2024 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company

PPL companies

Case No. 2024-00326

Volume I

This Integrated Resource Plan represents a snapshot of an ongoing resource planning process using current business assumptions. The planning process is constantly evolving and may be revised as conditions change and as new information becomes available. Before embarking on any final strategic decisions or physical actions, the Companies will continue to evaluate alternatives for providing reliable energy while complying with all regulations in a least-cost manner. Such decisions or actions will be supported by specific analyses and will be subject to the appropriate regulatory approval processes.

Table of Contents

2024 IRP Resource Assessment
2024 RTO Membership Analysis
Natural Gas Fuel Security Analysis – October 2024
Generation Forecast Process
Transmission Information
2024 IRP Generation Replacement & Retirement Scenarios – Impact to the LG&E/KU Transmission System
2024 IRP Long-Term Firm Transfer Analysis – Impact to the LG&E/KU Transmission System

4 Format

4.(1) Organization

This plan is organized by using the Section and Subsection numbers found in the Administrative Regulation 807 KAR 5:058, "Integrated Resource Planning by Electric Utilities," as shown in the preceding Table of Contents. This report is filed with the Public Service Commission of Kentucky in compliance with the aforementioned regulation.

4.(2) Identification of individuals responsible for preparation of the plan

Chris Balmer, Director Transmission Strategy and Planning

John Bevington, Director Business and Economic Development

Josh Boone, Manager Transmission Strategy and Planning

Brandan Burfict, Sr. Manager Generation & Gas Ops

Rebecca Cash, Sr. Manager Environmental Regulatory Compliance & Policy

Robert Conroy, VP State Regulation and Rates

Michael Drake, Director Generation Services

Philip Imber, Director Environmental Compliance

Lana Isaacson, Manager Energy Efficiency Programs

Tim Jones, Manager Sales Analysis and Forecasting

Rick E. Lovekamp, Manager Regulatory Strategy/Policy

Beth McFarland, VP Transmission

Shannon Montgomery, VP Customer Services

Aron Patrick, Director Technology Research and Analysis

Karmen Powell, Manager Distribution Electric Engineering

Derek Rahn, Acting Director Customer Programs

Michael Sebourn, Manager Generation Planning

David S. Sinclair, VP Energy Supply and Analysis

Steve Turner, VP Power Production

Peter Waldrab, VP Electric Distribution

Stuart Wilson, Director Energy Planning, Analysis and Forecasting

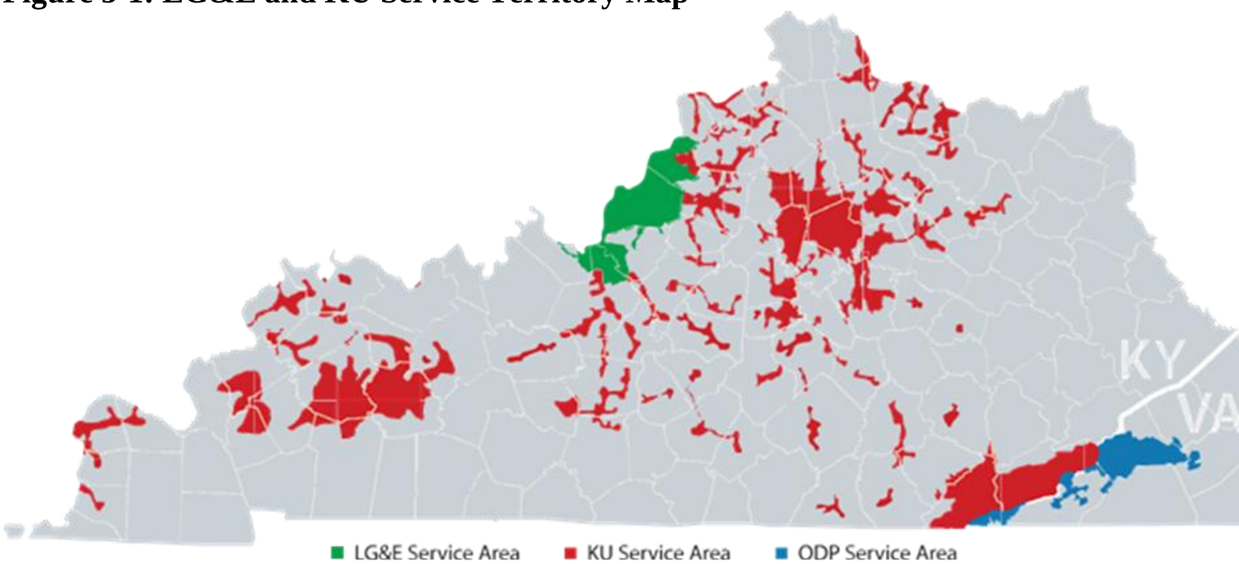
5 Plan Summary

5.(1) Utility Overview and Planning Objectives

5.(1).(a) Utility Overview

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies"), part of the PPL Corporation ("PPL") family of companies, are regulated utilities that serve more than 1.3 million customers and have consistently ranked among the best companies for customer service in the United States. LG&E serves almost 335,000 natural gas and 436,000 electric customers in Louisville and 16 surrounding counties. KU serves 573,000 customers across two time zones in 77 Kentucky counties and five counties in Virginia, where KU operates under the name Old Dominion Power Company (see Figure 5-1). In addition, KU provides wholesale power to two municipalities in Kentucky.

Figure 5-1: LG&E and KU Service Territory Map



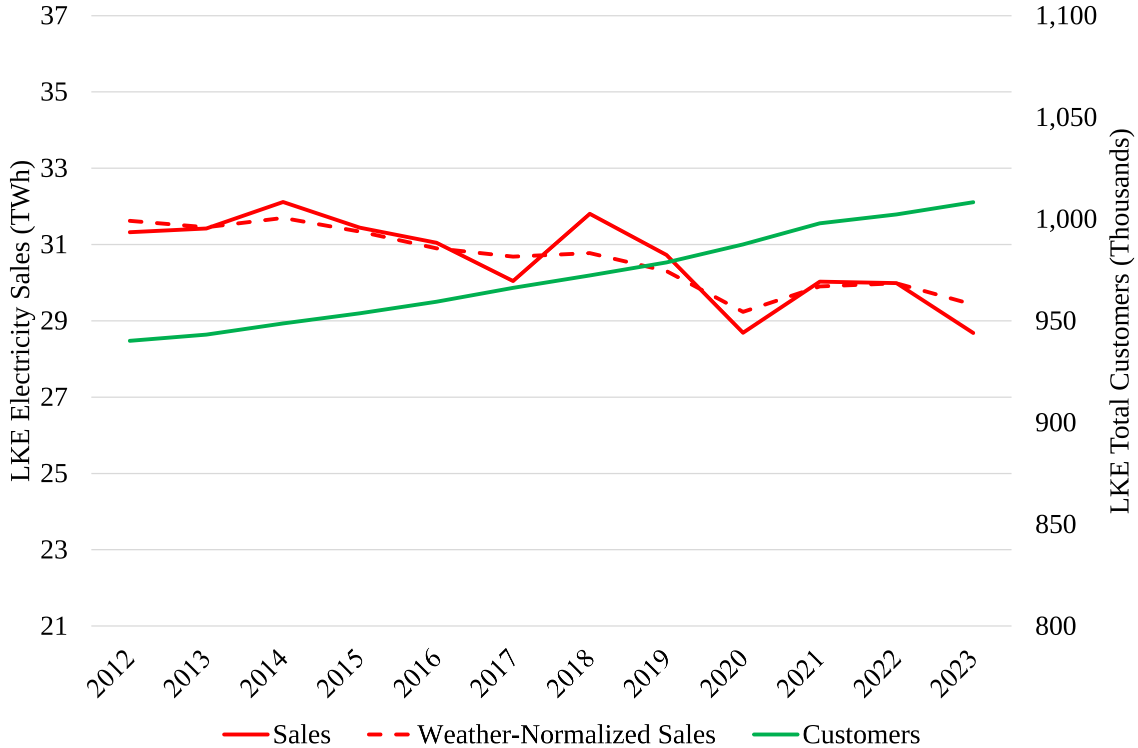
The goal of the Companies' resource planning process is to provide safe, reliable, and low-cost service to their customers while complying with all laws and regulations. Safe, reliable, and low-cost electricity is vital to Kentucky's economy and public safety, and customers expect electricity to be available at all times and in all weather conditions. As a leading manufacturer of automobiles, steel, and other products, Kentucky was the 8th most electricity-intensive U.S. state in 2022 as measured by the ratio of electricity consumption and state gross domestic product.[1] Based on rates effective January 1, 2024, the Companies' rates for Industrial tariffs were 9% lower than the national average.[2]

[1] Electricity consumption is from the following link: https://www.eia.gov/electricity/state/; GDP comes from either of the following links: https://en.wikipedia.org/wiki/List_of_U.S._states_and_territories_by_GDP or https://www.bea.gov/data/gdp/gdp-state.

[2] Edison Electric Institute (EEI) Typical Bills and Averages Rates Report Winter 2024, Pages 263 and 272.

Figure 5-2 shows actual and weather-normalized energy requirements and total customers in the LG&E and KU service territories since 2012. Prior to 2020, energy requirements were slightly declining as increased consumption from the addition of new customers was more than offset by mining sector declines, industrial production efficiency improvements, and efficiency improvements in residential and commercial end-uses. Energy requirements declined significantly in 2020 due to the COVID-19 pandemic but have recovered to the slightly declining trend observed prior to the pandemic.

Figure 5-2: LG&E and KU Energy Requirements and Customers, 2012-2023[3]



The composition of the Companies' electricity consumption has remained fairly consistent since 2010, with residential, commercial, and industrial customers each accounting for approximately one-third of total energy requirements. For the 12 months ending in June 2024, the composition of electricity consumption by class was approximately 35% residential, 25% commercial, 30% industrial, and 10% other.

To serve their customers' needs, the Companies have developed a portfolio of generation and demand-side management and energy efficiency ("DSM-EE") resources with the operational capabilities and attributes needed to reliably serve customers' year-round energy needs at a reasonable cost. Table 5-1 contains a summary of the Companies' fully dispatchable, renewable, and limited-duration resources.[4]

---

[3] Energy requirements exclude municipal customers that departed in 2019.
[4] A detailed listing of the Companies' generation resources is included in Table 8-4.

Table 5-1: LG&E and KU Resources, September 2024

Resource	Number of Units	Unit Size (Summer MW)[5]	Total Net Capacity (MW)[5]	
			Summer	Winter
Fully Dispatchable				
Coal[6]	11	297 - 549	4,867	4,910
Natural Gas Combined Cycle ("NGCC")[7]	1	691	691	691
Large-Frame SCCT	14	121 - 159	2,007	2,253
Small-Frame SCCT[8]	3	12 – 23	47	55
Total Fully Dispatchable Resources	**29**	**12 - 549**	**7,612**	**7,909**
Renewable				
Solar[9]	4	0.03 – 10	12.4	12.4
Hydro	11	11.2 – 12.6	134.2	134.2
Wind	1	0.09	0.09	0.09
Total Renewable Resources	**16**	**0.03 – 12.6**	**147**	**147**
Limited-Duration				
Curtailable Service Rider	N/A	N/A	110	115
Demand Conservation Program	N/A	N/A	60	35
Total Limited-Duration Resources	N/A	N/A	**170**	**150**

In addition to these generation resources, the Companies operate an electric grid consisting of almost 28,000 miles of electric transmission and distribution lines.

5.(1).(b) Planning Objectives

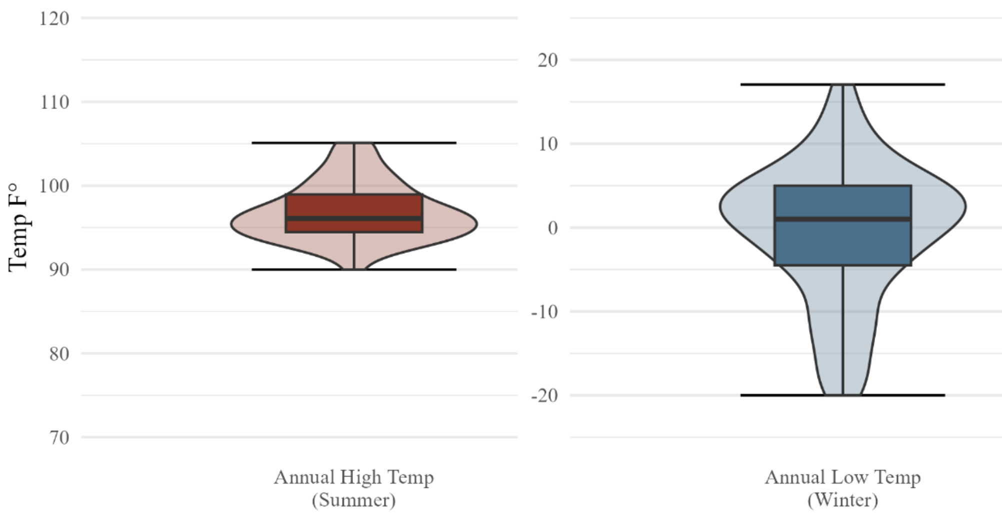
The Companies' overarching resource planning objective is straightforward: Develop a resource plan that will enable the Companies to serve all customers safely, reliably, and at the lowest reasonable cost at all times, day or night, and in all seasons and weather conditions.

To help meet this objective, resource adequacy is focused significantly on serving customers during extreme weather events. Temperatures in Kentucky can range from below zero degrees

[5] Unit Size and Total Net Capacity reflect net seasonal capacities for both fully dispatchable and limited-duration resources. Renewable resources reflect AC nameplate capacity.
[6] Includes the Companies' share of Ohio Valley Electric Corporation ("OVEC") and reflects their 75% ownership share of Trimble County 1 & 2.
[7] In 2024, the Companies increased the capacity of Cane Run 7's two combustion turbines. The facility's output is currently limited to its network integration transmission service level of 691 MW until a transmission study and any required transmission network upgrades are completed to allow the facility to reach its full net potential of 697 MW summer and 759 MW winter, which is assumed to be in 2026.
[8] Small-frame SCCTs comprise Paddy's Run 12 and Haefling 1 & 2. All of the Companies' other SCCTs are large-frame SCCTs.
[9] Includes Brown Solar, the first five arrays of the Companies' Simpsonville Solar (Solar Share) facility, and two small Business Solar facilities that total less than 1 MW.

Fahrenheit to above 100 degrees Fahrenheit. Figure 5-3 shows the distribution of annual high and low temperatures in Louisville over the last 51 years. From 1973 to 2023, the median annual high temperature was 96 degrees Fahrenheit and the median annual low temperature was 4 degrees Fahrenheit. Additionally, the variability of low temperatures in the winter is significantly greater than the variability of high temperatures in the summer.

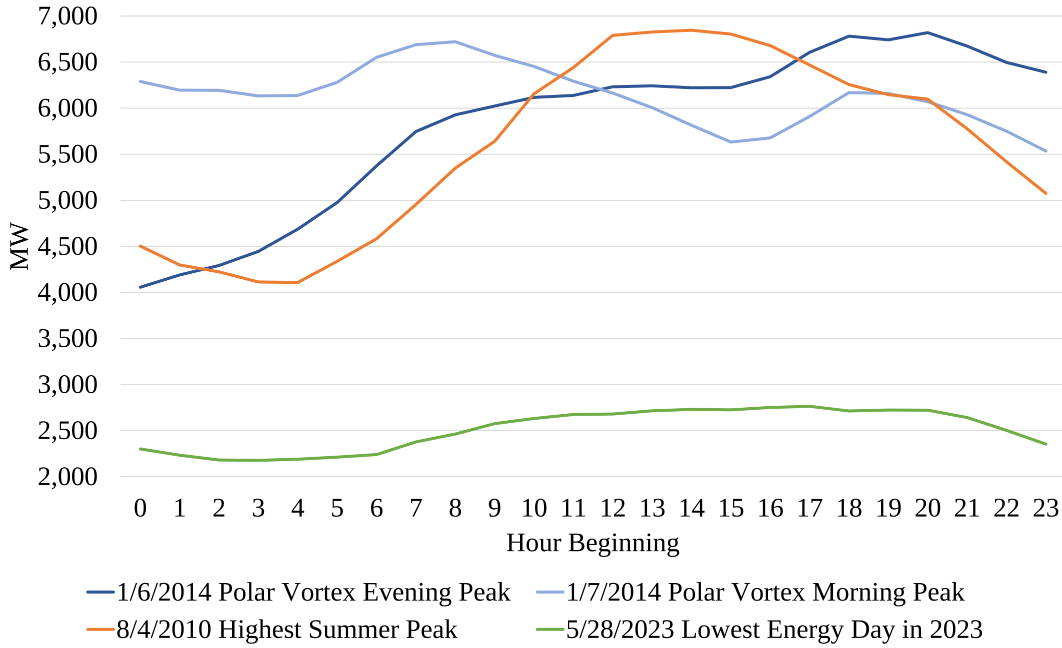
Figure 5-3: Annual High and Low Temperature Distributions (1973-2023)[10]



An understanding of the way customers use electricity is also critical for planning a generation, transmission, and distribution system that can reliably serve customers in every moment. The Companies are somewhat unique in that their annual peak demands can occur in both the summer and winter months. As seen in Figure 5-4, summer peak demands typically occur in the afternoons, while winter peaks typically occur in the mornings or evenings during non-daylight hours. In addition, hourly demands can vary by nearly 600 MW from one hour to the next and 3,000 MW in a single day. The Companies' highest hourly demand occurred in August 2010, but since then, the Companies have experienced seven annual peak demands in excess of 6,400 MW, five of these occurred during the winter months, and the last summer peak exceeding 6,400 MW occurred in 2012.[11] The Companies' resource adequacy considerations are primarily focused on the winter months given the potential for higher and more volatile peak demands in the winter months.

[10] The limits of the box in the boxplots reflect the 25th and 75th percentiles while the "whiskers" represent the maximum and minimum. The shaded area behind the boxplot, called a violin plot, represents the distribution of points. The width of the violin represents the proportion of the data at that value.
[11] These statistics exclude municipal customers that departed in 2019.

Figure 5-4: Select Load Profiles (MWh), 2010-2023[12]



To safely and reliably serve customers' needs at the lowest reasonable cost requires evaluating the different roles that different types of generation resources play in serving customers around the clock and in all seasons and weather conditions. Fully dispatchable resources are resources that can be dispatched any time and operated for days or months at a time, and they include baseload and peaking resources. The Companies' baseload resources are an excellent source of low-cost energy, while peaking resources are better-suited for following load during peak periods and for responding to unit outages.[13] The Companies' renewable resources include Brown Solar, Solar Share, and Business Solar and the Ohio Falls and Dix Dam hydro units. These resources have little to no fuel or emissions costs, but their availability is uncertain during peak load conditions. Limited-duration resources can only be dispatched several hours at a time and, in the case of the Companies' dispatchable DSM and CSR programs, have limited availability. In addition to the ability to serve load during the annual system peak hour, the generation fleet must have the ability to produce low-cost baseload energy, the ability to respond to unit outages and follow load, and the ability to instantaneously produce power when customers want it. The Companies evaluate all these characteristics of their existing and potential future resources in ongoing resource planning efforts to help meet their overarching planning objective.

The Companies have a well-established annual planning process that has enabled them to reliably meet their customers' around-the-clock energy needs both in the short-term and long-term at the lowest reasonable cost. This Integrated Resource Plan ("IRP") represents a snapshot of this planning process using current business assumptions and assessment of risks. Because the planning

[12] Peak demands exclude municipal customers that departed in 2019.
[13] Compared to coal units, simple-cycle combustion turbines ("SCCTs") have higher dispatch costs but lower carrying costs, shorter start-times, and better ramping capabilities.

process is constantly evolving, the Companies' resource plan may be revised as conditions change and as new information becomes available. Even though the IRP represents the Companies' analysis of the best options to meet customer needs at this point in time, this plan is reviewed, re-evaluated, and assessed against other market available alternatives prior to commitment and implementation.

The Companies considered the Commission Staff Report on the 2021 Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company dated September 2022 (Case No. 2021-00393) while preparing this IRP. The Companies have addressed the suggestions and recommendations contained in the Staff report. A summary of the ways in which these suggestions and recommendations were addressed is provided in Volume III ("Recommendations in PSC Staff Report on the Last IRP Filing").

5.(2) IRP Models and Methods

The Companies' integrated resource planning process begins with the development of a robust forecast of hourly energy requirements or "load." Then, a resource plan is developed with the goal of meeting future energy requirements at the lowest reasonable cost. The models, methods, data, and key assumptions for each part of the planning process are summarized in the following sections.

Energy Requirements

The production of a robust forecast of system energy requirements is a prerequisite for efficient planning and control of utility operations. The modeling techniques employed by the Companies allow energy and demand forecasts to be tailored to address the unique characteristics of the KU and LG&E service territories. The Companies' forecasts reflect the economics of existing end-use technologies. Although the Commission has deemed the Companies' approach to load forecasting reasonable in recent IRP and certificate of public convenience and necessity ("CPCN") cases,[14] the Companies still look for ways to improve the forecast each year. Typically, these improvements are minor and do not depart fundamentally from methods the Companies have used for years.

Models and Methods

Energy requirements are the sum of electricity sales and transmission and distribution losses. LG&E and KU's electricity sales forecasts are developed through econometric modeling of energy sales by rate class, but also incorporate specific intelligence on the prospective energy requirements of the Companies' 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

[14] *See, e.g., 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, Order at 63-65 (Ky. PSC Nov. 6, 2023); 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).

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, and FERC wholesale. Within the retail jurisdictions, the forecast typically distinguishes several classes of customers including residential, commercial, and industrial.

The econometric models used to produce the forecast 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.

Sales to several of the Companies' largest customers are forecast based on information obtained through direct discussions with these customers. These regular communications allow the Companies to directly adjust sales expectations given the first-hand knowledge of the utilization outlook for these companies. The modeling of residential and commercial sales also incorporates elements of end-use forecasting – covering base load, heating, and cooling components of sales – that recognize expectations with regard to appliance saturation trends, efficiencies, and price or income effects.

Once monthly sales forecasts are developed for each of the Companies' rate classes, the sales forecasts are aggregated by company and adjusted for transmission and distribution losses to produce a preliminary forecast of monthly energy requirements for each company. Monthly energy requirements for each company are then allocated to hours using normalized load duration curves and adjusted to reflect the forecasted impact of increasing adoption of distributed solar generation and electric vehicles as well as the addition of economic development loads with distinct load shapes.[15]

A more detailed description of the Companies' forecasting models and methods is included in Volume II ("Energy and Demand Forecast Process").

[15] The forecasted impact of increasing distributed solar generation and electric vehicle penetrations must be layered into the forecast of hourly energy requirements separately because the normalized load durations curves used to allocate monthly energy requirements to hours are derived based on hourly loads in historical periods with immaterial amounts of distributed solar generation and electric vehicle consumption. High load factor customers also have distinct load shapes that must be layered in separately.

Resource Planning

The Companies' resource planning process consists of the following activities:

1. Review of supply-side and demand-side resource options
2. Assessment of reserve margin constraints and capacity contribution
3. Development of long-term resource plan

The models and methods for each of these activities are summarized in the following sections.

Technology Update – Models and Methods

The Companies' IRP reviews new supply-side and demand-side resource options. Fully dispatchable resource options include large-frame simple-cycle combustion turbines ("SCCT"), natural gas combined cycle combustion turbines ("NGCC"), and small modular nuclear reactors ("SMR"). Renewable resource options include land-based wind resources located in Kentucky and Indiana as well as utility-scale solar resources located in Kentucky. Limited-duration resources can only be dispatched several hours at a time and include 4-hour and 8-hour battery energy storage systems ("BESS" or "battery storage"), new dispatchable DSM programs, and an expansion of the Companies' Curtailable Service Rider ("CSR"). A summary of these resources is included in Volume III ("2024 IRP Technology Update"). Resource costs and assumptions are based on the "Moderate" scenario in National Renewable Energy Laboratory's 2024 Annual Technology Baseline ("NREL's 2024 ATB"), updated cost estimates for resources contemplated in the Companies' 2022 CPCN filing, and the Companies' own analysis.

Resource Adequacy Analysis – Models and Methods

The Companies' resource adequacy analysis was used to determine reserve margin constraints and capacity contributions for resource planning. The Companies use PLEXOS, a resource planning model, to develop resource plans that minimize the cost of serving customers' load under normal weather conditions while meeting minimum summer and winter reserve margin constraints. The minimum reserve margin constraints generally enable the model to account for uncertainty associated with resource availability and weather. Capacity contributions for limited-duration resources enable the model to account for the fact that limited-duration resources do not contribute to reliability in the same way that fully dispatchable resources do. The Companies develop these inputs using the Strategic Energy & Risk Valuation Model ("SERVM"), a resource adequacy model, by assessing the adequacy of various resource portfolios over a wide range of weather and unit availability scenarios. The analysis used to develop these inputs is summarized in IRP Volume III (2024 IRP Resource Adequacy Analysis).

Long-Term Resource Planning Analysis – Models and Methods

The Companies developed least-cost resource plans for three load scenarios and four environmental scenarios (12 "load and environmental" scenarios in total). To do this, they first used PLEXOS to develop resource plans for each load and environmental scenario across five fuel price scenarios, resulting in 60 total resource plans. The Companies then evaluated each resource plan with detailed production costs over each of the fuel price scenarios to determine which resource plan for a given load and environmental scenario is lowest cost across all fuel price scenarios. A complete summary of this analysis is included in Volume III ("2024 IRP Resource Assessment").

PLEXOS models and evaluates thousands of resource plans to determine which one minimizes the cost of serving customers while meeting reserve margin and other constraints. A resource planning model necessarily makes simplifying assumptions to reduce model run times, and a key consideration for any resource planning model is the level of granularity used to develop resource plans. Less granular analyses require more simplifying assumptions and have shorter run times, but too many simplifying assumptions may prevent the model from properly evaluating resources with limited availability or run times. Thus, it is important to evaluate resource plans with an appropriate level of granularity and then verify the results with detailed production costs.

After PLEXOS identifies which resources to include in a resource portfolio, the Companies model the portfolio's generation production costs in detail using PROSYM, an hourly chronological dispatch model. PLEXOS and PROSYM use the same inputs (e.g., they use the same natural gas and coal prices), but the Companies used PROSYM rather than PLEXOS for detailed production cost modeling because they have used and configured PROSYM over a number of years to do such modeling relatively quickly.

Finally, the Companies use a Financial Model built in Excel to calculate and compare present value of revenue requirements ("PVRR") values for various portfolios. Inputs to the Financial Model include capital and fixed operating costs for new and existing resources as well as generation production costs developed in PROSYM. The costs for new and existing resources are the same costs modeled in PLEXOS and used to develop the least-cost portfolio.

Volume III – *Generation Forecast Process* provides additional details regarding the Companies' development of the generation forecasting models.

Resource Planning Inputs and Uncertainties

The primary focus of resource planning is risk management. Key categories of risk are how customers use electricity, the performance of generation units, the price of fuel and other commodities, and the future impact of new state and federal regulations. The following sections summarize key resource planning inputs and uncertainties.

1. Long-Term Energy Requirements ("Load") Forecast

A summary of the Mid (base), High, and Low load forecasts and key uncertainties surrounding the load forecast is included in Section 5.(3), and an extended discussion is included in Section 7.

2. "Weather Year" Load Forecasts for Reliability Planning

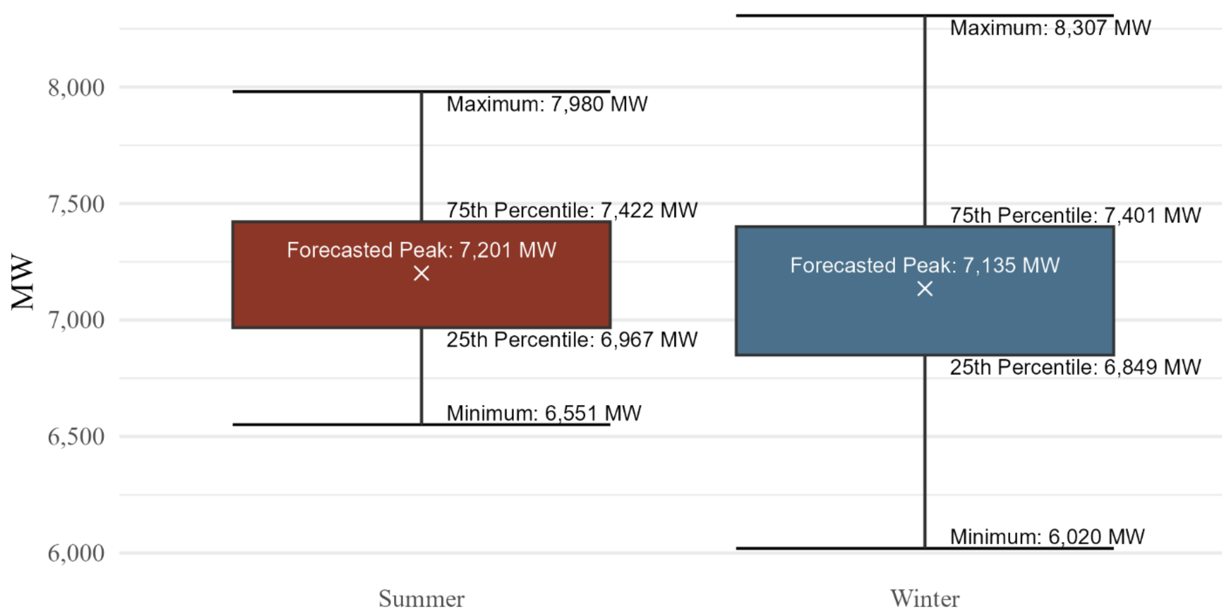
The Companies develop their long-term Mid, High, and Low load forecasts with the assumption that weather will be average or "normal" in every year.[16] While this is a reasonable assumption for long-term resource planning, weather from one year to the next is never the same. For this reason,

[16] The Companies use the most recent 20 years of historical weather data to develop their normal weather forecast, and weather does not explain any differences between the forecasts. Factors that explain differences between the forecasts include economic development, electrification, distributed generation, energy efficiency, and customer growth.

to support the Companies' Resource Adequacy Analysis, the Companies produced 51 hourly load forecasts for 2032 based on weather in each of the last 51 years (1973-2023). The year 2032 is particularly important because it is the first full year in the Mid load forecast scenario with all economic development load additions.

Figure 5-5 contains distributions of the Companies' summer and winter peak demands for 2032 based on these "weather year" forecasts. The values labeled "Forecasted Peak" (i.e., 7,201 MW in the summer and 7,135 MW in the winter) are the Companies' forecasts of summer and winter peak based on average peak weather conditions over the past 20 years. While the Forecasted Peak is higher in the summer, the variability in peak demands is much higher in the winter.[17] This is largely due to the wider range of low temperatures that can be experienced in the winter and because electric heating systems consume significantly more energy during extreme cold weather when the need for backup resistance heating is triggered. The variability in energy requirements due to weather is a key consideration in resource planning.

Figure 5-5: Mid Forecast Distribution of Summer and Winter Peak Demands, 2032



[17] The distributions in **Error! Reference source not found.** do not reflect load reductions associated with the Companies' Curtailable Service Rider ("CSR") because this program is modeled as a generation resource; CSR load reductions are forecast to be 110-115 MW in 2032. The maximum winter peak demand (8,307 MW) is forecasted based on the weather from January 20, 1994 when the average temperature was -9 degrees Fahrenheit and the low temperature was below -20 degrees Fahrenheit. For comparison, the Companies' peak demand on January 6, 2014 during the polar vortex was 7,114 MW when the average temperature was 8 degrees Fahrenheit and the low temperature was -3 degrees Fahrenheit. CSR customers were curtailed during this hour and the departing municipals' load was 285 MW.

3. State and Federal Regulations

The Companies' Resource Assessment considered four environmental regulation scenarios:

<u>No New Regulations</u>

This scenario assumes the Good Neighbor Plan (concerning the ozone National Ambient Air Quality Standards ("NAAQS")), 2024 Effluent Limit Guidelines ("ELG"), and recent Clean Air Act ("CAA") Section 111(b) and (d) Greenhouse Gas ("GHG") Rules or their equivalents do not take effect over the IRP planning period, and no new regulations are implemented through the end of the IRP planning period (2039) that require significant investment for environmental compliance.[18]

<u>Ozone NAAQS (Good Neighbor Plan)</u>

This scenario assumes the 2024 ELG and GHG Rules or their equivalents do not become effective during the IRP planning period, but the Good Neighbor Plan or its equivalent does become effective. In this case, because selective catalytic reduction ("SCR") is a Reasonably Achievable Control Technology for ozone NAAQS compliance, the Companies assume SCR will be needed to operate Ghent 2 in the ozone season beyond 2030. The timing of the need for SCR is based on the Good Neighbor Plan's daily NOx emission limit beginning in 2030. The Good Neighbor Plan also limits NOx emissions for the ozone season beginning in 2028.

<u>Ozone NAAQS + ELG</u>

This scenario builds on the Ozone NAAQS scenario and assumes the 2024 ELG or its equivalent will also become effective, but GHG Rules or their equivalents do not become effective during the IRP planning period. Although the Companies have commented that the Best Available Control Technology determinations for the 2024 ELG are not adequately justified, the EPA has authority to implement the final rule, the technologies exist, and there are no particular impediments to implementation. Therefore, the Companies believe the Ozone NAAQS + ELG scenario is the most likely environmental scenario.

<u>Ozone NAAQS + ELG + GHG</u>

This scenario assumes the Good Neighbor Plan, 2024 ELG, and Greenhouse Gas Rules or their equivalents all become effective during the IRP planning period.[19] Although the EPA is obligated to set source performance standards, they must be achievable and adequately demonstrated. Among the standards are carbon capture transport and storage. There is no regulatory standard for storage wells or CO_2 pipelines in Kentucky, and implementing CO_2 transport or storage is not achievable on the GHG Rule's compliance timeline. Co-firing natural gas or full gas conversion are compliance alternatives for the GHG Rules; however, implementing additional natural gas transportation pipelines on the compliance timeline is questionable. Retiring generation is a compliance alternative for the GHG Rules, but retirements require reliable replacement capacity. Replacing generation at the scale necessary for compliance is not reasonable on the GHG Rules' timeline. Therefore, the Companies assign a low likelihood to this scenario.

[18] All of these environmental regulations are defined and discussed at length in Section 6.
[19] The Companies evaluated GHG Rules as a carbon constraint and did not separately model a carbon tax.

4. Generating Unit Operating Life

As a simplifying assumption in the 2021 IRP, the Companies assumed all coal units would retire at the end of their book depreciation lives. In the Companies' 2022 CPCN and DSM-EE application, the Companies performed a more detailed analysis to evaluate the economics of retiring coal units impacted by recently promulgated environmental regulations (Mill Creek 1, Mill Creek 2, Ghent 2, and Brown 3). In doing this, they assumed all other resources would operate through the end of the analysis period to focus the analysis on the decisions immediately at hand. For the 2024 IRP, at the Commission's request, the Companies configured PLEXOS to evaluate the economics of all coal unit retirements.

5. Generating Unit Performance

Uncertainty related to the performance and availability of generating units is a key consideration in assessing resource adequacy. From one year to the next, the average availability of generating units is fairly consistent. However, the timing and duration of unplanned outage events in a given year can vary significantly. Therefore, in addition to weather uncertainty, the Companies' resource adequacy studies consider the uncertainty in unit availability by evaluating a wide range of unit availability scenarios. Section 3.1 in Volume III (2024 IRP Resource Adequacy Analysis) demonstrates the impact of different availability assumptions on loss of load expectation.

6. Fuel and Emission Prices

For the 2024 IRP Resource Assessment, the Companies developed five fuel price scenarios using the methodology that was used to develop fuel price scenarios for their 2022 CPCN Resource Assessment, which the Commission found to be credible and reasonable in its Final Order in that proceeding.[20] In these fuel price scenarios, natural gas prices are the primary price setting factor, with coal prices derived from gas prices beginning in 2025 based on different historical coal-to-gas ("CTG") price ratios. Sections 4.1.4 and 5.6 in Volume III (2024 IRP Resource Assessment) summarize the Companies' fuel and emission price scenarios.

In past IRPs, the Companies placed a cost on CO_2 emissions in some scenarios to evaluate the risk of future CO_2 regulations. In this IRP, because the Companies evaluated compliance with the Greenhouse Gas Rules, they did not evaluate any scenarios with a CO_2 price.

7. Generation Resource Costs

One significant development in this IRP is higher generation resource costs. As noted in Volume III (2024 IRP Technology Update), the costs of new NGCC and SCCT have increased more in recent years than renewables and battery storage, and significant tax incentives are available for renewables and battery storage. In addition, whereas the costs of NGCC and battery storage are projected to increase from the beginning of the analysis period, the costs of renewables and battery storage are projected to decline for several years before escalating slowly through the end of the

[20] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan*, Case No. 2022-00402, Order at 93-94 (Ky. PSC Nov. 6, 2023) ("The Commission finds that LG&E/KU's evidence regarding the relationship between coal and natural gas prices is credible. … [W]hether projected separately or together, the Commission believes that it is reasonable to assume a relationship between coal prices and natural gas prices. … [T]he Commission finds that LG&E/KU's fuel price scenarios were reasonable ….").

analysis period. This is particularly significant for the cost of solar, which is projected in nominal terms to decrease by more than 30% by 2035. The Companies' Resource Assessment tests this assumption by evaluating a sensitivity where the cost of solar is assumed to escalate slowly from the beginning of the analysis period.

5.(3) Energy Requirements ("Load") Forecasts

In accordance with 807 KAR 5:058 Section 7(3), the Companies developed a base load forecast (called the "Mid" forecast in this IRP), as well as High and Low forecasts of energy requirements to evaluate resource planning decisions under multiple load scenarios.

The Companies' load forecasting process continues to account for important macroeconomic data, customer usage history and trends, and other energy usage drivers such as projected end-use efficiency and saturation data (e.g., the saturation of high-efficiency heat pumps for residential customers).

Of particular importance to this IRP is economic development activity. Kentucky's economic development progress has been historic for the last several years, and the state continues to invest heavily to ensure this progress continues. The evolution of economic development projects puts more emphasis on energy availability than ever before. Site selection consultants indicate that energy availability and cost are among the top ten most important factors in site selection over the last two years, and energy availability was tied for first on the list in 2022. Energy availability is a necessity to compete for major projects in primary metals manufacturing, indoor agriculture, battery production, and now data centers. Energy-intensive data centers are crucial to consumers, businesses, and the safety and security of our nation. They support critical business applications, store valuable business and personal data, keep data safe from threats, and serve as a foundation for modern business and government applications.

Therefore, potential new data centers are a key load forecast driver in this IRP. To model the effects of such large potential loads, as well as other important items such as distributed generation and energy efficiency, the Companies created three load forecast scenarios, as shown in Table 5-2 below, to study what the lowest-cost portfolios might be across a reasonable range of possible future load scenarios:

Table 5-2: 2024 IRP Load Forecast Scenarios—Key Differences

Load Scenario	Data Centers in 2032	Distributed Generation in 2032	Energy Efficiency, CVR, AMI, and Other Energy Reductions in 2032[21]
Low	0 MW	275 MW	2,150 GWh
Mid	1,050 MW	150 MW	1,500 GWh
High	1,750 MW	125 MW	700 GWh

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

As shown in Figure 5-6 and Figure 5-7 below, annual energy requirements and seasonal peaks in the Low load scenario gradually decrease over the planning horizon due to energy efficiency and distributed generation in combination with minimal economic development load growth and the loss of two large customers in the 2030s. In contrast, by 2032 in the Mid and High load scenarios annual energy requirements increase by over 30% to over 60%, respectively, and seasonal peak demands increase by about 1,000 MW to 2,000 MW, respectively, relative to the Low load forecast scenario. 2032 is an important year for the Mid and High load forecasts because it is the year in which all assumed new data center load is fully online, making it a key year for resource planning in this IRP.

