amount of capacity the Companies project rather than the higher levels some other states have achieved?

A. As of the end of 2024, about 0.6% of the Companies' residential customers were solar net metering customers. That might seem small compared to certain other states, such as California (about 23% residential solar) and Arizona (about 14% residential solar).[47]

---

[46] The Kentucky Energy and Environment Cabinet was selected in April 2024 to receive $62,450,000 through the Solar for All grant competition to develop solar programs that enable low-income and disadvantaged communities to deploy and benefit from distributed residential solar.

[47] NREL, "Solar Industry Update, Spring 2024" at 36 (May 14, 2024), available at https://www.nrel.gov/docs/fy24osti/90042.pdf (accessed Jan. 8, 2025).

Putting aside state-level policy directives and incentives that might explain part of the difference, as well as wealth and income differences that could affect solar adoption, two significant factors that affect solar adoption and that the Companies reflect in their modeling are the solar resource (which directly affects capacity factor) and electric rates. According to NREL data, nearly all of Kentucky's geography has an annual average daily solar irradiance between 4 and 4.5 kWh/m^2. The vast majority of Arizona's and most of California's geography has an annual average daily solar irradiance greater than 5.25 kWh/m^2, with large portions at or above 5.75 kWh/m^2. These translate into capacity factor ranges of 16.1% to 19.6% for Arizona and California compared to Kentucky's 14.5% to 15.2%. Rates also matter, as shown in the table below:

State	Solar Adoption Rate (% residential customer population)[48]	Average daily solar irradiance (kWh/m2)[49]	Average Residential Electricity Price (cents per kWh)[50]
North Carolina	0.5%	4.5 - 5.4	15.16
Kentucky	0.6%	4 - 4.5	10.35
Maine	0.8%	4 - 4.5	26.39
Vermont	1.5%	< 4.0 – 4.4	22.62
New Jersey	2.0%	4 - 4.5	19.32
Massachusetts	2.3%	4 - 4.5	29.17
Arizona	14%	5.25 and up	13.40
California	23%	5.25 and up	27.66

[48] Annual Electric Power Industry Report, Form EIA-861 detailed data files (2023). https://www.eia.gov/electricity/data/eia861/

[49] US Annual Solar DNI, https://www.nrel.gov/gis/solar-resource-maps.html

[50] Electric Power Monthly, Table 5.6.A. "Average Price of Electricity to Ultimate Customers by End-Use Sector, by State, September 2024 and 2023 (Cents per Kilowatthour)," available at https://www.eia.gov/electricity/monthly/archive/november2024.pdf (accessed Jan. 16, 2025).

With higher solar irradiance and rates, it is unsurprising that Arizona and California have much higher rates of residential solar deployment. In contrast, states with solar irradiance and rates more comparable to Kentucky, such as North Carolina, have solar deployment closer to that of Kentucky. For these reasons, it is unlikely that Kentucky solar will reach California's or Arizona's levels of solar penetration, and the 2025 CPCN Load Forecast's projection that about 2.8% of residential customers in the Companies' service territory will install solar by 2054 is reasonable.

OTHER FOUNDATIONAL LOAD FORECAST ASSUMPTIONS AND INPUTS: ELECTRIC VEHICLES

Q. Does the electric load forecast reflect the impact of EVs?

A. Yes. From 2017 to 2023, the estimated number of EVs in operation in the Companies' service territories grew by an average of 43% per year from 1,415 to 12,284.[51] The Companies forecast EVs-in-operation will increase to over 57,633 by 2032 and to over 553,667 by the end of 2054. For reference, the Companies' EV forecast assumes the total number of cars in the Companies' service territory by 2054 will be around 1.9 million, with roughly 29% of those cars being EVs.

Like distributed solar generation, the future penetration of EVs is a key forecast uncertainty as it has the potential to increase energy requirements, particularly in the non-daylight hours. The Companies' EV forecast model considers historical adoption of EVs, the comparison of EV to internal combustion engine vehicle costs, and the total number of cars possible in the service territory, but it is unable to account for sudden technological innovation that could cause a dramatic shift from historical adoption

[51] An EV is defined for this purpose as a vehicle that is plugged in and charged by electricity. This means all-electric vehicles or plug-in hybrids.

patterns. The EV forecast also does not account for potential supply chain issues stemming from electricity laws and incentives passed or in the process of being passed in other states. For example, as of September 2024, California, Colorado, Delaware, Maryland, Massachusetts, New Jersey, New York, Oregon, Rhode Island, Vermont, Virginia, and Washington have adopted Advanced Clean Cars II regulations, which require vehicle manufacturers to deliver for sale all new cars and passenger trucks with an ultimate plan that requires zero-emissions by 2035.[52] This increased demand for EVs in those states may limit their availability for purchase in Kentucky.

The primary factors impacting electricity consumption by EVs are the number of EVs in the Companies' service territories and the distance driven per vehicle, though resource planning considerations for EVs focus less on these factors and more on the way customers charge their vehicles. If EVs are charged early in the evenings (e.g., when customers get home from work), EV charging could exacerbate summer and winter peak energy requirements and potentially create the need for additional peaking capacity or load control programs. The Companies' load forecast assumes primarily overnight EV charging that occurs at residences and has minimal impact on projected seasonal peak loads, as shown in the figures below:

[52] Rhode Island Department of Environmental Management, "Advanced Clean Cars II (ACCII) & Advanced Clean Trucks (ACT) Informational Fact Sheet," available at https://dem.ri.gov/sites/g/files/xkgbur861/files/2024-09/ACCIIACT%20Factsheet%20%282%29.pdf#:~:text=What%20other%20states%20have%20adopted%20ACCII%20and/or,adopted%20the%20Advanced%20Clean%20Cars%20II%20regulations. (accessed Feb. 12, 2025). *See also* https://ww2.arb.ca.gov/our-work/programs/advanced-clean-cars-program/about (accessed Feb. 16, 2025).