Figure 5-6: 2024 IRP Annual Energy Requirements (GWh)[22]

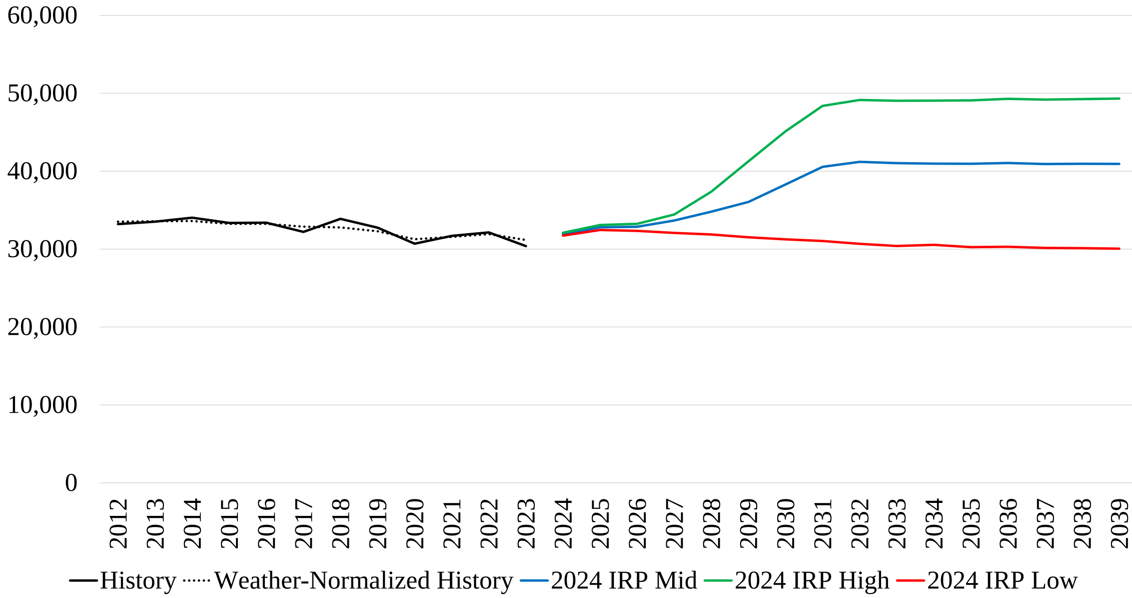
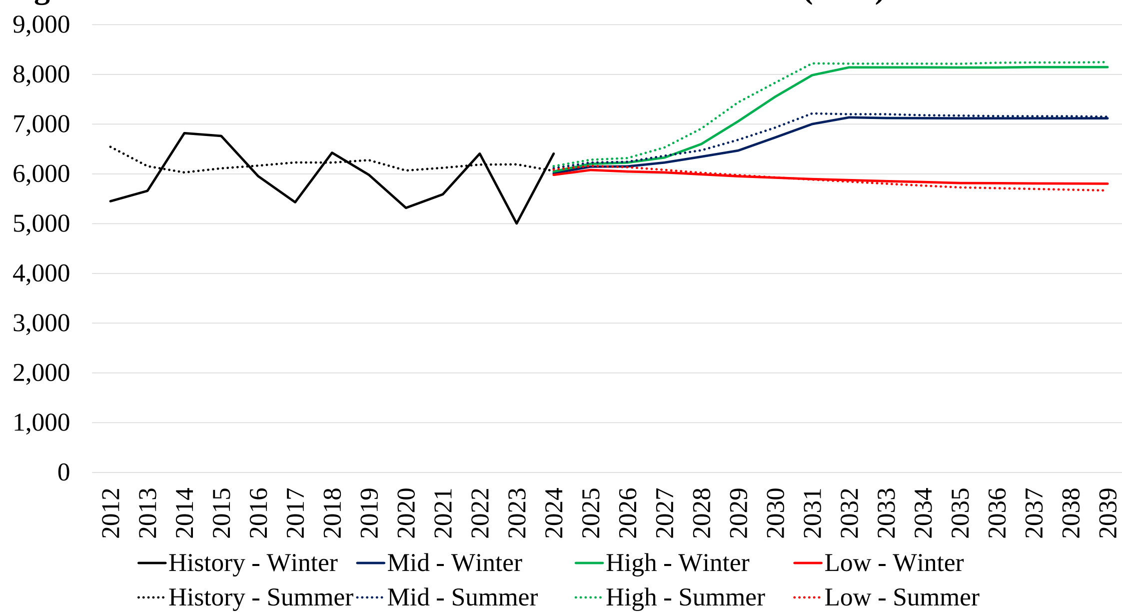


Figure 5-7: 2024 IRP Winter and Summer Peak Demands (MW)[22]



Based on current economic development activity, including data centers, the Companies assign a low likelihood to the Low forecast. The 2024 IRP therefore focuses primarily on the Mid and High load forecasts, though the analysis considers all three forecasts.

Two important observations regarding the data above are:

[22] History excludes municipal customers that departed in 2019.

- **The Companies' system is now consistently dual-peaking.** Figure 5-7 above shows that the Companies' system peaks routinely occur in the winter, and the highest peaks in the last ten years have all occurred in the winter. This means the Companies must plan to serve peak loads not only on sunny summer days when solar is maximally producing, but also during cold, non-daylight winter hours. Importantly, the Companies' customers tend to consume more than half of their daily energy during non-daylight hours in the winter, as well as more than 30% during non-daylight hours in the summer. Therefore, the Companies' resource planning must consider not just peak load conditions but also total energy needs in all hours and seasons.

- **All the load forecasts assume significant amounts of energy-reducing measures, including from the Companies' DSM-EE Programs and distributed generation.** For example, as shown in Table 5-2 above, the Companies' Mid load forecast includes nearly 1,500 GWh annually of energy 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' proposed 2024-2030 DSM-EE Program Plan and new programs beyond 2030. These reductions are in addition to significant reductions observed historically from customers' actions to use electricity more efficiently. The Mid load forecast further assumes 150 MW of installed distributed solar capacity by 2032. These items have a non-trivial impact on the Companies' load forecast.

Key Forecast Assumptions and Uncertainties

The following is a discussion of key energy requirement forecast assumptions and uncertainties. Note that the weather and cost of service assumptions do not change among the three load forecast scenarios.

1. Economic Development

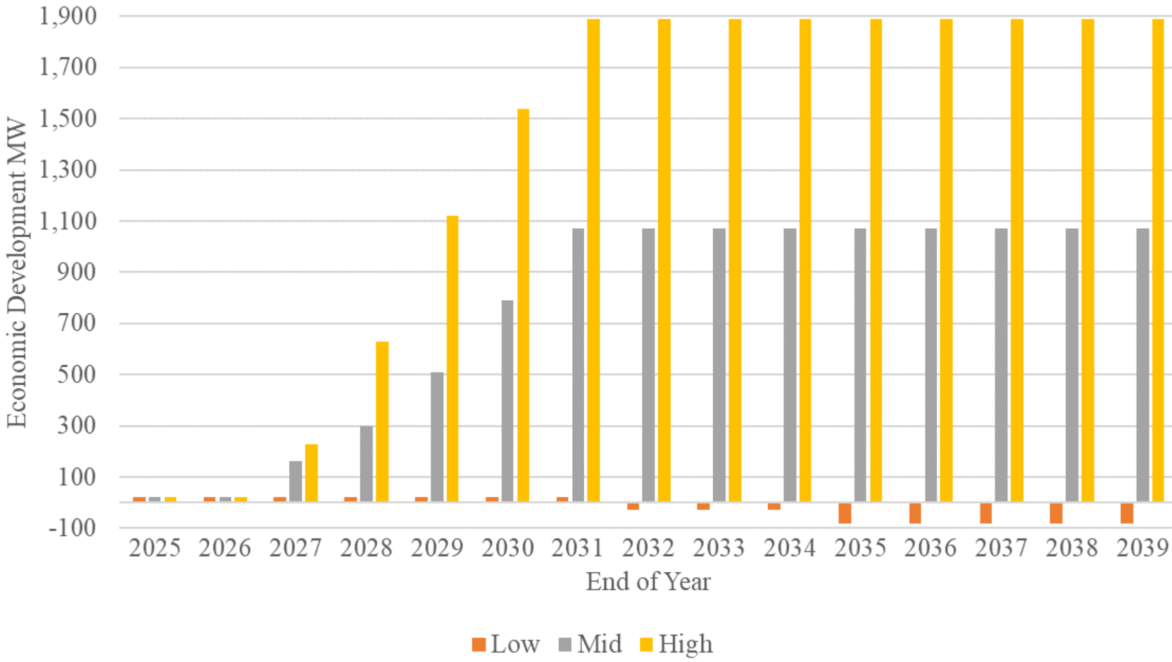
As noted above and discussed at length in Section 7, Kentucky's economic development progress has been historic for the last several years, and the state continues to invest heavily to ensure this progress continues. Of particular importance to this IRP is potential data center load. Data centers tend to be large, with each potentially ranging from several hundred megawatts to one gigawatt or more, and they have exceptionally high load factors, i.e., in the range of 95%.

The IRP considers three economic development load growth scenarios to address this uncertainty and opportunity. The Mid scenario assumes 1,050 MW of data center load by 2032 and another relatively small economic development project. The High scenario assumes 1,750 MW of data center load in addition to the smaller project plus the second phase of the Blue Oval SK ("BOSK") electric vehicle battery production facility. Figure 5-8 compares the three economic development scenarios the Companies contemplated. The Mid and High scenarios account for small portion of data center load growth projections for the U.S. as a whole.[23] In the Low scenario, zero data centers

[23] The Mid scenario represents 4.2% of data center load growth in the U.S. from a recent Newmark study (https://www.nmrk.com/storage-nmrk/uploads/documents/2023-U.S.-Data-Center-Markets.pdf) and 9.4% of EPRI's Moderate growth projection (https://restservice.epri.com/publicdownload/000000003002028905/0/Product). The High scenario represents 7.5% of EPRI's High growth projection and only 4.3% of their Higher growth projection.

and only the one small project result in insignificant growth. Additionally, the Low scenario assumes a couple of large customers leave the service territory later in the 2030s. The Companies assign a low likelihood to the Low scenario.

Figure 5-8: Economic Development Growth Projections (GWh)



2. Normal Weather

The Companies develop their long-term energy requirements forecasts with the assumption that weather will be average or "normal" in every year. Thus, weather does not explain any differences between the Low, Mid, and High long-term energy requirements forecasts. The Companies use the most recent 20 years of historical weather data to develop their normal weather forecast. The Companies have consistently used this period to calculate normal weather because it provides a more recent view of weather than a 30-year normal, and changes from one year to the next when updating a 20-year normal are significantly less volatile than a 10-year normal. According to a recent Itron survey, a 20-year normal is most common among electric utility forecasters.

3. Economic Assumptions

Economic assumptions in the Companies' Mid energy requirements forecast are taken from S&P Global's May 2024 U.S. Economic Outlook.[24] For the U.S. overall, S&P Global projects 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.

[24] See Volume II ("S&P Global Market U.S. Economic Outlook – May 2024").

In Kentucky, S&P Global projects 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. The same downside risks that are present for the U.S. economic expansion also present potential headwinds for the Kentucky economy.

4. Energy Efficiency

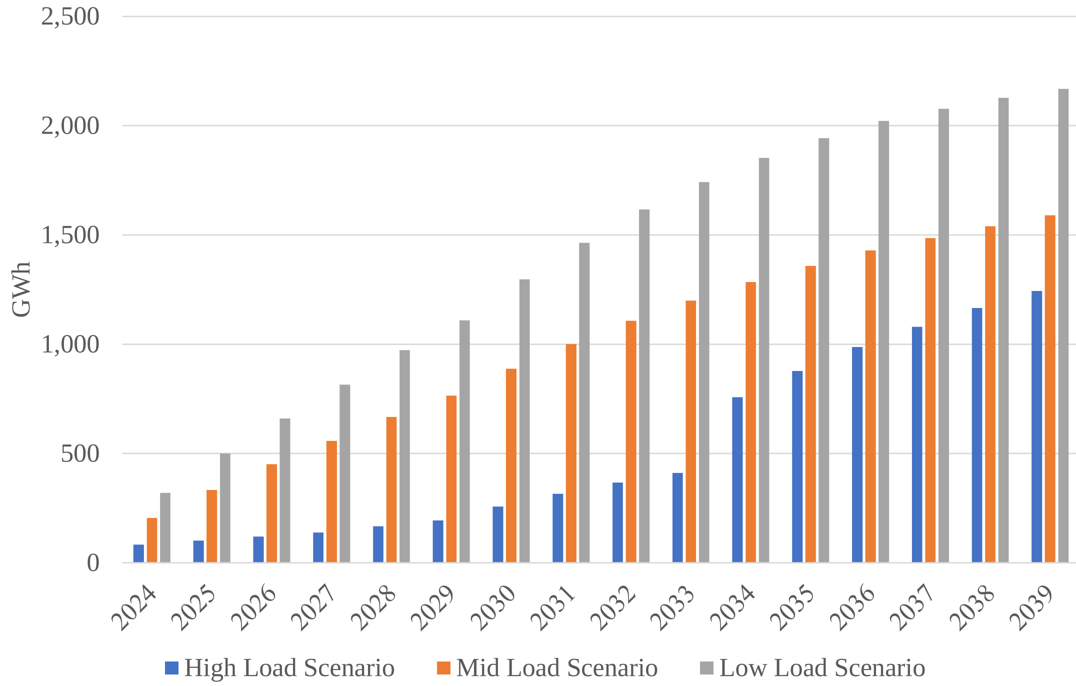
As noted previously, the Companies' Mid load forecast includes nearly 1,500 GWh of reductions by 2032 from customer-initiated energy efficiency improvements, AMI-related conservation load reduction and ePortal savings, distributed generation, and the energy efficiency effects of the Companies' proposed 2024-2030 DSM-EE Program Plan as well as new programs beyond 2030. These reductions are in addition to significant reductions observed historically from customers' actions to use electricity more efficiently.

Forecasted energy efficiency improvements account for the Inflation Reduction Act ("IRA") that President Biden signed in August 2022. The IRA is expected to impact load through a variety of programs designed to incentivize either reduced consumption through distributed solar and more energy efficient appliances, or electrification (which would likely increase consumption) through EVs and heat pumps. The Mid energy requirements forecast assumes continued energy efficiency improvements consistent with the IRA and Companies' DSM-EE programs as well as continuation of Department of Energy ("DOE") energy efficiency standards.

Forecasted 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 projected to continue throughout the forecast period.

Forecasted end-use efficiency improvements are explicitly incorporated in residential and commercial forecasts through the statistically adjusted end-use modeling approach described in Volume II. Figure 5-9 shows the impacts of energy efficiency improvements on the residential and commercial sales forecasts in the forecast scenarios. As seen in the figure, the combined impact of company-sponsored and customer-initiated energy efficiency improvements are assumed to increase throughout the IRP planning period.

Figure 5-9: Impact of Energy Efficiency Improvements on Residential and Commercial Sales Forecast[25]



5. Cost of Service

Electricity prices are a consideration in the electric load forecast. The load forecasting process explicitly contemplates short-run price elasticity of demand via statistically adjusted end-use models. In addition, the Mid load forecast represents the Companies' view of the most likely development in 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. Electricity prices are assumed to increase by 2.3 percent per year, consistent with long-term inflation expectations.[26]

If higher-than-expected prices materialize, the Companies anticipate a decline in sales as compared to the current forecast (all else equal) due to the negative price elasticities incorporated into the forecasting models. Therefore, the Low load scenario can act as a proxy for a high electricity price scenario.

6. Customer Growth

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. Further, the forecasted 2024-2039 growth rate averages tenth in the US as compared to the average rate over the previous ten years. If such growth exceeds expectations, it would tend to increase load over time.

[25] With accelerated efficiency gains, end-use efficiencies are assumed to reach 2044 levels by 2034.

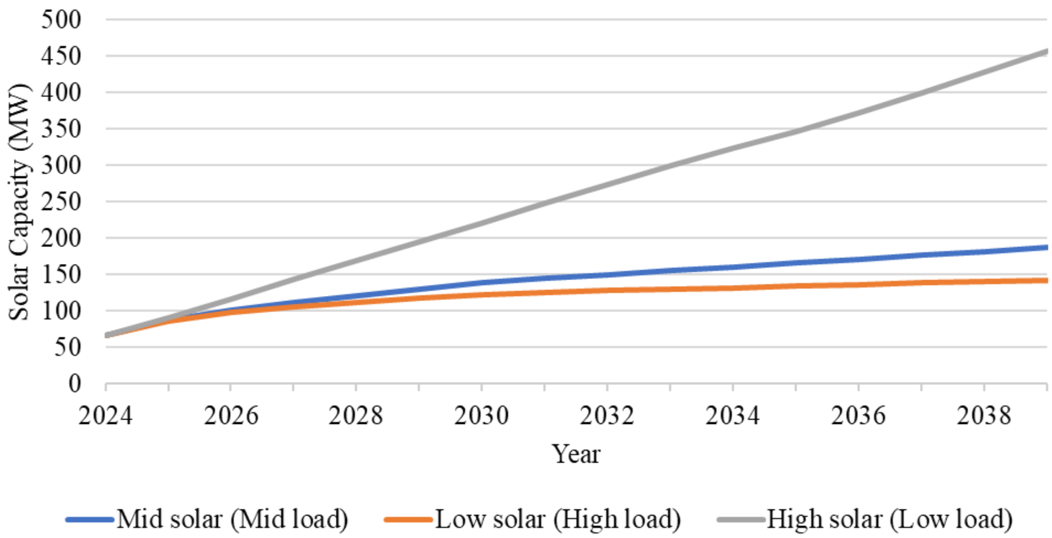
[26] See Volume II ("Inflation Assumptions").

7. Distributed Generation and Battery Storage

The Companies' load forecasts explicitly account for expected distributed generation. Distributed generation includes generation from net metering and qualifying facilities ("QF") customers. Because about 99.8% of all distributed generation installations connected to the Companies' facilities in their service territory are solar, the Companies model solar as the sole distributed generation resource to forecast energy production from distributed generation and to forecast how distributed generation capacity will grow over the IRP planning horizon.[27] The Companies further discuss this approach and the rationale for it in Section 7.

The distributed generation forecast scenarios embedded in the Companies' Low, Mid, and High load forecasts are shown in Figure 5-10 below.

Figure 5-10: Distributed Generation Forecast Scenarios



The different trajectories of distributed generation over time shown in Figure 5-10 above result from different assumptions about the economics of distributed solar in each scenario. The single most important difference is that the High solar (Low load) scenario assumes net metering continues indefinitely, whereas the Low and Mid solar scenarios assume that net metering capacity is capped at 1% of the Companies' annual peak load in 2025, meaning that all distributed generation added thereafter would be compensated at QF cost-based rates rather than net metering rates.[28] Compared to the Mid solar forecast, customer growth in the Low solar (High load) scenario is slower and the size of new net metering installations is smaller as customers size their arrays to limit excess solar energy sold back to the grid after the 1% cap is reached.

---

[27] Of the Companies' more than 5,400 distributed generation customers, there are only 11 non-solar distributed generation installations; 1 is hydro and the remainder are wind. No new non-solar distributed generation installations have occurred in the past 6 years, the most recent being a wind installation in 2018.

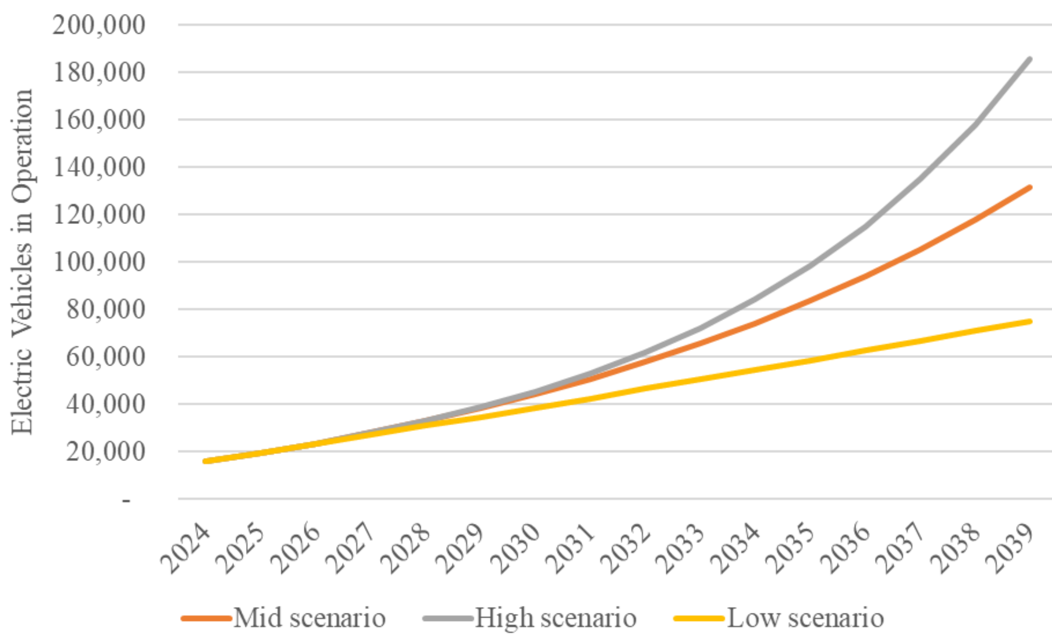
[28] See KRS 278.466(1).

Regarding customers' battery storage, due to the low rates of energy storage adoption,[29] uncertainty around charging and discharging patterns, and unknown adoption numbers of battery storage for non-net metering customers, the Companies do not explicitly forecast distributed battery adoption. In this IRP, the distributed generation forecast implicitly assumes the level of battery storage increases with customer growth.

8. Electric Vehicles

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. From 2017 to 2023, the estimated number of electric vehicles ("EVs")[30] in operation in the LG&E and KU service territories grew by an average of 43% per year from 1,415 to 12,284. EVs in operation are forecast in the Mid load forecast to increase to over 130,000 by the end of 2039, accounting for 8% of the 1.7 million cars assumed to be in the Companies' service territory in total by 2039. Figure 5-11 shows the mid, low, and high forecasts for the number EVs in the Companies' service territories.

Figure 5-11: Electric Vehicles in Operation, 2024 - 2039



The high EV scenario contemplates not only continued patterns of EV adoption, but rapid growth starting in the 2030s. The high scenario inherently assumes, either through new technological innovations, significant advances to charging infrastructure, or updated vehicle emissions standards, that EVs will eventually either become less expensive than internal combustion engine

[29] The Companies are aware of only 1,849 kW of distributed battery energy storage system capacity across 286 customer installations at the end of 2023.

[30] 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.

(“ICE”) vehicles or essentially become the only option for consumers due to more stringent vehicle emissions standards.

The low scenario assumes that there will be a slow-down of incremental growth in EV adoption rates like the U.S. experienced during the first quarter of 2024,[31] though a similar slowdown is not yet evident in the Companies’ service territory.

The primary factors impacting total electricity consumption by EVs are the number of EVs and the distance driven per vehicle, though the timing of EV charging is at least equally important for resource planning. If EVs are charged overnight when energy requirements would otherwise be low, the vehicles can likely be charged with the Companies’ existing dispatchable generation assets. Conversely, 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.

9. Space Heating Electrification

The Companies account for space heating electrification in their load forecasts. The Companies assume in the High load forecast that space heating electrification penetration will increase more rapidly than in the Mid forecast. Conversely, the Companies assume in the Low load forecast that space heating electrification penetration will increase more slowly than in the Mid forecast. The Companies provide a full discussion of space heating electrification in Section 7.

Summary of Impact of Key Assumptions and Uncertainties on Load Forecasts

Figure 5-12 shows the disaggregated impact of each High and Low scenario assumption on the Mid energy requirements forecast. (Note that the weather and cost of service assumptions discussed in the section above do not change among the three load forecast scenarios and therefore are not reflected in the figures below.) In either scenario, the impact of economic development cannot be overstated. With the second phase of the Blue Oval SK battery park (in the high scenario only) and new data centers, economic development customers have extremely high load factors, so the energy impact is significant. In fact, energy swings by nearly 10,000 GWh on either side of the Mid forecast. The other uncertainties in the forecast are minimal within the IRP period when compared to the size of these economic development customers.

---

[31] U.S. share of electric and hybrid vehicle sales decreased in the first quarter of 2024. U.S. Energy Information Administration (EIA) - May 14, 2024. https://www.eia.gov/todayinenergy/detail.php?id=62063

Figure 5-12: High and Low Scenario Energy Requirements Differences (GWh)

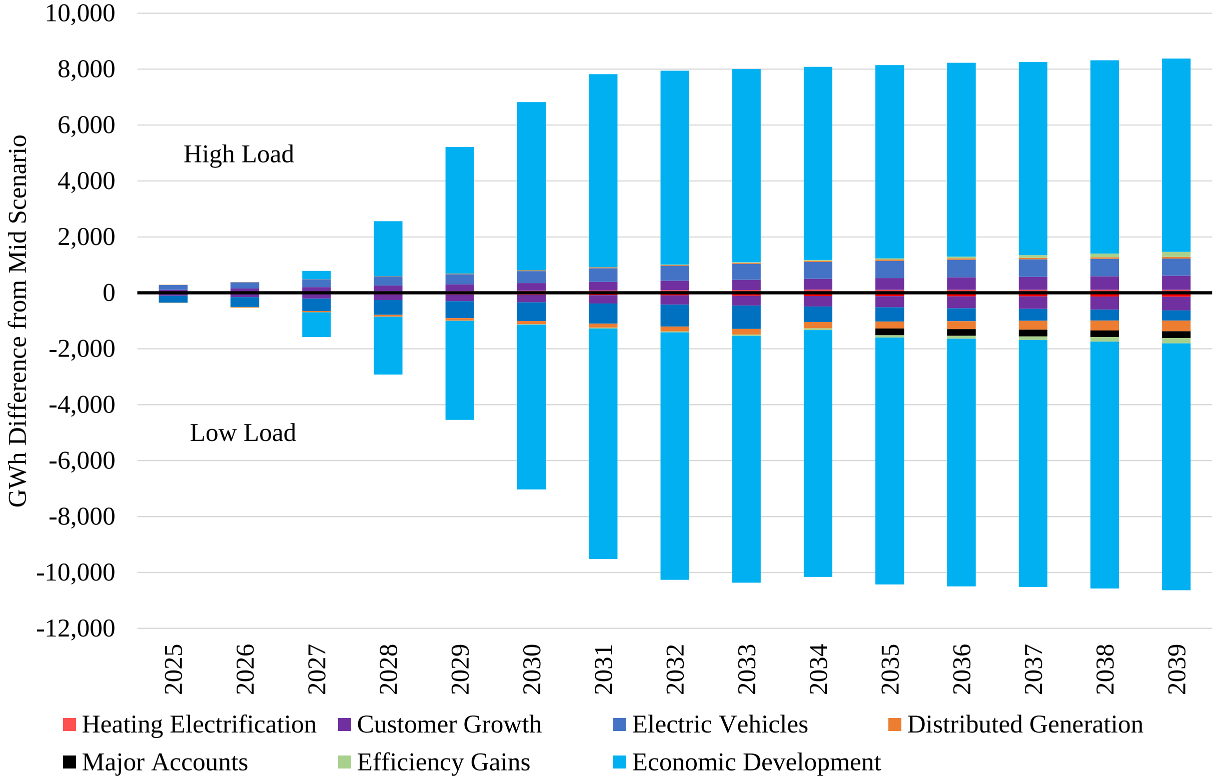


Figure 5-13 and Figure 5-14 show the disaggregated impact of each high and low scenario assumption on the Mid summer and winter peak demand forecasts, respectively. Once again, the impact of economic development on peaks cannot be overstated on the total peaks. Economic development loads are the majority of the reason for scenario peaks moving nearly 1,000 MW above and below the mid forecast in each season. In the low scenario, greater adoption of distributed generation also causes the summer peak to trend lower over the IRP period such that the winter peak is essentially the same as the summer peak by the end of the IRP period. The summer peaks have downside risk due to distributed generation while the winter peaks have upside risk due to space heating electrification.

Figure 5-13: High and Low Scenario Summer Peak Differences (MW)

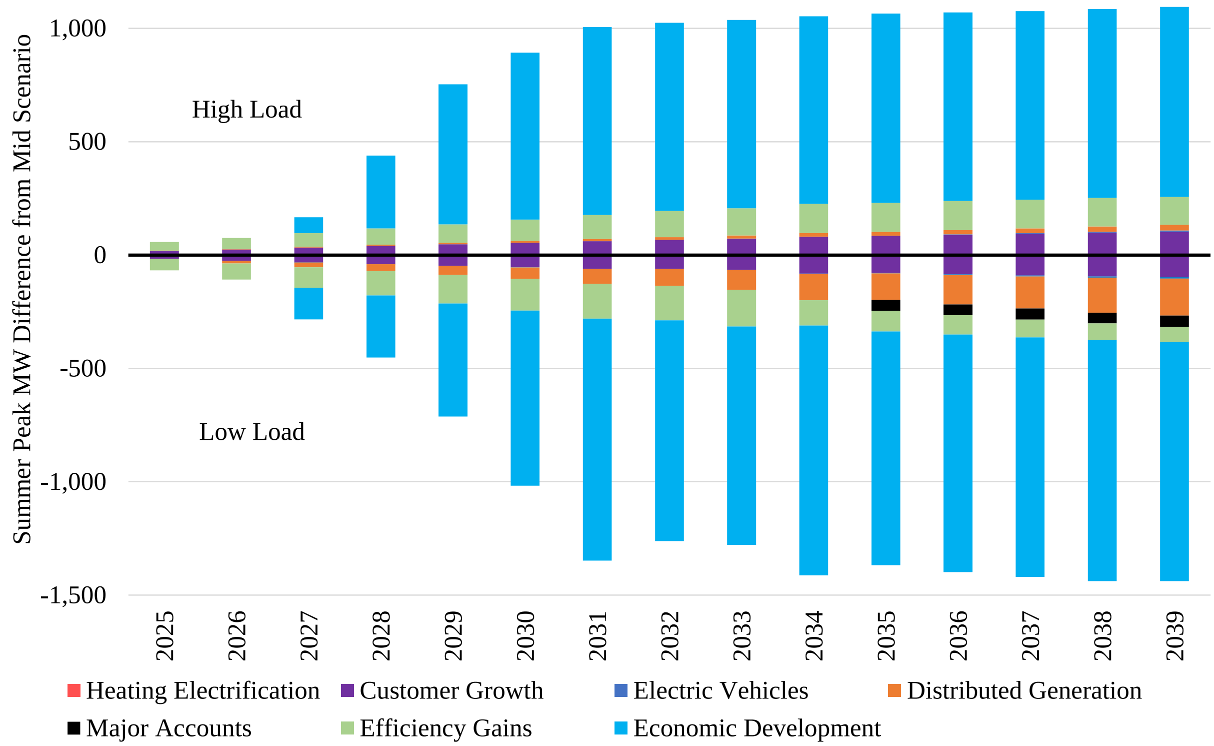
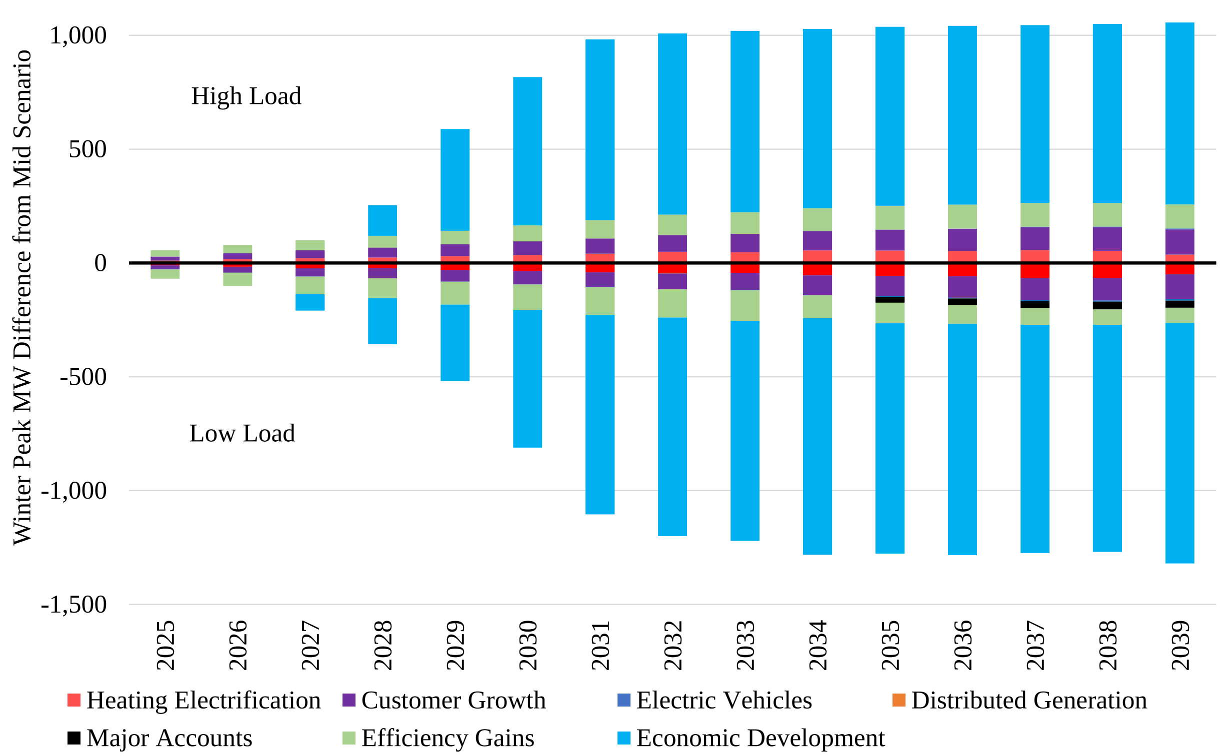


Figure 5-14: High and Low Scenario Winter Peak Differences (MW)



5.(4) Recommended Resource Plan

The Companies developed least-cost resource plans subject to reserve margin and other constraints for each load and environmental scenario (12 scenarios in total comprising three load scenarios and four environmental scenarios). To do this, the Companies first used PLEXOS to develop resource plans for each of the 12 load and environmental scenario across each of the five fuel price scenarios, resulting in 60 total resource plans. The Companies then evaluated each resource plan with detailed production costs over each of the fuel price scenarios to determine which resource plan for a given load and environmental scenario is lowest cost across all fuel price scenarios.

The Companies established minimum winter and summer reserve margin constraints with the goal of limiting loss-of-load expectation ("LOLE") to one day in 10 years. This analysis is summarized in Volume III (2024 IRP Resource Adequacy Analysis). These "1-in-10" reserve margins are 29% in the winter and 23% in the summer. In addition to reserve margins, the Companies' modeling considered constraints due to legislative unit retirement restrictions, landfill storage capacity, and technology availability. Volume III (2024 IRP Resource Assessment) contains a summary of the Companies' Resource Assessment.

The Companies included a total of twelve different new resources in their resource assessment. These consisted of three fully dispatchable resource types (SCCT, NGCC, and small modular nuclear reactors), three renewable resource options (utility-scale solar, Kentucky wind resources, and Indiana wind resources), and six limited-duration resources (4-hour BESS, 8-hour BESS, three dispatchable DSM measures, and an expansion of the Companies' CSR-2 tariff rider). The Companies based their resource costs and assumptions on the "Moderate" scenario in National Renewable Energy Laboratory's 2024 Annual Technology Baseline, updated cost estimates for resources contemplated in the Companies' 2022 CPCN filing, and the Companies' own analysis.

The Companies also included in their resource modeling environmental retrofit options for existing coal-fired units to allow them to comply with Ozone NAAQS and ELG regulations, as well as the option to convert existing coal units to co-fire natural gas. In contrast, because carbon capture and sequestration technology ("CCS") and infrastructure are unlikely to be sufficiently developed by the time it is needed to comply with GHG Rules (i.e., by 2032 in this planning horizon), and because their costs and possible future commercial viability and availability remain highly uncertain, the Companies did not include them in their IRP modeling

For the reasons discussed in Section 5.(2) (State and Federal Regulations), the Companies believe the Ozone NAAQS + ELG environmental scenario is the most likely environmental scenario. In addition, for the reasons discussed in Section 5.(3) (Economic Development), the Companies believe the likelihood of the low load forecast scenario with no economic development load growth is very low. Therefore, the Companies developed their Recommended Resource Plan based on the results of the Mid load, Ozone NAAQS + ELG and High load, Ozone NAAQS + ELG scenarios.

Table 5-3 contains the least-cost resource plans across all fuel scenarios for these two load and environmental scenarios. In both scenarios, new NGCC resources and battery storage ("BESS") charged by existing resources are added to serve economic development load growth. The least-cost portfolios include all new demand response measures but no additional CSR. With higher costs for new resources and EPA's obligation to drive local NAAQS attainment, SCR is added to Ghent 2 in 2030 but could be needed as early as 2028.[32] Brown 3 is retired in 2035 due in part to landfill constraints. The Companies comply with the 2024 ELG rules at Ghent and Trimble County via zero liquid discharge, but not at Mill Creek due in part to landfill constraints. Finally, the Brown and Mill Creek coal units are replaced by NGCC and SCCT capacity.

Table 5-3: Least-Cost Resource Plans (Ozone NAAQS + ELG)[33]

	Least-Cost Resource Plans Ozone NAAQS + ELG	
Year	**Mid Load, Solar Cost Sensitivity[32]**	**High Load**
2028	+Disp DSM	+Disp DSM; +300 MW 4hr BESS
2029		+700 MW 4hr BESS
2030	Retire BR3; Add GH2 SCR; +1 NGCC; ELG @ GH, TC; +100 MW 4hr BESS	Add GH2 SCR; +1 NGCC; ELG @ GH, TC
2031	+400 MW 4hr BESS	Retire BR3; +1 NGCC; +200 MW 4hr BESS
2032	+200 MW 4hr BESS	+200 MW 4hr BESS
2033		
2034		
2035	Retire MC3-4; +1 NGCC; +200 MW 4hr BESS	Retire MC3-4; +1 NGCC; +1 SCCT
2036		
2037		
2038		
2039		

Table 5-4 contains the least-cost resource plans in the Mid load, Ozone NAAQS + ELG and High load, Ozone NAAQS + ELG scenarios, as well as the Recommended Resource Plan and an Enhanced Solar Resource Plan. To develop the Recommended Resource Plan, the Companies started with the resource plan that is least-cost in the Mid load, Ozone NAAQS + ELG scenario and modified it to (1) support the potential for high economic development load growth and CO_2

[32] Unlike the High load scenario, the least-cost resource plan in the Mid load scenario does not initially include an SCR on Ghent 2. However, this is predicated upon the availability of almost 2,000 MW of solar at costs more than 30 percent lower than today, which is inconsistent with the Companies' recent market experience and potentially not possible to execute. When considering a sensitivity case where solar prices do not decline as predicted by NREL's 2024 ATB, the least-cost resource plan for the Mid load scenario includes an SCR on Ghent 2.
[33] PLEXOS was configured to add NGCC (660 net winter MW) and SCCT (258 net winter MW) in one-unit increments and BESS in 100 MW increments.

regulations and (2) have no regrets should high load or CO_2 regulations not come to fruition. The Mid load, Ozone NAAQS + ELG scenario includes the retirements of Brown 3 and Mill Creek 3-4, ELG compliance at the Ghent and Trimble County stations via zero liquid discharge, and the additions of two NGCCs, 900 MW of battery storage, and a Ghent 2 SCR. In the Recommended Resource Plan, to support the potential for high economic development load growth and CO_2 regulations, the additions of the Ghent 2 SCR and 400 MW of battery storage are accelerated to 2028, the addition of the second NGCC is accelerated to 2031, and the retirement of Brown 3 is deferred to 2035. In addition, 500 MW of solar is added in 2035 after prices fall to hedge natural gas price volatility and future CO_2 regulation risk.

The Recommended Resource Plan is a "no regrets" resource plan because the accelerated resources are needed by 2035 if high economic load growth or CO_2 regulations do not come to fruition. Furthermore, the addition of 500 MW of solar reflects the likelihood that some level of solar will be least-cost even without CO_2 regulations. More information regarding the Recommended Resource Plan is included in Section 8.

Table 5-4: Recommended Resource Plan and Enhanced Solar Resource Plan (only years in which changes occur are shown)

Year	Least-Cost Resource Plans Ozone NAAQS + ELG		Recommended Resource Plan Ozone NAAQS + ELG Mid Load	Enhanced Solar Resource Plan Ozone NAAQS + ELG Mid Load
	Mid Load, Solar Cost Sensitivity	High Load		
2028	+Disp DSM	+Disp DSM; +300 MW 4hr BESS	+Disp DSM +400 MW 4hr BESS; Add GH2 SCR	+Disp DSM +400 MW 4hr BESS; Add GH2 SCR +200 MW Solar
2029		+700 MW 4hr BESS		
2030	Retire BR3; Add GH2 SCR; +1 NGCC; ELG @ GH, TC; +100 MW 4hr BESS	Add GH2 SCR; +1 NGCC; ELG @ GH, TC	+1 NGCC; ELG @ GH, TC	+1 NGCC; ELG @ GH, TC +200 MW Solar
2031	+400 MW 4hr BESS	Retire BR3; +1 NGCC; +200 MW 4hr BESS	+1 NGCC	+1 NGCC
2032	+200 MW 4hr BESS	+200 MW 4hr BESS		+600 MW Solar
2035	Retire MC3-4; +1 NGCC; +200 MW 4hr BESS	Retire MC3-4; +1 NGCC; +1 SCCT	Retire MC3-4; Retire BR3; +500 MW 4hr BESS; 500 MW Solar	Retire MC3-4; Retire BR3; +500 MW 4hr BESS

The Companies' IRP analysis also addresses transmission considerations. The Companies' Long-Term Transfer Analysis shows that the Companies would not require any transmission upgrades to accommodate exports from the Companies to surrounding systems for long-term firm transfers of up to 1,000 MW. The Companies similarly would not require transmission upgrades to accommodate long-term firm transfers to the Companies of up to 300 MW from PJM or MISO and up to 100 MW from TVA. Relatively small investments would be required to increase that import capacity to 500 MW for all three surrounding systems and to 1,000 MW for imports from

MISO, but a fairly significant investment (almost $55 million) would be required to increase the capacity to 1,000 MW from TVA and PJM. But merely increasing import capability does not assure there will be supply adequate to serve the Companies, as they experienced during Winter Storm Elliott. Moreover, for the purposes of IRP modeling, placing a resource farther from the Companies (i.e., in a neighboring system) causes additional transmission cost to access the same resource that could be avoided by placing the resource on the Companies' system, making the resource unlikely to be selected unless there is an offsetting benefit, e.g., a significantly better wind resource.

The Companies identify transmission construction projects and upgrades required for maintaining the adequacy of their transmission system for meeting projected customer demands. The construction projects currently identified are included in Volume III ("Transmission Information").

The Companies are also filing with their IRP an updated RTO membership analysis, which continues to show there is no reason to pursue RTO membership at this time, particularly due to the extreme volatility in capacity market rules and capacity auction results in PJM.

Finally, the Companies are also filing contemporaneously with their IRP a Natural Gas Fuel Security Analysis that addresses the economics of possible gas compression and storage, as well as dual-fuel capability and fuel oil storage, for the Companies' existing and possible future gas-fired generation. A summary of this analysis is included in Volume III (Natural Gas Fuel Security Analysis – October 2024).

5.(5) Steps to be Taken During Next Three Years to Implement Plan

Over the next three years, the Companies will be taking steps to implement nearly all of the approved resource changes from their 2022 CPCN (Case No. 2022-00402).[34] Consistent with the Commission's Order, Mill Creek 1 will be retired at the end of 2024 and Mill Creek 2 will be retired in 2027 after Mill Creek 5 is commissioned. In addition, the Companies will commission 125 MW of 4-hour battery storage at E.W. Brown in 2026 as well as two 120 MW solar farms in Mercer (2026) and Marion (2027) Counties. Consistent with the continuing importance of solar in the Companies' resource planning discussed above, the Companies will continue to study opportunities to deploy cost-effective solar and other renewable resources.

[34] The Companies do not presently expect that the approved solar PPAs will advance under their approved terms, though both the 2024 IRP Recommended Resource Plan and the Enhanced Solar Resource Plan contain significant amounts of new solar. Of the six total solar PPAs into which the Companies have entered, including two prior to the 2022 CPCN and DSM-EE case, (a) one has been canceled by the developer due to interconnection issues, (b) one has been canceled by the developer due to a significant project price increase, and (c) one with a price reopener has been contractually terminated due to the Companies' unwillingness to proceed at a much higher price than in the original agreement. The remaining three PPAs appear unlikely to proceed under their approved terms. This IRP therefore does not include these PPAs. But again, the Companies' 2024 IRP Recommended Resource Plan and the Enhanced Solar Resource Plan both contain significant amounts of new solar in addition to hundreds of megawatts of new battery storage, which could help pave the way for additional new renewable resources in the future.

Despite a considerable amount of uncertainty due to load and environmental regulations, the least-cost resource plans in this IRP indicate some additional resource changes that will require more immediate attention. First, additional resources are needed to support economic development load growth and a combination of NGCC and battery storage is the least-cost way to support this growth. Second, with higher costs for new resources and EPA's obligation to drive local NAAQS attainment, SCR is needed on Ghent 2 as early as 2028. A Ghent 2 SCR in 2028 will drive self-compliance to NOx reductions that support Kentucky's obligations to 2015 Ozone NAAQS attainment and provide assurance the unit will be available to support economic development load growth.

As AMI is finalizing implementation, the Companies will continue to evaluate new and current DSM mechanisms that leverage AMI data and communications through the development of pilot programs. The Companies will closely evaluate these programs to assess their ability to avoid or defer the need for supply-side resources as well as engage customers.

Finally, the Companies will continue to monitor developments in battery storage and key issues impacting the way customers use electricity. In addition, the Companies will continue to monitor developments related to environmental regulations, in particular NAAQS for ozone and regulations aimed at reducing CO_2 emissions. Any new information from this research will be incorporated in the Companies' annual planning process.

5.(6) Key Issues that Could Affect Plan Implementation

As noted in the above section, despite a considerable amount of uncertainty due to load and environmental regulations, the least-cost resource plans in this IRP indicate the need for additional resources to support economic development load growth. Therefore, the primary issue that could affect plan implementation is a significant turn of events that reverses progress to date in the state's economic development efforts.

6 Significant Changes

The following sections summarize significant changes since the 2021 IRP was filed in October 2021, but relevant comparisons to the 2022 CPCN are also included.

Load Forecast & Economic Development

Table 6-1 compares the Companies' Mid energy requirements forecasts from the 2024 IRP, 2021 IRP, and 2022 CPCN. Compared to the 2021 IRP, energy requirements in the 2024 IRP are 31.7% higher by 2032 due to the addition of new economic development loads, which include data centers and the first phase of BOSK. Compared to the 2022 CPCN, energy requirements in the 2024 IRP period are slightly lower through 2027 due to the delay of the second phase of BOSK but significantly higher thereafter.

Table 6-1: Companies' Energy Requirements Forecast (Mid Load Scenario, GWh)

Year	2024 IRP	2021 IRP	2022 CPCN	2024 IRP Less 2021 IRP	2024 IRP less CPCN
2024	31,913	32,045	32,324	-132	-411
2025	32,808	31,839	33,050	969	-242
2026	32,867	31,648	33,156	1,219	-289
2027	33,668	31,532	34,026	2,136	-358
2028	34,806	31,519	34,076	3,287	730
2029	36,057	31,370	33,920	4,687	2,137
2030	38,292	31,279	33,808	7,013	4,484
2031	40,569	31,243	33,769	9,326	6,800
2032	41,200	31,283	33,827	9,917	7,373
2033	41,033	31,196	33,717	9,837	7,316
2034	40,971	31,172	33,675	9,799	7,296
2035	40,949	31,188	33,676	9,761	7,273
2036	41,057	31,289	33,792	9,768	7,265
2037	40,930	31,207	33,710	9,723	7,220
2038	40,949	31,247	33,753	9,702	7,196
2039	40,943	31,259	33,754	9,684	7,189
2024-2039 CAGR	1.67%	-0.17%	0.29%		

Table 6-2 compares the 2024 IRP, 2021 IRP, and 2022 CPCN winter peak demand forecasts for the combined companies. In the 2024 IRP, winter peak demands in the 2024 IRP are nearly 1,400 MW higher than the 2021 IRP and over 900 MW higher than the CPCN in 2032.

Table 6-2: Winter Peak Demand Forecasts (MW)

Year	2024 IRP	2021 IRP	2022 CPCN	IRP Change	CPCN Change
2024	6,015	5,859	5,912	156	103
2025	6,146	5,831	6,058	315	88
2026	6,150	5,806	6,058	344	92
2027	6,227	5,790	6,213	437	15
2028	6,347	5,777	6,211	570	135
2029	6,471	5,758	6,210	713	261
2030	6,733	5,750	6,209	983	524
2031	7,003	5,736	6,208	1,266	795
2032	7,135	5,738	6,206	1,397	929
2033	7,123	5,726	6,205	1,397	918
2034	7,121	5,715	6,204	1,406	917
2035	7,118	5,719	6,202	1,399	915
2036	7,118	5,737	6,201	1,380	917
2037	7,118	5,720	6,200	1,398	918
2038	7,118	5,722	6,199	1,396	920
2039	7,117	5,722	6,197	1,395	920
2024-2039 CAGR	1.13%	-0.16%	0.31%		

Table 6-3 compares the 2024 IRP, 2021 IRP, and 2022 CPCN summer peak demand forecasts for the combined companies. In the 2024 IRP, summer peak demand is more than 1,150 MW higher than the 2021 IRP and nearly 800 MW higher than the CPCN in 2032.

Table 6-3: Summer Peak Demand Forecasts (MW)

Year	2024 IRP	2021 IRP	2022 CPCN	2024 IRP Less 2021 IRP	2024 IRP less CPCN
2024	6,115	6,179	6,200	-64	-85
2025	6,228	6,150	6,303	78	-75
2026	6,242	6,113	6,308	129	-66
2027	6,365	6,088	6,427	277	-62
2028	6,474	6,067	6,425	407	49
2029	6,686	6,055	6,422	631	264
2030	6,931	6,056	6,419	875	512
2031	7,216	6,033	6,416	1,182	800
2032	7,201	6,035	6,413	1,166	788
2033	7,201	6,029	6,411	1,171	790
2034	7,179	6,020	6,408	1,158	771
2035	7,171	6,023	6,405	1,148	766
2036	7,161	6,026	6,402	1,135	759
2037	7,160	6,027	6,399	1,132	760
2038	7,158	6,039	6,397	1,119	762
2039	7,149	6,037	6,394	1,111	755
2024-2039 CAGR	1.05%	-0.15%	0.21%		

Figure 6-1 shows sales forecast changes from the 2021 IRP by class. By far the largest change to the Companies' projections are in the commercial and industrial classes. Growth in the commercial class is explained by the addition of data center load, and growth in the industrial class is explained by growth in the auto manufacturing sector, which includes the Blue Oval SK Battery Park.

Figure 6-1: 2024 IRP GWh Changes from 2021 IRP by Class

Generation Resource Costs

Table 6-4 shows how capital costs ($/kW) and the sum of capital and non-fuel O&M ($/kW-yr) for selected resources have increased from the 2021 IRP and the 2022 CPCN filing.[35] Capital costs for SCCT and NGCC technologies have increased more than the capital costs for solar and BESS. In addition, compared to the 2021 IRP, the impact of the Inflation Reduction Act's ("IRA's") tax incentives on solar and BESS costs is much greater (e.g., the IRA's production tax credit reduces the sum of capital and non-fuel O&M for solar by 27%, whereas the ITC previously available for solar reduced this sum by only 20%).[36] Finally, while the costs of SCCT and BESS are not directly comparable due to their different operating characteristics, this is the first time the sum of capital and non-fuel O&M for BESS (with tax incentives) is lower than SCCT.

[35] The sum of capital and non-fuel O&M ($/kW-yr) reflects the levelized cost of capacity including capital, fixed O&M, and firm gas transportation costs, as well as the effect of production and investment tax credits as applicable.
[36] Tax incentives are available for solar and BESS via the IRA provided construction begins by 2035.

Table 6-4: Capital Costs ($/kW) and Sum of Capital and Non-Fuel O&M ($/kW-yr) for Selected Resources

	2021 IRP 2022 $		2022 CPCN[37] 2026/2027 $		2024 IRP 2030 $	
Resource	**Capital ($/kW)**	**Capital + Non-Fuel O&M ($/kW-yr)**	**Capital ($/kW)**	**Capital + Non-Fuel O&M ($/kW-yr)**	**Capital ($/kW)**	**Capital + Non-Fuel O&M ($/kW-yr)**
SCCT	885	127	679	83	1,636	182
NGCC	1,008	140	1,048	117	2,121	222
Solar No ITC/PTC	1,305	126	1,462	136	1,902	183
Solar with ITC/PTC		101		90		133
4-hr BESS No ITC	1,274	172	2,159	300	2,049	265
4-hr BESS with ITC		N/A		138		138

Generation Capacity Needs

Table 6-5 contains a summary of winter and summer total reserve margins and capacity needs from the 2021 IRP compared to the 2024 IRP.

When the 2021 IRP was filed, the resource plan reflected the retirement of Mill Creek 1 in 2024 and the small-frame SCCTs in 2025. Because Mill Creek 1 and 2 cannot operate simultaneously during the ozone season due to NO_x limits, one of the units (300 MW) was assumed to be unavailable in the summer from 2022 to 2024. The Rhudes Creek solar facility (100 MW nameplate) was assumed to come online in 2023 and an additional 160 MW of Green Tariff Option 3 solar was added in 2025. None of this capacity was available to serve winter peak because the Companies' winter peak occurs at night. Approximately 79% of the new solar capacity was assumed to be available to serve summer peak. The Companies' target reserve margin range was 17 to 24 percent in the summer and 26 to 35 percent in the winter. Based on those reserve margin ranges, the Companies anticipated being capacity sufficient until at least 2028, when the Companies would have a small reserve margin deficit in the summer and a larger reserve margin deficit in the winter after the assumed retirements of Mill Creek 2 and Brown 3.

The 2024 IRP continues to reflect the retirement of Mill Creek 1 in 2024 and the small-frame SCCTs in 2025 but excludes the Rhudes Creek solar facility and the Green Tariff Option 3 solar that were included in the 2021 IRP. The 2024 IRP also includes the retirement of Mill Creek 2 in 2027 and the addition of the Company-owned resources approved in the 2022 CPCN Order including Mill Creek 5, the Brown Battery Energy Storage System, Mercer County Solar, Marion County Solar, and demand response programs from the Companies' 2024-2030 DSM-EE Program Plan. A capacity increase on Cane Run 7 in 2026 to reach the full potential of its 2024 turbine upgrades is also assumed. The 2024 IRP's minimum reserve margin targets are 23% in summer and 29% in winter based on limiting loss-of-load expectation ("LOLE") to one day in 10 years.

[37] 2022 CPCN values reflect costs as filed. The Companies provided an update to NGCC capital costs of $1,466/kW based on bids received in their response to the Joint Intervenors' Post-Hearing Data Request 4.1 in Case No. 2022-00402.

These assumptions result in capacity needs as soon as 2025 and more significant capacity needs starting in 2030.

Table 6-5: Reserve Margin and Capacity Need Comparison, Mid Load (MW)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
2021 IRP													
Winter													
Reserve Margin	38.2%	32.8%	33.4%	33.8%	21.7%	22.1%	22.3%	22.6%	22.5%	22.8%	3.7%	-1.0%	-3.5%
Capacity Need	-2,240	-1,913	-1,939	-1,954	-1,254	-1,274	-1,282	-1,295	-1,293	-1,305	-213	57	203
Summer													
Reserve Margin	23.8%	25.7%	26.4%	26.9%	15.6%	15.8%	15.8%	16.2%	16.2%	16.3%	-1.6%	-5.6%	-7.7%
Capacity Need	-1,410	-1,348	-1,452	-1,472	-1,578	-1,614	-1,637	-947	-958	-956	-978	-975	-980
2024 IRP													
Winter													
Reserve Margin	35.2%	26.7%	26.8%	28.7%	32.5%	30.1%	25.1%	20.4%	18.3%	18.7%	18.7%	18.8%	18.8%
Capacity Need	-672	143	134	18	-219	-73	264	602	764	736	733	728	727
Summer													
Reserve Margin	24.1%	21.5%	25.1%	30.1%	28.4%	24.6%	20.2%	15.6%	16.0%	16.2%	16.6%	16.7%	16.9%
Capacity Need	-433	94	-132	-453	-349	-105	192	533	505	492	462	450	434

Supply-Side and Demand-Side Resources

The Companies' resource portfolio has not changed materially since the 2021 IRP. The approved changes to the Companies' resource portfolio moving forward are noted above.[38]

[38] The Companies do not presently expect that the approved solar PPAs will advance under their approved terms, though both the 2024 IRP Recommended Resource Plan and the Enhanced Solar Resource Plan contain significant amounts of new solar. Of the six total solar PPAs into which the Companies have entered, including two prior to the 2022 CPCN and DSM-EE case, (a) one has been canceled by the developer due to interconnection issues, (b) one has been canceled by the developer due to a significant project price increase, and (c) one with a price reopener has been contractually terminated due to the Companies' unwillingness to proceed at a much higher price than in the original agreement. The remaining three PPAs appear unlikely to proceed under their approved terms. This IRP therefore does not include these PPAs. But again, the Companies' 2024 IRP Recommended Resource Plan and the Enhanced Solar Resource Plan both contain significant amounts of new solar in addition to hundreds of megawatts of new battery storage, which could help pave the way for additional new renewable resources in the future.

Environmental Regulations

Significant changes to environmental regulations since the 2021 IRP are briefly summarized in the following sections. Section 8.(5).(f) contains a more complete discussion of current environmental regulations.

Cross-State Air Pollution Rule/Good Neighbor Plan

On June 29, 2021, the Revised Cross State Air Pollution Rule ("CSAPR") Update rule became effective to address non-attainment issues with the 2008 ozone National Ambient Air Quality Standards ("NAAQS") in the northeastern states. Certain areas of the United States were not meeting the 2008 ozone standard (75 parts per billion or "ppb"). Additionally, in response to setting the 2015 ozone NAAQS at 70 ppb, EPA released a federal implementation plan ("FIP") as a method for lowering emissions of nitrogen oxide ("NO_x") emissions in affected areas to achieve compliance with the NAAQS. After issuing a proposed rule in 2022 and disapproving several state implementation plans ("SIP") at the beginning of 2023, the FIP for the 2015 ozone NAAQS ("Good Neighbor Plan") was published on June 5, 2023. Following disapproval of the SIPs, several states, including Kentucky, requested review of that action and won stays of their SIP disapprovals. These stays resulted in EPA not being able to implement the Good Neighbor Plan in those states because EPA cannot enforce a FIP if a SIP has not been deemed insufficient to achieve the NAAQS requirements.

Because EPA was unable to implement the Good Neighbor Plan in those initial states with stays of their SIP disapproval, EPA issued an interim final rule on July 31, 2023, essentially reverting those states back to implementation of the Revised CSAPR Update Rule. One particular change for affected units is that the interim rule restricts trading of allowances between units in the Group 2 trading programs, and units under the interim rule are unable to trade allowances with any unit within the Good Neighbor Plan's Group 3 trading program.

In addition to legal proceedings regarding the SIP disapprovals, legal proceedings regarding requests for review of and requests for stay of implementation of the Good Neighbor Plan have begun. These legal actions are taking place in multiple venues including the U.S. Supreme Court. Until the cases reach conclusion, the fate of the Good Neighbor Plan is in question.

The Companies will continue to operate and maintain the affected facilities in compliance with the interim final rule and Revised CSAPR Update requirements. The Companies will also continue to follow the Good Neighbor Plan-related court proceedings to determine what actions will need to be taken at the conclusion of the cases. Regardless of the outcomes, the EPA is obligated to drive attainment of the 2015 Ozone NAAQS. Given local non-attainment in the Louisville-Jefferson County area, Kentucky's significant impact to downwind states, and the lack of Reasonably Achievable Control Technology on some units, the Companies have exposure to further NO_x reductions in support of attainment.

National Ambient Air Quality Standards ("NAAQS") – Ozone and $PM_{2.5}$

The current (i.e., 2015) primary and secondary ozone NAAQS remain at 70 ppb. On September 8, 2022,[39] the Louisville Metro Air Pollution Control District ("LMAPCD") in conjunction with KDAQ submitted a request to EPA to redesignate the Louisville-Jefferson County, KY marginal non-attainment area to attainment for the 2015 8-hour ozone NAAQS based on certified ozone monitoring data from 2019 through 2021. Contrarily, on September 15, 2022, EPA finalized actions on non-attainment designations for the 2015 ozone NAAQS. In that action, 25 "marginal" non-attainment areas (including the Louisville-Jefferson County area) were reclassified as "moderate" non-attainment areas. In a parallel action, on April 18, 2023, in response to the September 8, 2022 request, EPA proposed to finalize the redesignation of the Louisville-Jefferson County, KY area to attainment status based on the 2019 through 2021 data, but it has not finalized the redesignation. Unfortunately, the Louisville-Jefferson County, KY area has indicated non-attainment status with the 2015 8-hour ozone standard based on monitored ozone levels from 2021 through 2023 and thereby may not achieve attainment status by an August 3, 2024 deadline. This would mean the Louisville-Jefferson County, KY area may be redesignated a "serious" non-attainment area, escalating the need for localized NO_x reductions.

On August 21, 2023, EPA announced plans to review the ozone NAAQS prior to its 2025 five-year review deadline. The EPA's Clean Air Scientific Advisory Committee has previously suggested lowering the ozone standard to 65-68 ppb. Therefore, even as plans are put in place and actions are taken to bring areas into attainment with the 70 ppb ozone standard, it is possible that the standard would be lowered, and once again those areas would be determined to be non-attainment for ozone. Such a determination will start the process of establishing a new RACT and implementing further NO_x reductions at all sources in those areas.

The Companies' Mill Creek Generating Station is located in the Louisville-Jefferson County, KY, ozone non-attainment area. From 2020 through retirement of either Mill Creek Unit 1 or Unit 2, LMAPCD has imposed, via an Agreed Board order, an additional 15-ton total daily NO_x emissions limitation on the Mill Creek Generating Station for the months of May through October in an effort to aid the ozone non-attainment area achieve attainment status. Despite the Companies' efforts toward meeting this limit, exceedances of the 70 ppb ozone standard in the Louisville-Jefferson County area have continued to occur. Based on that information and the potential redesignation of the Louisville-Jefferson County, KY non-attainment area to serious non-attainment status, it is unclear what other efforts may be requested of the Companies' operations to help the area reach attainment status.

Regarding the primary annual 2.5 micron particulate matter ("$PM_{2.5}$") NAAQS, EPA finalized a lowering of the $PM_{2.5}$ standard from 12.0 $\mu g/m^3$ to 9.0 $\mu g/m^3$ on May 6, 2024. EPA, with input from states and tribes, have two years to designate an area to be in attainment or non-attainment of the standard. Designations will be based on the most recent set of air monitoring or modeling data at the time of the proposed designation. Additionally, a three-year deadline has started for

[39] *See* Air Quality State Implementation Plans; Approvals and Promulgations: Kentucky; Air Quality Designation; Redesignation of the Kentucky Portion of the Louisville, KY-IN 2015 8-Hour Ozone Nonattainment Area to Attainment, available at https://www.regulations.gov/document/EPA-R04-OAR-2022-0789-0009.

states to submit revisions to their SIPs to show they are ready to implement the revised NAAQS. Once EPA designates an area to be in non-attainment of the NAAQS, the agency responsible for that area has 18 months to submit revisions of the SIP outlining strategies and emission control measures that will be used to bring the area into attainment status. Based on data available at the time of this IRP filing, the Louisville-Jefferson County area could likely be designated non-attainment for the new $PM_{2.5}$ standard. Therefore, the Companies' operations in or near that area could be requested to aid in achieving attainment status. The Companies will continue to follow these NAAQS developments and implement any needed changes to ensure compliance.

Greenhouse Gases

On January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the Affordable Clean Energy ("ACE") rule and remanded it to EPA for further proceedings consistent with the court's opinion.[40] On October 29, 2021, the Supreme Court granted review of the case, specifically agreeing to hear the parties' arguments on whether EPA's Section 111(d) authority allows the Agency to regulate the electric generation industry in a manner as broadly as the Clean Power Plan ("CPP"). The Supreme Court rendered a 6-to-3 decision on June 30, 2022.[41] At the outset of the opinion, Chief Justice Roberts framed the core issue before the Court as "whether [the CPP's] broader conception of EPA's authority is within the power granted to it by the Clean Air Act."[42] The majority's answer was that the generation shifting approach of the CPP exceeded the powers granted to EPA by Congress. The Court determined that this type of regulation, which would have impacted the economy on a nationwide scale, is not authorized by Section 111(d) of the Clean Air Act ("CAA") and is a "major question" that requires a "clear congressional authorization" to EPA.[43] The Court reversed and remanded the case back to the D.C. Circuit for further proceedings.[44] On October 27, 2022, the D.C. Circuit recalled its previous mandate and issued an amended judgment to deny the petitions for review of the CPP and hold remaining challenges to the ACE Rule in abeyance pending EPA's ongoing effort to develop a replacement rule. EPA published a final replacement rule regulating greenhouse gas ("GHG") emissions from electric utility units ("EGUs") on May 9, 2024. As finalized, the rule: 1) repealed the ACE rule; 2) created emission guidelines for GHG emissions from existing fossil fuel-fired steam EGUs under Section 111(d) of the CAA; 3) revised the GHG new source performance standards ("NSPS") from new and reconstructed fossil fuel-fired stationary combustion turbines; and 4) revised the standards of performance for coal-fired EGUs which undertake a large modification (i.e., increases the unit's hourly emissions rate by more than 10 percent). The rule will require states to develop implementation plans which include strategies for affected EGUs to potentially install GHG emission controls, make changes to operations such as changing fuels, or make commitments to retire in order to achieve compliance with emission limits outlined in the rule.

[40] *American Lung Ass'n v. E.P.A.*, 985 F.3d 914 (D.C. Cir. 2021).
[41] *West Virginia v. EPA*, 597 U.S. 697 (2022).
[42] *Id.* at 706.
[43] *Id.* at 723 and 732.
[44] *Id.* at 735.

EPA did not finalize emission guidelines for GHG emissions from existing fossil fuel-fired stationary combustion turbines. For those existing stationary turbines, EPA developed a non-rulemaking regulatory docket to gather more information for a rulemaking to be proposed at a later date.

Subsequent to EPA's finalizing of the EGU GHG rule, several petitions for review of and motions for stay of the final rule have been filed with several courts, including the U.S. Supreme Court.[45] The Companies will continue to follow these GHG issues and assess their impacts on operating facilities.

Effluent Limitations Guidelines Rule

On May 9, 2024, EPA published the final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category ("2024 ELG") to revise the 2020 Effluent Limitations Guidelines ("2020 ELG"). The 2024 ELG became effective on July 8, 2024, and sets a compliance period of as-soon-as-possible but no-later-than December 31, 2029 (with the exception of certain subcategories).

The 2020 ELG established numeric limits for flue gas desulfurization wastewater ("FGDW") based on a Best Available Technology Economically Achievable ("BAT") of chemical precipitation + biological treatment. The 2020 ELG also required that facilities utilizing Bottom Ash Transport Water ("BATW") discharge no more than 10% of BATW system volume per day on a 30-day rolling average.

In the 2024 ELG, EPA establishes zero-discharge limits applicable to FGDW, BATW, and Combustion Residual Leachate ("CRL") based on a suite of zero-discharge technologies (membrane filtration and thermal evaporation or spray dryer evaporation) as BAT. Additionally, EPA reserves BAT determination for Legacy Wastewater ("LWW") for facilities that commence surface impoundment closure prior to the 2024 ELG's effective date and instead will continue to allow National Pollutant Discharge Elimination System ("NPDES") permitting authorities to use their Best Professional Judgement ("BPJ") to establish limits through the facility's NPDES permit. For facilities commencing surface impoundment closure after the 2024 ELG's effective date, EPA establishes mercury and arsenic numeric limits on LWW based on a BAT of chemical precipitation. Until the 2024 ELG applicability date for each facility set by the permitting authority, that facility must meet limitations for FGDW and BATW established by the 2020 ELG.

The 2024 ELG creates a new permanent cessation of coal combustion subcategory ("Cessation Subcategory") for units permanently ceasing coal combustion by December 31, 2034. Facilities seeking to qualify for the 2034 Cessation Subcategory must satisfy the 2020 ELG's limits for FGDW and BATW no later than December 31, 2025, and submit a Notice of Planned Participation ("NOPP") by December 31, 2025. Facilities that qualify for the Cessation Subcategory are subject

[45] Regarding the stay petition to the U.S. Supreme Court, on October 16, 2024, the Court denied the petition. *West Virginia v. EPA*, 604 U.S. ___ (Oct. 16, 2024), available at https://www.supremecourt.gov/opinions/24pdf/24a95_n7ip.pdf. Justice Thomas stated he would have granted the stay, and Justices Kavanaugh and Gorsuch opined, "[T]he applicants have shown a strong likelihood of success on the merits as to at least some of their challenges to the Environmental Protection Agency's rule." *Id.*

to the no discharge limit for FGDW and BATW after April 30, 2035 and are subject to mercury and arsenic limits for CRL no later than April 30, 2035.

Coal Combustion Residual Rules

On May 8, 2024, the EPA augmented the 2015 coal combustion residuals ("CCR") regulations when it published the Legacy CCR Surface Impoundment Rule. The new rule identified two new types of CCR units, Legacy CCR surface impoundments and CCR management units ("CCRMUs"), that would be subject to the CCR regulations. The revisions require that all subject facilities undertake investigations to determine how many CCRMUs exist, their extent, and their status.

Additionally, the Legacy CCR Surface Impoundment Rule also includes several new and revised definitions intended to further clarify EPA's intentions as they relate to compliance. The changes create two performance-based expectations for any unit that has or will undergo in-place closure. First, closing or closed Legacy CCR Units must remove all free liquids from the pore spaces between CCR particles. Second, no additional liquids can migrate into the closed Legacy CCR unit from any direction, regardless of whether the liquids originate from precipitation, flooding, normal groundwater flows, or fluctuating hydraulic conditions. Because these changes present many challenges to the industry and, in some cases, conflict with closure processes that have already been implemented or completed, the Companies expect the rule to undergo further refinement, either from legal challenges or as EPA undertakes site-by-site permitting relating to the CCR rule, as mandated by Congress in the Water Infrastructure Improvements for the Nation Act of 2016.

7 Load Forecasts

7.(1) Specification of Historical and Forecasted Information Requirements by Class

The data submissions in the following subsections conform to the specifications provided in Section 7.(1) of Administrative Regulation 807 KAR 5:058 to the fullest extent possible. Energy and demand forecasts reflect the impact of the Companies' energy efficiency programs, but demand response programs are modeled as supply-side resources.

7.(2) Specification of Historical Information Requirements

The data submissions in the following subsections conform to the specifications provided in Section 7.(2) of Administrative Regulation 807 KAR 5:058 to the fullest extent possible. Energy and demand forecasts reflect the impact of the Companies' energy efficiency programs, but demand response programs are modeled as supply-side resources.

7.(2).(a) Average Number of Customers by Class

Table 7-1: KU Average Number of Customers by Class

	2019	2020	2021	2022	2023
Residential	434,374	438,537	441,873	443,577	446,660
Commercial	82,544	83,029	83,751	83,730	83,431
Industrial	1,795	1,737	1,703	1,674	1,644
Public Authority	8,462	8,627	8,706	8,748	1,502
Public Street and Highway Lighting	1,166	1,188	1,278	1,409	8,810
Virginia Retail	27,790	27,804	27,481	27,599	27,565
Req. Sales for Resale	6	3	3	3	3
Total Customers	556,137	560,925	564,795	566,740	569,615

Table 7-2: LG&E Average Number of Customers by Class

	2019	2020	2021	2022	2023
Residential	365,910	371,301	375,455	378,001	381,561
Commercial	44,329	44,921	45,930	46,525	46,667
Industrial	558	547	547	548	548
Street Lighting	639	625	620	576	542
Public Authority	4,417	4,449	4,611	4,744	4,802
Total Customers	415,853	421,843	427,163	430,394	434,120

7.(2).(b) Annual Energy Sales & Energy Requirements

Table 7-3: KU Annual Energy Sales & Requirements (GWh)

	2019	2020	2021	2022	2023
SYSTEM BILLED SALES:					
Recorded	19,002	17,726	18,683	18,663	17,854
Weather Normalized	18,756	18,108	18,723	18,576	18,362
SYSTEM USED SALES:					
Recorded	19,385	17,834	18,513	18,832	17,763
Weather Normalized	19,236	18,325	18,629	18,711	18,420
ENERGY REQUIREMENTS:					
Recorded	20,733	18,972	19,726	20,051	18,854
Weather Normalized	20,573	19,495	19,850	19,922	19,551
SALES BY CLASS:					
Residential	6,080	5,968	5,984	6,169	5,546
Commercial	4,100	3,723	3,804	3,912	3,768
Industrial	6,101	5,663	6,159	6,135	6,007
Lighting	36	28	24	22	20
Public Authorities	1,539	1,426	1,502	1,530	1,464
Requirement Sales for Resale	826	368	373	376	344
KENTUCKY Retail	18,682	17,176	17,846	18,144	17,149
VIRGINIA Retail	703	658	667	688	614
SYSTEM LOSSES	1,324	1,114	1,186	1,190	1,063
Utility Use	24	24	27	29	28
ENERGY REQUIREMENTS	20,733	18,972	19,726	20,051	18,854
Weather Normalized:					
Residential	5,960	6,338	6,073	6,074	6,032
Commercial	4,081	3,790	3,814	3,888	3,874
Industrial	6,101	5,663	6,159	6,135	6,007
Lighting	36	28	24	22	20
Public Authorities	1,532	1,446	1,506	1,525	1,495
Requirement Sales for Resale	829	371	374	376	348
VIRGINIA Retail	697	689	679	691	644

Table 7-4: LG&E Annual Energy Sales & Requirements (GWh)

	2019	2020	2021	2022	2023
SYSTEM BILLED SALES:					
Recorded	11,724	10,964	11,344	11,327	10,860
Weather Normalized	11,461	11,147	11,287	11,268	11,125
SYSTEM USED SALES:					
Recorded	11,656	11,007	11,289	11,355	10,858
Weather Normalized	11,450	11,195	11,238	11,273	11,171
ENERGY REQUIREMENTS:					
Recorded	12,451	11,726	11,976	12,091	11,532
Weather Normalized	12,232	11,926	11,921	12,005	11,863
SALES BY CLASS:					
Residential	4,229	4,122	4,193	4,231	3,923
Commercial	3,830	3,518	3,607	3,634	3,496
Industrial	2,500	2,359	2,450	2,440	2,384
Public Authorities	1,083	998	1,030	1,042	1,048
Lighting	14	10	9	8	7
TOTAL LG&E SALES	11,656	11,007	11,289	11,355	10,858
SYSTEM LOSSES	773	697	663	713	652
Utility Use	22	22	24	23	22
ENERGY REQUIREMENTS	12,451	11,726	11,976	12,091	11,532
WEATHER NORMALIZED SALES BY CLASS:					
Residential	4,078	4,256	4,184	4,162	4,162
Commercial	3,788	3,560	3,571	3,623	3,560
Industrial	2,500	2,359	2,450	2,440	2,384
Public Authorities	1,070	1,010	1,024	1,040	1,058
Lighting	14	10	9	8	7

7.(2).(c) Recorded and Weather-Normalized Coincident Peak Demands

Table 7-5: KU Coincident Peak Demands (MW)[46]

	2019	**2020**	**2021**	**2022**	**2023**
SUMMER					
Actual	3,671	3,565	3,586	3,650	3,553
	2018/2019	**2019/2020**	**2020/2021**	**2021/2022**	**2022/2023**
WINTER					
Actual	4,098	3,693	3,828	3,844	4,396

Table 7-6: LG&E Coincident Peak Demands (MW)

	2019	**2020**	**2021**	**2022**	**2023**
SUMMER					
Actual	2,607	2,504	2,537	2,537	2,639
	2018/2019	**2019/2020**	**2020/2021**	**2021/2022**	**2022/2023**
WINTER					
Actual	1,882	1,658	1,761	1,695	2,011

Table 7-7: Combined Company Coincident Peak Demands (MW)[46]

	2019	**2020**	**2021**	**2022**	**2023**
SUMMER					
Actual	6,278	6,069	6,123	6,187	6,191
	2018/2019	**2019/2020**	**2020/2021**	**2021/2022**	**2022/2023**
WINTER					
Actual	5,980	5,351	5,589	5,539	6,407[47]

7.(2).(d) Sales and Demand for Customers with Firm, Contractual Commitments

Table 7-8: KU Energy Sales and Coincident Peak Demand for Firm and Contractual Commitment Customers

	2019	**2020**	**2021**	**2022**	**2023**
Energy Sales (GWh)	18,274	16,768	17,332	17,716	16,759
Coincident Peak Demand (MW)	3,522	3,411	3,430	4,374	3,473

[46] Values exclude departed municipal customers.
[47] This peak is from the Winter Storm Elliott event. The peak value shown is the actual observed value on the system that day, which was reduced by curtailments. Without curtailments, the value is estimated to be 6,626 MW.

Table 7-9: LG&E Energy Sales and Coincident Peak Demand for Firm and Contractual Commitment Customers

	2019	2020	2021	2022	2023
Energy Sales (GWh)	11,154	10,713	10,982	11,030	10,552
Coincident Peak Demand (MW)	2,538	2,472	2,507	2,001	2,602

7.(2).(e) Energy Sales and Coincident Peak Demand for Interruptible Customers

Table 7-10: KU Interruptible Customer Energy Sales and Combined Company Coincident Peak

	2019	2020	2021	2022	2023
Energy Sales (GWh)	1,111	1,066	1,181	1,116	1,004
Coincident Peak Demand (MW)	149	154	155	22	80

Table 7-11: LG&E Interruptible Customer Energy Sales and Combined Company Coincident Peak

	2019	2020	2021	2022	2023
Energy Sales (GWh)	502	294	307	325	306
Coincident Peak Demand (MW)	69	33	30	10	37

7.(2).(f) Annual Energy Losses

Table 7-12: KU Annual Energy Losses

	2019	2020	2021	2022	2023
Annual Energy Loss (GWh)	1,324	1,114	1,186	1,190	1,063
Loss Percent of Energy Requirements	6.8%	6.2%	6.4%	6.3%	6.0%

Table 7-13: LG&E Annual Energy Losses

	2019	2020	2021	2022	2023
Annual Energy Loss (GWh)	773	697	663	713	652
Loss Percent of Energy Requirements	6.6%	6.3%	5.9%	6.3%	6.0%

7.(2).(g) Impact of Existing Demand-Side Management Programs

Table 7-14 contains the cumulative impact of DSM-EE programs on both energy and demand. Descriptions of DSM-EE programs are included in Section 8.

Table 7-14: Impact of Existing DSM-EE Programs (cumulative for KU and LG&E)

	2019	2020	2021	2022	2023
Energy Savings (GWh)	1,255	1,338	1,429	1,487	1,546
Demand Savings (MW)	508	537	551	559	555

7.(2).(h) Other Data Illustrating Historical Changes in Load and Load Characteristics

Actual sales and customer data as reported in tables in Sections 7.(2)(a-f) above are calculated using the Companies' FERC Form 1 filings as the basis for class segmentation. Historical actual calendar (not weather-normalized) average energy use-per-customer by class is shown in Table 7-15 and Table 7-16. Historical percentage share of class sales (not weather-normalized) to total energy sales is presented in Table 7-17 and Table 7-18. Section 5 and Section 6 provide a more detailed discussion of end-use and class-level trends.

Table 7-15: KU Average Annual Use-per-Customer by Class (kWh)

	2019	2020	2021	2022	2023
Residential	13,997	13,610	13,542	13,907	12,502
Commercial	49,665	44,838	45,418	46,726	45,007
Industrial	3,398,989	3,260,154	3,616,849	3,665,020	3,588,314
Public Authority	181,871	165,263	172,490	174,908	167,306
Utility Use & Other	30,741	23,312	18,413	15,444	14,397

Table 7-16: LG&E Average Annual Use-per-Customer by Class (kWh)

	2019	2020	2021	2022	2023
Residential	11,558	11,103	11,168	11,192	10,282
Commercial	86,403	78,312	78,538	78,112	74,921
Industrial	4,480,247	4,313,318	4,478,297	4,453,251	4,350,983
Public Authority	245,085	224,284	223,443	219,560	218,310
Utility Use and Other	21,232	16,790	14,651	13,641	12,502

Table 7-17: KU Class Percentage of Total Energy Sales

	2019	2020	2021	2022	2023
Total Residential	31%	33%	32%	33%	31%
Commercial	21%	21%	21%	21%	21%
Industrial	31%	32%	33%	33%	34%
Public Authority	8%	8%	8%	8%	8%
Utility Use and Other	0%	0%	0%	0%	0%
Virginia Retail	4%	4%	4%	4%	3%
Req. Sales for Resale	4%	2%	2%	2%	2%
Total Company	100%	100%	100%	100%	100%

Table 7-18: LG&E Class Percentage of Total Energy Sales

	2019	2020	2021	2022	2023
Residential	36%	37%	37%	37%	36%
Commercial	33%	32%	32%	32%	32%
Industrial	21%	21%	22%	21%	22%
Public Authority	9%	9%	9%	9%	10%
Lighting	0%	0%	0%	0%	0%
Total Company	100%	100%	100%	100%	100%

7.(3) Specification of Forecast Information Requirements

The information regarding the energy sales and peak load forecasts in the following subsections conform to the specifications outlined in Section 7.(3) of 807 KAR 5:058 to the fullest extent possible.