Figure 15: Managed EV Charging Profile Compared to 2032 Summer Peak

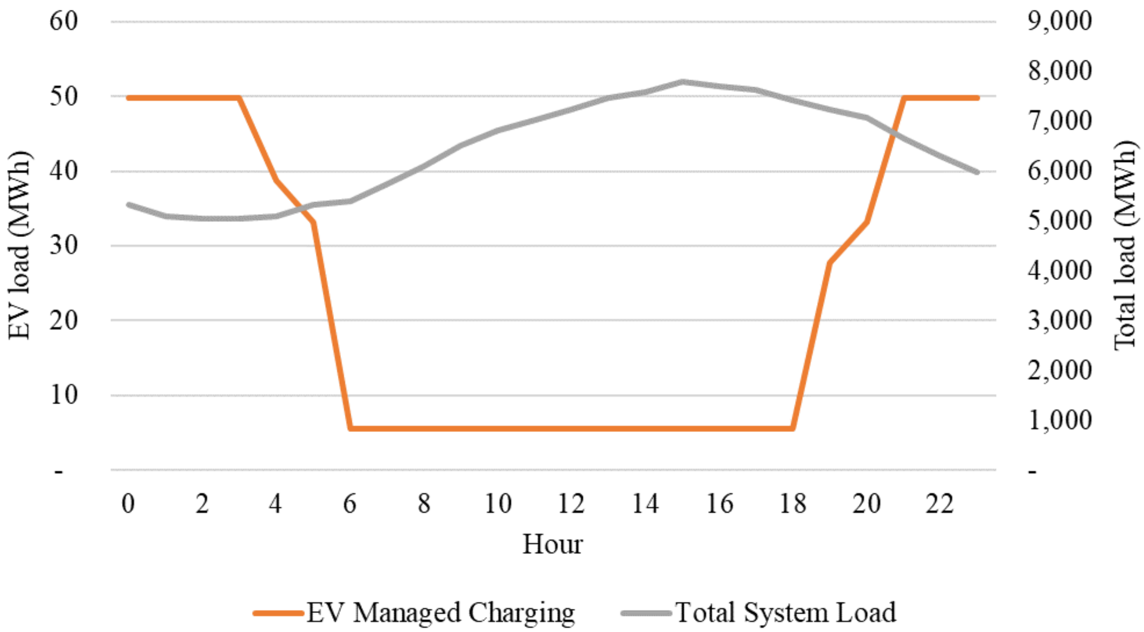
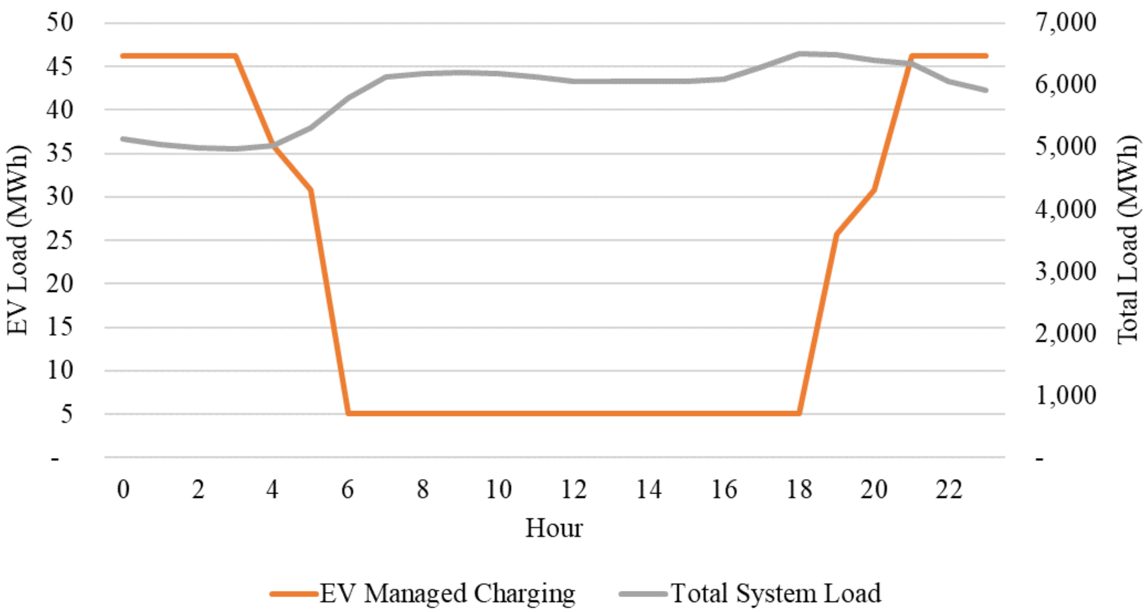


Figure 16: Managed EV Charging Profile Compared to 2032 Winter Peak

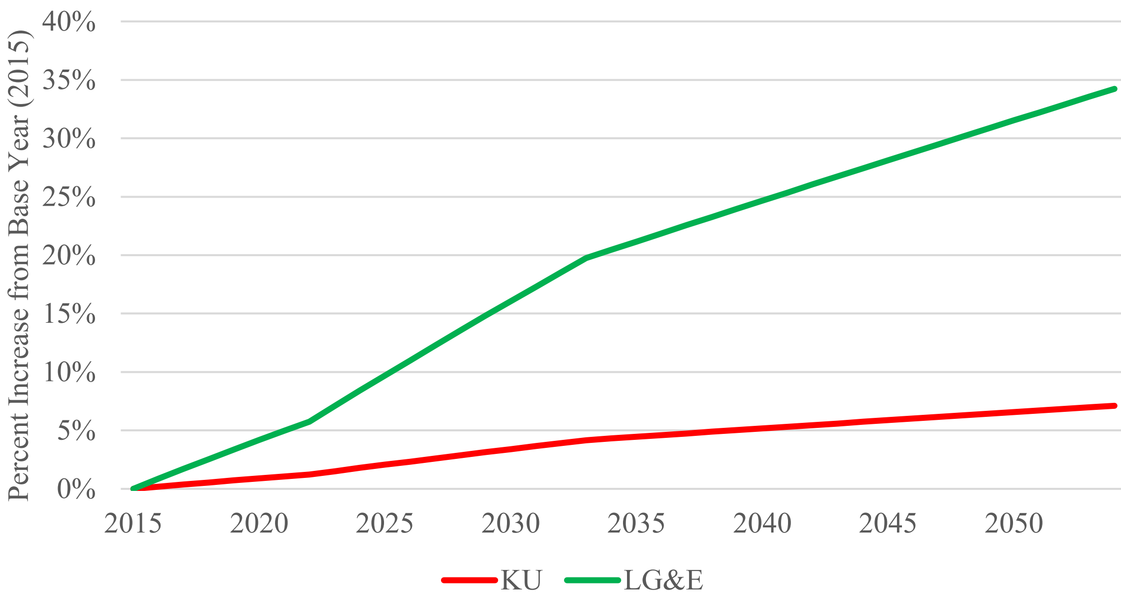


<u>OTHER FOUNDATIONAL LOAD FORECAST ASSUMPTIONS AND INPUTS: SPACE HEATING ELECTRIFICATION</u>

Q. How did the Companies account for space heating electrification in the 2025 CPCN Load Forecast?

A. In this load forecast, the Companies assumed new customers would have electric heating penetrations comparable to the average of such penetrations for new customers in 2011 through 2022, which is about 69% for KU and 46% for LG&E (compared to 59% and 21%, respectively, for residential customers added in 2010 or earlier). Although the load forecast further assumes a small portion of existing premises will switch from gas to electric, the vast majority of the projected change in electric space heating, shown in Figure 17 below as an index to 2015 as the base year, results from increased electric heating penetrations in new construction, not changes to heating sources in existing homes. Unsurprisingly, the percentage increase in LG&E is higher because a much smaller percentage of customers have electric heating today as compared to the KU service territory.

Figure 17: Space Heating Saturation Percentage Change by Company



<u>OTHER FOUNDATIONAL LOAD FORECAST ASSUMPTIONS AND INPUTS: AMI, CUSTOMER GROWTH, AND PRICE ELASTICITY OF DEMAND</u>

Q. Did the Companies consider AMI-related benefits in the 2025 CPCN Load Forecast?

A. Yes. The forecast assumes that two AMI-related measures, namely CVR and AMI-related ePortal savings, will reduce energy requirements. By 2032, CVR reduces annual sales by 205 GWh, and AMI-related ePortal reductions are approximately 56 GWh.

Q. How did the Companies account for customer growth in their load forecast?

A. The residential customer growth rate in the load forecast is just over 0.5% per year, which is slightly more pessimistic than the Companies' customer growth trends for more than a decade but is consistent with S&P Global Household projections for Kentucky.[53] A potential for upside for Kentucky's economy is rapid growth in the state's housing market. S&P Global is forecasting total housing starts in Kentucky to be the eighteenth highest in the United States during 2024. Moreover, the forecasted 2024-2039 growth rate averages tenth in the US as compared to the average rate over the previous ten years. The growth has been centered in and around the state's largest metro areas of Louisville and Lexington, a trend that is expected to continue. Louisville in particular has seen rapid growth in multifamily housing with new monthly multifamily housing permits nearly doubling in the July 2023 to June 2024 period compared to July 2011 to June 2019. Elizabethtown has also shown significant growth in multifamily housing with more new multifamily housing permits from January 2023 to June 2024 than in the entirety of the 2011-2019 period.