7.(4) Energy and Demand Forecasts

7.(4).(a) Forecasted Sales by Class and Total Energy Requirements

Table 7-19: KU Forecasted Calendar Sales by Class and Total Energy Requirements after DSM (GWh)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Residential	6,057	6,020	5,997	5,982	5,991	5,950	5,931	5,929	5,954	5,932	5,937	5,946	5,983	5,974	5,993	6,015
Commercial	3,966	3,935	3,896	3,857	3,829	3,787	3,751	3,722	3,704	3,670	3,648	3,629	3,621	3,597	3,584	3,571
Industrial	6,221	7,207	7,392	7,413	7,406	7,385	7,380	7,372	7,376	7,350	7,335	7,328	7,341	7,329	7,327	7,328
Total C/I	10,186	11,142	11,288	11,270	11,235	11,172	11,131	11,094	11,080	11,020	10,982	10,957	10,962	10,926	10,911	10,899
Public Authority	1,507	1,494	1,480	1,469	1,462	1,452	1,446	1,439	1,436	1,427	1,421	1,417	1,417	1,412	1,410	1,408
Utility Use and Lighting	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Sales for Resale	362	381	382	392	393	393	394	394	395	396	396	397	398	398	398	398
Total Kentucky	18,131	19,056	19,167	19,132	19,100	18,986	18,922	18,876	18,884	18,794	18,756	18,736	18,780	18,729	18,730	18,739
Virginia	646	649	644	640	637	631	626	621	618	613	609	605	602	597	593	589
Total KU Calendar Sales	18,777	19,705	19,812	19,772	19,737	19,617	19,547	19,497	19,502	19,407	19,365	19,341	19,382	19,326	19,324	19,328
Utility Use and Losses	1,227	1,249	1,245	1,238	1,232	1,210	1,203	1,196	1,195	1,187	1,170	1,167	1,167	1,137	1,134	1,132
Total Requirements	20,004	20,954	21,057	21,010	20,969	20,827	20,750	20,693	20,697	20,594	20,535	20,508	20,549	20,463	20,458	20,460

Table 7-20: LG&E Forecasted Calendar Sales by Class and Total Energy Requirements after DSM (GWh)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Residential	4,138	4,125	4,118	4,115	4,128	4,115	4,116	4,132	4,164	4,173	4,194	4,220	4,263	4,282	4,316	4,353
Commercial	3,596	3,576	3,549	4,398	5,551	6,969	9,264	11,566	12,152	12,094	12,075	12,058	12,075	12,027	12,017	12,007
Industrial	2,420	2,414	2,413	2,413	2,416	2,412	2,411	2,409	2,412	2,406	2,405	2,404	2,408	2,403	2,403	2,403
Public Authority	1,044	1,043	1,039	1,035	1,034	1,029	1,024	1,021	1,020	1,015	1,012	1,010	1,010	1,006	1,005	1,004
Utility Use and Lighting	7	7	7	7	7	7	7	6	6	6	6	6	6	6	6	6
Total LG&E Calendar Sales	11,205	11,165	11,126	11,967	13,136	14,531	16,822	19,134	19,754	19,694	19,692	19,698	19,763	19,724	19,748	19,773
Utility Use and Losses	704	689	685	691	701	700	720	742	748	745	744	743	745	743	743	710
Requirements	11,909	11,854	11,811	12,658	13,837	15,231	17,542	19,876	20,502	20,439	20,436	20,441	20,508	20,467	20,491	20,483

7.(4).(b) Summer and Winter Peak Demand

Table 7-21: KU Summer and Winter Coincident Peak Demand after DSM (MW)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Summer	3,554	3,664	3,682	3,678	3,687	3,653	3,632	3,623	3,601	3,623	3,648	3,573	3,583	3,578	3,564	3,584
	23/24	**24/25**	**25/26**	**26/27**	**27/28**	**28/29**	**29/30**	**30/31**	**31/32**	**32/33**	**33/34**	**34/35**	**35/36**	**36/37**	**37/38**	**38/39**
Winter	4,158	4,289	4,306	4,322	4,362	4,290	4,301	4,283	4,290	4,341	4,286	4,271	4,281	4,275	4,273	4,210

Table 7-22: LG&E Summer and Winter Coincident Peak Demand after DSM (MW)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Summer	2,561	2,564	2,560	2,687	2,787	3,033	3,299	3,592	3,600	3,577	3,530	3,598	3,578	3,581	3,594	3,564
	23/24	**24/25**	**25/26**	**26/27**	**27/28**	**28/29**	**29/30**	**30/31**	**31/32**	**32/33**	**33/34**	**34/35**	**35/36**	**36/37**	**37/38**	**38/39**
Winter	1,857	1,857	1,844	1,905	1,985	2,181	2,432	2,719	2,845	2,782	2,835	2,847	2,836	2,843	2,845	2,907

7.(4).(c) Monthly Sales by Class and Total Energy Requirements

Table 7-23: KU Monthly Calendar Sales by Class and Total Energy Requirements after DSM (GWh)

	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	2024	731	634	504	373	387	456	537	521	408	378	487	641	6,057
	2025	735	611	500	372	384	453	534	518	406	377	487	642	6,019
Commercial	2024	352	325	314	293	321	342	372	370	332	314	300	330	3,965
	2025	352	315	315	291	320	339	370	368	329	312	298	328	3,937
Industrial	2024	507	492	505	505	536	522	538	560	525	525	501	503	6,219
	2025	610	563	604	584	615	607	626	644	602	601	574	577	7,207
Total C/I	2024	859	817	819	798	857	864	910	930	857	839	801	833	10,184
	2025	962	878	919	875	935	946	996	1,012	931	913	872	905	11,144
Public Authority	2024	127	118	118	116	126	130	140	142	132	122	116	119	1,506
	2025	125	116	118	114	125	129	140	141	131	121	115	118	1,493
Utility Use and	2024	2	2	2	2	1	1	1	1	2	2	2	2	20
Other (Lighting)	2025	2	2	2	2	1	1	1	1	2	2	2	2	20
Sales for Resale	2024	36	28	29	26	29	32	34	34	29	28	28	30	363
	2025	37	30	31	27	31	34	36	36	30	29	29	31	381
Total Kentucky	2024	1,755	1,599	1,472	1,315	1,400	1,483	1,622	1,628	1,428	1,369	1,434	1,625	18,130
	2025	1,861	1,637	1,570	1,390	1,476	1,563	1,707	1,708	1,500	1,442	1,505	1,698	19,057
Virginia	2024	82	69	58	45	42	42	45	45	41	46	56	73	644
	2025	83	68	60	46	43	42	46	46	41	46	56	73	650
Total KU Calendar	2024	1,837	1,668	1,530	1,360	1,442	1,525	1,667	1,673	1,469	1,415	1,490	1,698	18,774
	2025	1,944	1,705	1,630	1,436	1,519	1,605	1,753	1,754	1,541	1,488	1,561	1,771	19,707
Requirements	2024	1,978	1,794	1,627	1,437	1,525	1,627	1,783	1,793	1,554	1,492	1,579	1,815	20,004
	2025	2,088	1,827	1,729	1,514	1,604	1,710	1,870	1,877	1,630	1,566	1,651	1,889	20,955

Table 7-24: LG&E Monthly Calendar Sales by Class and Total Energy Requirements after DSM (GWh)

	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	2024	375	330	288	248	307	408	483	467	342	260	283	347	4,138
	2025	379	320	287	247	305	407	482	466	341	260	283	349	4,126
Commercial	2024	293	274	275	265	301	331	361	358	311	280	266	283	3,598
	2025	295	265	275	265	301	329	359	356	309	278	263	281	3,576
Industrial	2024	197	180	193	196	207	211	219	227	209	199	193	188	2,419
	2025	196	178	194	192	210	211	219	226	208	199	193	188	2,414
Public Authority	2024	89	81	81	81	84	93	100	100	91	83	79	84	1,046
	2025	89	80	82	79	86	92	100	99	90	82	78	83	1,040
Utility Use and Other	2024	1	1	1	1	0	0	0	0	1	1	1	1	8
	2025	1	1	1	1	0	0	0	0	1	1	1	1	8
Total LG&E Calendar	2024	955	866	838	791	899	1,043	1,163	1,152	954	823	822	903	11,209
	2025	960	844	839	784	902	1,039	1,160	1,147	949	820	818	902	11,164
Requirements	2024	1,014	912	883	830	955	1,119	1,258	1,243	1,011	866	862	956	11,909
	2025	1,019	887	884	822	958	1,113	1,253	1,238	1,006	862	859	953	11,854

7.(4).(d) Forecasted Impact of Existing Demand-Side Management Programs

The impacts of existing and future DSM-EE programs on energy sales and peak demands are discussed in Section 8.(3).(e). The energy sales forecasts presented in the preceding sections include the impacts of the energy efficiency programs.

7.(5) Historical and Forecast Information for a Multi-State Integrated Utility System

This section is not applicable to KU. Virginia energy sales constitute less than 5 percent of total KU sales. Energy sales for Virginia are shown as a separate line item in Table 7-3, while demand is treated as part of KU's overall system demand.

7.(6) Updates of Load Forecasts

Any updates to load forecasts will be filed when adopted by the Companies.

7.(7) Load Forecasting Methodology Description and Discussion

7.(7).(a) Data Sets Used in Producing Forecasts

A detailed discussion of these inputs is included in Volume II ("Energy & Demand Forecast Process").

7.(7).(b) Key Assumptions and Judgments

The following is a discussion of key energy requirement forecast assumptions and uncertainties.

1. Economic Development

Kentucky's economic development progress has been historic for the last several years, and the state continues to invest heavily to ensure this progress continues. More than $250 million has been committed from the state budget since 2022 to fund site development, including megasites, within Kentucky communities, which provides certainty and speed to market for projects considering this region of the country.

The evolution of economic development projects puts more emphasis on energy availability than ever before. An annual survey of site selection consultants indicates that energy availability and cost are among the top ten most important factors in site selection over the last two years, and energy availability was tied for first on the list in 2022. Energy availability is a necessity to compete for major projects in primary metals manufacturing, indoor agriculture and battery production, and now data centers.

Multiple sources are projecting significant data center growth in the United States through 2030. For example, in a recent publication, EPRI projects data centers will grow to consume 4.6% to 9.1% of U.S. electricity generation annually by 2030, with individual data centers ranging in size between 100 MW and 1,000 MW.[48] Similarly, a Newmark publication projects data center demand to grow by 18 GW by 2030.[49] Given the nature of their operations, data centers have extremely high load factors – upwards of 95%. Energy intensive data centers are crucial to consumers, businesses, and the safety and security of our nation. They support critical business applications,

[48] https://www.epri.com/research/products/000000003002028905
[49] https://www.nmrk.com/storage-nmrk/uploads/documents/2023-U.S.-Data-Center-Markets.pdf

store valuable business and personal data, keep data safe from threats, and serve as a foundation for modern business and government applications.

Kentucky has a number of advantages that would make data center and manufacturing customers want to locate within the state. It is centrally located in the United States and is within a one-day drive of two-thirds of the U.S. population. It also has a skilled workforce combined with relatively low-cost electricity prices, tax incentive opportunities, and responsive state, community, and utility business partners. Additionally, the Companies have Green Tariff options for customers interested in further investment in renewables.

Data centers specifically require significant amounts of electric power, low to moderate risk of adverse weather events and natural disasters, availability of telecommunications infrastructure, water for equipment cooling, and favorable tax incentives. Kentucky is well positioned with respect to most, if not all, of these requirements.

It should be noted that data centers can significantly add to the economic vibrancy of our state and local communities. A PWC report prepared for the Data Center Coalition in 2023 states that federal, state, and local tax impact of the data center industry in 2021 was nearly $100 billion, a number that will grow exponentially as the industry continues its massive expansion.[50] The report also states that more than 60,000 jobs and $7 billion of GDP are attributable to the data center industry in Ohio alone.

The Companies' Economic Development team is working with a growing number of data center projects that vary in stages of development, but which mostly have very large power requirements.[51] Based upon their interest and the projections of growth across the U.S., it is reasonable to assume that a portion of U.S. growth in data center load will occur within the Companies' service territory.

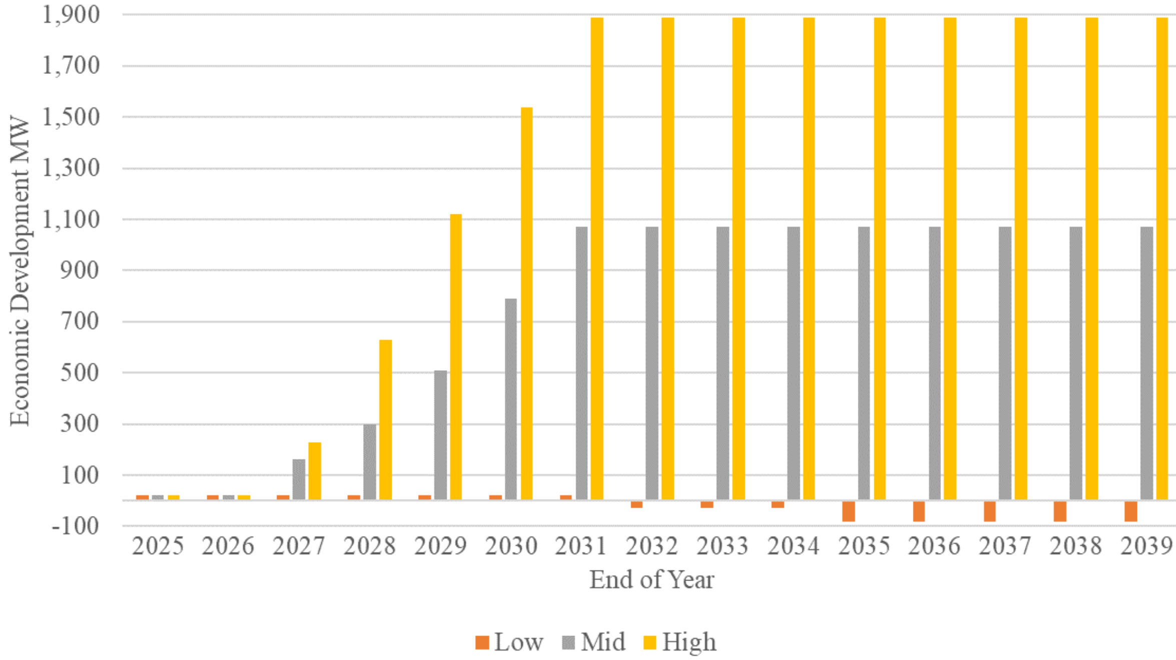
As noted, Kentucky's economic development is on a hot streak. Continuing this streak requires proper resource planning, especially given that planning and executing adequate utility resources almost always requires longer lead times than it takes for businesses to construct new or expand existing facilities. The addition of any new large accounts in the service territory would in many cases spur new commercial and residential growth in the area. Due to the magnitude of data center loads, economic development is a key uncertainty in this load forecast.

The IRP considers three economic development load growth scenarios. The Mid scenario assumes 1,050 MW of data center load by 2032 and another, relatively speaking, small economic development project. The High scenario assumes 1,750 MW of data center load in addition to the smaller project plus the second phase of BOSK. Figure 7-1 compares the three economic development scenarios the Companies contemplated. The Mid and High scenarios account for

[50] Available at https://www.centerofyourdigitalworld.org/impact-study/#07.
[51] https://www.canarymedia.com/articles/clean-energy/virginia-plans-to-turn-defunct-mines-into-clean-powered-data-centers.

small portion of data center load growth projections for the U.S. as a whole.[52] In the Low scenario, zero data center and only the one small project result in insignificant growth. Additionally, the Low scenario assumes a couple of large customers leave the service territory later in the 2030s. The Companies assign a low likelihood to the Low scenario.

Figure 7-1: Economic Development Growth Projections through 2039 (GWh)



2. Normal Weather

The Companies develop their long-term energy requirements forecasts with the assumption that weather will be average or "normal" in every year. Thus, weather does not explain any differences between the Low, Mid, and High long-term energy requirements forecasts. The Companies use the most recent 20 years of historical weather data to develop their normal weather forecast. The Companies have consistently used this period to calculate normal weather because it provides a more recent view of weather than a 30-year normal, and changes from one year to the next when updating a 20-year normal are significantly less volatile than updating a 10-year normal. According to a recent Itron survey, a 20-year normal is most common among electric utility forecasters.

3. Economic Assumptions

Economic assumptions in the Companies' mid energy requirements forecast are taken from S&P Global's May 2024 U.S. Economic Outlook.[53] For the U.S. overall, S&P Global projects real

---

[52] The Mid scenario represents 4.2% of data center load growth in the U.S. from a recent Newmark study (https://www.nmrk.com/storage-nmrk/uploads/documents/2023-U.S.-Data-Center-Markets.pdf) and 9.4% of EPRI's Moderate growth projection (https://restservice.epri.com/publicdownload/000000003002028905/0/Product). The High scenario represents 7.5% of EPRI's High growth projection and only 4.3% of their Higher growth projection.

[53] See Volume II ("S&P Global Market U.S. Economic Outlook – May 2024").

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 forecasted 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.

In Kentucky, S&P Global projects 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. The same downside risks that are present for the U.S. economic expansion also present potential headwinds for the Kentucky economy.

4. Energy Efficiency

As noted previously, the Companies' Mid 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' proposed 2024-2030 DSM-EE Program Plan as well as new programs beyond 2030. These reductions are in addition to significant reductions observed historically from customers' actions to use electricity more efficiently. From 2010 to 2023, residential and commercial weather-normalized use-per-customer decreased by a total of 10% and 13%, respectively, due primarily to customer-initiated energy efficiency and the Companies' DSM-EE programs. Notably, heat pumps and central air conditioners have become more efficient in recent history, and the light emitting diode ("LED") has revolutionized the lighting market and significantly reduced electricity consumption for lighting.[54]

Forecasted energy efficiency improvements account for the Inflation Reduction Act ("IRA") that President Biden signed in August 2022. The IRA supports the Biden administration's economy-wide GHG reduction target (50-52% vs. 2005 levels by 2030) through various means, including tax credits, grants, loans, and rebates for clean technologies. The IRA is expected to impact load through a variety of programs designed to incentivize either reduced consumption through distributed solar and more energy efficient appliances, or electrification (which would likely increase consumption) through EVs and heat pumps.

The Mid energy requirements forecast assumes continued energy efficiency improvements consistent with the IRA and Companies' DSM programs as well as continuation of Department of Energy ("DOE") energy efficiency standards. A portion of improved energy efficiency occurs naturally as appliances fail and require replacement. Because of advances in technology and updates to federal standards, appliance replacement options with even the lowest efficiency ratings are more efficient than most options were 15 or more years ago. For those that need to replace appliances anyway, particularly related to HVAC or water heating, incentives such as those offered in the IRA or the Companies' proposed DSM-EE programs may allow them to purchase a more

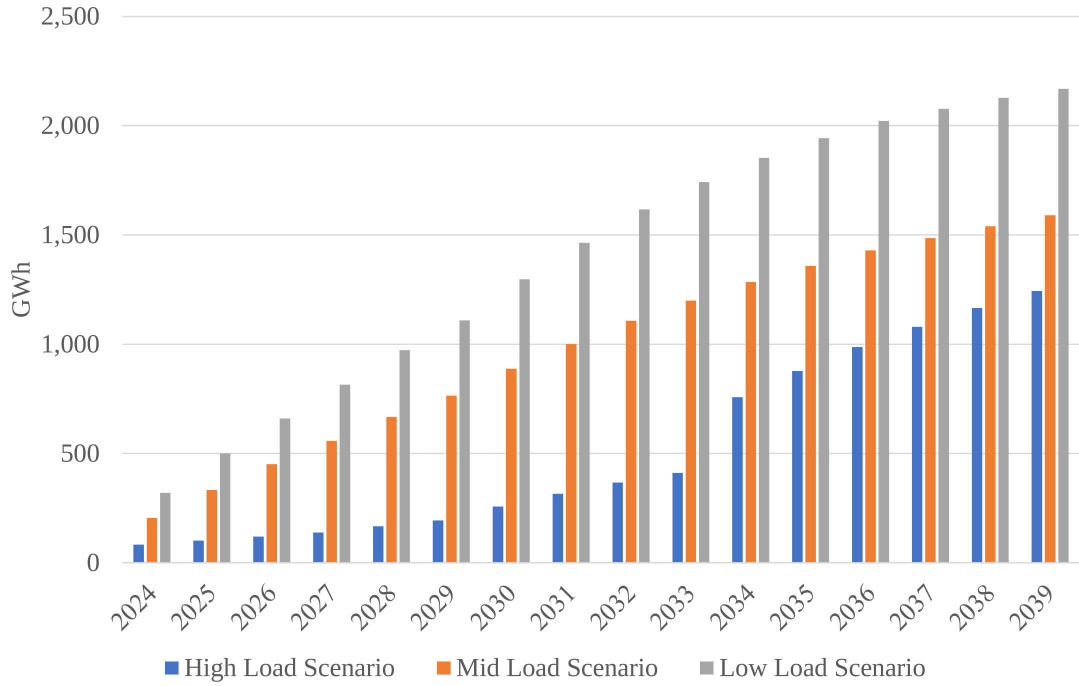
[54] A 60-watt equivalent LED consumes 9 watts per hour, approximately 85 percent less than the equivalent incandescent light bulb, 31 percent less than an equivalent compact fluorescent light ("CFL"), and 79 percent less than the equivalent halogen bulb.

efficient model than they otherwise would have. Thus, like IRA energy-efficiency efforts and incentives, DSM-EE can drive a more rapid increase in average appliance efficiency in the service territory.

Forecasted 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. In some cases, customers have leveraged energy efficiency measures to expand their operations without increasing load. Customer-initiated energy efficiency improvements like these are projected to continue throughout the forecast period.

Forecasted end-use efficiency improvements are explicitly incorporated in residential and commercial forecasts through the statistically adjusted end-use modeling approach described in Volume II. Figure 7-2 shows the impacts of energy efficiency improvements on the residential and commercial sales forecasts in the forecast scenarios. As seen in the figure, the combined impact of Company-sponsored and customer-initiated energy efficiency improvements are assumed to increase throughout the IRP planning period. By 2039, energy efficiency improvements in the Mid forecast reduce residential and commercial sales by over 7.5 percent compared to a scenario where end-use efficiencies are assumed to remain unchanged. The Mid load forecast assumes residential and commercial use-per-customer will decrease by an additional 6% and 9% from 2023 levels, respectively, by 2032. Also, the energy efficiency assumptions in the forecast results in summer peak demand reductions in 2032 of 230 MW and winter peak demand reductions of 171 MW compared to a forecast with flat energy efficiency assumptions.

Figure 7-2: Impact of Energy Efficiency Improvements on Residential and Commercial Sales Forecast[55]



5. Cost of Service

Electricity prices are a consideration in the electric load forecast. 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.[56]

The Companies evaluate the robustness of elasticity assumptions and sensitivity to changes in both price and elasticity. The economics of distributed generation and electric vehicles are of particular interest. However, their effects on electricity demand could offset as distributed generation decreases the quantity demanded while electric vehicles increase the quantity demanded at a given price. Other factors increasing the price of electricity would accelerate the payback on distributed generation, but EV adoption could be hindered by increasing electricity prices as the total cost of EV ownership increases.

The load forecasting process explicitly contemplates short-run price elasticity of demand via statistically adjusted end-use models. The Companies continue to incorporate private solar and electric vehicle forecasts into the Mid load forecast. Thus, major potential drivers of change in long-run price elasticity of demand are incorporated into the load forecast directly as opposed to

[55] With accelerated efficiency gains, end-use efficiencies are assumed to reach 2044 levels by 2034.

[56] 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

via the price elasticity of demand proxy. The Companies continue to view this delineation as appropriate and necessary given the hourly load profiles of these technologies. The Mid load forecast represents the Companies' view of the most likely development in 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.

Electricity prices are assumed to increase by 2.3 percent per year, consistent with long-term inflation expectations.[57] If higher-than-expected prices materialize, the Companies anticipate a decline in sales as compared to the current forecast (all else equal) due to the negative price elasticities incorporated into the forecasting models. The means by which residential or commercial customers would make such changes to reduce their consumption in the long-run would most likely be through more efficient end-uses and installation of distributed generation. Customer growth would likely weaken as compared to what the service territory has experienced over the past decade. Large customers in highly competitive industries would be more likely to move their business elsewhere or find ways to significantly reduce their demand. Given these factors and what has been mentioned in the paragraphs immediately above, the Low load scenario displayed in Figure 5-6 can also act as a more specific proxy for a high electricity price scenario.

6. Customer Growth

The residential customer growth rate in the Mid forecast is just over 0.5% per year. The High and Low forecasts assume roughly +/- 50% of the Mid forecast growth rate, respectively. 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. Further, 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.

7. Distributed Generation and Battery Storage

Currently, 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, there are only 11 non-solar distributed generation installations; one is hydro and the remainder are wind. No new non-solar distributed generation installations have occurred in the past 6 years, the most recent being a wind installation in 2018.

The Companies' experience with their customers' adoption of distributed solar generation shows that customers generally become more inclined to adopt it as its economics improve, but also that most customers have adopted solar even when it was not clearly economical. As the following discussion shows, solar is likely to remain the dominant form of distributed generation customers

[57] See Volume II ("Inflation Assumptions").

will choose to serve their needs and to connect to the Companies' distribution system over the forecast period.

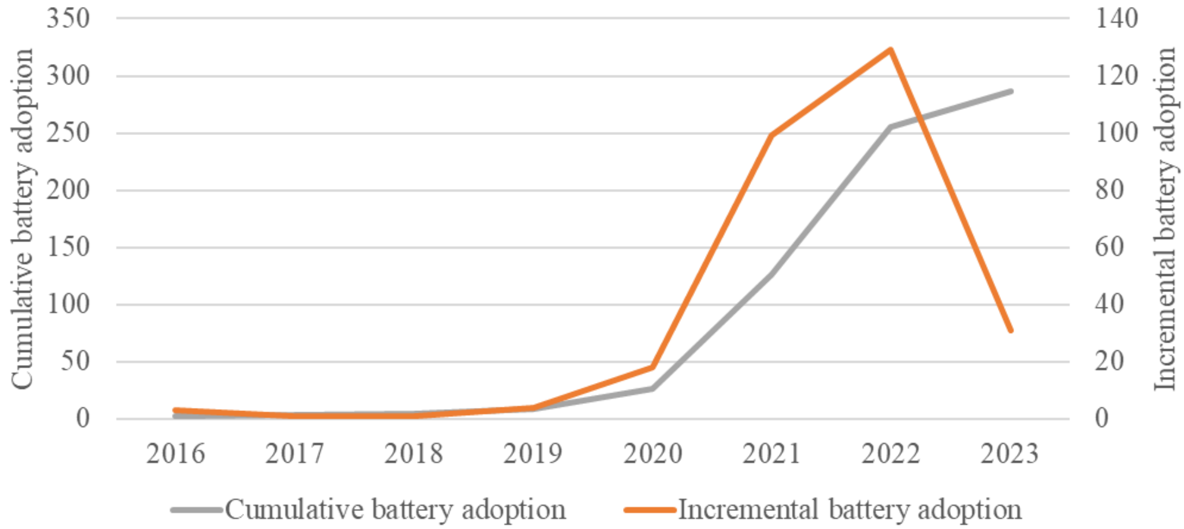
The Companies' analysis of distributed energy resources assumes customers will choose the most economically advantageous form of distributed generation. This analysis assumes that customers will determine what is most economically favorable primarily based on a distributed energy resource's levelized cost of energy ("LCOE"), but also what is most practical and feasible given their housing situation. The basis of the LCOE assumption is that the vast majority of current and anticipated distributed energy resource-installing customers take service under rate schedules with energy rates that do not vary by time of day. In addition, the Companies' current Net Metering Service rider for new net metering customers (NMS-2) and qualifying facility riders (SQF and LQF) do not vary credit for exported energy based on season or time of day. Therefore, an economically rational customer would be more inclined to install a distributed energy resource as the resource's LCOE decreased to the expected benefit of avoided energy consumption and credit for any exported energy.

Not only is solar better than its competitors when it comes to LCOE, it is also often the most practical. 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.

While batteries may be the most feasible of all options in terms of physical location, their LCOE is not competitive when compared to solar under the Companies' current rate design. Batteries can only serve to increase total energy consumption for residential customers given AC to DC losses when charging and DC to AC losses when discharging. Given a flat residential rate per kWh, 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 off-peak rates or the tariff rate and the net metering sellback rate is likely not enough for customers to justify the up-front cost. However, some customers may purchase battery storage as a backup power supply.

The Companies are aware of their net metering customers having only 1,849 kW of distributed battery storage capacity across 286 installations at the end of 2023, which is only about 6% of the Companies' existing net metering customer base. Most often, these energy storage systems are paired with a distributed solar installation. On average, the battery installation size is about 6.8 kW with sizes ranging from 0.4 to 30.72 kW. The most common install size is 4.5 kW. Figure 7-3 shows the cumulative and incremental number of net metering solar customers with battery installations by year. It is worth noting that after an uptick in 2021 and 2022, incremental battery storage adoption in 2023 fell off significantly.

Figure 7-3: Adoption of battery storage devices by net-metering customers



Currently, the Companies do not have access to data concerning how these customers are using their batteries. The Companies are also unsure to what extent non-net metering customers have battery storage as there is no mechanism to track this today outside of net metering. Due to the low rates of energy storage adoption, uncertainty around charging and discharging patterns, and unknown adoption numbers of battery storage for non-net metering customers, the Companies do not explicitly forecast distributed battery adoption, but will continue to monitor. For now, the distributed generation forecast implicitly assumes the level of battery storage increases with customer growth.

Therefore, in response to the Commission's recommendation from the last IRP, resources other than distributed solar are not anticipated to materially affect load. For the reasons mentioned in the discussion above, the Companies' load forecast explicitly assumes all distributed generation additions will be solar for the IRP period.

Distributed generation includes generation from net metering and qualifying facilities ("QF") customers. The economics of distributed solar depend on several factors: electricity usage patterns and their correlation to solar irradiance (i.e., the extent to which solar generation reduces consumption from the grid), the availability of investment tax credits ("ITC"), the capital and annual operating cost of solar, the retail energy rate charged by the utility to the end user, and the energy rate paid by the utility for any excess energy that is pushed onto the grid. Figure 7-4 shows cumulative net-metering solar customer and capacity adoption.

Figure 7-4: Cumulative Net Metering Customer and Capacity Adoption

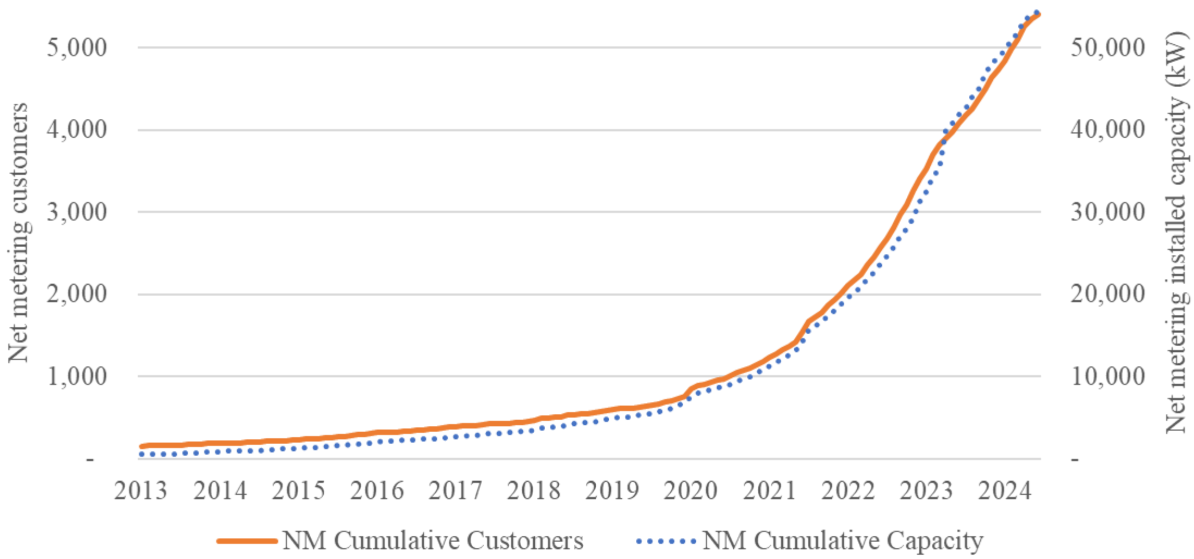
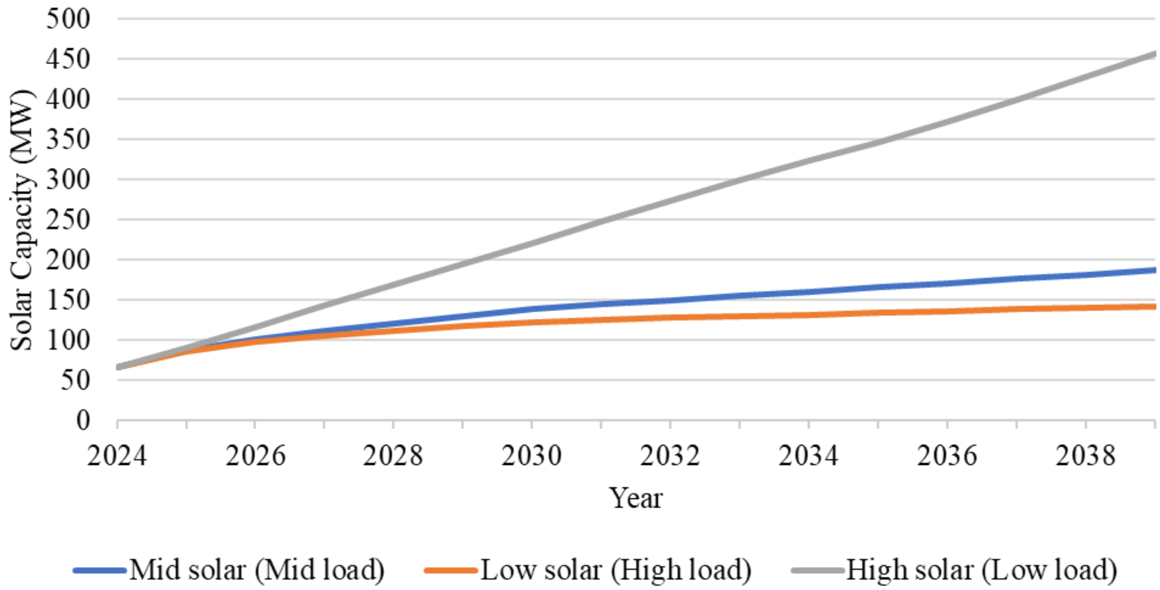


Figure 7-5 contains the Companies' mid, low, and high distributed solar generation forecasts. All net metering forecasts were created using a consumer choice model, in which the ratio of net-metering customers to total residential customers is predicted by the avoided cost-to-LCOE ratio, which is weighted by the potential universe of net-metering customers per company. The avoided-cost-to-LCOE ratio is computed as a function of the above economic factors.

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.

Figure 7-5: Distributed Generation Forecast Scenarios



The mid distributed solar generation forecast assumes retail rate paid for excess generation, instantaneous netting of usage and generation, and a continuation of the federal ITC for residential customers. After 2025, the mid solar 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[58] from 2025-2030 obscures this trend. After the 1% cap is hit, the payment for excess generation drops to the QF repayment rate. This lessens the benefits of selling back to the grid, so it is assumed that customers will be less likely to overbuild their solar installations. However, the number of customers choosing to install solar will be less affected; average customer growth after the cap is hit is not adjusted in the mid forecast. This is similar to the Companies' distributed generation forecast in the most recent CPCN.

Compared to the mid forecast, customer growth in the low solar (High load) scenario is slower and the size of new net metering installations is smaller as customers size their arrays to limit excess solar energy sold back to the grid after the cap is reached. The high solar (Low load) scenario assumes the 1% cap on total installed net metering capacity is removed, which would most likely occur due to a change in law at the state or federal level. As a result, the high solar scenario is identical to the mid solar forecast through the end of 2024, and then continues to grow thereafter with no changes to amount of solar installed per customer.

[58] 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.

Figure 7-6 and Figure 7-7 show the impact of distributed solar generation on hourly energy requirements for a sample day in the mid and high solar scenarios, respectively. The impact is small in the mid solar scenario but much larger in the high solar scenario.

Figure 7-6: Hourly Forecast Profile for August 26th, 2039 (Mid Solar Scenario)

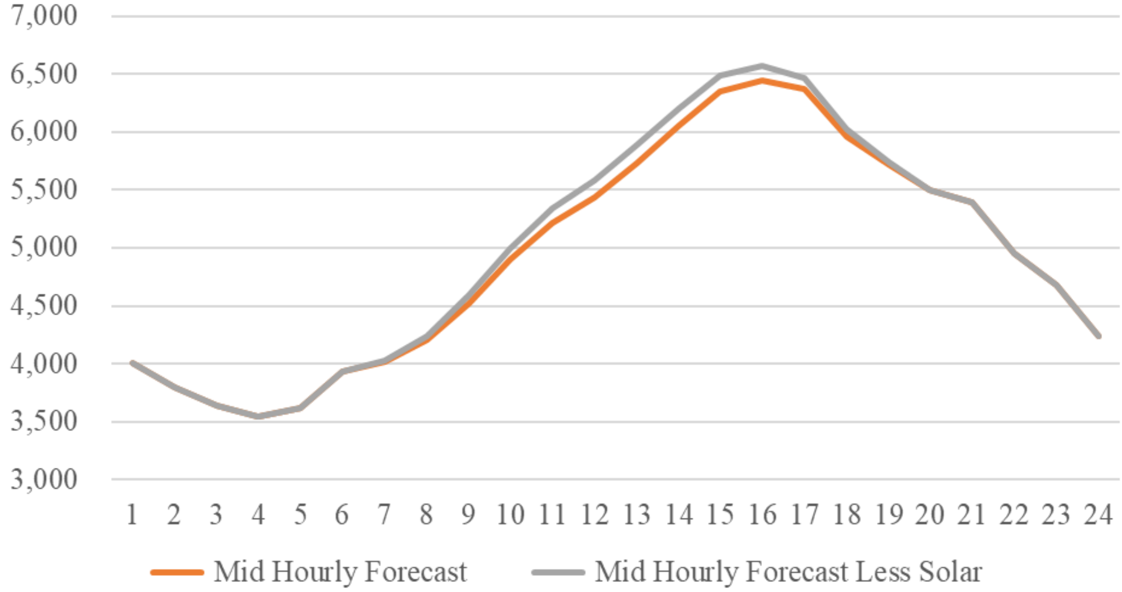
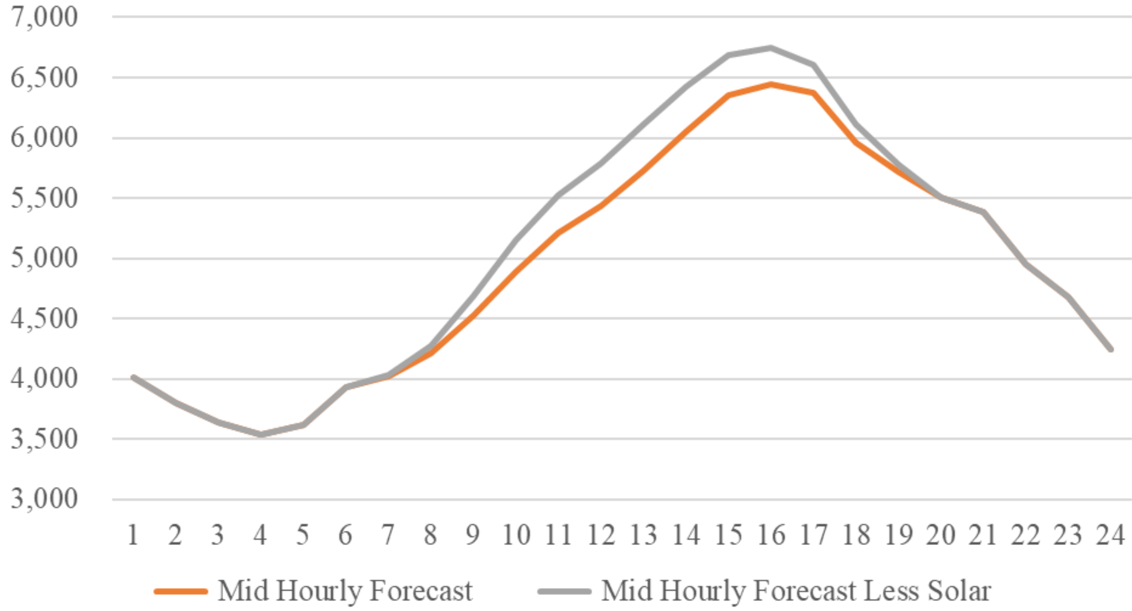
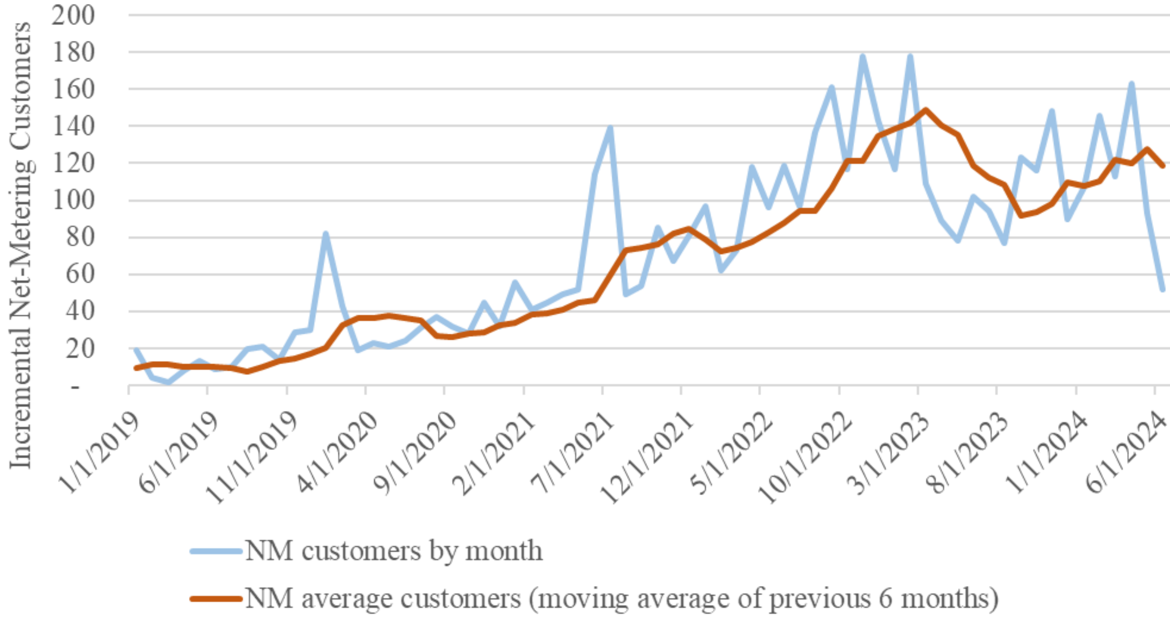


Figure 7-7: Hourly Forecast Profile for August 26th, 2039 (High Solar Scenario)



As is the case with battery adoption, net metering incremental adoption rates in the past year have slowed. Figure 7-8 shows monthly incremental net metering adoptions through June 2024.

Figure 7-8: Incremental Net Metering Customer Adoption by Month (Jan 2019 - Jun 2024)



Once again, the Companies' experience with their customers' adoption of distributed solar generation shows that customers generally become more inclined to adopt it as its economics improve, but also that some customers adopted solar even when it was not clearly economical. Recent solar panel and installation costs in addition to interest rate increases could explain the dip in incremental adoptions. Overall, the forecast results are consistent with the assumptions that base electricity rates will increase at the assumed rate of inflation while, according to the Companies' adjusted NREL's projections, solar costs will generally continue to decrease after the recent uptick. To illustrate, the figures below show the projected levelized cost of solar across the specified period compared to the blended compensation a customer would receive at 20%, 40%, and 60% exported energy levels.

Figure 7-9: RS blended solar compensation compared to adjusted NREL LCOE

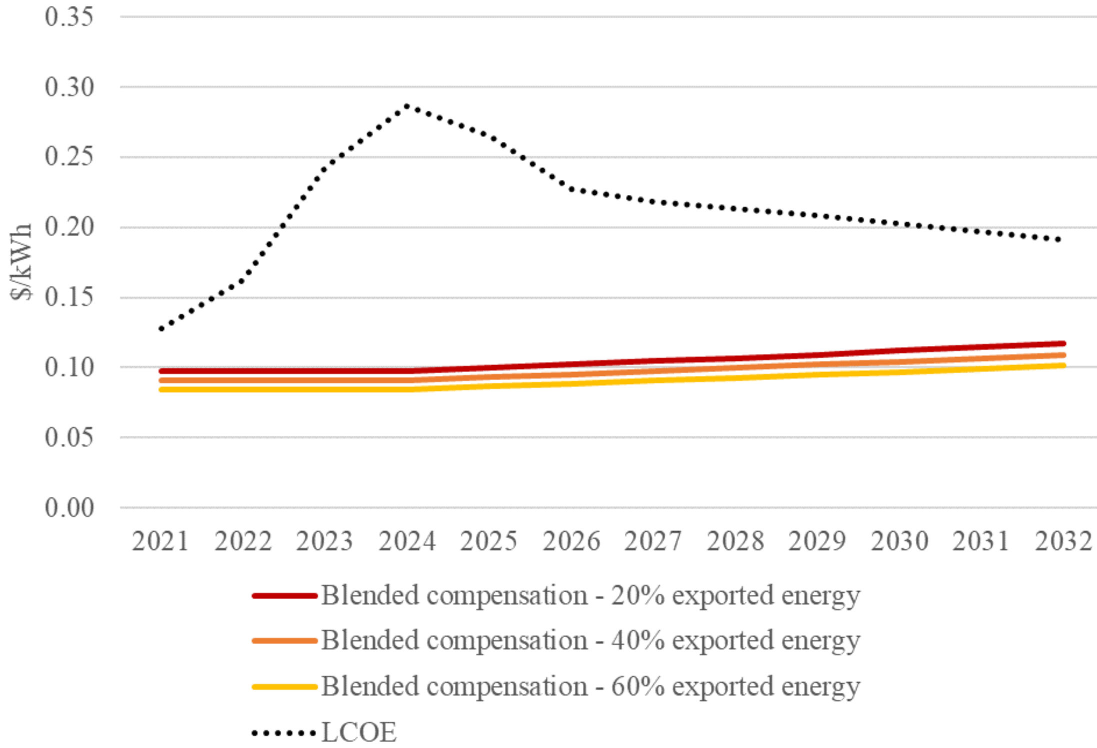


Figure 7-10: GS blended solar compensation compared to adjusted NREL LCOE

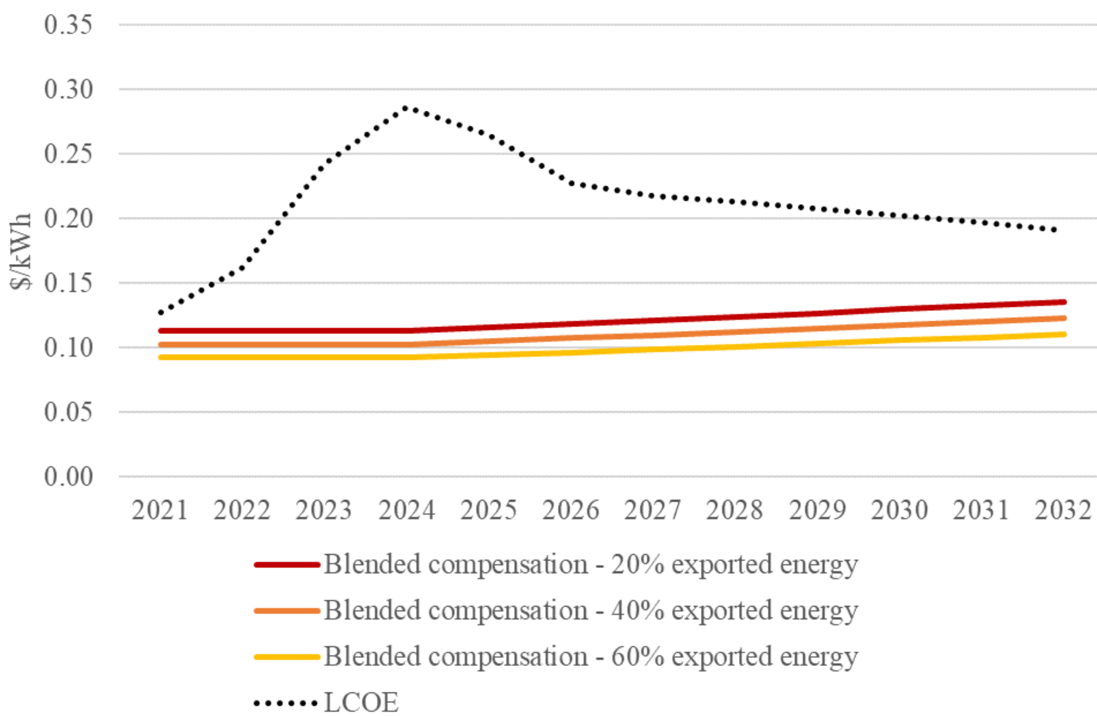
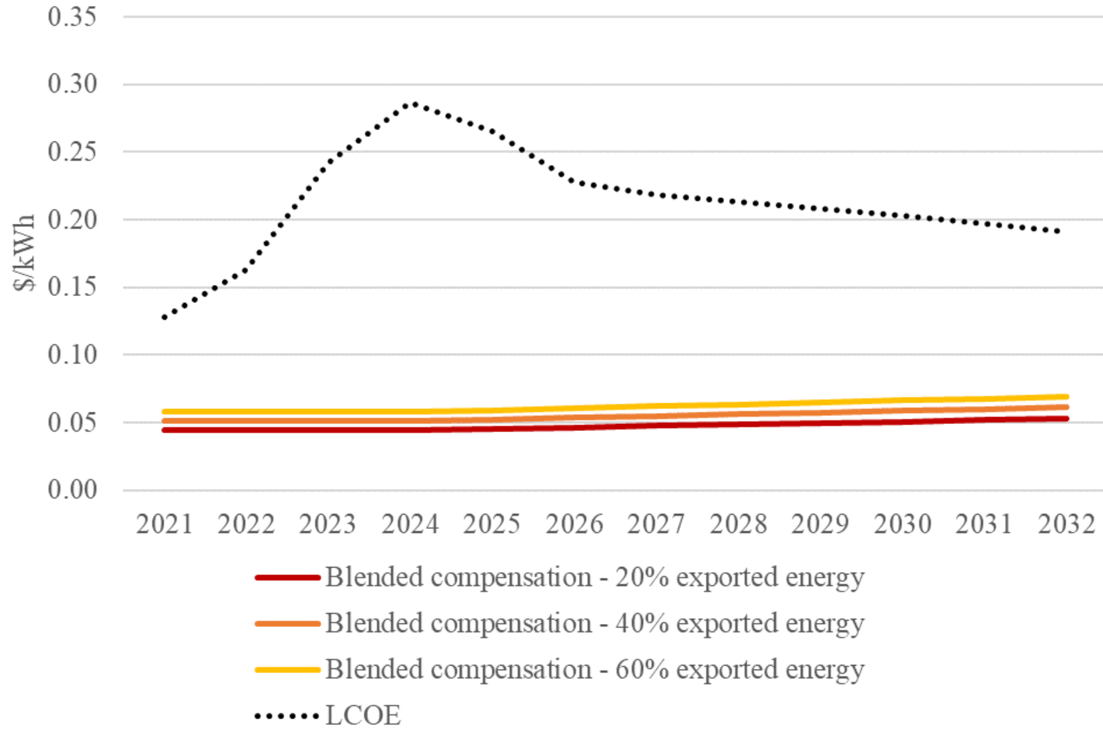


Figure 7-11: PS blended solar compensation compared to adjusted NREL LCOE



Further evidence that most net metering customers are interested in the economics of the systems they install is what has occurred since Rider NMS-2 became effective on September 24, 2021. Rider NMS-2 provides dollar-denominated bill credits for exported energy at Commission-prescribed rates. Rider NMS-2 bill credit rates are lower than retail RS and GS rates, providing an economic incentive for customers installing distributed solar to size their systems to minimize energy exports while serving as much of their own load as possible. This could help explain why, for example, the average net metering installation prior to September 2021 had a capacity of about 9.3 kW, whereas the average net metering installation from October 2021 through June 2024 had a capacity of about 8.5 kW.[59]

That observation of NMS-2 customers is also consistent with the figures above, which show the effective weighted compensation an NMS-2 customer would receive in the form of avoided retail energy rates and NMS-2 bill credits at different percentages of energy exports, which would receive NMS-2 bill credits (all rates and credits are currently tariffed amounts). These figures demonstrate that for customer classes with energy rates above the NMS-2 credit (i.e., RS and GS), it is economically beneficial to minimize the amount of energy exported to the grid and compensated at the NMS-2 rate. For this reason, should the NMS-2 rate for energy exports be reduced in the future, the response will likely be continued adoption, but smaller panel sizes compared to today. The Companies did not analyze a situation in which such customers would receive no compensation for exported energy because it would be inconsistent with their SQF tariff provisions to provide no compensation for such energy. Instead, as noted above and consistent with the Companies' tariffs, the Companies modeled providing customers SQF compensation for exported energy after reaching the 1% capacity level.

The figures also demonstrate that for customers that have demand charges (such as PS customers) and therefore have much lower energy rates, it is more challenging to cost-justify net metering. PS customers have the opposite effect of RS and GS in that their weighted average compensation improves the more they can sell back to the grid. However, the LCOE on the charts being further away from the weighted compensation lines shows that LCOE would have to drop significantly for distributed generation to be cost-justified for these customers, assuming minimal reductions to demand as it only takes 15 minutes to set a monthly billed demand in a billing period.

As a final note on the reasonableness of the distributed generation forecast, about 0.6% of the Companies' residential customers as of mid-2024 are solar net metering customers. This might seem small compared to certain other states, such as California (about 23% residential solar) and Arizona (about 14% residential solar). [60] However, 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. According to EIA, the average retail price of electricity in Arizona in 2024 was 13.40 cents per kWh and California's was 27.66; Kentucky's was 10.35.[61]

With such dramatic differences in solar resources and rates, it is unsurprising that Arizona and California have much higher rates of residential solar deployment. States with solar irradiance and rates more comparable to Kentucky, absent state policies to require or highly incentivize customers to deploy solar, tend to have solar deployment closer to those seen in the Companies' Kentucky service territories. For these reasons, it is unlikely that Kentucky solar will reach California's or Arizona's levels of solar penetration, and the Mid load forecast's projection that about 1.7% of residential customers in the Companies' service territory will install solar by 2039 is reasonable.

8. Electric Vehicles

From 2017 to 2023, the estimated number of electric vehicles ("EVs") in operation in the LG&E and KU service territories grew by an average of 43% per year from 1,415 to 12,284 (see Figure 7-12 for adoption from 2010-2023).[62] EVs-in-operation are forecast in the mid forecast to increase to over 130,000 – or ten times the current level – by the end of 2039. 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 EV model considers

[59] Averages are calculated using kW of net metering solar installations that are currently active in the LG&E or KU service territory.

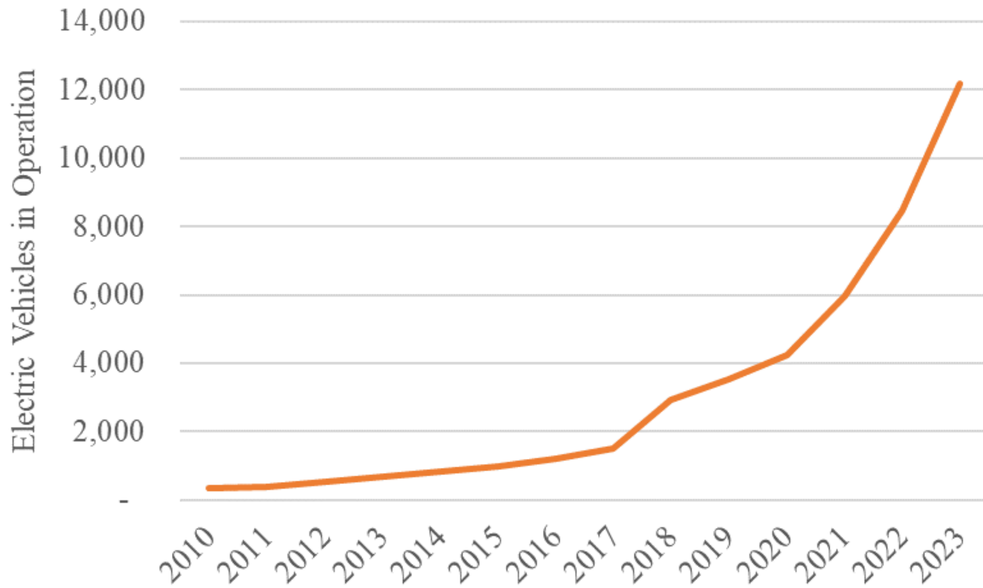
[60] Solar Industry Update Spring 2024 – May 14, 2024 (NREL). https://www.nrel.gov/docs/fy24osti/90042.pdf

[61] Average Price of Electricity to Ultimate Customers by End-Use Sector by State, June 2024 and 2023 (Cents per Kilowatthour) (EIA) - https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a

[62] 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.

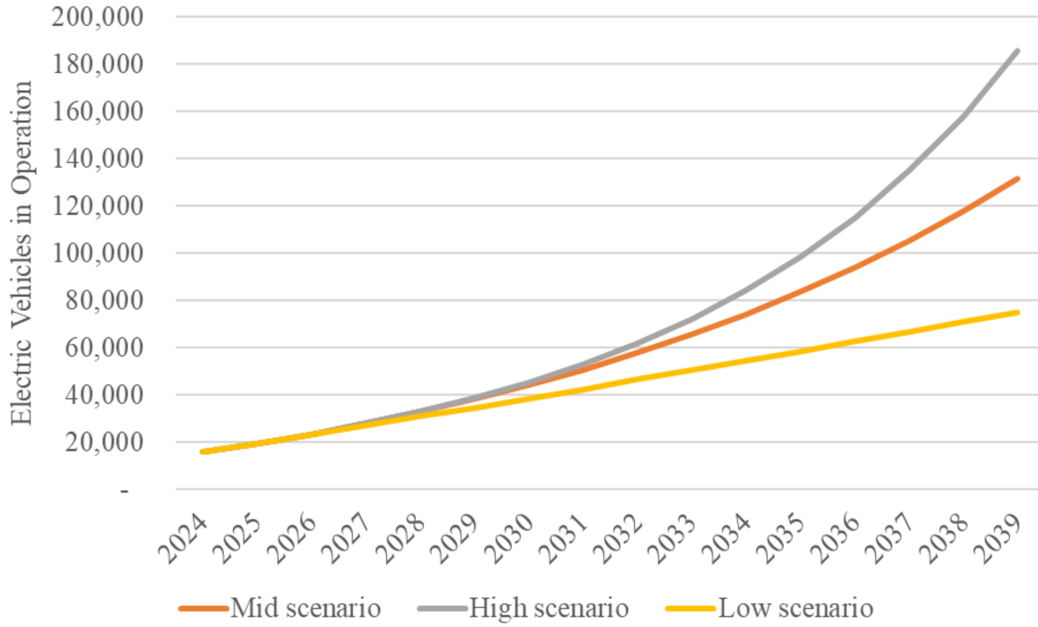
historical adoption of EVs, the comparison of EV to internal combustion engine ("ICE") car costs, and the total number of cars possible in the service territory but is unable to account for sudden technological innovation that could cause a dramatic shift from historical adoption patterns. The EV forecast 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, all sales of new, light-duty passenger vehicles in California must be BEVs or PHEVs by 2035 and New York passed a similar law not long after California did. If more states pass similar bans on gas-powered vehicles, then the increased demand for EVs in those states may limit their availability for purchase in Kentucky.

Figure 7-12: Cumulative Historical EV Adoption from 2010-2023



For reference, the mid EV forecast assumes the total number of cars in the Companies' service territory by 2039 to be around 1.7 million, with roughly 8% of those cars being EVs. Figure 7-13 shows the mid, low, and high forecasts for the number EVs in the Companies' service territories.

Figure 7-13: Electric Vehicles in Operation, 2024-2039



The high EV scenario contemplates not only continued patterns of EV adoption, but rapid growth starting in the 2030s. The high scenario inherently assumes, either through new technological innovations, significant advances to charging infrastructure, or updated vehicle emissions standards, that EVs will eventually either become less expensive than ICE vehicles or essentially become the only option for consumers due to more stringent vehicle emissions standards. It is also plausible that as Kentucky increasingly becomes, as Gov. Beshear has described it, the EV battery production capital of the United States, more Kentuckians will want to purchase EVs, just as any number of Kentuckians may be partial to Ford and Toyota due to their manufacturing presence in the Commonwealth.

The low EV scenario assumes that there will be a slow-down of incremental growth in EV adoption rates like the U.S. experienced during the first quarter of 2024.[63] It should be noted that this slowdown is not yet evident in the incremental growth currently seen in the service territory. However, recent news that would support the low scenario is Ford's announcement of an indefinite delay of Phase 2 of the BlueOval SK battery park.

The primary factors impacting electricity consumption by EVs are the number of EVs in the Companies' service territories and the distance driven per vehicle. However, resource planning considerations for EVs focus less on these factors and more on the way customers charge their vehicles. The timing of charging for EVs is an important consideration. If EVs are charged overnight when energy requirements would otherwise be low, the vehicles can likely be charged with the Companies' existing dispatchable generation assets. Conversely, if EVs are charged early in the evenings (e.g., when customers get home from work), EV charging could exacerbate

[63] U.S. share of electric and hybrid vehicle sales decreased in the first quarter of 2024. U.S. Energy Information Administration (EIA) - May 14, 2024. https://www.eia.gov/todayinenergy/detail.php?id=62063

summer and winter peak energy requirements and potentially create the need for additional peaking capacity or load control programs. The Companies' load forecasts assume primarily overnight EV charging that occurs at residences. In Figure 7-14 and Figure 7-15, the managed charging profile shifts EV charging to later in the evening when load is lower. If the generation fleet moves away from dispatchable resources toward more intermittent resources, EV charging times may need to shift to periods of the day when the intermittent resources are available. However, unless significant workplace charging infrastructure is built, that would also require vehicle owners to be at home during the day, which may not be feasible.

Figure 7-14: Managed EV Charging Profile Compared to 2039 Summer Peak

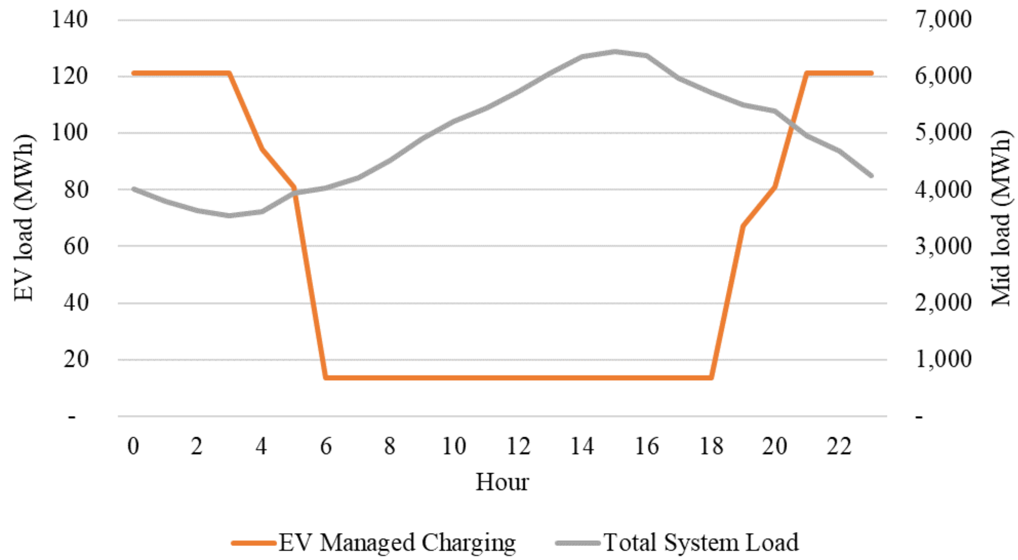
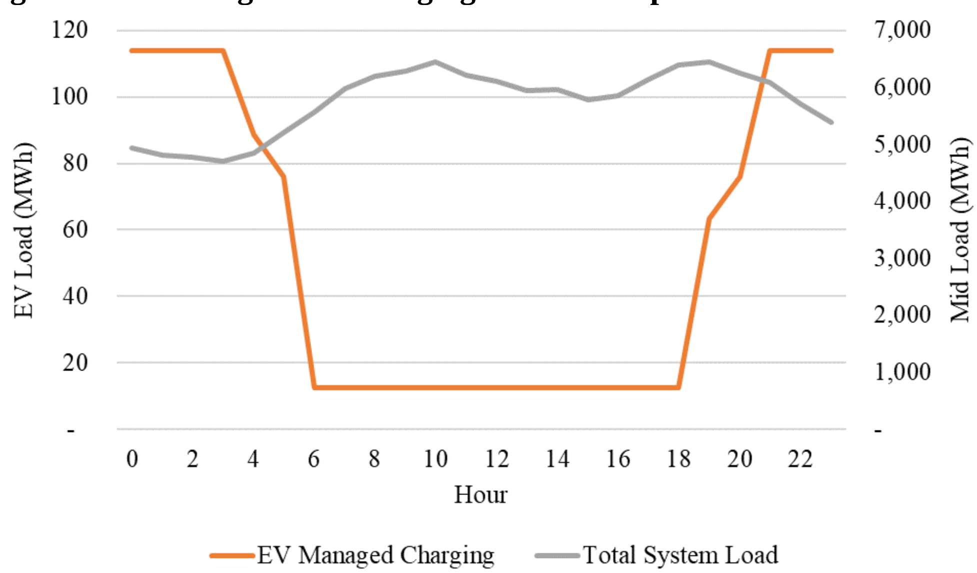


Figure 7-15: Managed EV Charging Profile Compared to 2039 Winter Peak



9. *Space Heating Electrification*

Table 7-25 and Table 7-26 show the use-per-customer ("UPC") declines of each new cohort,[64] which is equivalent to the year the residence was completed. Unsurprisingly, the more recently the home was built, the more efficient it is. These residential UPC reductions are in both LG&E and KU service territories despite the increased incidence of electric heating. Indeed, much of the reductions is attributed to the installation of increasingly efficient lighting and other end-uses as well as a more efficient housing structure in terms of insulation and windows.

Compared to premises added through 2010, a greater percentage of residential premises added since 2010 have electric space heating (see again Table 7-25 and Table 7-26). In the KU service territory, about 56 percent of all residential premises built 2010 or prior have electric space heating, but roughly 70 percent of new residential premises added since 2010 have electric space heating. This increase is even more pronounced in the LG&E service territory, where about 50 percent of residential premises added since 2010 have electric space heating versus only 24 percent for residential premises built 2010 or prior.

Table 7-25: KU Electric Heating Penetration

Cohort	Estimated Electric Heating Penetration	Average Billed kWh in 2023	Premises
<= 2010	56%	12,787	376,311
2011	71%	13,599	4,023
2012	74%	13,187	3,830
2013	72%	13,359	4,193
2014	70%	13,243	3,440
2015	70%	12,895	3,466
2016	69%	12,422	4,116
2017	67%	11,868	4,734
2018	67%	12,116	3,961
2019	67%	11,879	3,948
2020	65%	11,474	4,187
2021	70%	11,278	4,189
2022	69%	11,439	4,084

[64] Cohort is used to refer to a group of residences completed in the same year, i.e., 2011 cohort would refer to premises that were completed and became customers sometime during 2011.

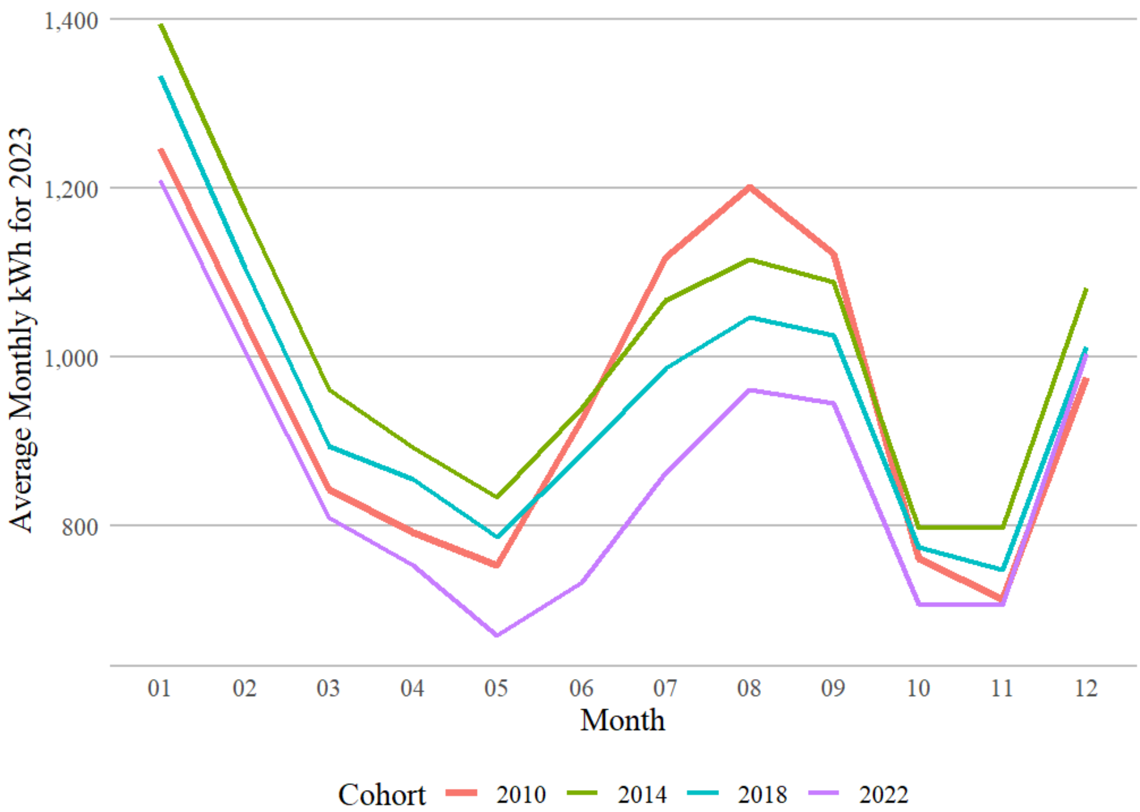
Table 7-26: LG&E Electric Heating Penetration

Cohort	Estimated Electric Heating Penetration	Average Billed kWh in 2023	Premises
<= 2010	24%	10,413	323,662
2011	36%	11,382	2,356
2012	37%	12,788	2,072
2013	41%	12,756	2,484
2014	47%	11,315	3,252
2015	48%	11,625	3,218
2016	49%	11,509	3,066
2017	48%	10,733	3,700
2018	45%	11,072	3,470
2019	52%	10,730	3,572
2020	53%	9,613	4,993
2021	49%	10,654	3,424
2022	50%	9,665	3,609

All other things equal, cohorts with a higher electric heating penetration would be expected to consume more electricity annually on average, but this has not been the case for those added in recent years. For example, as seen in the tables above, despite a higher electric heating penetration, the average consumption in 2023 for premises added in 2022 (11,439 kWh for KU and 9,665 kWh for LG&E) is lower than that for premises added through 2010. This result reflects the previously mentioned gains in lighting and cooling end-use efficiencies as well as the fact that recent customer growth has been concentrated in urban areas where homes are smaller on average than in rural areas, in part due to the higher incidence of multifamily units in urban areas.

Figure 7-16 compares the monthly use-per-premise in 2023 for four premise cohorts. Compared to premises added through 2010, newer premises have significantly lower usage in the summer months and more similar usage in the winter months.

Figure 7-16: Monthly Average Use-Per-Customer by Estimated Housing Vintage



Additional discussion of key assumptions and judgments is included in Volume II ("Energy & Demand Forecast Process").

7.(7).(c) General Methodological Approach
Section 5.(2) contains an overview of the load forecasting process. A more detailed description of the forecast process, including model design, is included in Volume II ("Energy & Demand Forecast Process").

7.(7).(d) Treatment and Assessment of Forecast Uncertainty
Section 7.(7).(b) summarizes the uncertainties that could affect the load forecasts of KU and LG&E. Across forecast cycles, forecast uncertainty is addressed by reviewing and revising the model specifications to ensure that the relationships between variables are properly quantified and that the structural relationships remain valid.

Within each forecast cycle, there is uncertainty in the forecast values of the independent variables. To address this uncertainty, the Companies develop high and low forecast scenarios to support sensitivity analysis of the various resource acquisition plans being studied.

7.(7).(e) Sensitivity Analysis
High and Low energy requirements forecasts are presented below along with a discussion of the uncertainties considered in developing these forecasts, which uncertainties and assumptions are fully discussed above in Section 7.(7).(b).

The Companies' High and Low energy requirements forecasts are summarized in Table 7-27 along with the Mid energy requirements forecast. Compared to the Mid forecast, the High scenario reflects increased economic development load in which multiple data center customers join the service territory. Additionally, but far less impactful, are a variety of other factors occurring simultaneously: electric vehicles grow more quickly than in the mid forecast, reaching 15 times current levels by 2039; residential customers grow 50% faster than in the mid forecast (0.83% versus 0.55%) beginning in 2024; energy efficiency and distributed generation grow more slowly than in the Mid forecast; and electric space heating is adopted more quickly than assumed in the Mid forecast. However, it is important to note that existing customers who replace old electric furnaces with more efficient heat pumps will actually have lower electricity consumption during the winter months.

Conversely, the Low scenario assumes no data center customers join the service territory and 100 MW of industrial load leaves the service territory in the 2030s. In addition, residential customer growth is 50% slower than in the Mid forecast (0.27% versus 0.55%) and a new federal or state law eliminates the 1% cap on net metering capacity.[65] Finally, space heating electrification occurs more slowly than assumed in the Mid forecast.

Table 7-27: Energy Requirements Forecasts, Combined Companies (GWh)

Year	Mid	High	Low
2024	31,913	32,090	31,727
2025	32,808	33,092	32,452
2026	32,867	33,251	32,339
2027	33,668	34,455	32,086
2028	34,806	37,372	31,882
2029	36,057	41,270	31,516
2030	38,292	45,114	31,262
2031	40,569	48,392	31,049
2032	41,200	49,142	30,678
2033	41,033	49,039	30,409
2034	40,971	49,057	30,551
2035	40,949	49,096	30,261
2036	41,057	49,284	30,301
2037	40,930	49,188	30,158
2038	40,949	49,263	30,120
2039	40,943	49,320	30,051

Figure 7-17 shows the disaggregated impact of each High and Low scenario assumption on the Mid energy requirements forecast. In either scenario, the impact of economic development cannot be overstated. With the second phase of the Blue Oval SK battery park (in the High scenario only) and new data centers, economic development customers have extremely high load factors, so the energy impact is significant. In fact, energy swings by nearly 10,000 GWh on either side of the

Mid forecast, as shown in Table 7-27 and Figure 7-17. The other uncertainties in the forecast are minimal within the IRP period when compared to the size of these economic development customers.

Figure 7-17: High and Low Scenario Energy Requirements Differences (GWh)

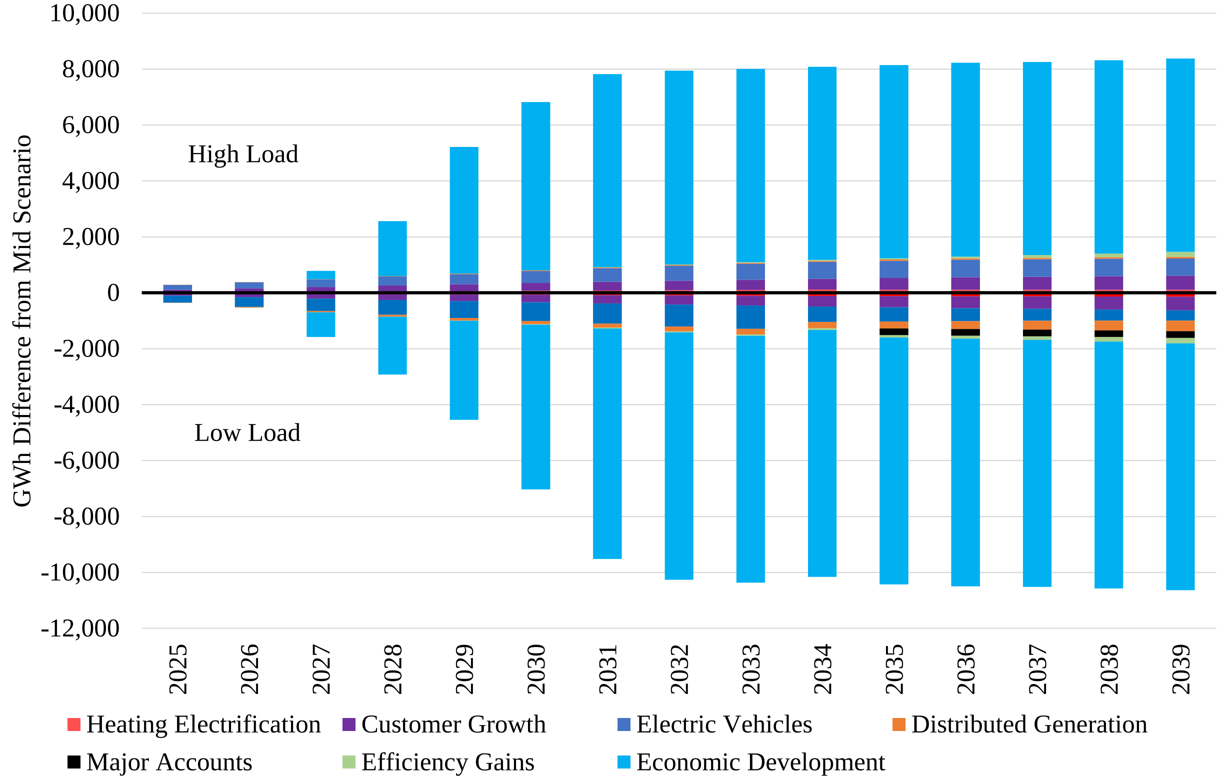


Table 7-28 summarizes the Mid, High, and Low forecasts for summer and winter peak demands. In addition, Figure 7-18 and Figure 7-19 show the disaggregated impact of each High and Low scenario assumption on the Mid summer and winter peak demand forecasts, respectively. The Companies are much closer to seasonal parity now compared to the 2021 IRP. However, the economic development loads tend to be slightly summer peaking even with their very high load factors, so this is anticipated to maintain the current gap between summer and winter. This change essentially offsets the impact of distributed generation's reduction of the summer peak over time. Once again, the impact of economic development on peaks cannot be overstated on the total peaks. Economic development loads are the majority of the reason for scenario peaks moving nearly 1,000 MW above and below the Mid forecast in each season. In the Low scenario, greater adoption of distributed generation also causes the summer peak to trend lower over the IRP period such that the winter peak is essentially the same as the summer peak by the end of the IRP period. The summer peaks have downside risk due to distributed generation while the winter peaks have upside risk due to space heating electrification.