Q. Did the Companies consider the price elasticity of demand in the load forecast?

[53] *See* Exh. TAJ-2 for S&P Global Household projections for Kentucky.

A. Yes. The Companies' forecast models incorporate class-specific estimates of price elasticity between -0.1 and -0.15, which are supported by estimates from both the EIA and energy consultant Itron.[54]

The load forecasting process explicitly contemplates short-run price elasticity of demand via statistically adjusted end-use models, and the Companies continue to incorporate distributed solar and electric vehicle forecasts into their load forecast. The Companies continue to view this delineation as appropriate and necessary given the hourly load profiles of these technologies. The 2025 CPCN Load Forecast represents the Companies' view of the most likely development of end-use saturations and efficiencies, electric vehicle adoption, distributed energy resources, and economic conditions in the service territory, all of which are impacted by electricity prices.

THE COMPANIES HAVE REASONABLY ACCOUNTED FOR KNOWN UNCERTAINTIES IN THE 2025 CPCN LOAD FORECAST

Q. In sum, have the Companies reasonably accounted for known uncertainties in the 2025 CPCN Load Forecast?

A. Yes. There are always known and unknown uncertainties associated with any forecast, including this one. Among the known uncertainties that could result in greater demand and energy requirements than forecast here are greater than anticipated data center or other economic development load growth and greater or more rapid EV adoption, customer growth, and space heating electrification. Again, the timing of EV charging is also important, and this uncertainty does not have a balanced risk; they would all result in higher load than is forecast.

[54] Price Elasticity for Energy Use in Buildings in the United States –January 2021 (EIA). https://www.eia.gov/analysis/studies/buildings/energyuse/pdf/price_elasticities.pdf.

Uncertainties that could cause lower demand and energy requirements than forecast here include greater or more rapid adoption of distributed generation or energy efficiency, as well as slower economic development or even the loss of existing industrial or commercial load.

The 2025 CPCN Load Forecast reasonably addresses all of these uncertainties, and it provides the Companies' best forecast of customers' future needs based on information available today.

CONCLUSION

Q. Is the Companies' 2025 CPCN Load Forecast reasonable and reliable for resource planning purposes?

A. Yes. The Companies' 2025 CPCN Load Forecast is a reasonable forecast of customers' hourly energy needs for the next 30 years. Regarding the Companies' existing customers, it is a load forecast very similar to the Companies' 2022 CPCN Load Forecast that the Commission explicitly found reasonable in several respects and did not find unreasonable in any respect just over a year ago. The Companies' forecast of economic development load is also reasonable, and perhaps conservative, projecting that a fraction of the more than 6,000 MW of such load currently in the Companies' economic development queue will ultimately locate in the Companies' service territories. It demonstrates that customers will continue to have robust demand and energy requirements in all hours and all seasons, day and night. Therefore, I conclude that the 2025 CPCN Load Forecast is reliable for resource planning purposes.

Q. What is your recommendation to the Commission?

A. I recommend the Commission accept the 2025 CPCN Load Forecast as reasonable and reliable for making resource decisions in this case.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Tim A. Jones**, being duly sworn, deposes and says that he is Manager – Sales Analysis and Forecast for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Tim A. Jones

Tim A. Jones

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 12th day of February 2025.

Caroline J. Davison

Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

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

APPENDIX A

Tim A. Jones
Senior Manager Sales Analysis and Forecasting
LG&E and KU Services Company
2701 Eastpoint Parkway
Louisville, Kentucky 40223

Employment

LG&E and KU Energy

Senior Manager Sales Analysis and Forecasting	Dec. 2024 – present
Manager of Sales Analysis and Forecasting	June 2019 – Dec. 2024
Energy Analyst III, Sales Analysis & Forecasting	June 2016 – June 2019

Schneider Electric

Manager, Data Processing	Aug. 2014 – May 2016
Manager, Data Analysis	Apr. 2012 – Aug. 2014
Senior Data Analyst	Mar. 2010 – Apr. 2012
Data Analyst	Apr. 2007 – Mar. 2010
Sourcing Analyst	July 2006 – Apr. 2007
Regulated Markets Analyst	Feb. 2005 – July 2006

Education

Bellarmine University

Bachelor of Science in Mathematics	Dec. 2004

Civic Activities

National Kidney Foundation

Golf Scramble Committee Member	Nov. 2013 – June 2018

Exhibit TAJ-1

Electric Sales and Demand Forecast Process

PPL companies

Sales Analysis & Forecasting
February 2025

Table of Contents

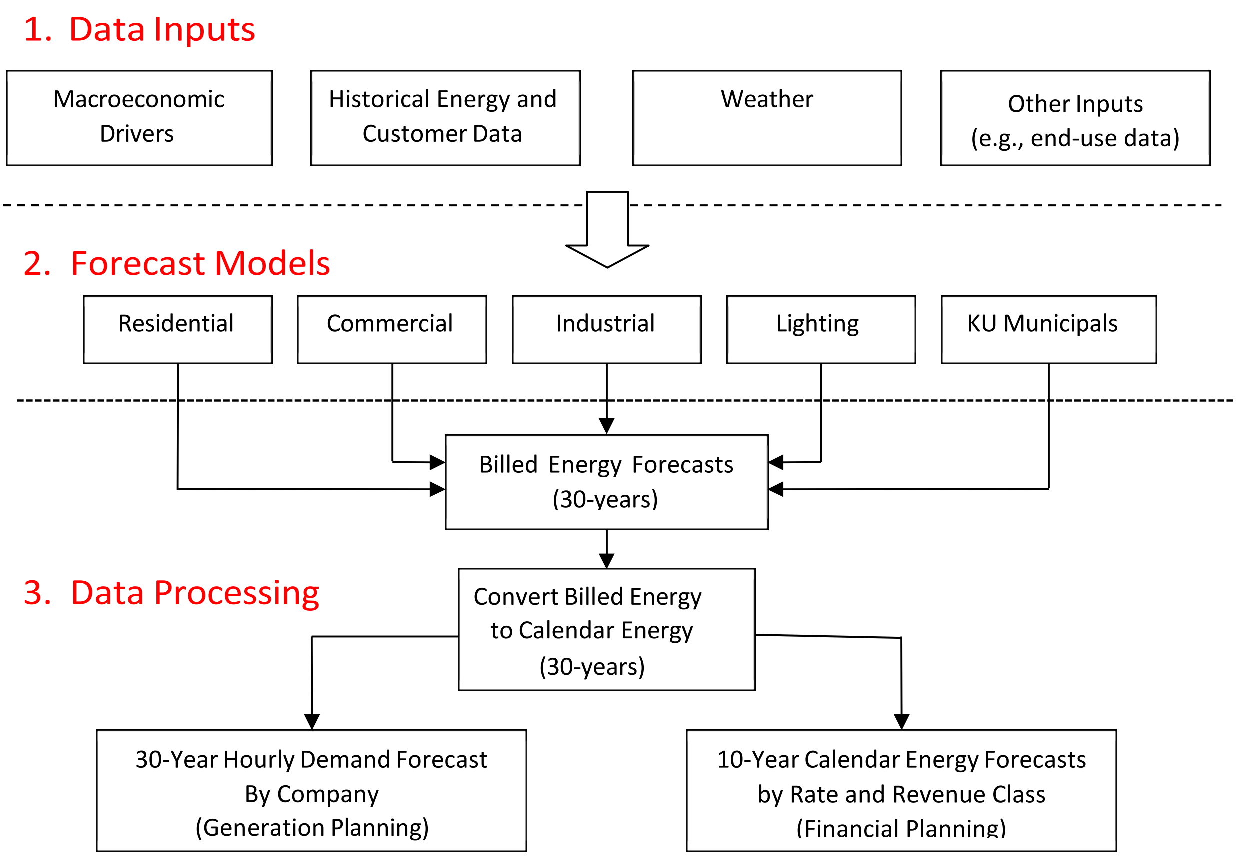
1 Introduction 3
2 Software Tools 5
3 Input Data 6
3.1 Processing of Weather Data 7
3.1.1 Historical Weather by Billing Period 7
3.1.2 Normal Weather by Billing Period 7
4 Forecast Models 9
4.1 Residential Forecasts 9
4.1.1 Residential Customer Forecasts 10
4.1.2 Residential Use-per-Customer Forecasts 10
4.2 Commercial and Industrial Forecasts 11
4.2.1 General Service Forecasts 13
4.2.2 KU Secondary Forecast 13
4.2.3 KU All-Electric School Forecast 13
4.2.4 ODP School Service Forecast 14
4.2.5 LG&E Secondary Forecast 14
4.2.6 LG&E Special Contract Forecast 14
4.2.7 ODP Secondary Forecast 14
4.2.8 ODP Municipal Pumping Forecast 14
4.2.9 KU Primary Forecast 14
4.2.10 KU Retail Transmission Service Forecast 14
4.2.11 KU Fluctuating Load Service Forecast 14
4.2.12 LG&E Primary Forecast 15
4.2.13 LG&E Retail Transmission Service Forecast 15
4.2.14 ODP Industrial Forecast 15
4.3 KU Municipal Forecasts 15
4.4 Lighting and EV Charging Forecasts 15
4.5 Distributed Solar Generation Forecast 16
4.6 Electric Vehicle Forecast 16
4.7 Advanced Metering Infrastructure (“AMI”) Benefits 17
4.7.1 Conservation Voltage Reduction (“CVR”) 17
4.7.2 AMI ePortal Savings 17
4.8 Billed Demand Forecasts 17
5 Data Processing 18
5.1 Billed-to-Calendar Energy Conversion 18
5.2 Hourly Energy Requirements Forecast 19
5.2.1 Normal Hourly Energy Requirements Forecast 19
5.2.2 Weather-Year Forecasts 20
6 Review 22