Table 7-28: Peak Demand Forecasts, Combined Companies (MW)

	Winter			Summer		
Year	**Mid**	**High**	**Low**	**Mid**	**High**	**Low**
2024	6,015	6,047	5,982	6,115	6,155	6,087
2025	6,146	6,203	6,078	6,228	6,285	6,160
2026	6,150	6,228	6,049	6,242	6,318	6,135
2027	6,227	6,327	6,029	6,365	6,532	6,081
2028	6,347	6,600	5,991	6,474	6,913	6,022
2029	6,471	7,059	5,952	6,686	7,439	5,976
2030	6,733	7,551	5,924	6,931	7,833	5,930
2031	7,003	7,984	5,896	7,216	8,222	5,886
2032	7,135	8,142	5,876	7,201	8,218	5,844
2033	7,123	8,141	5,856	7,201	8,217	5,802
2034	7,121	8,141	5,836	7,179	8,216	5,766
2035	7,118	8,140	5,816	7,171	8,215	5,729
2036	7,118	8,140	5,813	7,161	8,235	5,714
2037	7,118	8,148	5,809	7,160	8,240	5,699
2038	7,118	8,148	5,806	7,158	8,239	5,683
2039	7,117	8,148	5,803	7,149	8,248	5,668

Figure 7-18: High and Low Scenario Summer Peak Differences (MW)

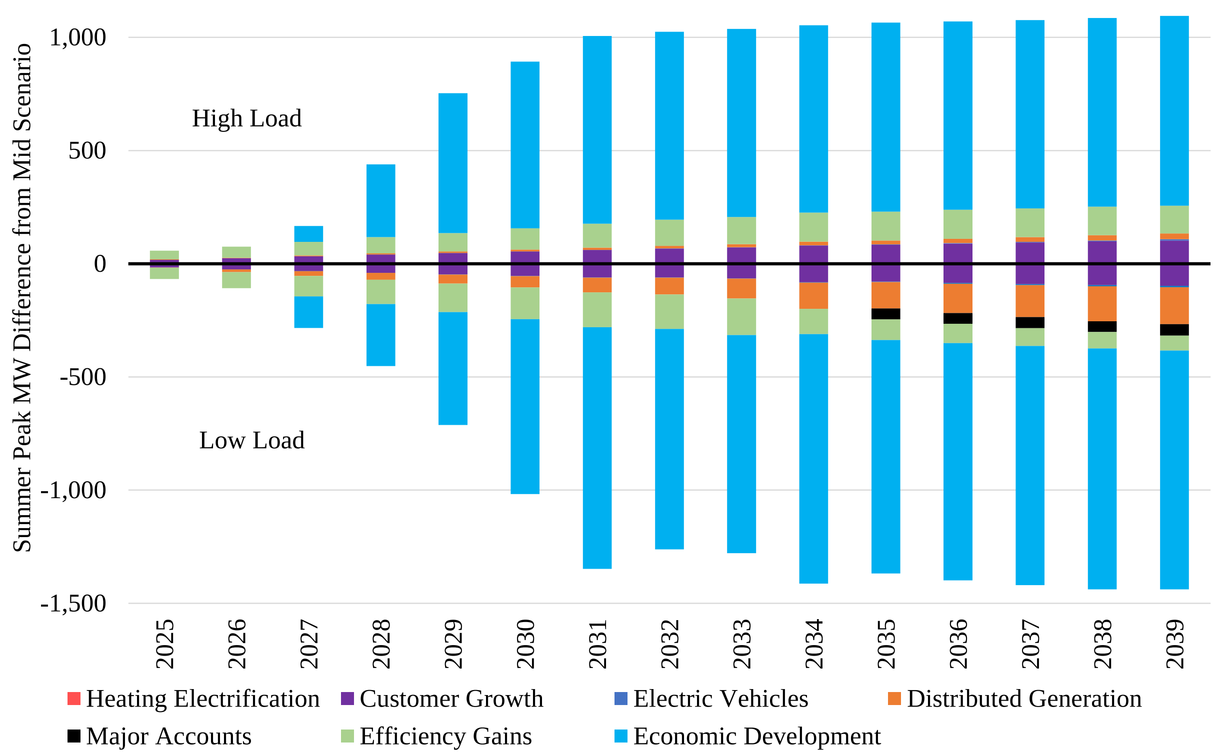
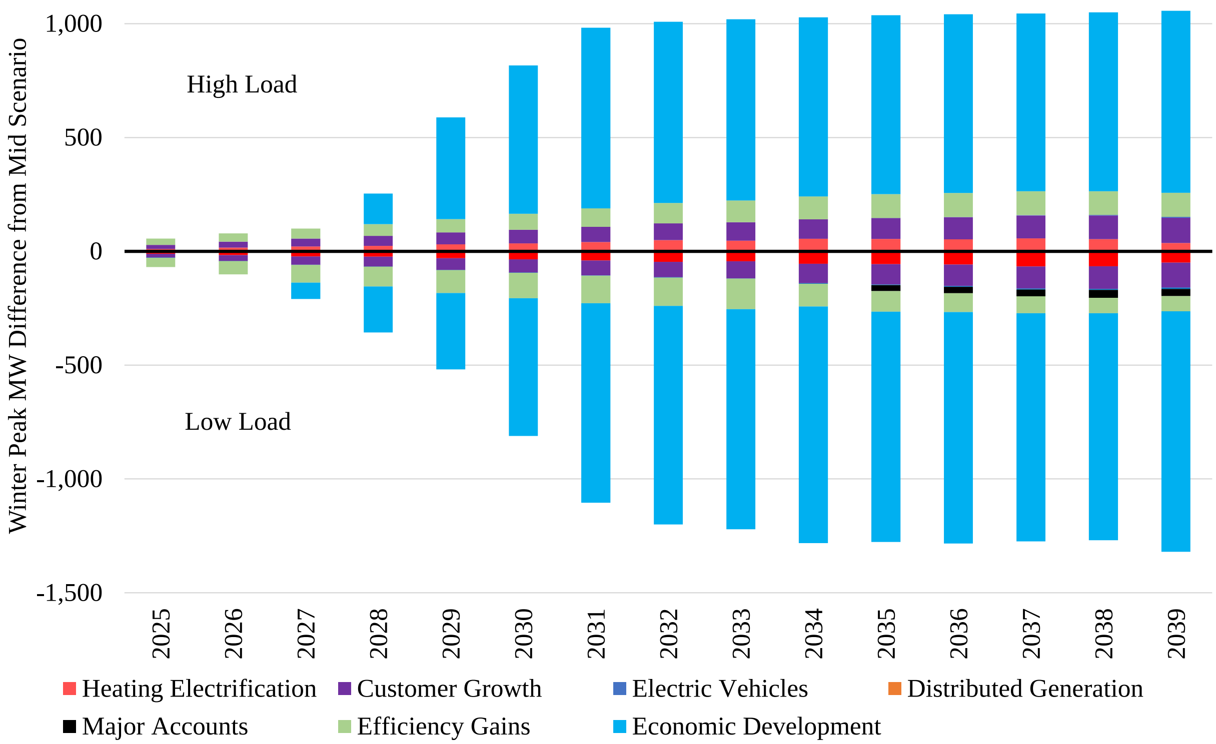


Figure 7-19: High and Low Scenario Winter Peak Differences (MW)



7.(7).(f) Research and Development

While the Companies use proven econometric techniques to create a robust load forecast, they also conduct research into additional or alternative ways of providing additional insight or explanatory power for their forecasts.

Customer behavior is a key component to robust load forecasting. Since the last IRP, the Companies have surveyed their residential customers to see the kinds of decisions they are making when it comes to home appliances, distributed generation, and other energy-related topics. In addition to surveying customers, the Companies evaluate the economics of end-uses that could materially impact the load forecast if widely adopted, such as electric heat pumps or distributed solar. Therefore, not only are the Companies evaluating what the economics would suggest customers would do in *theory*, the Companies are also evaluating what customers have *actually* done. Finally, the Companies have attended conferences and participate in broader industry groups. In 2024, the Companies sent load forecasting representatives to the AHR Conference and the Itron Load Forecasting Conference. Itron also conducts a survey of the over 100 participating load forecasting entities that participate in this energy forecasting group.

7.(7).(g) Development of End-Use Load and Market Data

The Companies obtain data on class level end-uses from Itron and the EIA, specifically for residential and commercial customers. As mentioned in the section above, the Companies participate in an energy forecasting group managed by Itron, in which collaborative efforts with the EIA and other utilities help identify best practices in load forecasting. In addition, participation in industry groups specializing in load research such as AEIC Load Research & Analytics helps gain access to data and insights.

The Companies also seek to use other sources of data to supplement their load research program. The addition of AMI will provide a valuable source of data to understand residential end-use trends. Thus far, AMI data has been used to analyze impacts of Winter Storm Elliot and direct load control events.

The Companies also use direct feedback from large customers to understand their usage. To further their knowledge and understanding, the Companies plan to continue residential customer surveys, ad hoc studies, and the Companies' online panel.

8 Resource Assessment and Acquisition Plan

8.(1) Plan Overview

The 2024 IRP Recommended Resource Plan is shown in Table 8-1. As discussed in Volume III (2024 IRP Resource Assessment), the Companies developed the Recommended Resource Plan by modifying the least-cost resource plan in the Mid Load, Ozone NAAQS + ELG scenario to (1) support the potential for high economic development load growth and CO_2 regulations and (2) have no regrets should high load or CO_2 regulations not come to fruition. The Mid load, Ozone NAAQS + ELG scenario includes retirements of Brown 3 and Mill Creek 3-4, ELG compliance at the Ghent and Trimble County stations via zero liquid discharge, and the additions of new dispatchable DSM measures, two NGCCs, 900 MW of battery storage, and a Ghent 2 SCR. In the Recommended Resource Plan, to support the potential for high economic development load growth and CO_2 regulations, the additions of the Ghent 2 SCR and 400 MW of battery storage are accelerated to 2028, the addition of the second NGCC is accelerated to 2031, and the retirement of Brown 3 is deferred to 2035. In addition, 500 MW of solar is added in 2035 after prices fall to hedge natural gas price volatility and future CO_2 regulation risk. The Recommended Resource Plan is a “no regrets” resource plan because the accelerated resources are needed by 2035 if high economic development load growth or CO_2 regulations do not come to fruition. Furthermore, the addition of 500 MW of solar reflects the likelihood that some level of solar will be least-cost even without CO_2 regulations.

Table 8-1: Recommended Resource Plan (Ozone NAAQS + ELG, Mid Load)

Year	Resource Changes
2028	+Dispatchable DSM +400 MW 4hr BESS; Add Ghent 2 SCR
2029	
2030	+1 NGCC; ELG @ Ghent, Trimble County
2031	+1 NGCC
2032	
2033	
2034	
2035	Retire Mill Creek 3-4; Retire Brown 3; +500 MW 4hr BESS; 500 MW Solar;
2036	
2037	
2038	
2039	

Table 8-2 and Table 8-3 contain the Companies’ winter and summer peak demand and resource summaries in the Recommended Resource Plan.

Table 8-2: Winter Resource Summary (MW, Mid Load, Recommended Resource Plan)

	2025	2028	2029	2030	2031	2032	2035	2037	2039
Peak Load	**6,146**	**6,347**	**6,471**	**6,733**	**7,003**	**7,135**	**7,118**	**7,118**	**7,117**
Fully Dispatchable Generation Resources									
Existing Resources	7,909	7,977	7,977	7,977	7,977	7,977	7,977	7,977	7,977
Retirements/Additions									
Coal[66]	-300	-601	-601	-601	-601	-601	-1,897	-1,897	-1,897
Small-Frame SCCTs[67]	-55	-55	-55	-55	-55	-55	-55	-55	-55
NGCC[68]	0	660	660	1,320	1,980	1,980	1,980	1,980	1,980
Total	7,554	7,981	7,981	8,641	9,301	9,301	8,005	8,005	8,005
Reserve Margin	22.9%	25.8%	23.3%	28.3%	32.8%	30.4%	12.5%	12.5%	12.5%
Renewable/Limited-Duration Resources									
Existing Resources	72	72	72	72	72	72	72	72	72
Existing CSR	115	115	115	115	115	115	115	115	115
Existing Disp. DSM[69]	45	110	124	125	135	145	158	160	163
Retirements/Additions									
Solar[70]	0	0	0	0	0	0	0	0	0
BESS[71]	0	465	465	465	465	465	890	890	890
Dispatchable DSM	0	1	2	3	3	5	8	9	10
Total	231	763	777	779	789	800	1,242	1,246	1,250
Total Supply	**7,785**	**8,744**	**8,758**	**9,420**	**10,090**	**10,101**	**9,247**	**9,251**	**9,255**
Total Reserve Margin	**26.7%**	**37.8%**	**35.3%**	**39.9%**	**44.1%**	**41.6%**	**29.9%**	**30.0%**	**30.0%**
Capacity Need[72]	**143**	**-557**	**-411**	**-735**	**-1,057**	**-897**	**-65**	**-69**	**-74**

[66] Mill Creek 1 will be retired at the end of 2024. Mill Creek 2 will be retired after Mill Creek 5 is commissioned in 2027. The Recommended Resource Plan includes 4 MW auxiliary load for an SCR on Ghent 2 in 2028 and the retirement of Brown 3, Mill Creek 3, and Mill Creek 4 in 2035.
[67] This analysis assumes Haefling 1-2 and Paddy's Run 12 are retired in 2025.
[68] Mill Creek 5 is assumed in-service in 2027. The Recommended Resource Plan includes additional NGCC units in 2030 and 2031.
[69] Existing Dispatchable DSM reflects expected load reductions under normal peak weather conditions.
[70] This analysis assumes 120 MW of solar capacity is added in 2026, and another 120 MW of solar capacity is added in 2027. The Recommended Resource Plan includes an additional 500 MW of solar capacity in 2035. Capacity values reflect 0% expected contribution to winter peak capacity.
[71] Brown BESS is assumed in-service in 2026. The Recommended Resource Plan includes an additional 400 MW of 4-hour BESS capacity in 2028 and another 500 MW of 4-hour BESS capacity in 2035. Capacity values reflect 100% capacity contribution for Brown BESS and 85% capacity contribution for the additional 4-hour BESS.
[72] The winter capacity need is based on a 29% winter minimum reserve margin target. Positive values reflect a capacity deficit.

Table 8-3: Summer Resource Summary (MW, Mid Load, Recommended Resource Plan)

	2025	2028	2029	2030	2031	2032	2035	2037	2039
Peak Load	**6,228**	**6,474**	**6,686**	**6,931**	**7,216**	**7,201**	**7,171**	**7,160**	**7,149**
Fully Dispatchable Generation Resources									
Existing Resources	7,612	7,618	7,618	7,618	7,618	7,618	7,618	7,618	7,618
Retirements/Additions									
Coal[73]	-300	-601	-601	-601	-601	-601	-1,881	-1,881	-1,881
Small-Frame SCCTs[74]	-47	-47	-47	-47	-47	-47	-47	-47	-47
NGCC[75]	0	645	645	1,290	1,935	1,935	1,935	1,935	1,935
Total	7,265	7,615	7,615	8,260	8,905	8,905	7,625	7,625	7,625
Reserve Margin	16.7%	17.6%	13.9%	19.2%	23.4%	23.7%	6.3%	6.5%	6.7%
Renewable/Limited-Duration Resources									
Existing Resources	106	107	107	107	107	107	107	107	107
Existing CSR	110	110	110	110	110	110	110	110	110
Existing Disp. DSM[76]	84	150	166	170	179	190	208	216	227
Retirements/Additions									
Solar[77]	0	201	201	201	201	201	619	619	619
BESS[78]	0	465	465	465	465	465	890	890	890
Dispatchable DSM	0	1	2	3	3	5	8	9	10
Total	300	1,034	1,051	1,056	1,065	1,078	1,942	1,952	1,963
Total Supply	**7,565**	8,649	8,666	9,316	9,970	9,983	9,567	9,577	9,588
Total Reserve Margin	**21.5%**	33.6%	29.6%	34.4%	38.2%	38.6%	33.4%	33.8%	34.1%
Capacity Need[79]	**95**	-686	-442	-791	-1,095	-1,125	-747	-770	-796

The Companies' resource planning process consists of the following activities:

1. Review of supply-side and demand-side resource options
2. Assessment of reserve margin constraints and capacity contribution
3. Development of long-term resource plan

The models and methods for each of these activities are summarized in Section 5.(2). The results of these analyses are presented in Section 5.(4) and a complete summary of each analysis is included in Volume III.

---

[73] Mill Creek 1 will be retired at the end of 2024. Mill Creek 2 will be retired after Mill Creek 5 is commissioned in 2027. The Recommended Resource Plan includes 4 MW auxiliary load for an SCR on Ghent 2 in 2028 and the retirement of Brown 3, Mill Creek 3, and Mill Creek 4 in 2035.

[74] This analysis assumes Haefling 1-2 and Paddy's Run 12 are retired in 2025.

[75] Mill Creek 5 is assumed in-service in 2027. The Recommended Resource Plan includes additional NGCC units in 2030 and 2031.

[76] Existing Dispatchable DSM reflects expected load reductions under normal peak weather conditions.

[77] This analysis assumes 120 MW of solar capacity is added in 2026, and another 120 MW of solar capacity is added in 2027. The Recommended Resource Plan includes an additional 500 MW of solar capacity in 2035. Capacity values reflect 83.7% expected contribution to summer peak capacity.

[78] Brown BESS is assumed in-service in 2026. The Recommended Resource Plan includes an additional 400 MW of 4-hour BESS capacity in 2028 and another 500 MW of 4-hour BESS capacity in 2035. Capacity values reflect 100% capacity contribution for Brown BESS and 85% capacity contribution for the additional 4-hour BESS.

[79] The summer capacity need is based on a 23% summer minimum reserve margin target. Positive values reflect a capacity deficit.

8.(2) Options Considered for Inclusion in Plan

The following sections describe the options considered for the Companies' resource plan.

8.(2).(a) Improvements to and More Efficient Utilization of Existing Facilities

Generation

Reliable operation of the Companies' generation fleet is key to the delivery of safe, cost-effective electric service to our customers. The Companies employ several strategies to ensure this reliability in the long term by keeping equipment in optimal operating condition, as well as in the short-term in extreme weather conditions. The Companies' generating assets have routinely exceeded Equivalent Forced Outage Rate ("EFOR") expectations for many years, demonstrating a record of reliable operation. Additionally, the Companies' knowledgeable and experienced work force understands how to operate and maintain assets in a proven, cost effective, and reliable manner. The Companies present information in this section to detail their practices to maintain generation equipment reliability into the future.

Fleetwide Operational Reliability

Fuel (coal) can be readily inventoried at each of the Companies' coal-fired generation stations, mitigating short-term fuel supply risks. Generally, fuel supply risks include natural gas pipeline interruptions due to cyber-attacks or weather, delayed or interrupted rail and barge transportation due to snow, ice, or high river conditions, and ice or snow accumulation on solar panels and wind turbines. Typically, sufficient fuel is inventoried at each coal-fired facility to provide for 30 days of operation. The Companies' fleet of coal-fired and natural gas-fired generation reliably responds to meet customer demands for electricity and can be dispatched according to demands in opposition to intermittent energy resources such as solar and wind.

In addition to freeze protection systems on plant equipment referenced later in this section, each plant maintains a Cold Weather Plan. These documents are based on NERC requirements and industry standards for seasonal readiness. The plans include check lists for relevant areas of the plant, and fuel acquisition and delivery guidelines for severe winter conditions, both coal and gas. The plans are discussed each year in the fourth quarter at each location. Checklists have been created that prescribe actions to take when temperatures reach freezing, including cooling tower preparation, portable heater deployment, material handling preparation, monitoring of water intakes, and instrument line checks. Actions and checklists are reviewed after each winter to ensure operations were not affected due to freezing conditions, and changes are made accordingly.

Currently, the generation fleet is in the process of implementing an Operational Technology (OT) Cyber Security Governance Program over the next several years. It is a collaborative process that incorporates a detailed phased roadmap encompassing the following risk-reducing mitigation strategies: governance; asset and change management; network segmentation; access control; anti-virus, patch, and vulnerability management; disaster recovery and business continuity; network monitoring; and system hardening. Each strategy provides a level of defense in depth for the fleet that equates to concurrent and continuous cyber security functions, which are cyber-industry best practices for identifying, protecting against, detecting, responding to, and recovering from cyber-attacks.

The Companies actively participate in research with the Electric Power Research Institute ("EPRI"). Working with EPRI provides valuable technical insights that help the Companies continue their record of reliable operation. An example of a current effort with EPRI is flexible operations to prepare the existing fleet for the increased penetration of non-dispatchable resources. The Companies also participate in EPRI research programs aligned with mechanical, electrical, and cyber reliability of our generating assets.

Maintenance Schedules and Practices

Maintenance schedules are coordinated across the Companies' generation fleet such that the outages will have the least economic impact to the customers and the Companies and will maximize fleet reliability. Outages are scheduled in lower-load seasons so they can reliably return to service during peak demand.

The Companies continue to plan multi-week outages to perform equipment inspections and repairs so that the units in the fleet continue running efficiently during the maintenance interval. These unit outages are generally scheduled on 12-24 month intervals based on the necessary scope of work. The Companies continue to target eight-year maintenance intervals for major turbine overhauls. As equipment inspections during these outages reveal potential issues, affected components can be repaired or replaced as needed. Equipment enhancements are analyzed and installed when determined to be the most prudent option. Projected remaining life of units is considered when determining outage intervals.

Predictive maintenance is a practice geared to prevent failure and reduce maintenance costs by monitoring the condition of operating equipment, identifying issues, and recommending proactive maintenance practices prior to equipment failure. Alternative approaches would consider running equipment to failure or performing maintenance on time-based intervals. These approaches would result in increased cost and decreased reliability. The technologies that are primarily used to monitor equipment condition are vibration analysis, oil sample analysis, thermography, and electrical motor testing. Abnormal conditions like looseness, misalignment, imbalance, and bearing failure can be diagnosed with vibration data and can support root cause failure analyses. Oil samples are collected from plant equipment and analyzed in a lab to look for early indications of an equipment problem. Oil analysis can help identify issues such as excessive wear, water ingression, temperature excursions, or breakdown of critical compounds that are necessary for proper lubrication. Thermography is another technology that is used to identify issues with mechanical or electrical equipment. Identifying areas where insulation has been damaged can be an easy way to troubleshoot a problem before the equipment fails.

Controls Systems, Generators, Exciters, and Electrical Systems

Technologically advanced controls continue to be one of the most proven applications for maintaining the efficiency and reliability of generating stations. New technologies allow for tighter control of key operating parameters and provide for coordination of integrated systems not previously available with analog controls. The transition to distributed controls systems ("DCS") took place on all of the major generating units years ago. The digital hardware requires periodic upgrade and replacement. All major DCS vendors have periodic system upgrades to maintain control platform stability. In order to continue to leverage the operational efficiencies enabled by digital controls the investments in control system upgrades will continue. The Companies have invested in DCS simulators across the fleet to enhance operator training and to provide a test bed for proposed logic changes.

Each unit has a generator step up ("GSU") transformer and associated auxiliary transformers to feed the switchyard, supply power to the grid, and to the plant for auxiliary usage. These transformers have cooling systems that are installed to ensure that the oil or gas that fills the transformer does not overheat, especially in extreme summer conditions. Remote monitoring of these GSUs and certain auxiliary transformers in the fleet are being expanded to monitor the condition of these assets. Instrumentation is being installed to identify failures in transformer bushings by detecting increased temperature and resistance in the components. Oil degradation in oil-filled transformers is also monitored using dissolved gas analysis. The Companies have procured and maintain spare GSUs for select units to reduce the impact of equipment failure.

During planned maintenance outage windows technical experts will inspect electrical and mechanical connections in and around the generator housing. Prioritizing these inspections at the beginning of long planned outages allows time to address any findings. Unit telemetry data (vibration, flux probe, his speed electrical fault data) is utilized to guide scope creation for contractors brought on site to perform the work and to assure adequate parts are available to return the unit to service on time.

Freeze protection is installed on critical systems that could experience sub-freezing temperatures during winter operation. Examples of freeze protection include resistive heating, insulation, motor heaters, and weather-resistant enclosures. Extreme minimum design temperatures have been and continue to be specified in site conditions for all new construction projects. Additionally, plant operating personnel monitor and evaluate freeze-protection systems during winter months to ensure that equipment is properly protected, especially when extreme cold is anticipated. Upgrades and enhancement to freeze-protection systems are planned and executed as needed.

Turbines and Boiler Feed Pumps

Another proven area to maintain efficiency in generating stations is restoring degraded turbines through regular turbine overhauls. A worn or degraded turbine fails to extract the maximum possible energy from the steam, thus decreasing the station efficiency. Turbine overhauls include inspecting the rotors for any issues such as excessive wear or cracking, ensuring all stationary sealing joints are serviceable, refurbishing radial steam seals, replacing inlet seal rings, ensuring optimal steam flow by restoring area dimensions on rotating and stationary blading, and polishing defects in the steam path to return the efficiency of the turbine to at or near design values. Major steam turbine overhauls are planned on an eight-year cycle for all units in the Companies' generation fleet.

Similar to turbine degradation, boiler feed pump degradation also robs the steam and water cycle of efficiency. These pumps are driven by small steam turbines or electric motors, and if worn, additional power is required to produce the required flow. In the case of turbine driven pumps, the turbine is overhauled as well to restore its efficiency. Feed pump and associated drive turbine overhauls are planned throughout the fleet on regular intervals to maintain reliability.

Boilers/HRSGS/Air Heaters/Combustion Components

The Companies continue to make improvements in boiler reliability and preventing tube leaks that cause forced outages. Continued inspection, repair, and replacement of boiler tubes will allow the fleet to maintain this improved reliability and reduced outage rate. The heat recovery steam generators (HRSGs) on Cane Run 7 have successfully been cleaned with CO_2 blasting. This effort will continue into the future as needed to maintain expected performance. Specialty cleaning is needed on the HRSGs due to the finned tubing and lack of access for traditional cleaning methods. Insulation and lagging on the HRSGs and associated piping are routinely evaluated to ensure reliability in winter operation because they are outside units.

On coal burning units, burners are routinely inspected and repaired to ensure that coal is burned as efficiently as possible. Air heaters transfer energy from the exiting flue gas to the combustion air entering the boiler and pulverizers so that the combustion is more efficient. The baskets in the air heaters serve as the heat transfer medium and need to be replaced periodically to maintain reliable operation, as well as optimize heat transfer efficiency. The Companies inspect burners, pulverizers, and air heater baskets during planned maintenance outages, and plan for major replacements or overhauls as needed to ensure reliable operation.

HEP/Feedwater Systems

High Energy Piping (HEP) systems that carry steam to and from the boiler are subject to high stress due to the temperatures and pressures at which these systems operate. It is important to inspect them periodically using visual and non-destructive examination (NDE) techniques to identify cracking and other failure mechanisms before they pose a risk to operational safety and unit reliability. HEP inspections are generally planned for all units in the Companies' fleet on three- to five-year intervals. These inspections also identify and address insulation issues to minimize energy loss. As units get closer to the end of their useful life, major HEP component replacements may be necessary.

Feedwater heaters use extraction steam from the turbine to heat the boiler feed water prior to entering the boiler. Preheating the boiler feedwater using extraction steam improves the thermal efficiency of the steam cycle. However, feedwater heaters can develop leaks, which causes inefficient operation and can force a unit to be taken offline for repairs. The Companies have taken steps to mitigate leaks and continue to conduct repairs or replacements as needed.

Environmental Control Systems

SCRs reduce NO_x emissions in flue gas via ammonia injection and reaction with a catalyst. SCR catalyst must be in proper operating condition to remove NO_x and fully react with the ammonia. Any unused ammonia, referred to as ammonia slip, can form ammonium bisulfate ("ABS") on downstream components. ABS formation leads to additional ash buildup and associated maintenance issues. The Companies regularly sample and test this catalyst and maintain a long-range plan for replacement to ensure reliable operation of the SCRs.

A combination of electrostatic precipitators and pulse jet fabric filters ("PJFFs") are used to remove particulate from the flue gas downstream of the boiler. The precipitators remove particulate by collecting it on electrically charged plates. Electrical components are upgraded and replaced as needed to ensure reliable particulate removal. The PJFFs act as filters to collect mercury via removing particulate in a series of bags that are then emptied into hoppers. The bags and their support cages require periodic replacement to ensure particulate removal and associated compliance with environmental regulations. All PJFFs in the fleet will undergo bag and cage replacements (based on measured bag condition and sample analysis) during the plan period.

Compliance with new effluent limit guidelines (ELG) has required each affected plant to build new physical/chemical water treatment systems that are currently in service. New systems for biological treatment of FGD wastewater are being installed at Ghent, Mill Creek, and Trimble County. All of these systems will be commissioned by the end of 2024. Freeze protection on these systems will ensure that they function reliably and efficiently in winter conditions. Future environmental regulations may require modifications or additions to these systems.

Condensers/Cooling Towers/Circulating Water Pumps

Cooling towers are used to cool the circulating water that absorbs energy from the turbine exhaust in the steam condenser. Towers are inspected periodically to ensure fill and fans (for mechanical draft towers) are in proper working order. In freezing conditions, water can freeze in the tower fill, causing damage and loss of efficiency. It is best practice to shut off cooling tower fans or bypass the tower periodically to prevent ice from damaging the tower and impacting reliability. The Companies continue to repair and rebuild towers to ensure maximum operational reliability and to ensure freeze protection and bypassing capabilities are available. Gearbox repairs for cooling tower fans are planned for all mechanical draft towers to maintain reliable operation. Proper gearbox maintenance and lubrication practices prevents operational issues in hot weather conditions. Cooling tower pumps are also inspected and repaired as needed to ensure adequate cooling water flow reaches the condensers. Condensers are cleaned manually during maintenance outages to remove debris left by the circulating water in the tubes and on the tube sheets in the water boxes. Buried circulating water piping systems that transport water between cooling towers and condensers have experienced failures due to deterioration. Projects have been executed or are being planned to line the interior of these systems to maintain future reliability.

Combustion Turbines

Significant efforts to maintain the reliability and efficiency of the Companies' combustion turbine fleet continue in the plan. Hot Gas Path Inspection ("HGPI") outages occur at scheduled intervals on combustion turbines based on hours of operation and number of starts. This type of outage includes complete inspection and any necessary repairs from the air inlet section to the exhaust section, and includes all compressor, combustor, and turbine components. HGPIs for most combustion turbines are scheduled within the planning period.

Combustion turbines are designed to operate outside in peak ambient conditions. Therefore, the freeze protection on instruments and piping is routinely inspected, repaired, and upgraded as needed. Inlet cooling systems allow more air to be passed through the CT when the inlet temperature increases. These systems are maintained and inspected to provide the most efficient cooling for summer peak operations. Inlet filtration keeps debris from accumulating on and fouling the compressor section. The filters are cleaned periodically to ensure proper air flow to the compressor. Compressors are also washed as needed when operational data indicates a loss of efficiency due to fouling.

Hydroelectric Units

Dix Dam will continue to undergo improvements to maintain the reliability of the plant going forward, including an overhaul of the crest gate, valve overhaul, and runner replacement.

Ohio Falls will similarly continue to undergo improvements to maintain the reliability of the units. These projects include trash rack guide repairs, replacement of the powerhouse roof, control system upgrades, runner inspections, and structural improvements to the headworks.

Distribution

LG&E and KU develop annual and long-term distribution system operations, maintenance, and investment plans designed to provide safe, reliable, resilient, secure and high-quality electric service to customers at a fair cost. Evolving customer expectations, acceleration of behind-the-meter distributed energy resources ("DER"), advancement in behind-the-meter technologies, and increased system threats are amplifying associated challenges and necessitating more robust system planning processes and tools, greater utilization of data analytics and science, and more strategic investments in grid modernization, hardening, and security.

LG&E and KU's distribution reliability and resiliency planning processes place emphasis on data collection and analytics, prioritization of system improvement opportunities, and identification and execution of investment strategies that provide for top quartile reliability performance and assure voltage at the point of delivery satisfies regulatory requirements. Focused investments in modernization and hardening of the distribution system over the last ten years have resulted in downward trends in service interruption frequencies (25% lower) and durations (19% lower) using standard IEEE reliability indices. During three of the last four years, customers experienced the lowest average interruption frequency in the Companies' history when excluding IEEE 1366 major event days. Similarly, customers experienced their lowest average interruption durations during three of the last four years when excluding IEEE 1366 major event days.

The greatest contribution to improved reliability in recent years has been the advancement of distribution automation ("DA") since 2017. The installation of more than 2,200 Supervisory Control and Data Acquisition ("SCADA") connected reclosers on the distribution system, and deployment of an advanced distribution management system ("ADMS") and distribution SCADA have enabled automated detection of fault conditions, isolation of faults, and expedited service restoration ("FLISR"), helping to minimize impacts of faults on the distribution grid. From 2022 through July 2024, FLISR has successfully saved over 38,000 customer service interruptions and over 2.6 million customer minutes interrupted.

In addition to the DA program, LG&E and KU have completed, and continue to execute, numerous projects to install, upgrade, or replace distribution substation transformers in the Companies' service territories to serve new customers and improve service reliability. New business requests in the service territory have increased since 2012 but gains in energy efficiency technology have slowed load growth. Because of this, capacity investment needs have waned, allowing for increased focus on system reliability, resiliency, and aging infrastructure replacement investments. Projects that improve reliability performance of poorer performing circuits and mitigate the effects of major equipment failure have received the most emphasis in recent years. Advanced data analytics tools and resources are now allowing LG&E and KU to more wisely invest in areas of concern based on outage history, geo-spatial characteristics, and environmental factors.

LG&E and KU are deploying an Advanced Metering Infrastructure ("AMI") with an expected completion in 2026. Associated technology will enable the Companies to collect more detailed information about distribution system components, interconnected DER, and customer load characteristics. Using this data, the Companies will be able to more accurately manage system voltage and power quality, pinpoint outage fault-locations, and proactively identify potential equipment overload conditions.

One of the specific use-cases for AMI data is dynamic volt/var optimization ("VVO"). Historically, utilities have controlled the system voltage and reactive power by measuring conditions at substations, applying models to predict voltage and reactive power at the point of delivery, and manually adjusting transformer taps or capacitor banks to regulate voltage and reactive power. LG&E and KU are leveraging AMI to automate and optimize voltage and reactive power control, enabling reduced system losses. The Companies are pulling data from AMI, distribution automation devices, and SCADA-enabled substation equipment to provide real-time insight into voltage and reactive power across the network. The Companies are adding SCADA control to transformer tap changers, voltage regulators, and capacitor banks to allow volt/VAR equipment to be remotely operated. All of this data and SCADA functionality is integrated into grid control software (ADMS) to allow for intelligent closed-loop VVO. VVO will also support implementation of conservation voltage reduction ("CVR"). CVR is a subset of the VVO functionality focused on intentionally lowering the distribution system voltages on targeted system components to reduce resistive load. For customers with heavy resistive loads, such as baseboard heating, this results in energy savings for customers and reduced fuel consumption for generators.

Increasingly, customer outages are being driven by extreme weather conditions. Since 2020, outage duration and frequency during major event days, defined by IEEE 1366, have increased. LG&E and KU's territory experiences tornadoes, severe thunderstorms, ice storms, and occasional hurricanes. To improve system resiliency, LG&E and KU have developed optimized design criteria based on data analytics of observed weather patterns in our service area. This has led to higher wind design criteria, increased ice loading design criteria, and additional design considerations surrounding facility placement within floodplains. LG&E and KU are also expanding the use of more resilient non-wood structures such as steel, ductile iron, and sectional composite.

LG&E and KU are committed to protecting the health and safety of our employees, contractors, customers, and the public. As an extension of this commitment, LG&E and KU have developed methods to address concerns surrounding wildfire risk as it pertains the presence of LG&E and KU facilities. FEMA assembles probabilistic models of wildfire risk from USDA, US Forest

Service, and others as part of their annual National Risk Index – National Risk Index Technical Documentation (fema.gov). These models predict burn probability ("BP"), defined as "the risk of an area being burned by a large fire that escapes initial suppression and spreads" and fire intensity level. This modeling identifies portions of the LG&E and KU service territory that are at increased risk for wildfire. The intent of our wildfire mitigation effort is to assess LG&E and KU facilities in higher risk areas and determine what system enhancements, if any, are appropriate to mitigate the risk of LG&E and KU facilities igniting a wildfire and improve the ability of facilities to withstand a wildfire.

In 2010, LG&E and KU initiated a Pole Inspection and Treatment Program. Since the program started, the Companies have inspected more than 754,000 wood poles, retreated more than 334,000 wood poles with preservative, and replaced more than 28,000 defective poles.

Moving forward, the Companies will continue to invest in grid modernization to increase the flexibility of the distribution system and support integration of DER, and meet the capacity demands associated with accelerating electrification of customer end use devices and vehicles.

To plan for system capacity needs, LG&E and KU have long leveraged industry accepted practices for forecasting load requirements on distribution components. Substation transformer loads are monitored nearly continuously, and peak loads are tracked and recorded on an hourly basis. This information is used to create ten-year peak load forecasts for the purpose of targeting more detailed system capacity studies and developing alternatives for addressing forecasted capacity constraints. The contribution of all connected load and DERs are currently included in load forecasts at the distribution substation transformer level. These forecasts, along with other key system information, are used to develop a joint ten-year plan for major capacity enhancements necessary to address load growth and improve system performance. In addition to planned major enhancements, the Companies' distribution personnel continue to plan and construct an appropriate level of conductors, distribution transformers, and other equipment necessary to satisfy the normal service needs of new and existing customers.

Distributed generation introduces an additional level of complexity to efficiently plan and operate the distribution system. While the LG&E and KU service areas do not have a large amount of distributed generation today, the total capacity of these resources continues to grow. Many of the grid enhancements previously mentioned (DA, VVO, AMI, etc.) provide greater situational awareness about the locational and timing benefits and dependability of interconnected DER resources.

The Companies also continue to learn from utility industry leaders and plan their systems to accommodate future distributed generation and renewables integration. As part of this learning effort, LG&E and KU continue to participate in industry forums and studies that are developing more robust system modeling tools to enable more efficient integration and optimization of distributed energy resources into the distribution grid, as well as processes to incorporate non-wires solutions when addressing future capacity constraints. Furthermore, these industry forums help the Companies stay abreast of developments in inverter technologies and industry regulations and standards which govern the operation and integration of DERs, to assure optimization of distributed resources at local and aggregate levels. The Companies continue to evolve their distributed energy resource integration framework based on associated best practices and tools. The integration framework assures that the Companies can maintain high levels of system reliability and power quality, model and understand locational value and impacts on the distribution system, and leverage interconnected distributed energy resources to deal with system constraints and improve operational efficiencies.

As customer adoption and interconnection requests of DER increase, LG&E and KU plan to implement a fully online DER interconnection application portal to manage associated administrative processes. The online portal will provide a streamlined and quicker interconnection process for customers and installers. Additionally, it will automate many tasks that are performed manually today. By linking to various internal databases and modeling tools, the Companies will be able to conduct hosting capacity analyses and publish study results near real-time in the portal.

Finally, the Companies continue to design, build, and operate the distribution system in a cost-effective, efficient manner. Substation and distribution transformers are purchased using Total Ownership Cost criteria that minimize the first cost and the cost of losses over the life of the asset. In April 2024, the US Department of Energy (DOE) released energy efficiency standards for new distribution service transformers projected to result in up to 20% efficiency benefits per transformer relative to prior models. The Companies are working with suppliers to implement these standards ahead of the 2029 effective date. The Companies continue to install capacitors on the distribution system to provide more efficient use of transmission, substation, and distribution facilities. The Companies plan to continue to design for near unity power factor at the substation bus where capacitor installations on the distribution system are reasonable and feasible.

Transmission

The Companies routinely identify transmission construction projects and upgrades required to maintain the adequacy of their transmission system to meet projected customer demands. These projects are provided separately in Volume III ("Transmission Information").

8.(2).(b) New Demand-Side Management Programs

The Companies received Commission approval in November 2023 in Case No. 2022-00402 for an expanded DSM-EE portfolio that covers the period of 2024-2030. This DSM-EE portfolio represents the Companies' largest offering of programs and budget to date with a variety of programs that allows for participation from every customer segment. In addition to the approved DSM-EE portfolio, this IRP includes three potential demand-response program enhancements in the Companies' Resource Assessment.

Additional discussion of the Companies' demand-side management programs and the program enhancements are contained in Section 8.(3).(e). An in-depth description and discussion of the recently approved DSM portfolio is also contained in Exhibit JB-1 from Case No. 2022-00402.

8.(2).(c) New Generating Facilities

The models and methods used to identify the resource options included in the resource planning analyses are summarized in Section 5.(2). A complete summary of this review is included in Volume III ("2024 IRP Technology Update").

8.(2).(d) Non-Utility Generation Options

The Companies consider short-term market purchases from other utilities on a non-firm basis. The Companies offer tariffs for Large Capacity Cogeneration and Small Power Production Qualifying Facilities. As needed, the Companies use an RFP process to obtain offers for energy and capacity from the electricity market.

8.(3) Existing and Planned Resource Data

The following sections provide details regarding the Companies' existing and planned resources.