1 Introduction

The Sales Analysis & Forecasting group develops the sales and demand forecasts for Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies"). This document summarizes the processes used to produce the sales and demand forecasts.

The forecast process can be divided into three parts (see Figure 1). The first part of the forecast process involves gathering and processing input data. Key inputs to the forecast process include macroeconomic, historical energy, customer, weather, and end-use appliance shares and efficiencies data.

Figure 1: Load Forecasting Process Diagram



In the second part of the forecast process, input data is used to specify several forecast models for each company.[1] Generally, each model is used to forecast energy sales for a group of customers with homogeneous energy-use patterns within the same or similar tariff rates. Most of the forecast models

[1] Model specification is the process of determining what variables are appropriate to include or exclude from a statistical model.

produce monthly energy forecasts on a billed basis.[2] In the third part of the forecast process, the billed energy forecasts are allocated to calendar months and then to rate and revenue classes for the Financial Planning department.[3] In addition, a forecast of hourly energy requirements is developed for the Generation Planning department.[4]

At many points during the forecast process, the results are reviewed to ensure they are reasonable. For example, the new forecast is compared to (i) the previous forecast and (ii) weather-normalized actual sales for the comparable period in prior years. Each part of the forecast process and the software tools used to produce the forecast are discussed in more detail in the following sections.

[2] Customers are assigned to one of 20 billing portions. This is discussed further in Section 7.

[3] Rate class defines the tariff assigned to each customer meter while Revenue class is a higher-level grouping; a Revenue class consists of one or more rate classes.

[4] Energy requirements are equal to sales plus transmission and distribution losses.

2 Software Tools

The following software packages are used in the forecast process:

1. Microsoft Office
2. R
3. SAS
4. Metrix ND (Itron)

SAS, R, and Metrix ND are used to specify forecast models. Microsoft Office is primarily used for analysis and presentations.

3 Input Data

Table 1 provides a summary of data inputs. The sections that follow describe key processes used to prepare the data for use in the forecast process.

Table 1: Summary of Forecast Data Inputs

Data	Source	Format
State Macroeconomic and Demographic Drivers (e.g., Employment, Wages, Households, Population)	S&P Global[5]	Annual or Quarterly by County – History and Forecast
National Macroeconomic Drivers	S&P Global	Annual or Quarterly – History and Forecast
Personal Income	S&P Global	Annual by County
Weather	National Oceanic and Atmospheric Administration ("NOAA")	Daily HDD/CDD Data and Hourly Solar Irradiance by Weather Station – History
Billing Portion Schedule	Revenue Accounting	Monthly Collection Dates – History and Forecast
Appliance Saturations/Efficiencies	Energy Information Administration ("EIA"), Itron	Annual – History and Forecast
Structural Variables (e.g., dwelling size, age, and type)	EIA, Itron	Annual – History and Forecast
Elasticities of Demand	EIA and Historical Data	Annual – History
Billed Sales History	CCS Billing System	Monthly by Service Territory and Rate Group
Number of Customers History	CCS Billing System	Monthly by Service Territory and Rate Group
Energy Requirements History	Energy Management System ("EMS")	Hourly Energy Requirements by Company
Annual Loss Factors	2012 Loss Factor Study (by Management Applications Consulting, Inc.) and Historical Data	Annual Average Loss Factors by Company
Solar Installations	CCS Billing System, National Renewable Energy Laboratory ("NREL"), S&P Global	Monthly Net Metering and Qualifying Facility Customers, Private Solar Costs

[5] Formerly known as IHS Markit.

Electric Vehicles	S&P Global, Bloomberg New Energy Finance ("BNEF"), NREL, Electric Power Research Institute ("EPRI"), EIA, Kelley Blue Book	Monthly Cars on Road (historical), Monthly Cars on Road (forecast), Hourly EV Charging Shapes

3.1 Processing of Weather Data

Weather is a key explanatory variable in the electric forecast models. The weather dataset from NOAA's National Climatic Data Center ("NCDC") contains temperature (maximum, minimum, and average), heating degree days ("HDD"), and cooling degree days ("CDD") for each day and weather station over the past 20+ years. This data is used to create (a) a historical weather series by billing period, (b) a forecast of "normal" weather by billing period.[6] Each of these processes is summarized below.

3.1.1 Historical Weather by Billing Period

The process used to create the historical weather series by billing period consists of the following steps:

1. Using historical daily weather data from the NCDC, sum the HDD and CDD values by billing portion. Each historical billing period consists of 20 portions. The Companies' historical meter reading schedule contains the beginning and ending date for each billing portion.
2. Average the billing portion total HDDs and CDDs by billing period.

3.1.2 Normal Weather by Billing Period

The Companies' process to produce their forecast of normal weather by billing period starts with producing a daily forecast of normal weather.[7] The Companies' process for developing their daily forecast (summarized below in Steps 2-5) is consistent with the process the NCDC uses to create its daily normal weather forecast.[8] The Companies' process to create their forecast of normal weather by billing period consists of six steps:

1. Compute the forecast of normal monthly weather by *calendar* month by averaging monthly degree-day values over the period of history upon which the normal forecast is based. The normal weather forecast is based on the most recent 20-year historical period. Therefore, the normal HDD value for January is the average of the 20 January HDD values in this period.
2. Compute "unsmoothed" daily normal weather values by averaging temperature, HDDs, and CDDs by calendar day. The unsmoothed normal temperature for January 1st, for example, is computed as the average of the 20 January 1st temperatures in the historical period. This process excludes February 29.
3. Smooth the daily values using a 30-day moving average centered on the desired day. The

[6] "Normal" weather is defined as the average weather over a 20-year historical period. The Companies do not attempt to forecast any trends in weather.
[7] Weather data in the electric forecast is taken from the weather stations at the Louisville Muhammad Ali International Airport (LG&E), Blue Grass Airport (KU), and Tri-Cities Airport (ODP).
[8] The NCDC derives daily normal values by applying a cubic spline to a specially prepared series of the monthly normal values.

"smoothed" normal temperature for January 1st, for example, is computed as the average of the unsmoothed daily normal temperatures between December 16th and January 15th.

4. Manually adjust the values in Step 3 so that the following criteria are met:
    1. The sum of the daily HDDs and CDDs by month should match the normal monthly HDDs and CDDs in Step 1.
    2. The daily temperatures and CDDs should be generally increasing from winter to summer and generally decreasing from summer to winter. The daily HDD series should follow a reverse trend.

    These criteria ensure the daily normal series is consistent with the monthly normal series.
5. Sum the HDD and CDD values by billing portion. The Companies' forecast meter reading schedule contains the beginning and ending date for each billing portion through the end of the forecast period. Use only historical weather that has actually occurred on February 29th when billing portions include leap days.
6. Average the billing portion totals by billing period.

4 Forecast Models

LG&E and KU's electricity sales forecasts are developed primarily through econometric modeling of energy sales by rate class, but also incorporate specific intelligence on the prospective energy requirements of the utilities' largest customers. Econometric modeling captures the observed statistical relationship between energy consumption – the dependent variable – and one or more independent explanatory variables such as the number of households or the level of economic activity in the service territory. Forecasts of electricity sales are then derived from a projection of the independent variable(s).

This widely accepted approach can readily accommodate the influences of national, regional, and local (service territory) drivers of electricity sales. This approach may be applied to forecast the number of customers, energy sales, or use-per-customer. The statistical relationships will vary depending upon the jurisdiction being modeled and the class of service.

The LG&E sales forecast comprises one jurisdiction: Kentucky-retail. The KU sales forecast comprises three jurisdictions: Kentucky-retail, Virginia-retail (served by KU in Virginia as Old Dominion Power Company, "ODP"), and FERC-wholesale.[9] Within the retail jurisdictions, the forecast typically distinguishes several classes of customers including residential, commercial, public authority, and industrial.

The econometric models used to produce the forecast must pass two critical tests. First, the explanatory variables of the models must be theoretically appropriate and widely used in electricity sales forecasting. Second, the inclusion of these explanatory variables must produce statistically significant results that lead to an intuitively reasonable forecast. In other words, the models must be theoretically and empirically robust to explain the historical behavior of the Companies' customers. These forecast models are discussed in detail in the following sections.

4.1 Residential Forecasts

The Companies develop a residential forecast for each service territory. For the KU and LG&E (also referred to herein as "LE") service territories, the residential forecast includes all customers on the Residential Service ("RS"), Residential Time of Day ("RTOD"), and Volunteer Fire Department ("VFD") rate schedules. The ODP (also referred to herein as "OD") Residential forecast includes all customers on the RS rate schedule.[9] Residential sales are forecast for each service territory as the product of a customer and a use-per-customer forecast. See Table 2 for a summary:

[9] For the purposes of this document, the KU service territory comprises KU's Kentucky-retail and FERC-wholesale jurisdictions. The ODP service territory comprises the Virginia-retail jurisdiction.

Table 2: Residential Forecast Models and Rates

Forecast Model	Rate	Billing Determinants
KU_RS	KU Residential Service KU Residential Time-of-Day Energy Service KU Residential Time-of-Day Demand Service KU Volunteer Fire Department	Customers, Energy, Billed Demand
LE_RS	LE Residential Service LE Residential Time-of-Day Energy Service LE Residential Time-of-Day Demand Service LE Volunteer Fire Department	Customers, Energy, Billed Demand
OD_RS	OD Residential Service	Customers, Energy

4.1.1 Residential Customer Forecasts

The number of residential customers is forecast by service territory as a function of the number of forecast households or population in the service territory. Household and population data by county and Metropolitan Statistical Area ("MSA") is available from S&P Global.

4.1.2 Residential Use-per-Customer Forecasts

Average use-per-customer is forecast using a Statistically-Adjusted End-Use ("SAE") Model. The SAE model combines econometric modeling with traditional end-use modeling. The SAE approach defines energy use as a function of energy used by heating, cooling, and other equipment.

Use-per-Customer = a1*XHeat + a2*XCool + a3*XOther

Inputs for developing the heating, cooling, and other variables include weather (HDDs and CDDs), appliance saturations, efficiencies, and economic and demographic variables such as income, population, members per household, and electricity prices. Once the historical profile of these explanatory variables has been established, a regression model is specified to identify the statistical relationship between changes in these variables and changes in the dependent variable, use-per-customer. A more detailed discussion of each of these components and the methodology used to develop them is contained in Appendix B.

The load forecast uses EIA/Itron inputs that are projections of end-use efficiencies and adjusted electric space heating saturations over time. It is very difficult to determine which reductions in the history occurred because of DSM programs and which occurred because of customer-initiated efficiency gains. Because of this, historical data used in the residential and general service models is not adjusted for previous or current non-dispatchable demand side management and energy efficiency ("DSM-EE") programs, so the forecasts incorporate both customer-initiated energy efficiency in addition to impacts of utility DSM programs moving forward.

Through rebates, tax incentives, or credits, the Inflation Reduction Act ("IRA") is another mechanism to accelerate energy efficiency. The IRA is incorporated in the EIA/Itron projections of end-uses.

4.2 Commercial and Industrial Forecasts

Table 3 and Table 4 list the rate schedules included in the commercial and industrial forecasts. A relatively small number of the Companies' largest industrial customers account for a significant portion of total industrial sales, and any economic development opportunities, expansion, or reduction in operations by these customers can significantly impact the Companies' load forecast. Because of this, sales are forecast based on information obtained through direct discussions with these customers, their key account managers, and the economic development team. During these discussions, the customers are given the opportunity to review and comment on the usage and billed demand forecasts that the Companies create for them. This first-hand knowledge of the utilization outlook for these companies allows the Companies to directly adjust sales expectations. The following sections summarize the Companies' commercial and industrial forecasts.