8.(3).(a) Map of Existing and Planned Facilities

A map of the Companies' transmission system and generating facilities and a list of planned transmission projects are included in Volume III ("Transmission Information").

8.(3).(b) List Existing and Planned Generating Resources

Table 8-4 shows the characteristics of the Companies' existing and currently planned generating resources. The following tables show the actual and projected cost and operating information. Costs not included in the Companies' business plan assume 2.3% annual inflation.

Table 8-4: KU and LG&E Existing and Planned Electric Generation Facilities

Plant	Unit	Location	Status	Operation Date	Facility Type	Net Capability (MW)[1] 2024/25 Winter	Net Capability (MW)[1] 2025 Summer	Entitlement KU	Entitlement LGE	Fuel Type	Fuel Storage Capacity	Upgrades, Derates, Retirements
Fully Dispatchable Resources												
Cane Run	7	Louisville	Existing	2015	Turbine	691	691	78%	22%	Gas	None	2026 uprate[2]
E.W. Brown	3	Burgin	Existing	1971	Steam	416	412	100%	NA	Coal (Rail)	350,000 Tons	2035 retire
	5			2001	Turbine	130	130	47%	53%	Gas	2,200,000 Gal. Oil	
	6			1999		171	146	62%	38%			
	7			1999		171	146					
	8			1995		128	121	100%	NA	Gas / Oil		
	9			1994		138	121					
	10			1995		138	121					
	11			1996		128	121					
	12		Planned	2030		660	645	TBD	TBD	Gas	None	
Ghent	1	Ghent	Existing	1974	Steam	479	475	100%	NA	Coal (Barge)	1,200,000 Tons	
	2			1977		486	485					2028 SCR
	3			1981		476	481					
	4			1984		478	478					
Haefling	1-2	Lexington	Existing	1970	Turbine	27	24	100%	NA	Gas	None	2025 retire
Mill Creek	1	Louisville	Existing	1972	Steam	300	300	NA	100%	Coal (Barge & Rail)	1,000,000 Tons	2024 retire
	2			1974		297	297					2027 retire
	3			1978		394	391					2035 retire
	4			1982		486	477					2035 retire
	5		Planned	2027	Turbine	660	645	69%	31%	Gas	None	
Paddy's Run	12	Louisville	Existing	1968	Turbine	28	23	NA	100%	Gas	None	2025 retire
	13			2001		175	147	47%	53%			
Trimble County	1	Near Bedford	Existing	1990	Steam	493 (370)[3]	493 (370)[3]	0%	75%	Coal (Barge)	1,000,000 Tons (HS) 250,000 Tons (PRB)	
	2			2011		760 (570)[3]	732 (549)[3]	61%	14%			
	5-6			2002	Turbine	358	318	71%	29%	Gas	None	
	7-10			2004		716	636	63%	37%			
New NGCCs	1	TBD	Planned	2031	Turbine	660	645	TBD	TBD	Gas	None	
Renewable/Limited Duration Resources												
E.W. Brown	Solar	Burgin	Existing	2016	Solar	10	10	61%	39%	Solar	None	
	Wind		Existing	2024	Wind	0.09	0.09	64%	36%	Wind	None	
	BESS		Planned	2026	Battery	125	125	NA	100%	NA	None	
Ohio Falls	1-8	Louisville	Existing	1928	Hydro	100.6	100.6	NA	100%	Water	None	
Dix Dam	1-3	Burgin	Existing	1925	Hydro	33.6	33.6	100%	NA	Water	None	
Simpsonville Solar[4]	1	Simpsonville	Existing	2019	Solar	2.1	2.1	56%	44%	Solar	None	
Marion County Solar	1	Marion Co	Planned	2027	Solar	120	120	63%	37%	Solar	None	
Mercer County Solar	1	Mercer Co	Planned	2026	Solar	120	120	63%	37%	Solar	None	
New Solar	1	TBD	Planned	2035	Solar	500	500	TBD	TBD	Solar	None	
New Battery Storage	1	TBD	Planned	2028	Battery	400	400	TBD	TBD	NA	None	
	2			2035		500	500					

[1] The ratings for non-dispatchable resources reflect AC nameplate.
[2] In 2024, the Companies increased the capacity of Cane Run 7's two combustion turbines. The facility's output is currently limited to its network integration transmission service level of 691 MW until a transmission study and any required transmission network upgrades are completed to allow the facility to reach its full net potential of 697 MW summer and 759 MW winter, which is assumed to be in 2026.
[3] Ratings in parentheses represent the Companies' 75% ownership shares of Trimble County Units 1 and 2.
[4] Five of Simpsonville Solar's eight phases are complete. The remaining phases will be constructed as customers fully subscribe, for a total of approximately 3 MW (AC).

Table 8-5: Capacity Factors

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Brown 3	32%	34%	38%	26%	27%	22%	22%	18%	19%	19%	18%	N/A	N/A	N/A	N/A	N/A
Brown 5, 8-11	3%	4%	4%	3%	3%	0.6%	0.5%	0.5%	0.0%	0.2%	2%	3%	3%	3%	2%	3%
Brown 6-7	3%	7%	9%	6%	6%	5%	4%	3%	2%	2%	3%	12%	12%	11%	10%	11%
Brown BESS	N/A	N/A	1.3%	1.3%	1.2%	0.9%	1.0%	1.2%	1.0%	0.8%	1.1%	1.7%	2.4%	1.9%	1.4%	1.7%
Brown Solar	19%	19%	19%	19%	19%	20%	19%	19%	19%	20%	19%	20%	19%	19%	19%	20%
Cane Run 7	70%	86%	73%	87%	72%	88%	80%	79%	70%	79%	68%	86%	87%	87%	89%	87%
Dix Dam 1-3	25%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
Ghent 1	63%	61%	72%	55%	52%	49%	53%	38%	45%	43%	38%	61%	58%	48%	57%	58%
Ghent 2	61%	56%	49%	36%	60%	66%	55%	52%	57%	50%	58%	67%	55%	61%	61%	61%
Ghent 3	64%	61%	64%	67%	61%	68%	55%	52%	58%	55%	56%	57%	63%	64%	62%	63%
Ghent 4	52%	64%	59%	57%	49%	55%	53%	44%	44%	42%	42%	57%	51%	57%	54%	57%
Haefling 1-2	0%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Marion County Solar	N/A	N/A	N/A	24%	25%	24%	24%	24%	25%	25%	26%	24%	25%	24%	25%	25%
Mercer County Solar	N/A	N/A	27%	25%	25%	24%	24%	24%	25%	25%	26%	24%	25%	24%	25%	25%
Mill Creek 1	61%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mill Creek 2	41%	64%	43%	84%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mill Creek 3	55%	79%	71%	75%	67%	66%	67%	73%	66%	70%	69%	N/A	N/A	N/A	N/A	N/A
Mill Creek 4	69%	75%	71%	66%	70%	68%	66%	74%	69%	75%	71%	N/A	N/A	N/A	N/A	N/A
Mill Creek 5	N/A	N/A	N/A	83%	84%	87%	84%	78%	83%	83%	83%	75%	85%	85%	85%	80%
Ohio Falls 1-8	33%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%
Paddy's Run 12	0%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Paddy's Run 13	7%	6%	6%	5%	3%	2%	1.5%	1.5%	0.5%	0.9%	2%	5%	5%	4%	5%	5%
Trimble County 1	80%	64%	84%	75%	81%	80%	80%	68%	80%	68%	77%	77%	82%	77%	83%	78%
Trimble County 2	65%	79%	72%	74%	77%	80%	75%	69%	67%	72%	72%	77%	75%	76%	75%	76%
Trimble County 5-10	16%	13%	20%	17%	14%	13%	8%	5%	7%	5%	8%	21%	19%	20%	17%	19%
Simpsonville Solar	20%	18%	18%	18%	20%	20%	20%	20%	19%	20%	20%	20%	20%	20%	19%	20%
New NGCC	N/A	N/A	N/A	N/A	N/A	N/A	81%	80%	80%	80%	80%	84%	84%	84%	83%	84%
New BESS	N/A	N/A	N/A	N/A	0.5%	0.5%	0.5%	0.5%	0.6%	0.3%	0.7%	0.7%	0.7%	0.6%	0.7%	0.7%
New Solar	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	24%	25%	25%	25%	25%

Table 8-6: Equivalent Availability Factors

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Brown 3	91%	83%	88%	76%	88%	83%	76%	88%	84%	88%	84%	N/A	N/A	N/A	N/A	N/A
Brown 5, 8-11	87%	85%	85%	85%	86%	83%	84%	84%	87%	87%	84%	87%	87%	87%	87%	87%
Brown 6-7	87%	90%	91%	86%	91%	91%	92%	92%	92%	91%	84%	93%	93%	93%	93%	93%
Brown BESS	N/A	N/A	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Brown Solar	20%	19%	19%	19%	19%	20%	19%	19%	19%	20%	19%	20%	19%	19%	19%	20%
Cane Run 7	73%	88%	77%	92%	77%	92%	88%	92%	81%	92%	81%	88%	90%	90%	92%	90%
Dix Dam 1-3	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%
Ghent 1	88%	83%	95%	83%	85%	80%	95%	87%	89%	95%	89%	89%	89%	80%	89%	89%
Ghent 2	88%	95%	85%	80%	88%	94%	86%	88%	94%	86%	94%	94%	79%	88%	88%	88%
Ghent 3	90%	81%	80%	92%	87%	92%	83%	85%	92%	89%	89%	80%	89%	89%	89%	89%
Ghent 4	86%	92%	81%	87%	80%	85%	92%	87%	85%	89%	87%	89%	80%	89%	89%	89%
Haefling 1-2	71%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Marion County Solar	N/A	N/A	N/A	24%	25%	24%	24%	24%	25%	25%	26%	24%	25%	24%	25%	25%
Mercer County Solar	N/A	N/A	27%	25%	25%	24%	24%	24%	25%	25%	26%	24%	25%	24%	25%	25%
Mill Creek 1	91%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mill Creek 2	56%	87%	85%	91%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mill Creek 3	77%	85%	92%	91%	80%	92%	83%	92%	83%	88%	87%	N/A	N/A	N/A	N/A	N/A
Mill Creek 4	92%	81%	90%	79%	81%	92%	80%	92%	83%	92%	87%	N/A	N/A	N/A	N/A	N/A
Mill Creek 5	N/A	N/A	N/A	87%	90%	90%	90%	84%	90%	90%	90%	79%	90%	90%	90%	84%
Ohio Falls 1-8	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%
Paddy's Run 12	74%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Paddy's Run 13	93%	91%	91%	91%	62%	54%	91%	91%	91%	91%	91%	91%	91%	91%	91%	91%
Trimble County 1	91%	72%	90%	87%	91%	87%	91%	79%	91%	78%	87%	85%	90%	85%	90%	85%
Trimble County 2	78%	88%	75%	84%	84%	84%	84%	81%	77%	84%	84%	84%	84%	84%	84%	84%
Trimble County 5-10	93%	87%	92%	93%	92%	90%	82%	89%	93%	90%	89%	93%	93%	93%	93%	93%
Simpsonville Solar	20%	18%	18%	18%	20%	20%	20%	20%	19%	20%	20%	20%	20%	20%	19%	20%
New NGCC	N/A	N/A	N/A	N/A	N/A	N/A	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%
New BESS	N/A	N/A	N/A	N/A	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
New Solar	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	24%	25%	25%	25%	25%

Table 8-7: Average Heat Rate (MMBtu/MWh)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Brown 3	11.9	11.6	11.6	11.8	11.9	11.8	12.0	12.0	12.1	12.1	12.0	N/A	N/A	N/A	N/A	N/A
Brown 5, 8-11	13.4	15.1	14.9	15.2	15.5	15.5	15.2	14.7	14.9	15.5	15.4	15.4	16.0	15.9	15.7	15.8
Brown 6-7	10.8	11.0	11.1	11.2	11.1	11.4	11.3	11.2	11.3	11.4	11.1	11.4	11.4	11.4	11.4	11.4
Brown BESS	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Brown Solar	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Cane Run 7	6.6	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5
Dix Dam 1-3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Ghent 1	10.8	10.9	10.8	11.0	10.9	10.9	11.0	11.0	11.0	11.0	11.0	10.9	10.9	10.9	10.9	10.9
Ghent 2	10.7	10.7	10.6	10.6	10.8	10.7	10.8	10.8	10.8	10.9	10.8	10.7	10.7	10.7	10.7	10.7
Ghent 3	10.7	10.6	10.6	10.7	10.7	10.6	10.7	10.8	10.8	10.8	10.8	10.7	10.7	10.7	10.7	10.7
Ghent 4	10.9	10.8	10.8	10.8	10.9	10.8	10.9	10.9	10.9	10.9	10.9	10.8	10.9	10.8	10.9	10.8
Haefling 1-2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Marion County Solar	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mercer County Solar	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mill Creek 1	10.5	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mill Creek 2	10.6	10.5	10.5	10.5	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mill Creek 3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	N/A	N/A	N/A	N/A	N/A
Mill Creek 4	10.0	10.3	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	N/A	N/A	N/A	N/A	N/A
Mill Creek 5	N/A	N/A	N/A	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Ohio Falls 1-8	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Paddy's Run 12	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Paddy's Run 13	10.9	10.9	11.0	11.2	11.1	11.2	11.1	11.1	11.2	11.4	11.0	11.4	11.3	11.3	11.4	11.5
Trimble County 1	10.4	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Trimble County 2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2
Trimble County 5-10	10.7	10.9	10.9	10.9	11.0	11.1	11.2	11.3	11.2	11.3	11.1	11.3	11.4	11.4	11.4	11.5
Simpsonville Solar	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
New NGCC	N/A	N/A	N/A	N/A	N/A	N/A	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
New BESS	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
New Solar	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table 8-8: Cost of Fuel ($/MMBtu)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Brown 3	[redacted]															
Brown 5, 8-11	[redacted]															
Brown 6-7	[redacted]															
Brown BESS	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Brown Solar	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Cane Run 7	[redacted]															
Dix Dam 1-3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Ghent 1	[redacted]															
Ghent 2	[redacted]															
Ghent 3	[redacted]															
Ghent 4	[redacted]															
Haefling 1-2	[redacted]															
Marion County Solar	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mercer County Solar	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mill Creek 1	[redacted]															
Mill Creek 2	[redacted]															
Mill Creek 3	[redacted]															
Mill Creek 4	[redacted]															
Mill Creek 5	[redacted]															
Ohio Falls 1-8	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Paddy's Run 12	[redacted]															
Paddy's Run 13	[redacted]															
Trimble County 1	[redacted]															
Trimble County 2	[redacted]															
Trimble County 5-10	[redacted]															
Simpsonville Solar	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
New NGCC	N/A	N/A	N/A	N/A	N/A	N/A	[redacted]									
New BESS	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
New Solar	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table 8-9: Capital Costs

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
New NGCC																
$/kW							2,121	2,152								
$M							1,384	1,404								
New Battery Storage																
$/kW					2,109							2,119				
$M					844							1,059				
New Solar																
$/kW												1,561				
$M												780				

Capital cost assumptions in Table 8-9 are in nominal "overnight" dollars.

Table 8-10: Production Costs

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Variable and Fixed O&M Costs ($M)[80]	[redacted]															
Average Variable Production Costs (cents/kWh)	[redacted]															
Total Electricity Production Costs (cents/kWh)	[redacted]															

[80] Variable and fixed operating and maintenance costs include the cost of fuel.

8.(3).(c) Electricity Purchases and Sales

Table 8-11 provides a forecast of the Companies' electricity transactions.

Table 8-11: Electricity Purchases and Sales (GWh, Mid Energy Requirements Forecast)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
OVEC	719	652	789	826	790	794	732	693	690	675	684	736	716	706	693	692
Market Purchases	66	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Off-System Sales	-120	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

8.(3).(d) Electricity Purchases from Non-Utility Sources

Table 8-12 shows the forecasted capacity and energy purchases from non-utility sources.

Table 8-12: Electricity Purchases from Non-Utility Sources

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Qualified Facilities																
Capacity (MW)	7	8	8	9	10	10	11	12	12	13	13	14	15	15	16	16
Energy (GWh)	9	10	11	12	13	13	14	15	16	16	17	18	19	20	20	21

8.(3).(e) Demand-Side Management Programs

The Companies received approval for their 2024-2030 DSM-EE Program Plan in Case No. 2022-00402, which expands existing programs and adds new programs. The following programs are currently operating and are assumed to operate throughout the IRP planning period:

- Income-Qualified Solutions which include WeCare for Homeowners & Renters and WeCare for Property Owners & Managers,
- Business Solutions which include Business Rebates and Small Business Audit & Direct Install,
- Connected Solutions which includes Residential & Small Nonresidential Demand Conservation, Bring Your Own Device, Optimized EV Charging, and Online Marketplace, and Business Demand Response.

Four additional approved programs will begin operation in 2025 and 2026 and are assumed to operate throughout the IRP planning period:

- Beginning in 2025: Peak Time Rebates and Residential Online Audit & Rebates.
- Beginning in 2026: Appliance Recycling and Business Midstream Lighting.

After soliciting input from their DSM Advisory Group, the Companies included three new potential program enhancements (measures) for analysis in this IRP. The program enhancements have the potential to provide cost-effective demand response capability to the Companies and their customers based on market research of other utility companies who offer similar programs, though the Companies have not sufficiently reviewed or developed these measures for potential implementation to conduct the Commission's prescribed cost-benefit tests on them. These potential program enhancements are:

1) a new measure within the existing Bring Your Own Device program for residential and small business customers to enroll customer-owned, dispatchable residential-style battery energy storage systems,
2) a new measure within the existing Bring Your Own Device program for residential customers to enroll customer-owned, whole home dispatchable back-up generation units, and
3) allowing small business customers with a measured base demand of 50 to 200 kW to participate in the Business Demand Response program.

This IRP demonstrates that the desirable characteristics of a demand response program that may offset dispatchable generation are: (1) cost-effectiveness; 2) the ability to provide around-the-clock energy reduction or fully dispatchable demand reduction, particularly in the winter months; and 3) the ability for participant opt-out during an event is low, thus increasing the certainty of achieving the intended load reduction.

The Bring Your Own Device program enhancements are expected to have these characteristics. However, participants in the Business Demand Response program do have the option to opt-out of an event and the load reduction is based on the participant's deployment of their unique load reduction plan. Despite these factors, Business Demand Response participants who meet the existing minimum 200 kW base demand eligibility criteria have typically performed near or above the aggregated nominated capacity. The program enhancement to include participation for customers between 50 – 200 kW, depending on the enrolled business type and the time of a dispatched event, may result in a higher number of opt-outs.

8.(3).(e).1 Targeted Classes and End-Uses

Demand Conservation

This program cycles central air conditioning units, water heaters, and pool pumps of participating residential and small business customers through a switch installed at the equipment. A signal is sent to the switch for it to cycle over the specified event period. Customers receive an event-based incentive for allowing the Companies to cycle their enrolled equipment during peak demand periods.

WeCare for Homeowners and Renters

This program is an education and weatherization program designed to reduce energy consumption of income-qualified residential customers. This program provides energy audits, energy education, and installation of weatherization and energy conservation measures in qualified single-family homes or buildings with fewer than four units. Customers applying for WeCare must be receiving assistance from at least one federal or state income-based program.

WeCare for Apartment Building Owners

This program is an education and weatherization program designed to reduce energy consumption for property owners with income-eligible tenants. This program provides energy audits, energy education, and installation of weatherization and energy conservation measures in qualified multi-family buildings with four or more units focusing on each occupied space and the common areas. At least 50% of the tenants within the property must be receiving assistance from at least one of the federal or state income-based programs. The property owner has the option to install energy efficient heating and cooling unit(s) or whole-building insulation and receive an incentive to help offset the project cost.

Business Rebates

This program provides non-residential customers with financial incentives to help replace aging and inefficient equipment for more energy efficient equipment. The incentives are available for one-to-one replacement or custom energy efficient measures, LEED certifications, and new construction or major renovation projects that exceeds the current building code.

Small Business Audit and Direct Install

This program provides in-person energy audits to qualifying small businesses and the installation of energy-saving products to help reduce energy usage and lower energy bills. It provides small business property owners and renters with a turnkey service to enhance the efficiency of the property at no additional cost.

Bring Your Own Device

This program is an event-based, load control resource that enables the Companies to directly manage summer and winter loads during hours of peak demand through qualifying smart wi-fi enabled thermostats and wi-fi enabled electric water heaters without the need for switches. Residential and small business customers who enroll in the program receive a one-time incentive for successfully enrolling and an additional incentive for each event in which they successfully participate.

Optimized EV Charging

This program allows the Companies to issue signals to qualifying EVs and qualifying EV supply equipment to affect the timing and level of EV charging as a means of active, targeted load management. In addition to the optimized charging schedule, the Companies may adjust customers' charging during for up to ten demand response events during the year. The participating residential customer receives a one-time incentive for signing up along with a monthly incentive for continuing to participate.

Online Marketplace

This program provides a marketplace where residential and small business customers can purchase discounted smart or learning thermostats, smart plugs, and smart strips, all of which use less energy and will help lower energy bills. This program also provides a link to enroll in the BYOD program when purchasing a smart or learning thermostat.

Business Demand Response

Through this program, participating larger business customers reduce their demand during peak period events by the amount they have elected to nominate into the program. Customers who successfully demonstrate a load reduction receive monetary incentives at the end of their 12-month term. The Companies provide software to participating customers that allows them to monitor their load reduction during the event and throughout all other days of the year.

Program Development and Administration

The Companies established the Program Development and Administration to capture the costs incurred in developing and administering the energy efficiency initiatives that are difficult to assign to an individual program. These costs include new program concept and initial design; market research related to new programming, research and technical evaluation of new technologies and programs, including potential studies; research and development for pilot programs; oversight and management of evaluation, measurement, and verification contractors; development of DSM-EE rates in Companies' tariffs that are submitted to the Commission; overall program tracking and management; integration of company and vendor software; attendance at energy efficiency and DSM-EE conferences and workshops; development of key personnel; membership in associated trade organizations, subscriptions to educational and trade publications; and office supplies and equipment related to general management of the energy efficiency organization.

Peak Time Rebates
This program, which will begin 2025, will be an event-based demand response resource that rewards residential and small business customers who successfully reduce their electric consumption during periods of high demand throughout the year. The Companies will notify customers in advance of peak demand events and provides tips that will help save and shift energy consumption during the events. This program uses AMI data to calculate rewards for customers for their energy reduction during each event.

Residential Online Audit and Rebates
This program, which will begin in 2025, will provide a web-based, self-guided assessment of a customer's home and includes information about the homes space and water heating, appliance and plug load, and other energy end uses. The audit will pull customer specific AMI interval data, when available, to provide an accurate picture of the customers disaggregated energy use. After completing the audit, customers will receive feedback on their energy-use behavior, energy-saving tips, and recommendations. Each participant has the option to receive a kit which includes energy efficiency measures for self-installation. Customers who install qualifying energy efficient equipment in their home will also be eligible to apply for and receive incentives.

Appliance Recycling
This program, which will begin in 2026, will offer residential customers and small business customers with residential-sized appliances an opportunity to safely dispose of and recycle inefficient but working refrigerators and freezers. Participating customers will receive a one-time rebate. If a customer also has a working, inefficient room air conditioner or dehumidifier, then that appliance may also be picked up for recycling while picking up the refrigerator or freezer. However, there is no additional incentive offered for the room air conditioner or dehumidifier. This program will reduce energy consumption and demand as well as the burden on Kentucky landfills by enabling the safe disposal of hazardous materials.

Business Midstream Lighting
This program, which will begin in 2026, will provide lighting incentives to distributors who stock and sell qualifying high-efficiency lighting equipment, which would then be passed on to the customer at the point of sale.

8.(3).(e).2 Program Durations
In Case No. 2022-00402, the Companies received Commission approval for their current DSM-EE Program Plan through 2030 (see above for program descriptions and deployment dates). For the purpose of this IRP, all approved programs are assumed to continue throughout the IRP planning period (i.e., through the end of 2039).

8.(3).(e).3 Energy and Peak Demand Impacts
The projected energy and peak demand impacts provided below reflect the Companies' currently approved DSM-EE Program Plan.

Table 8-13: Annual Impacts (Energy Efficiency Portfolio)

	Unit	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	**Total**
Energy[1]	MWh	92,446	101,411	130,165	150,229	153,233	132,065	115,034	**874,584**
Demand	MW	18.2	20.0	25.7	29.3	29.4	25.3	22.0	**170.0**
Gas	CCF	149,125	171,196	204,251	260,979	314,589	300,442	299,101	**1,699,683**

[1] Annual energy efficiency savings associated with measures sold through the Online Marketplace subcomponent of Connected Solutions are also shown in this table.

Table 8-14: Cumulative Impacts (Energy Efficiency Portfolio)

	Unit	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Energy[1]	MWh	92,446	193,857	324,022	474,251	627,484	759,549	874,584
Demand	MW	18.2	38.2	63.9	93.2	122.6	147.9	170.0
Gas	CCF	149,125	320,321	524,572	785,551	1,100,140	1,400,582	1,699,683

[1] Annual energy efficiency savings associated with measures sold through the Online Marketplace subcomponent of Connected Solutions are also shown in this table.

Table 8-15: Annual Impacts (Demand Conservation Portfolio)

	Unit	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Energy	MWh	288	361	444	554	667	782	782
Demand[1]	MW	154.7	155.7	160.4	174.7	197.3	207.5	206.9
Gas	CCF	0	0	0	0	0	0	0

[1] Annual impacts represent summer demand only.

The peak demand impacts of the approved demand response programs and the program enhancements for the period through 2039 are shown in the table below in MW. The values in 2025-2030 were included in the cost-effectiveness analysis for Case No. 2022-00402, whereas the values for 2031-2039 were updated assuming program continuation and deployment of the referenced program enhancements.

Table 8-16: Peak Demand Impacts by Program (MW)

Program	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Optimized EV Charging	0.6	0.9	1.2	1.8	2.4	3	3.452	3.968	4.564	5.248	6.036	6.94	7.288	7.652	8.036
Peak Time Rebates	4.42	8.84	17.68	31.45	31.45	31.45	31.45	31.45	31.45	31.45	31.45	31.45	31.45	31.45	31.45
Demand Conservation - AC	36.26	32.58	29.27	26.32	23.64	21.25	19.13	17.21	15.50	13.95	12.55	11.30	10.18	9.15	8.24
Demand Conservation - Water Heaters	0.95	0.84	0.73	0.64	0.57	0.51	0.46	0.41	0.37	0.33	0.30	0.27	0.24	0.22	0.20
Demand Conservation - Pool Pumps	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BYOD - Smart Water Heaters	0.000	0.005	0.008	0.011	0.017	0.025	0.032	0.040	0.050	0.055	0.060	0.066	0.073	0.080	0.088
BYOD - Smart Thermostats - Cooling Season	2.783	5.850	10.444	16.674	22.903	29.133	32.024	35.242	38.761	42.632	46.905	51.581	56.759	62.440	68.674
BYOD - Smart Thermostats - Heating Season	0.840	1.679	2.744	4.246	5.748	7.250	7.970	8.770	9.646	10.609	11.673	12.836	14.125	15.539	17.090
BYOD - Smart Wall HVAC Units (Room AC)	0.000	0.005	0.008	0.011	0.017	0.025	0.032	0.040	0.049	0.054	0.060	0.066	0.072	0.080	0.088
BYOD - Energy Storage*	0.00	0.00	0.48	0.64	0.80	0.97	1.13	1.29	1.45	1.61	1.77	1.93	2.09	2.25	2.41
BYOD - Whole Home Generator*	0.00	0.00	0.20	0.40	0.60	0.80	1.00	2.00	3.00	4.00	4.00	5.00	5.00	6.00	6.00
Business Demand Response (year-round) > 200 kW Base Demand	36	45	56	67	79	79	87	95	105	105	105	105	105	105	105
Business Demand Response (year-round) > 50 kW and < 200 kW Base Demand*	0.00	0.00	0.00	0.68	1.02	1.36	1.70	2.04	2.72	3.06	3.40	3.40	3.40	3.40	3.40
Forecasted Total - Cooling Season	81.36	93.73	115.76	145.76	162.12	167.21	176.96	188.90	202.65	207.12	211.27	216.74	221.29	227.46	233.32
Forecasted Total - Heating Season	42.21	56.13	78.05	106.36	120.73	123.54	133.29	144.77	157.61	160.77	163.12	166.36	168.16	171.11	173.21

* Measure or Program is not currently part of the 2024-2030 DSM/EE portfolio

8.(3).(e).4 Program Costs

The projected costs provided reflect the latest approved DSM-EE Program Portfolio.

Table 8-17: Program Costs

Costs ($000s)	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	**Total**
Program Development and Administration	3,628	3,556	2,710	2,889	2,769	2,801	2,983	**21,336**
Income-Qualified Solutions	10,060	10,072	10,239	10,106	10,123	10,141	10,160	**70,902**
Appliance Recycling Program	0	0	1,671	1,723	1,926	1,778	1,781	**8,880**
Residential Online Audit Program	0	1,085	1,265	1,597	1,681	1,636	1,640	**8,904**
Business Solutions	5,290	5,795	7,820	8,078	8,400	7,502	7,014	**49,899**
Connected Solutions	5,817	5,922	7,185	11,236	21,955	23,386	25,237	**100,739**
Peak Time Rebates	250	2,745	2,959	5,682	9,922	10,075	9,929	**41,562**
Nonresidential Demand Response Program	3,469	4,134	4,650	5,579	6,452	7,329	6,908	**38,520**
Total Portfolio Budget	**28,514**	**33,309**	**38,499**	**46,890**	**63,228**	**64,649**	**65,653**	**340,742**

Annual Program Budgets

The projected annual program budgets provided reflect the latest approved DSM-EE Program Portfolio.

Table 8-18: Annual Capital Budgets

Costs ($000s)	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	**Total**
Program Development and Administration	1,000	800	0	0	0	0	0	**1,800**
Connected Solutions	625	0	0	0	0	0	0	**625**
Peak Time Rebates	250	1,150	0	0	0	0	0	**1,400**
Nonresidential Demand Response Program	314	271	307	405	419	425	0	**2,142**
Total Portfolio Budget	**2,189**	**2,221**	**307**	**405**	**419**	**425**	**0**	**5,967**

8.(3).(e).5 Projected Energy Savings

The Companies project that the portfolio of all approved programs will reduce demand by 377 MW through 2030, as well as achieve energy savings of approximately 875 GWh.

8.(4) Planned Capacity and Energy Requirements Summary

The following sections summarize the Companies' forecasted demand and energy requirements and generation resources.

8.(4).(a) Resource Capacity Available at Summer and Winter Peak

Table 8-19 and Table 8-20 summarize the Companies' forecasted loads and resource capacities and the corresponding reserve margins for the summer and winter seasons.

Table 8-19: Summer Peak Demand and Resource Summary (MW)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Peak Load	**6,115**	**6,228**	**6,242**	**6,365**	**6,474**	**6,686**	**6,931**	**7,216**	**7,201**	**7,201**	**7,179**	**7,171**	**7,161**	**7,160**	**7,158**	**7,149**
Fully Dispatchable Generation Resources																
Existing Resources	7,612	7,612	7,618	7,618	7,618	7,618	7,618	7,618	7,618	7,618	7,618	7,618	7,618	7,618	7,618	7,618
Retirements/Additions																
Coal[81]	-300	-300	-300	-597	-601	-601	-601	-601	-601	-601	-601	-1,881	-1,881	-1,881	-1,881	-1,881
Small-Frame SCCTs[82]	0	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47
NGCC[83]	0	0	0	645	645	645	1,290	1,935	1,935	1,935	1,935	1,935	1,935	1,935	1,935	1,935
Total	7,312	7,265	7,271	7,619	7,615	7,615	8,260	8,905	8,905	8,905	8,905	7,625	7,625	7,625	7,625	7,625
Reserve Margin	19.6%	16.7%	16.5%	19.7%	17.6%	13.9%	19.2%	23.4%	23.7%	23.7%	24.0%	6.3%	6.5%	6.5%	6.5%	6.7%
Renewable/Limited-Duration Resources																
Existing Resources	106	106	107	107	107	107	107	107	107	107	107	107	107	107	107	107
Existing CSR	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
Existing Disp. DSM[84]	60	84	97	119	150	166	170	179	190	202	205	208	211	216	221	227
Retirements/Additions																
Solar[85]	0	0	100	201	201	201	201	201	201	201	201	619	619	619	619	619
BESS[86]	0	0	125	125	465	465	465	465	465	465	465	890	890	890	890	890
Dispatchable DSM[87]	0	0	0	1	1	2	3	3	5	6	8	8	9	9	10	10
Total	296	301	540	663	1,035	1,052	1,056	1,066	1,078	1,092	1,096	1,943	1,948	1,952	1,958	1,964
Total Supply	**7,588**	7,565	7,810	8,282	8,649	8,666	9,316	9,970	9,983	9,996	10,000	9,567	9,572	9,577	9,582	9,588
Total Reserve Margin	**24.1%**	21.5%	25.1%	30.1%	33.6%	29.6%	34.4%	38.2%	38.6%	38.8%	39.3%	33.4%	33.7%	33.8%	33.9%	34.1%
Capacity Need[88]	**-433**	95	-132	-453	-686	-442	-791	-1,095	-1,125	-1,139	-1,171	-747	-764	-770	-778	-796

[81] Mill Creek 1 will be retired at the end of 2024. Mill Creek 2 will be retired after Mill Creek 5 is commissioned in 2027. The Recommended Resource Plan includes 4 MW auxiliary load for an SCR on Ghent 2 in 2028 and the retirement of Brown 3, Mill Creek 3, and Mill Creek 4 in 2035.
[82] This analysis assumes Haefling 1-2 and Paddy's Run 12 are retired in 2025.
[83] Mill Creek 5 is assumed in-service in 2027. The Recommended Resource Plan includes additional NGCC units in 2030 and 2031.
[84] Existing Dispatchable DSM reflects expected load reductions under normal peak weather conditions.
[85] This analysis assumes 120 MW of solar capacity is added in 2026, and another 120 MW of solar capacity is added in 2027. The Recommended Resource Plan includes an additional 500 MW of solar capacity in 2035. Capacity values reflect 83.7% expected contribution to summer peak capacity.
[86] Brown BESS is assumed in-service in 2026. The Recommended Resource Plan includes an additional 400 MW of 4-hour BESS capacity in 2028 and another 500 MW of 4-hour BESS capacity in 2035. Capacity values reflect 100% capacity contribution for Brown BESS and 85% capacity contribution for the additional 4-hour BESS to account for their treatment in developing the minimum reserve margin targets.
[87] New dispatchable DSM programs reflect 39% capacity contribution.
[88] The summer capacity need is based on a 23% summer minimum reserve margin target. Positive values reflect a capacity deficit.

Table 8-20: Winter Peak Demand and Resource Summary (MW)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Peak Load	**6,015**	**6,146**	**6,150**	**6,227**	**6,347**	**6,471**	**6,733**	**7,003**	**7,135**	**7,123**	**7,121**	**7,118**	**7,118**	**7,118**	**7,118**	**7,117**
Fully Dispatchable Generation Resources																
Existing Resources	7,909	7,909	7,909	7,977	7,977	7,977	7,977	7,977	7,977	7,977	7,977	7,977	7,977	7,977	7,977	7,977
Retirements/Additions																
Coal[89]	0	-300	-300	-300	-601	-601	-601	-601	-601	-601	-601	-1,897	-1,897	-1,897	-1,897	-1,897
Small-Frame SCCTs[82]	0	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55
NGCC[90]	0	0	0	0	660	660	1,320	1,980	1,980	1,980	1,980	1,980	1,980	1,980	1,980	1,980
Total	0	7,554	7,554	7,622	7,981	7,981	8,641	9,301	9,301	9,301	9,301	8,005	8,005	8,005	8,005	8,005
Reserve Margin	7,909	22.9%	22.8%	22.4%	25.8%	23.3%	28.3%	32.8%	30.4%	30.6%	30.6%	12.5%	12.5%	12.5%	12.5%	12.5%
Renewable/Limited-Duration Resources																
Existing Resources	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Existing CSR	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115
Existing Disp. DSM[84]	35	45	60	82	110	124	125	135	145	156	157	158	159	160	162	163
Retirements/Additions																
Solar[91]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BESS[92]	0	0	0	125	465	465	465	465	465	465	465	890	890	890	890	890
Dispatchable DSM	0	0	0	1	1	2	3	3	5	6	8	8	9	9	10	10
Total	221	231	246	394	763	777	779	789	800	813	815	1,242	1,244	1,246	1,248	1,250
Total Supply	**8,130**	**7,785**	**7,800**	**8,016**	**8,744**	**8,758**	**9,420**	**10,090**	**10,101**	**10,114**	**10,116**	**9,247**	**9,249**	**9,251**	**9,253**	**9,255**
Total Reserve Margin	**35.2%**	**26.7%**	**26.8%**	**28.7%**	**37.8%**	**35.3%**	**39.9%**	**44.1%**	**41.6%**	**42.0%**	**42.1%**	**29.9%**	**29.9%**	**30.0%**	**30.0%**	**30.0%**
Capacity Need[93]	**-672**	**143**	**134**	**18**	**-557**	**-411**	**-735**	**-1,057**	**-897**	**-926**	**-931**	**-65**	**-67**	**-69**	**-71**	**-74**

[89] Mill Creek 1 will be retired at the end of 2024. Mill Creek 2 will be retired after Mill Creek 5 is commissioned in 2027. The Recommended Resource Plan includes 4 MW auxiliary load for an SCR on Ghent 2 in 2028 and the retirement of Brown 3, Mill Creek 3, and Mill Creek 4 in 2035.
[90] Mill Creek 5 is assumed in-service in 2027. The Recommended Resource Plan includes additional NGCC units in 2030 and 2031.
[91] This analysis assumes 120 MW of solar capacity is added in 2026, and another 120 MW of solar capacity is added in 2027. The Recommended Resource Plan includes an additional 500 MW of solar capacity in 2035. Capacity values reflect 0% expected contribution to winter peak capacity.
[92] Brown BESS is assumed in-service in 2026. The Recommended Resource Plan includes an additional 400 MW of 4-hour BESS capacity in 2028 and another 500 MW of 4-hour BESS capacity in 2035. Capacity values reflect 100% capacity contribution for Brown BESS and 85% capacity contribution for the additional 4-hour BESS to account for their treatment in developing the minimum reserve margin targets.
[93] The winter capacity need is based on a 29% winter minimum reserve margin target. Positive values reflect a capacity deficit.

8.(4).(b) Energy Requirements Summary

Table 8-21 summarizes the Companies' forecasted energy requirements.

Table 8-21: Energy Requirements Summary (GWh, Mid Energy Requirements Forecast)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Energy Requirements	29,664	32,808	32,869	33,664	34,811	36,061	38,295	40,573	41,204	41,036	40,975	40,951	41,069	40,939	40,959	40,951
Energy by Fuel Type																
Coal	22,522	24,913	24,448	21,737	22,000	22,370	21,192	19,659	20,370	19,946	20,217	16,345	15,928	15,886	16,219	16,312
Gas	6,093	6,857	7,032	10,321	11,099	12,006	15,469	19,321	19,232	19,492	19,149	21,929	22,424	22,370	22,037	21,921
Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	363	364	364	364	365	364	364	364	365	364	364	364	365	364	364	364
Solar	20	20	233	414	556	526	537	535	547	558	561	1,576	1,635	1,611	1,644	1,660
Battery Storage	0	0	14	14	32	27	30	32	34	21	37	72	82	66	70	73
Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm Purchases from Other Utilities																
OVEC	719	652	789	826	790	794	732	693	690	675	684	736	716	706	693	692
Firm Purchases from Non-Utility Sources	6	7	8	9	10	10	11	12	13	13	14	15	16	17	17	18

8.(4).(c) Energy Input and Generation by Fuel Type

Table 8-22 shows the Companies' forecasts of total generation required to meet load and total energy input by primary fuel type.