Table 3: Commercial Forecast Models and Rates

Forecast Model	Rate	Billing Determinants
KU_GS	KU General Service single-phase service KU General Service three-phase service KU General Time-of-Day Energy single-phase service KU General Time-of-Day Energy three-phase service KU General Time-of-Day Demand single-phase service KU General Time-of-Day Demand three-phase service	Customers, Energy
LE_GS	LE General Service single-phase service LE General Service three-phase service LE General Time-of-Day Energy single-phase service LE General Time-of-Day Energy three-phase service LE General Time-of-Day Demand single-phase service LE General Time-of-Day Demand three-phase service	Customers, Energy
OD_GS	OD General Service single-phase service OD General Service three-phase service	Customers, Energy
KU_AES	KU All Electric School single-phase service KU All Electric School three-phase service	Customers, Energy
OD_SS	OD School Service[10]	Customers, Energy, Billed Demand
KU_Sec	KU Power Service Secondary KU Time-of-Day Secondary Service	Customers, Energy, Billed Demand
LE_Sec	LE Power Service Secondary LE Time-of-Day Secondary Service	Customers, Energy, Billed Demand
OD_Sec	OD Power Service Secondary OD Time-of-Day Secondary Service	Customers, Energy, Billed Demand

[10] OD School Service rate is a collection of six smaller rates, which are OD School Service General Service Single-Phase, OD School Service General Service Three-Phase, OD School Service Power Service Primary, OD School Service Power Service Secondary, OD School Service Time-of-Day Primary Service, and OD School Service Time-of-Day Secondary Service.

Table 4: Industrial Forecast Models and Rates

Forecast Model	Rate	Billing Determinants
KU_Pri	KU Power Service Primary KU Time-of-Day Primary Service	Customers, Energy, Billed Demand
LE_Pri	LE Power Service Primary LE Time-of-Day Primary Service	Customers, Energy, Billed Demand
OD_Ind	OD Retail Transmission Service OD Time-of-Day Primary Service	Customers, Energy, Billed Demand
OD_PS_Pri	OD Power Service Primary	Customers, Energy, Billed Demand
KU_RTS	KU Retail Transmission Service	Customers, Energy, Billed Demand
LE_RTS	LE Retail Transmission Service	Customers, Energy, Billed Demand
KU_FLS	KU Fluctuating Load Service	Customers, Energy, Billed Demand
OD_FWP	OD Water Pumping Service	Customers, Energy

4.2.1 General Service Forecasts

The general service forecasts include all customers on the GS rate schedule. For each service territory, GS forecasts employ an SAE model like the model used to forecast residential use-per-customer. The main difference between the GS and RS forecast is that the GS model forecasts total sales (rather than use-per-customer) as a function of energy used by heating, cooling, and other equipment, as well as binary variables to account for anomalies in the historical data.[11] A more detailed discussion of this model is included in Appendix A.

As discussed in the Residential UPC forecast (Section 4.1.2), commercial end-use inputs incorporate impacts of the IRA. There were no space heating adjustments for commercial customers.

4.2.2 KU Secondary Forecast

The KU Secondary forecast includes all customers who receive secondary service on the PS rate schedule and all customers on the TODS rate schedule. Sales to these customers are modeled as a function of weather, end-use intensity projections, and binary variables that account for anomalies in the historical data.

4.2.3 KU All-Electric School Forecast

The KU All-Electric School forecast includes all customers on the AES rate schedule. Sales to these customers are modeled as a function of end-use intensity projections, weather, and monthly binaries in addition to binary variables to account for anomalies in the historical data.

[11] A binary variable is a variable that can only take on two possible values, e.g., 0 and 1. Coding historically anomalous data using a binary variable allows it to be excluded from modeling, which improves model specification and thus model predictions. For example, in some models, the periods affected by the Covid-19 pandemic are coded as "1" and unaffected periods are coded as "0." This coding effectively removes the significant impact of Covid-19 in a few historical months.

4.2.4 ODP School Service Forecast

The ODP School Service forecast includes all customers on the SS rate schedule. Sales to these customers are modeled as a function of a constant, a variable to capture energy efficiency trends, weather, and monthly binaries in addition to binary variables to account for anomalies in the historical data.

4.2.5 LG&E Secondary Forecast

The LG&E Secondary forecast includes all customers who receive secondary service on the PS rate schedule and all customers on the TODS rate schedule. Sales to these customers are modeled as a function of weather, economic variables, end-use intensity projections, and other binary variables to account for anomalies in the historical data.

4.2.6 LG&E Special Contract Forecast

LG&E has one customer that is served under a special contract. This customer's consumption is forecast separately based on information obtained through direct discussions with the customer.

4.2.7 ODP Secondary Forecast

The ODP Secondary forecast includes customers on the Power Service Secondary and Time-of-Day Secondary rate schedules. Sales to these customers are modeled as a function of energy used by heating equipment, cooling equipment, and other equipment as well as economic variables and other binary variables to account for anomalies in the historical data.

4.2.8 ODP Municipal Pumping Forecast

The ODP municipal pumping forecast consists of customers on the Water Pumping Service rate schedule. Sales to these customers are modeled using a trend based on recent sales.

4.2.9 KU Primary Forecast

The KU Primary forecast includes all customers who receive primary service on the PS rate schedule and all customers on the TODP rate schedule. Sales to these customers are modeled as a function of an economic variable, monthly binaries, and a binary variable to capture Covid-related usage changes. If necessary, the forecast is adjusted to reflect significant expansions or reductions for large customers in these rate classes that are forecast individually based on information obtained through direct discussions with these customers.

4.2.10 KU Retail Transmission Service Forecast

The KU Retail Transmission Service forecast includes customers who receive service on the RTS rate schedule. Sales for several large KU RTS customers are forecast individually based on information obtained through direct discussions with these customers. The majority of the remaining RTS customers are mining customers. Sales to these customers are modeled as a function of a mining index, an economic variable, a lag dependent variable, and a binary variable to capture Covid-related usage changes.

4.2.11 KU Fluctuating Load Service Forecast

The KU Fluctuating Load Service forecast includes the one customer on the FLS rate schedule and is developed based on information obtained through direct discussions with this customer.

4.2.12 LG&E Primary Forecast

The LG&E Primary forecast includes all customers who receive primary service on the PS rate schedule and all customers on the TODP rate schedule. Sales to these customers are modeled as a function of an economic variable and monthly binaries. If necessary, the forecast is adjusted to reflect significant expansions or reductions for large customers on these rate schedules that are forecast individually based on information obtained through direct discussions with these customers.

4.2.13 LG&E Retail Transmission Service Forecast

The LG&E Retail Transmission Service forecast includes customers who receive service on the RTS rate schedule. Sales for several large LG&E RTS customers are forecast individually based on information obtained through direct discussions with these customers. Sales to the remaining customers are modeled as a function of historical monthly usage.

4.2.14 ODP Industrial Forecast

The ODP industrial forecast includes all customers receiving primary service on the PS rate schedule as well as customers receiving service on the TODP or RTS rate schedules. ODP industrial sales are modeled as a function of mining production forecasts and a weather variable.

4.3 KU Municipal Forecasts

KU's municipal customers develop their own sales forecasts. These forecasts are reviewed by KU for consistency and compared to historical sales trends. KU directs questions, concerns, and potential revisions to the municipal customers. See Table 5 for a summary:

Table 5: KU Municipal Forecast Models and Rates

Forecast Model	Rate	Billing Determinants
KU_MuniPri	KU Wholesale (Bardstown)	Energy, Billed Demand
KU_MuniTran	KU Wholesale (Nicholasville)	Energy, Billed Demand

4.4 Lighting and EV Charging Forecasts

The Lighting and EV Charging forecasts include customers receiving service on the following rate schedules in Table 6:

Table 6: Lighting and EV Charging Forecast Models and Rates

Forecast Model	Rate	Billing Determinants
KU_EV Fast Charging	KU Electric Vehicle Fast Charging Service	Energy
KU_EV Charging	KU Electric Vehicle Charging Service	Energy
KU_LES	KU Lighting Energy Service	Energy
KU_OSL	KU Outdoor Sports Lighting Service	Customers, Energy, Billed Demand
KU_TES	KU Traffic Energy Service	Customers, Energy
KU_UM	KU Unmetered Lighting Service	Customers
LE_EV Fast Charging	LE Electric Vehicle Fast Charging Service	Energy
LE_EV Charging	LE Electric Vehicle Charging Service	Energy

LE_LES	LE Lighting Energy Service	Energy
LE_OSL	LE Outdoor Sports Lighting Service	Customers, Energy, Billed Demand
LE_TES	LE Traffic Energy Service	Customers, Energy
LE_UM	LE Unmetered Lighting Service	Customers
OD_UM	OD Unmetered Lighting Service	Customers

All Lighting and EV Charging energy is modeled using a trend based on recent sales.

4.5 Distributed Solar Generation Forecast

The net metering distributed solar generation forecast is based on a consumer choice model. The consumer choice model is driven by various economic and financial inputs, including the retail price for electricity, the levelized cost of energy ("LCOE") for solar installations, disposable personal income, monthly binaries, and the price paid for energy exported to the grid. The changes to the timing of the solar investment tax credit ("ITC") phase-out discussed in the IRA is included in the LCOE variable in this model. Two models are specified using the above variables to create both a near- term and a long-term model. This forecast is a blend of the output of these two models.

In addition to net metering, there is also a forecast of behind-the-meter ("BTM") qualifying facilities ("QF") customers. This forecast contemplates only BTM QF and not independent or merchant generators that may locate to the area. This model is based upon the historical trend in BTM QF adoptions as well as current capacity-per-installation levels.

For purposes of revenue forecasting, the reduced sales attributable to distributed generation are allocated by rate as a reduction to the respective rate forecasts. The hourly distributed generation forecast, which is represented as negative load, is added on top of the mid load forecast hourly shape discussed in Section 5.2.

4.6 Electric Vehicle Forecast

The electric vehicle forecast is based on a consumer choice model. The consumer choice model is driven by the cost difference between electric vehicles and internal combustion engine vehicles. The forecast assumes the tax credits discussed in the IRA. Consistent with previous filings, efficiency and miles driven assumptions are used to translate the vehicles-in-operation into an energy impact and that impact is allocated entirely to the Residential class.

For purposes of revenue forecasting, the EV sales forecast is allocated as an increase to the RS forecasts. The EV hourly profile, which assumes managed charging, is added on top of the mid load forecast hourly profile discussed in Section 5.2.

An additional, positive adjustment was made to account for National Electric Vehicle Infrastructure ("NEVI") funds that were discussed in the Infrastructure Investment and Jobs Act ("IIJA"). The forecast assumes EV fast chargers will locate in the service territory beginning in 2023 because of this legislation and grow over time. The TODS rates for LG&E and KU receive the adjustments. By 2028, these chargers are only forecast to add 2 GWh of load annually.

4.7 Advanced Metering Infrastructure ("AMI") Benefits

The forecast has two adjustments to account for the benefits AMI is anticipated to provide in terms of load reduction. These adjustments reduce load.

4.7.1 Conservation Voltage Reduction ("CVR")

CVR adjustments are phased in over time as AMI meters are deployed and the necessary distribution controls are installed. Beginning in 2030, the combined CVR adjustments reduce annual load by 205 GWh annually. Specifically, CVR reduces RS and GS sales. The adjustments are consistent with what was discussed in Exhibit LEB-3 in Case Nos. 2020-00349 and 2020- 00350.

4.7.2 AMI ePortal Savings

AMI ePortal savings are allocated to customers on rates that do not currently have access to interval data. This primarily includes RS, GS, KU AES, ODP SS, and PS rates. These are phased in as AMI meters are deployed and represent 0.35% of monthly sales reductions for the applicable rates upon full deployment. The adjustments are consistent with what was discussed in Exhibit LEB-3 in Case Nos. 2020-00349 and 2020-00350.

4.8 Billed Demand Forecasts

For most rates, regression models are developed to forecast billed demands primarily as a function of energy. For some rates, billed demand forecasts are developed by applying historical ratios of billed demand and energy to the energy forecast. For a given customer and month, tariff provisions can impact the relationship between billed demands and energy. For example, the base demand for a TODP customer is computed as the greater of several factors including the customer's contract capacity and highest measured demand for the preceding 11 billing periods. The Companies' forecasting process considers the potential impact of these factors on the overall forecasts. Base, peak, and intermediate demands for the Companies' largest customers are developed with input from the customer.

5 Data Processing

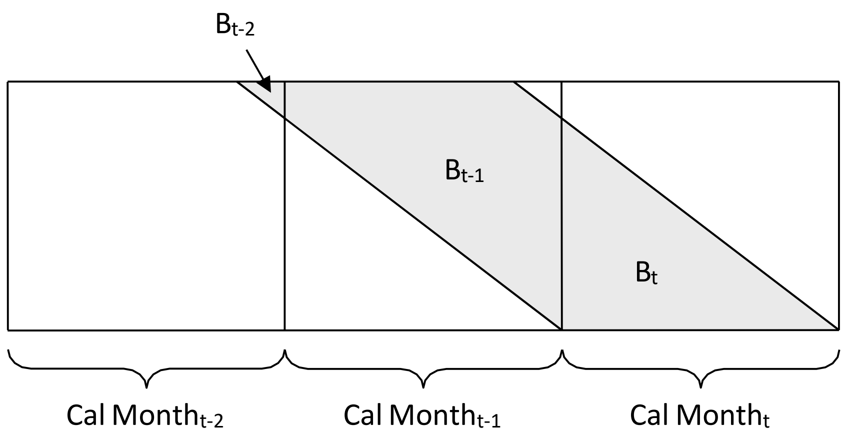
All customers are assigned to one of 20 billing portions. A billing portion determines what day of the month, generally, a customer's meter is read. Most customers' monthly bills include energy that was consumed in portions of more than one calendar month. This energy is referred to as "billed" energy and the majority of the Companies' forecast models are initially specified to forecast "billed" sales. The following processes are completed to prepare the forecasts for use as inputs to the Companies' revenue and generation forecasts:

- Billed-to-Calendar Energy Conversion
- Hourly Energy Requirements Forecast

5.1 Billed-to-Calendar Energy Conversion

Most forecast volumes must be converted from a billed to calendar basis to meet the needs of the Financial Planning department. The shaded area in Figure 2 represents a typical billing period (B). Area B_t represents the portion of billed energy consumed in the current calendar month (Cal $Month_t$). Area B_{t-1} represents the portion of billed energy consumed in the previous calendar month (Cal $Month_{t-1}$). Area B_{t-2} represents the portion of billed energy consumed in the calendar month two months prior to the current month (Cal $Month_{t-2}$). Not all billing periods include volumes that were consumed in the calendar month two months prior to the current month.

Figure 2: Billed and Calendar Energy



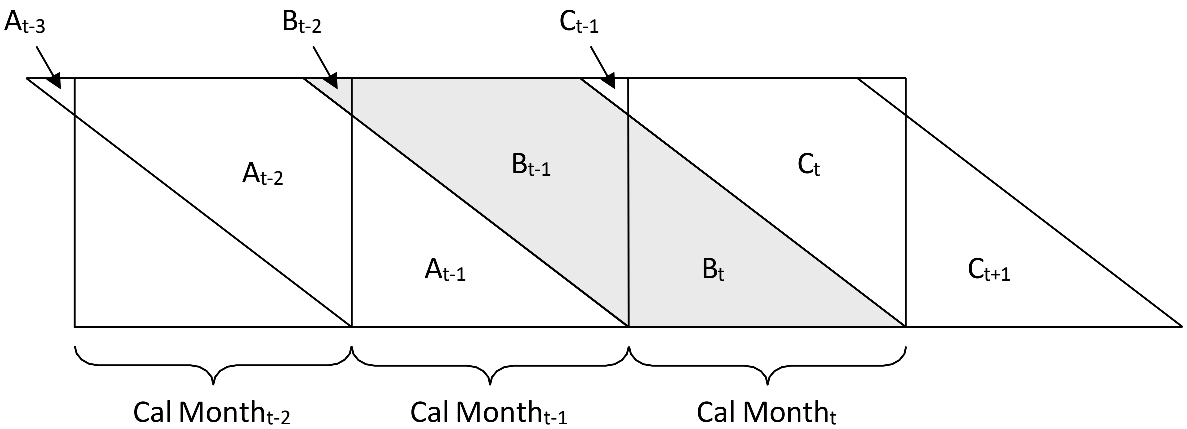
In this process, billed energy is allocated to calendar months based on when the energy is consumed. Furthermore, the weather-sensitive portion of the billed energy forecast is allocated to calendar months based on degree days (HDDs and CDDs) and the non-weather-sensitive portion is allocated based on billing days.[12] For example, the June billing period includes portions of June, May, and possibly April. Under normal

[12] For a given billing period, the number of degree days and billing days in each calendar month is computed as an average over the 20 billing portions.

weather conditions, June will have more CDDs than May. Therefore, a greater portion of the weather-sensitive energy in the June billing period will be allocated to the calendar month of June.

Figure 3 contains two additional billing periods (A & C). Calendar sales for Cal Month$_{t-1}$ is equal to the sum of energy in in billing period segments A_{t-1}, B_{t-1}, and C_{t-1}.

Figure 3 – Billed and Calendar Energy



5.2 Hourly Energy Requirements Forecast

5.2.1 Normal Hourly Energy Requirements Forecast

The Generation Planning department uses the hourly energy requirements forecast to develop resource expansion plans and a forecast of generation production costs. An hourly energy requirements forecast is developed for each company by adding losses to calendar-month sales and allocating the sum to hours in each month. The result reflects customers' hourly energy requirements under normal weather conditions. The following process is used to develop this forecast:

1. Sum calendar-month forecast volumes independent of distributed generation and incremental EV load by company. Then, add transmission and distribution losses as well as incremental company uses to compute monthly energy requirements. The sum of calendar-month forecast volumes for KU includes forecast volumes for the KU and ODP service territories.
2. Develop normalized load duration curves for each company and month based on 10 years of historical hourly energy requirements. For KU, to model the impact of the municipal departure, this process is completed based on historical energy requirements where the impact of the departing municipals has been removed.
3. Compute the ratio of hourly energy requirements and monthly energy requirements for each hour and company. Rank the ratios in each month from highest to lowest. The normalized load duration curves are computed by averaging the ratios by month, rank, and company.
    1. The winter and summer peak can occur in multiple months, and the predicted peak for a season (meaning winter or summer) is higher than the predicted peak for any individual month within the season. For this reason, the normalized load duration curves for January and August are adjusted to match peaks produced in separate seasonal models. This

process produces seasonal peak demand forecasts that are placed within January (winter) and August (summer).

4. Allocate total forecast monthly energy requirements by company to hours using the normalized load duration curves. For KU, the normalized load durations curves reflect the municipal departure.
5. Assign hourly energy requirements to specific hours in each month based on the ordering of days and weekends in the month. Historical reference years and months having matching calendar profiles as the forecast month (e.g., a historical August that begins on a Tuesday) are selected to be used for ordering purposes only.
6. Adjust the hourly energy requirements forecast to reflect the hourly forecast impact of distributed solar generation, electric vehicle, and other inputs having distinct load shapes. Said differently, the profiles attributable to solar, electric vehicles, and economic development are layered in separately. The solar profiles are developed to ensure that the underlying weather and solar irradiance align. Consistent with prior forecasts, EV managed charging is assumed for the hourly shape.

5.2.2 **Weather-Year Forecasts**

The Companies develop their hourly energy requirements forecast with the assumption that weather will be average or "normal" in every year (see discussion above in Section 5.2.1). While this is a reasonable assumption for long-term resource planning, weather from one year to the next is never the same. For this reason, to support the Companies' Reserve Margin Analysis and other studies focused on generation reliability, the Companies produce 51 hourly energy requirement forecasts for each year of the forecast based on actual weather in each of the last 51 years (1973 through 2023).

To create these "weather year" forecasts, the Companies develop a model to forecast hourly energy requirements as a function of temperature and calendar variables such as day of week and holidays. This model is used to forecast hourly energy requirements in each year of the forecast period based on hourly temperatures from the prior 51 calendar years but using calendar variables from the forecast period. The Companies produce two version of this analysis: a version where the forecast years are all identically shaped from a calendar perspective (i.e. all years start on a Sunday and leap days are excluded) and a version where forecast years match the calendar as it actually occurs. These two versions rely on identical modeling and weather, but are used for different purposes. The former version allows for a consistent load distribution across multiple years and is useful for analysis such as assessing reserve margin requirements, while the latter allows for accurate assessment of weather likelihood and is useful for analysis of minimum fuel burn requirements and outage planning. To ensure consistency with the Companies' energy forecast, the following steps are taken once the model outputs are available:

1. All hours of the weather year forecast are adjusted so that the mean of monthly energy requirements from the weather year forecasts equals monthly energy requirements in the mid energy forecast excluding those inputs having distinct load shapes.
2. Extreme points in the historical data are reviewed individually to ensure model predictions are reasonable based on recent experiences and knowledge of the Company's system load response. These points can be increased or decreased incrementally as appropriate.
3. At this point, inputs having distinct load shapes are added (or subtracted) on an hourly basis.

These include EV charging, distributed generation, and new major accounts.

   a. The hourly distributed generation profiles are layered in according to each weather year. For historical years for which we have solar irradiance data (since 1998), the distributed generation profile matches that year's weather profile. For prior years, the distributed generation profile represents an average irradiance of the years that are available.

4. All hours of the weather year forecast are again adjusted, but this time so that the mean of monthly energy requirements from the weather year forecasts equals monthly energy requirements in the mid energy forecast including those load forecast inputs having distinct load shapes.
5. The mean of the seasonal peaks of the weather years are then adjusted to match the seasonal peaks forecast using normal weather.[13]
6. Finally, all hours of the weather year forecast are adjusted so that the mean of seasonal energy requirements from the weather year forecasts equals seasonal energy requirements in the mid energy forecast, which include those load forecast inputs having distinct load shapes.

[13] Seasons are defined as winter (November, December, January, February), summer (June, July, August, September), and shoulder (March, April, May, October) in this context.

6 Review

In addition to assessing the reasonableness of models (discussed in introduction to Section 4), forecast results are visually inspected versus recent history and prior forecasts to ensure reasonableness of results. Because of the obligation to serve load in every hour, the Companies ensure monthly and hourly profiles are reasonable. To accomplish this, the new forecast is compared to (i) the previous forecast, (ii) weather-normalized actual sales for the comparable period in prior years, (iii) a range of historical actual sales and energy requirements, and (iv) the end-use projections assumed in the forecast models. This process ensures that the forecast is consistent with recent trends in the way customers are using electricity today and how that could change in the future.

Exhibit TAJ-2

Information in the exhibit is confidential and proprietary and is provided under seal pursuant to a petition for confidential protection. In addition, portions of the exhibit are voluminous and are provided pursuant to a motion to deviate.