Table 8-22: Generation and Energy Input by Fuel Type (Mid Energy Requirements Forecast)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Coal																
Energy (GWh)	22,522	24,913	24,448	21,737	22,000	22,370	21,192	19,659	20,370	19,946	20,217	16,345	15,928	15,886	16,219	16,312
Fuel Burn (000 Tons)	10,198	11,281	11,111	9,994	10,131	10,353	9,835	9,119	9,466	9,264	9,377	7,572	7,377	7,353	7,517	7,555
Fuel Burn (MMBtu)	237,512	259,140	254,418	225,893	228,912	232,354	220,754	204,740	212,633	207,925	210,429	169,306	164,852	164,332	168,083	168,951
Gas																
Energy (GWh)	6,093	6,857	7,032	10,321	11,099	12,006	15,469	19,321	19,232	19,492	19,149	21,929	7,138	9,214	8,917	8,966
Fuel Burn (000 MCF)	45,582	49,740	53,563	71,544	75,255	78,970	98,095	120,505	120,235	121,158	121,048	145,327	54,412	76,805	76,122	74,091
Fuel Burn (MMBtu)	48,388	52,777	56,812	75,353	78,793	82,797	102,108	124,974	124,603	125,630	125,458	151,133	57,514	80,547	79,784	77,741
Oil																
Energy (GWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Burn (000 Gal.)	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Burn (MMBtu)	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro																
Energy (GWh)	363	364	364	364	365	364	364	364	365	364	364	364	365	364	364	364
Solar																
Energy (GWh)	20	20	233	414	556	526	537	535	547	558	561	1,576	1,635	1,611	1,644	1,660
Battery Storage																
Energy (GWh)	0	0	14	14	32	27	30	32	34	21	37	72	82	66	70	73
Wind																
Energy (GWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

8.(5) Resource Planning Considerations

8.(5).(a) Methodology

The Companies' resource planning process consists of the following activities:

1. Review of supply-side and demand-side resource options
2. Assessment of reserve margin constraints and capacity contribution
3. Development of long-term resource plan

A high-level summary of these activities is included in "Resource Planning" in Section 5.(2). See Volume III for detailed overviews of these analyses.

8.(5).(b) Key Inputs and Uncertainties

The primary focus of resource planning is risk management. Key categories of risk stem from uncertainties related to the way customers use electricity, the performance of generation units, the price of fuel and other commodities, and the future impact of new state and federal regulations. See "Resource Planning Inputs and Uncertainties" in Section 5.(2) for a discussion of key resource planning inputs and uncertainties.

8.(5).(c) Decision Criteria

The goal of the resource planning process is to reliably meet customers' around-the-clock energy requirements both in the short-term and long-term at the lowest reasonable cost.

8.(5).(d) Required Reserve Margin

The reserve margin analysis is discussed in Sections 5.(2) and 5.(4) and a complete summary of this analysis is included in Volume III ("2024 IRP Resource Adequacy Analysis").

8.(5).(e) Research and Development

The Companies' Research and Development Department ("R&D") aims to prepare the Companies for tomorrow's problems. R&D focuses on emerging technologies pertinent to the Companies' future, including renewable and sustainable energy technologies, carbon capture, energy storage, and electric vehicles. R&D aims to conduct internal research projects, collaborate with groups across the Companies' lines of business, and partner with external organizations, such as EPRI, the University of Kentucky, and other research entities to leverage available resources and provide a bridge to technical information. R&D exists to support research and education activities and welcome collaboration on potential future projects, both long-term (strategic) and near-term (tactical). The energy industry constantly changes and utility companies must stay at the forefront of this change to continue to provide the best service possible to customers.

Carbon Capture Research

The Companies are global leaders in carbon capture research and operate one of the five carbon capture systems in operation at power plants in the United States today. Since 2006, the Companies have directly invested more than $4 million in the University of Kentucky's ("UK") decarbonization research. Leveraging funding from the Companies with a $14.5 million U.S. Department of Energy ("DOE") grant in 2011, the team installed a carbon capture slip-stream pilot demonstration system at the Companies' E.W. Brown plant. The post combustion process takes a small portion of the flue gas and uses an amine-based solvent to capture carbon dioxide. Since 2014, UK researchers have used this system to run tests for U.S. Department of Energy-funded research projects and have generated 94 publications and have had 13 U.S. patents issued for their work with another four patents pending. The site is operational and currently working on mimicking natural-gas flue gas to address the challenges of carbon capture at natural gas plants. The learnings from the research could be significant for adapting carbon capture systems for use with natural gas combined cycle power plants. In 2022, the Companies' were awarded a federally-funded project to evaluate the feasibility and conduct a Front End Engineering and Design of full scale carbon capture deployment at the Cane Run NGCC (Cane Run Unit 7). In 2024, the Companies were selected to evaluate building a 20-megawatt large pilot carbon capture unit at Cane Run NGCC as part of a Department of Energy award. Along with post-combustion carbon capture, the Companies are working with UK on direct air carbon capture that captures carbon dioxide from the air, regenerates the capture solvent, and produces hydrogen as a beneficial byproduct. The direct air capture process started as a bench scale federally funded project and is progressing to a pilot scale federally-funded project.

Renewable Integration Research Facility

To explore opportunities for renewable integration by the Companies, the R&D team operates the Renewable Integration Research Facility, a 3.7-acre area immediately adjacent to the E.W. Brown solar plant where emerging technologies can be tested and evaluated for future utility-scale deployment. At this facility, R&D operates Kentucky's first and largest utility-scale energy storage system, Kentucky's first utility-scale wind turbine, two 360-degree tracking solar panel arrays, solar powered electric vehicle charger, and a load bank. These assets can be operated as a microgrid, allowing the R&D team to collect real-time renewable data and run simulations using these on-site renewables to help inform future resource planning decisions.

Solar Photovoltaic ("PV") Generation

The ability to integrate more renewable generation and battery storage, as well as future penetration and charging patterns for electric vehicles, are key considerations for future resource planning decisions. Therefore, the Companies gained approval from the Kentucky Public Service Commission in December 2014 to build the first utility-scale solar PV plant in Kentucky. The project was completed in April 2016 for $25 million and began commercial operation in June 2016. R&D currently monitors this generation source closely and is working with industry research partners such as EPRI and universities to better understand performance, degradation, and maintenance needs. Solar generation can, for example, go from 100% of capacity to 10% of capacity within 90 seconds, highlighting the intermittent performance of solar. Monitoring solar output during winter months has revealed important modeling cases to ensure that a portfolio can withstand the worst times of solar generation and maintain reliable service. Advanced system modeling and performance monitoring is providing the Companies with valuable knowledge that will be used in the design and construction of any future sites. Another aspect of the Brown Solar project is that data collected from the site is also made publicly available via the Companies' external website at https://lge-ku.com/live-solar-generation.

At the Renewable Integration Research Facility, R&D has installed two 360 degree tracking solar panel arrays and is installing single-axis trackers to gather data and compare how those technologies perform. In contrast with the fixed solar panels that make up the 10-megawatt solar farm, these two 4.92-kilowatt DC arrays are 50 feet apart, each with a multi-axis tracker and 12 high efficiency 410W solar panels that optimize solar power output by rotating to face the sun as it moves through the sky. Tracking solar panels can capture more of the sun's energy than their fixed counterparts. These tracking solar panels are being studied to determine what role they could play in the Companies' future generation portfolio. The system will provide valuable data on solar output, optimizing solar generation, parasitic load, operations and maintenance requirements.

Wind Generation

Future resource planning decisions involving renewable resources require accommodations to be made for their intermittent nature. In Kentucky, solar generation is frequently utilized, but its intermittency discussed previously must be accounted for. Wind generation may provide a complementary renewable energy source for solar generation, given the tendency for wind to be the strongest at night and in the winter, when solar generation is less productive. In an effort to evaluate this possibility, R&D operates the first utility-scale wind turbine in Kentucky at the Renewable Integration Research Facility at the E.W. Brown plant. The 100-kilowatt turbine stands 120 feet tall from the ground to the blade hub, where three 45-foot-long blades are attached for a total height of 165 feet. This turbine is capable of yawing to optimize generation based on the direction of the wind. This project, completed at the end of 2023, is being used by the R&D team to evaluate the potential for wind generation to contribute to the Companies' generation portfolio. Data analysis and studies using data from the wind turbine at E.W. Brown plant will help to illuminate these possibilities. Further, R&D has partnered with UK's Power and Energy Institute of Kentucky to perform in-depth analysis of the state's wind generation opportunities to identify the most cost-effective locations for large scale wind generation.

Energy Storage

R&D is researching energy storage technologies regarding cost, performance, and advanced control techniques. The Companies operate Kentucky's first and largest utility-scale energy storage system — a 1-megawatt, 2-megawatt-hour lithium-ion battery, which is co-located with E.W. Brown Solar at the Renewable Integration Research Facility, allowing the Companies to explore how batteries can mitigate the inherent intermittency of solar power. The battery research site has testing bays for three separate megawatt-scale energy storage systems and was designed to accommodate various energy storage technologies. The Companies' investment was $2.5 million for infrastructure and EPRI invested $2 million for the first battery storage system. The battery is operated around the clock, charging during the day when solar power is available and discharging at night. During daylight hours, the system can perform solar-support functions including power smoothing. The Companies have also used this battery system to simulate reducing or limiting peak demand. Other advanced functions are Auto Volt-Var, during which the battery supplies or absorbs reactive power to maintain grid voltage at a reference value, and Auto Frequency Watt, in which the battery rapidly charges or discharges to reduce grid frequency variation. The battery's function is constantly monitored via a real-time battery performance dashboard to maintain awareness of hundreds of conditions remotely. Through partnership with local universities, the

Companies are also performing system modeling and developing applications for combining intermittent renewable generation with energy storage. Over the past six years, eight academic papers and presentations based on data retrieved from the E.W. Brown Solar Dashboard and E.W. Brown 1-megawatt, 2-megawatt-hour battery have been used in dozens of internationally published academic papers.

Vegetation Management

Land use is one of the greatest challenges to increasing renewable energy generation from sources of solar and wind. In the spring of 2020, R&D began a novel project to research the use of sheep for vegetation management around solar panels rather than conventional groundskeeping with lawn mowers and weed eaters. The E.W. Brown Generating Station is home to a 35-acre field of solar panels that needs to be maintained and mowed to keep the solar panels up and running. Mowing is both challenging and time-consuming because of row width and panel height. During the growing season, a flock of Shetland and Katahdin sheep from nearby Shaker Village are rotated through fenced paddocks at the E.W. Brown solar facility. The stocking density, vegetation preference, and rotation schedule are all part of the learnings for utilizing the sheep for vegetation management at a larger scale. Farmers from Shaker Village oversee the care of the flock, including veterinary services and shearing. The project has demonstrated that sheep grazing can be an effective form of vegetation management and that land used for solar generation can simultaneously be used for agricultural purposes.

Data Analytics

R&D has developed modeling capabilities to analyze the minute-to-minute impacts of intermittent renewable generation on the Companies' transmission and generation systems. The model is driven by years of data from the Companies' distribution, transmission, and generation assets, including the E.W. Brown solar and energy storage facilities, and publicly available weather data. Valuable insights have been gained from the model including methods for increasing the Companies' intermittent renewable hosting capacity. The model shows that the Companies can increase intermittent renewable capacity and minimize the negative impacts on reliability by adding natural gas combined cycle with carbon capture and storage or battery energy storage and by dispersing renewable capacity across the service territory. With this model, the Companies can also understand one of the greatest challenges to increasing renewable energy—land use—which has been quantified across thousands of simulated portfolios with varying amounts of intermittent renewable capacity.

Electric Transportation

R&D deployed some of the first electric vehicle chargers in Kentucky more than a decade ago and has been tracking developments with electric transportation, both from vehicle technology and charging infrastructure standpoints ever since. R&D is monitoring electric vehicle registrations in the Companies' service territory and at the state and national levels as well as tracking and analyzing usage data from electric vehicle charging stations in our territory. This data is used to develop energy demand forecasts and to help determine charging infrastructure locations. The Companies have also installed solar electric vehicle chargers and have been testing their functionality. Each solar charger station has backup battery storage that can charge EVs for two full charges in case of bad weather and poor solar collection. The solar chargers are also fitted with switches that can control where the energy for charging comes from in case solar is not optimal. The switch will move the charge over to the connected energy grid to ensure the EV can fully charge. The Companies also have twenty non-solar public electric vehicle charging stations across the state that are monitored and the data analyzed to inform future charging installation decisions. Through a partnership with EPRI, the Companies also monitor activities at other utilities for novel system adaptations for additional electric load from electric transportation.

Nuclear Generation

R&D has an all-of-the-above technology strategy for evaluating future electricity generation options. In 2022, the Companies partnered with the U.S. Department of Energy Idaho National Laboratory's Gateway for Accelerated Innovation in Nuclear to complete a 100% federally funded siting evaluation and technology assessment for the Companies' Ghent Generating Station. The study determined that the site had no exclusionary factors and is suitable for a nuclear small modular reactor plant but would have potential size constraints for a larger traditional nuclear reactor. Phase two of the study will explore alternative locations, along with grid reliability and economic modeling. R&D will continue to evaluate nuclear power's potential to contribute affordable and sustainable energy to future resource planning decisions as the Companies' current generating assets age.

8.(5).(f) Environmental Regulation Compliance and Planning

Acid Deposition Control Program

The Acid Deposition Control Program was established under Title IV of the CAAA and applies to the acid deposition that occurs when sulfur dioxide ("SO_2") and nitrogen oxides ("NO_x") are transformed into sulfates and nitrates and combine with water in the atmosphere to return to the earth in rain, fog, or snow. Title IV's purpose is to reduce the adverse effects of acid deposition through a permanent reduction in SO_2 emissions and NO_x emissions from 1980 levels in the 48 contiguous states. With further reductions in SO_2 and NO_x aided by rules such as the Clean Air Interstate Rule (2009/2010), Mercury Air Toxics Standards (2012), and the Cross-State Air Pollution Rule (initially implemented in 2015, updated in 2017, and revised in 2021), the Companies continue to comply with the Acid Deposition Control Program through allowance surrendering.

Cross-State Air Pollution Rule/Good Neighbor Plan

As an update to the 2021 IRP, the Revised Cross-State Air Pollution Rule ("CSAPR") Update Rule became effective on June 29, 2021, in an effort to bring affected areas into attainment with the 2008 ozone NAAQS (at 75 parts per billion "ppb"). The Revised CSAPR Update rule established a new CSAPR NO_x ozone season Group 3 trading program for just the 12 states (including Kentucky) identified in the rule. Within that Group 3 trading program, the Companies' ozone season NO_x allocations were reduced by 7% in 2021 and 15% in 2022 forward compared to the 2020 allocations of the CSAPR Update Rule. Additionally, the Revised CSAPR Update Rule converted the Companies' banked 2017 through 2020 Group 2 NO_x allowances to Group 3 allowances at an 8:1 ratio. That conversion was completed by August 13, 2021. The Companies self-comply with this rule through application of emissions controls and intracompany emission allocation transfers.

In parallel to the 2021 CSAPR, the EPA was working on regulations to address NO_x emission reduction requirements for affected areas (like Kentucky) to achieve and maintain compliance with the 2015 ozone NAAQS (70 ppb). On February 22, 2022, EPA proposed a disapproval of several State Implementation Plans ("SIP"), including Kentucky, after determining those SIPs were inadequate to eliminate significant contributions to nonattainment or interfere with maintenance of other states' NAAQS attainment. Where an approved SIP is not established, EPA must issue a Federal Implementation Plan ("FIP") to put programs or regulations in place to eliminate the significant contributions to non-attainment or interference with maintenance of the NAAQS. On February 28, 2022, EPA proposed the FIP for the 2015 Ozone NAAQS (i.e., "Good Neighbor Plan") to be implemented in States without approved SIPs. On January 31, 2023, EPA finalized the disapproval of the affected SIPs clearing the way for the Good Neighbor Plan to be implemented upon publication in the Federal Register. Prior to EPA publishing the Good Neighbor Plan, several states filed stay motions regarding the disapproval of their SIPs with their respective circuit court (e.g., Kentucky filed with the Sixth Circuit court on May 23, 2023) requesting that the SIP disapprovals be stayed until litigation on the legitimacy of the disapprovals could be decided. Several of the circuit courts granted administrative stays of SIP disapprovals.[94] [95] The administrative stays on SIP disapprovals halted implementation and compliance requirements of the Good Neighbor Plan FIP in applicable states. Kentucky was among those states.

On June 5, 2023, the Good Neighbor Plan was published in the Federal Register establishing August 4, 2023 as the effective date for the rule. As finalized, the Good Neighbor Plan rule accomplishes its compliance goal in part by revising and tightening the existing CSAPR NO_x allowance trading program with revised NO_x emissions budgets for fossil fuel-fired power plants in affected states beginning in the 2023 ozone season (May through September). The rule's emissions budgets initially assume the consistent operation of emissions controls already installed, not the installation of any additional controls. In 2024, emissions budgets for units without NO_x controls assume stringent operation levels of *state of the art* combustion controls with an emission rate of 0.199 lb. of NO_x per million British thermal unit ("mmBtu") of heat input. Beginning in 2026, emissions budgets assume installation of selective catalytic reduction ("SCR") controls at all coal-fired generating units over 100 MW, regardless of whether units actually have SCRs. In addition, the rule: imposes a backstop daily emissions rate limit of 0.14 lb/mmBtu with a three-to-one allocation surrender ratio (if exceeded) for large coal-fired units, which was to take effect in 2024 for SCR-equipped units and in 2030 for units without existing NO_x controls; limits the size of the emissions allowance bank, further limiting flexibility to operate non-SCR-equipped units; and beginning in 2025, annually recalibrate emissions budgets to account for new retirements, new units, and changing operation. In short, the Good Neighbor Plan effectively requires non-SCR-

[94] U.S. Court of Appeals for the 6th Circuit: *Kentucky vs EPA*, Case No, 23-3216. The 6th Circuit granted Kentucky an administrative stay on May 31, 2023.
[95] U.S. Court of Appeals for the 6th Circuit: *KY v. EPA*, *et al*, Case No. 23-3216/23-3225, The 6th Circuit denied venue change and granted motion to stay enforcement of SIP disapproval on July 25, 2023.

equipped coal units to cease operating, or operate only at very minimal levels, during each year's ozone season beginning in 2026.

Because EPA was not legally able to implement the Good Neighbor Plan in states that had stays in place for disapproval of their SIP (e.g., Kentucky), EPA issued an interim final rule on July 31, 2023 for established states with stays of their SIP disapprovals to revert back to implementation of the Revised CSAPR Update Rule. States under this interim rule had their NOx ozone season allowance trading programs placed back into Group 2 or a new Expanded Group 2. These states would not be able to trade with units that remained in the Good Neighbor Plan's Group 3 NOx ozone season allowance trading program. Kentucky and Louisiana were placed in the Expanded Group 2 and are only able to trade allowances with units in those states.

The Companies continue to comply and operate within the constraints of the interim final rule until resolution of the legal process to determine the validity of the SIP disapprovals. Additionally, separate legal actions that aim to determine the validity of the entire Good Neighbor Plan rule need to conclude for Companies to fully determine the impact of the Good Neighbor Rule. On September 25 and 29, 2023, the D.C. Circuit Court of Appeals denied several motions seeking to stay the entirety of the Good Neighbor Plan.[96] While the legal process continued in the lower court systems, the U.S. Supreme Court was petitioned for an emergency stay of the Good Neighbor Plan.[97] The Supreme Court took up the case and on June 27, 2024 issued a decision granting the emergency stay.[98] The Supreme Court order stays the enforcement of the Good Neighbor Plan for all affected units pending the D.C. Circuit's review and any petition for writ of certiorari. The Supreme Court found that the petitioners were likely to succeed on the merits because the Good Neighbor Plan "rested on an assumption that all the upwind States would adopt emissions-reduction measures up to a uniform level of costs to the point of diminishing returns," and EPA failed to reasonably assess the impact of removing upwind States from the program on that uniform cost level.

As stated earlier, the Companies continue to operate and maintain the affected facilities in compliance with applicable rules. As the Good Neighbor Plan related legal processes continue, the Companies will continue to follow those proceedings and develop plans for required compliance measures which may been needed once a decision is made on the final form of any applicable rules. Regardless of the outcomes from litigation around the Good Neighbor Plan, the EPA is obligated to drive attainment of the 2015 Ozone NAAQS. Given local non-attainment in Louisville-Jefferson County, Kentucky's significant impact to downwind states, and the lack of Reasonably Achievable Control Technology on some units, the Companies have exposure to further NO_x reductions in support of attainment.

---

[96] U.S. Court of Appeals for District of Columbia Circuit: *Utah et al vs EPA*, Case No. 23-1157, September 25, 2023.
[97] U.S. Supreme Court: *Ohio vs EPA*, Case No. 23A349 , October 13, 2023.
[98] U.S. Supreme Court: *Ohio vs EPA*, Case No. 23A349, 23A350, 23A351, 23A384, June 27, 2024

Hazardous Air Pollutant Regulations/Mercury and Air Toxics Standard

EPA developed final rules to establish national emission standards for hazardous air pollutants ("NESHAP") for the coal- and oil-fired electric utility industry. The Mercury and Air Toxics Standards ("MATS") rule was published in the Federal Register on February 16, 2012, and set emission limits for mercury, acid gases, toxic metals, and organics including dioxins and furans based on the maximum achievable control technology ("MACT") for the industry. Since the 2021 IRP, EPA issued revisions of the MATS rule on April 25, 2024, which lowered some hazardous air pollution emission standards, requires the use of monitoring systems instead of emissions testing when determining compliance with particulate matter ("PM") as a surrogate for related hazardous air pollution emission limits, and removed one of the two definitions for the term "startup."

The most impactful MATS revision for the Companies is the lowering and monitoring of the non-mercury hazardous air pollution standards by two-thirds. As of today, non-mercury metal continuous emission monitoring system are not certified or accepted by EPA. PM monitoring may be used as a surrogate. As a surrogate for compliance to the revised MATS non-mercury hazardous air pollutants, the filterable PM emission limit was reduced from 0.030 lb/mmBtu to 0.010 lb/mmBtu on a 30-boiler-operating-day average and requires use of PM continuous emissions monitoring systems ("PM CEMS"). These MATS revisions do not directly impact the Companies because all of the Companies' MATS-rule-affected units have been using PM CEMS for compliance since the MATS rule was originally published. The Companies' historical operating data depicts compliance with the lower PM emission limit; nonetheless, this reduction results in a significant reduction in compliance margin and a significant increase in compliance risk. Further, with this lower limit, the required PM CEMS quality assurance activities are now harder to achieve. One of the criteria for successful confirmation of the quality of a PM CEMS correlation curve is that annual testing must demonstrate test results stay within 25% of the PM emission limit from the correlation curve. Therefore, the emissions limit reduction (0.03 to 0.01) results in a 66% tighter PM test criteria. The Companies are assessing the use of non-mercury hazardous air pollution traps monitoring equipment that is unaffected by the PM test criteria to minimize compliance risk and enhance compliance margin.

The MATS rule revision that removed the second startup definition does not impact the Companies. The second startup definition allowed for a four hour window of startup operations that would not impact the determination of compliance with emission limits. However, the second definition of startup included stringent recordkeeping requirements that made it less palatable. EPA stated they removed the second startup definition from the rule because only a few units were using it. The Companies' MATS rule affected units have been using the rules first startup definition and are therefore not impacted by this revision.

Of additional note for the MATS rule, EPA has been working to establish electronic reporting (through their Emissions Collections and Monitoring Plan System). The original deadline for that reporting was January 1, 2024. However, EPA has had difficulty in making that transition. The Companies' compliance continues to be managed per MATS-defined monitoring, testing, work practices, record keeping, and reporting, which have been incorporated into facility operating permits. The Companies will continue to stay up-to-date with the electronic reporting developments, implement any needed change to internal processes, and comply with the required electronic reporting requirements.

The MATS revisions are being litigated. On August 6, 2024, the D.C. Circuit Court of Appeals denied motions for stay of the MATS revisions rule. The D.C. Circuit order also requested parties to submit a briefing proposal for the litigation proceedings to begin. Following the D.C. Circuit's denial of a stay, motions for emergency stay were filed with the U.S. Supreme Court. The Supreme Court denied the emergency stay motions on October 4, 2024. The D.C. Circuit proceedings continue. The Companies will continue to comply and operate within the constraints of the MATS rule and the revisions as applicable through the resolution of the legal process.

Hazardous Air Pollutant Regulations/Combustion Turbines

In March 2004, EPA promulgated NESHAP for stationary combustion turbines. Stationary combustion turbines were identified as major sources for formaldehyde, toluene, benzene, and acetaldehyde. The final rule (40 CFR 63, Subpart YYYY) applied to stationary combustion turbines located at major sources of hazardous air pollutant emissions. Many, but not all, of the Companies' combustion turbines are in this category. The rule also had different requirements for existing (i.e., commenced construction on or before January 14, 2003) and new combustion turbines (i.e., commenced construction after January 14, 2003). However, in August 2004, EPA stayed a portion of the rule pertaining to the types of combustion turbines the Companies employ. Therefore, the Companies have not been affected by this rule.

On March 9, 2020, following a requirement to perform reviews of NESHAP rules every eight years, EPA finalized revisions to the combustion turbine NESHAP rule. EPA maintained the same NESHAP limits (e.g., a formaldehyde limit of 91 ppb) after determining that the limits provided an ample margin of safety to protect public health and that no new cost-effective controls are available that could achieve further reductions. The revision clarifies that emissions during startup, shutdown, and malfunction operating periods should be included, and it added reporting requirements. However, the revision also did not lift the 2004 stay. EPA stated that more time was needed to review public comments and a petition to delist the stationary combustion turbines source category that was filed in August 2019.

On March 9, 2022, EPA published amendments to 40 CFR 63, Subpart YYYY that lifted the stay. All lean premix gas-fired turbines and diffusion flame gas-fired turbines that began construction or reconstruction after January 2003 at major sources of HAPS needed to comply with the 91ppb formaldehyde limit and other operating limitations. As of March 9, 2022, the two combustion turbines at the Companies' Cane Run Unit 7 were the only ones that began construction after January 2003. However, the Cane Run facility is designated as an area source of HAPS, not a major source, and is thereby unaffected by the amendments to 40 CFR 63, Subpart YYYY.

On July 15, 2024, construction began on the Companies' Mill Creek Unit 5 natural gas-fired combined cycle facility ("MC5"), which will use one combustion turbine. The Mill Creek Generating Station will continue to be designated as a major source of HAPS. Therefore, as of the date of this IRP, the MC5 combustion turbine is the only combustion turbine in the Companies affected by the requirements of 40 CFR 60, Subpart YYYY. The Companies will evaluate the applicability of the rule for any future combustion turbine construction projects.

National Ambient Air Quality Standards

SO_2

As an update to the 2021 IRP, the primary SO_2 NAAQS remains set at 75 ppb as set in 2010. All areas in which the Companies operate are in attainment with the primary SO_2 NAAQS. On April 3, 2024, EPA proposed to revise the secondary NAAQS for oxides of sulfur ("SO_x") to an annual standard at a level between 10 and 15 ppb, averaged over 3 years (compared to the current 3-hour standard set at 500 ppb). EPA sets secondary standards to protect the public welfare against adverse effects including ecological effects such as damage to vegetation. From an analysis EPA performed, EPA does not anticipate additional emissions reductions will be needed to meet the proposed secondary standard beyond those already needed for some areas to meet the current primary SO_2 NAAQS. The Companies' areas of operation are currently in attainment with the primary SO_2 NAAQS. Therefore, the proposed secondary SO_2 NAAQS is not expected to have an impact on the Companies operation.

NO_x/NO_2

As an update to the 2021 IRP, on November 16, 2018, the KDAQ proposed a revision to the State Implementation Plan ("SIP") that demonstrates the "good neighbor" provisions of the 2010 NO_2 NAAQS are being met and requests that EPA approve the demonstration for Kentucky to fully implement the 2010 1-hour oxides of nitrogen ("NO_2") NAAQS. EPA has still not acted on that request. On April 3, 2024, EPA proposed to retain the current secondary NO_2 NAAQS at an annual average of 53 ppb. The Companies are not expecting any impacts on operating facilities from primary or secondary NO_2 NAAQS issues but will continue to follow these issues.

Ozone

As an update to the 2021 IRP, the current (i.e., 2015) primary and secondary ozone NAAQS remain at 70 ppb. On September 8, 2022,[99] LMAPCD in conjunction with KDAQ submitted a request to EPA to redesignate the Louisville-Jefferson County, KY marginal non-attainment area to attainment for the 2015 8-hour ozone NAAQS based on certified ozone monitoring data from 2019 through 2021. Conversely, on September 15, 2022, EPA finalized actions on non-attainment designations for the 2015 ozone NAAQS. In that action, 25 "marginal" non-attainment areas (including the Louisville-Jefferson County area) were reclassified as "moderate" non-attainment areas. With that new status, the moderate non-attainment areas had a deadline to attain the standards by August 3, 2024. In parallel action, on April 18, 2023, in response to the September 8, 2022 request, EPA proposed to finalize the redesignation of the Louisville-Jefferson County, KY area to attainment status. The comment period on that proposal ended on May 18, 2023 and EPA has not finalized the redesignation of the Louisville-Jefferson County, KY area to attainment status. Unfortunately, the Louisville-Jefferson County, KY area has indicated non-attainment status with the 2015 8-hour ozone standard based on monitored ozone levels from 2021 through

[99] EPA proposed to redesignate Louisville KY in attainment of 2015 ozone NAAQS.

2023 and thereby may be in danger of not achieving attainment status by the August 2, 2024 deadline. This would mean the Louisville-Jefferson County, KY area may be redesignated into a "serious" non-attainment area. One impact of serious non-attainment status is that the major source threshold for requiring an air permit is reduced from 100 tons to 50 tons per year of NO_x and volatile organic compounds ("VOC"), meaning smaller sources may need to obtain major source permits or take limits to stay below the 50 ton per year threshold. Additionally, regulatory agencies responsible for a serious non-attainment area will need to investigate and put plans in place for issues like: (1) enhanced ozone monitoring, (2) reaching attainment, possibly through additional controls, (3) providing for enhanced vehicle inspection and maintenance programs, (4) clean-fuel vehicle programs, and others.[100] By regulation, the ozone NAAQS should be reevaluated again in 2025. On August 21, 2023,[101] EPA announced plans to review the ozone NAAQS prior to its five year review deadline. The EPA's Clean Air Scientific Advisory Committee has previously suggested lowering the ozone standard to 65-68 ppb. Therefore, even as plans are put in place and actions are taken to bring areas into attainment with the 70 ppb ozone standard, it is possible that the standard would be lowered, and once again those areas would be determined to be non-attainment for ozone. Such a determination will start the process of establishing a new RACT and implementing further NO_x reductions at all sources in those areas.

The Companies' Mill Creek Generating Station is located in the Louisville-Jefferson County, KY ozone non-attainment area. From 2020 through retirement of either Mill Creek Unit 1 or Unit 2, the Louisville Metro Air Pollution Control District ("LMAPCD") has imposed, via an Agreed Board order, an additional 15-ton total daily NO_x emissions limitation on the Mill Creek Generating Station for the months of May through October in an effort to aid the ozone non-attainment area achieve attainment status. Despite the Companies' efforts while meeting this limit, exceedances of the 70 ppb ozone standard in the Jefferson County area have continued to occur. Based on that information and the potential bump up of the Louisville-Jefferson County, KY non-attainment area to serious status, it is unclear what other efforts may be requested of the Companies operations to help the area reach attainment status. The Companies will continue to follow these ozone NAAQS issues and assess their impacts on operating facilities.

PM / $PM_{2.5}$

As an update to the 2021 IRP,EPA proposed (January 6, 2023) and finalized (published March 6, 2024, effective May 6, 2024) a revision of the primary annual $PM_{2.5}$ by lowering the level from 12.0 $\mu g/m^3$ to 9.0 $\mu g/m^3$.[102] On March 6, 2024, several states, including Kentucky, filed a petition for review in the D.C. Circuit challenging the revision.

EPA, with input from states and tribes, have two years to designate area in attainment or non-attainment of the standard. Designations will be based on the most recent set of air monitoring or modeling data at the time of the proposed designation. Additional, a three-year deadline has started for states to submit revisions to there SIPs to show they are ready to implement the revised NAAQS. Once EPA designates an area in non-attainment of the NAAQS, the agency responsible

---

[100] 42 USC Chapter 85, Subchapter 1, Part D, Section 7511a(c)
[101] EPA Initiates New Review of Ozone NAAQS
[102] EPA published revision of PM2.5 NAAQS.

for that area has 18 months to submit revisions of their SIP outlining strategies and emission control measures that will be used to bring the area into attainment status.

Based on data available at the time of this IRP filing, the Louisville-Jefferson County area could likely be designated non-attainment for the new $PM_{2.5}$ standard. Therefore, the Companies' operations in or near that area could requested to aid in achieving attainment status. As a result of installation of pulse jet fabric filters across the Companies' fleet, concerns with the changes to $PM/PM_{10}/PM_{2.5}$ NAAQS could be minimized since the equipment is considered a best available control technology for coarse and fine particulates. The Companies will continue to follow these issues involving PM NAAQS and assess their impacts on operating facilities.

On April 3, 2024, EPA proposed to retain the current secondary NAAQS for $PM_{2.5}$ at an annual average of 15 $\mu g/m^3$. Therefore, the Companies anticipate no actions are needed regarding maintaining compliance with the secondary $PM_{2.5}$ NAAQS.

Regional Haze

Since the 2021 IRP, the second planning period (2019-2028) of the Regional Haze rule continues. On July 11, 2024, the Commonwealth of Kentucky's Energy and Environment Cabinet held a public hearing to discuss a draft of the Regional Haze SIP for Kentucky's Class I area for the Second Planning Period. Within that document, the Companies will not have to take any further restrictions during the second Regional Haze planning period. However, EPA's requirements for implementation of the third planning period of the Regional Haze regulation will likely be published in 2028 for states to model sources impacting visibility in national parks. Even though Kentucky is below the glide path required for showing progress toward the rule's goal by 2064 (i.e., Kentucky is making more than the required progress toward the goal), the Companies may be requested to evaluate visibility or regional haze impacts of operations on Class 1 areas like Mammoth Cave National Park because EPA has stated that being below the glide path does not negate the need to evaluate impacts and possibly install controls. The Companies will continue to follow these issues and implement any needed changes to ensure compliance.

Greenhouse Gases

As an update to the 2021 IRP, on January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit court vacated the Affordable Clean Energy ("ACE") rule, which affected existing electric generating units, and remanded it to EPA for further proceedings consistent with the court's opinion.[103] The D.C. Circuit found that Section 111(d) of the Clean Air Act does not mandate the best system of emission reduction ("BSER") be limited to those measures that can be applied only at and to an individual source. Because EPA expressly based its repeal of the Clean Power Plan ("CPP") and its promulgation of the ACE rule on the premise that Section 111(d) limits BSER to such "behind-the-fence-line" measures, the D.C. Circuit held that both the CPP repeal and ACE rule must be vacated.

[103] *American Lung Ass'n v. E.P.A.*, 985 F.3d 914 (D.C. Cir. 2021).

On October 29, 2021, the U. S. Supreme Court granted review of the case, specifically agreeing to hear the parties' arguments on whether EPA's Section 111(d) authority allows the agency to regulate the electric generation industry in a manner as broadly as the CPP. Oral argument occurred on February 28, 2022, and the Supreme Court rendered its 6-to-3 decision on June 30, 2022.[104] At the outset of the opinion, Chief Justice Roberts framed the core issue before the Court as "whether [the CPP's] broader conception of EPA's authority is within the power granted to it by the Clean Air Act."[105] The majority's answer was that the generation shifting approach of the CPP exceeded the powers granted to EPA by Congress. The Supreme Court determined this type of regulation, which would have impacted the economy on a nationwide scale, is not authorized by Section 111(d) of the Clean Air Act ("CAA") and is a "major question" which requires a "clear congressional authorization" to EPA.[106] The Supreme Court reversed and remanded to case back to the D.C. Circuit for further proceedings.[107]

As a result of the Supreme Court's decision, on October 27, 2022, the D.C. Circuit rescinded its previous mandate and issued an amended judgment to deny the petitions for review of the CPP and hold remaining challenges to the ACE rule in abeyance pending EPA's ongoing effort to develop a replacement rule. On May 23, 2023, EPA published its proposal to address five separate actions under Section 111 of the CAA addressing GHG emissions from fossil fuel-fired EGUs. EPA proposed to: 1) revise the NSPS under Section 111(b) of the CAA for GHG emissions from new fossil fuel-fired stationary combustion turbine EGUs; 2) revise the NSPS for GHG emissions from fossil fuel-fired steam EGUs which undertake a large modification; 3) established emission guidelines pursuant to Section 111(d) of the CAA for GHG emissions from the largest, most frequently operated stationary combustion turbines; and 4) repeal the ACE rule. The Companies, along with many others, filed comments on the proposal by the August 8, 2023 extended deadline.

On May 9, 2024, EPA published its final version of the rule regulating GHGs from EGUs.[108] The rule finalized the following: 1) repeal of the ACE rule; 2) emission guidelines for GHG emissions from existing fossil fuel-fired steam EGUs under Section 111(d) of the CAA; 3) revisions of the GHG NSPS from new and reconstructed fossil fuel-fired stationary combustion turbines; and 4) revisions to the standards of performance for coal-fired EGUs which undertake a large modification (i.e., increases the unit's hourly emissions rate by more than 10 percent). EPA did not finalize emission guidelines for GHG emissions from existing fossil fuel-fired stationary combustion turbines. For those existing stationary turbines, EPA developed a non-rulemaking regulatory docket to gather more information for a rulemaking to be proposed at a later date.

As finalized, the emission guidelines for GHG emissions from existing fossil fuel-fired steam EGUs and coal-fired EGUs that undertake a large modification require:

1) For existing coal-fired EGUs that intend to operate beyond December 31, 2038, the EGU must achieve an 88.4 percent reduction in its annual GHG emissions by January

---

[104] *West Virginia v. EPA,* 597 U.S. 697 (2022).
[105] *Id.* at 706.
[106] *Id.* at 723 and 732.
[107] *Id.* at 735.
[108] Federal Register, at 89 Fed. Reg. 39,798.

1, 2032. EPA identified the best system of emission reduction ("BESR") to achieve that reduction is the installation of carbon capture and storage ("CCS") systems with a 90% capture efficiency.

2) For existing coal-fired EGUs that intend to permanently cease operations before January 1, 2039, the EGU must achieve a 16 percent reduction in its annual GHG emissions by January 1, 2030. EPA identified the BSER to achieve that reduction is the co-firing of natural gas at a level of 40 percent of the unit's annual heat input.
3) For existing coal-fired EGUs that intend to permanently cease operations prior to January 1, 2032, the EGU would be exempt from applicability of the rule. The planned retirements would be identified in the state implementation plan ("SIP") and federally enforceable.
4) For existing natural gas- and oil-fired steam EGUs that operate at an annual capacity factor of greater than 45 percent, the EGU must achieve a presumptive GHG emission standard of 1,400 pounds CO_2 per megawatt hour of gross electrical output ("lb CO_2/MWh-gross").
5) For existing natural gas- and oil-fired steam EGUs that operate at an annual capacity factor between greater than eight percent and less than or equal to 45 percent, the EGU must achieve a presumptive GHG emission standard of 1,600 lb CO_2/MWh-gross.
6) For existing natural gas- and oil-fired steam EGUs that operate at an annual capacity factor of less than or equal to eight percent, the oil-fired EGU must achieve a presumptive GHG emission standard of 170 pounds CO_2 per million British thermal units of heat input ("lb CO_2/MMBtu"), while the natural gas-fired EGU must achieve 130 lb CO_2/ MMBtu.

For new and reconstructed fossil fuel-fired stationary combustion turbines, the following standards apply:

1) If the EGU operates at a greater than 40 percent capacity factor, the EGU must achieve highly efficient generation and achieve a 12-operating month average emission rate of 800 lb CO_2/MWh-gross if rated for greater than or equal to 2,000 MMBtu per hour ("MMBtu/hr") or a 12-operating month average emission rate between 800 and 900 lb CO_2/MWh-gross if rated for less than 2,000 MMBtu/hr. Additionally, by January 1, 2032, the EGU must use CCS with 90 percent capture to achieve an emission rate of 100 lb CO_2/MWh-gross.
2) If the EGU operates at greater than or equal to 20 percent and less than or equal to 40 percent capacity factor, the EGU must achieve highly efficient best operating and maintenance practices to achieve a 12-operating month average emission rate of 1,170 lb CO_2/MWh-gross.
3) If the EGU operates at less than 20 percent capacity factor, the EGU must use lower emitting fuels (e.g., natural gas) and achieve a 12-operating month average emission rate of less than 160 lb CO_2/MMBtu.

To comply with the rule, the State must submit a State Implementation Plan (SIP) within two years of the effective date of the rule. The SIP must comply with Kentucky Revised Statutes in Chapter

224.20 that address performance standards for adopting carbon dioxide emissions reduction performance standards. These State standards potentially conflict with the Best System of Emission Reductions in the Federal rule. Further, a SIP that contemplated electric generating unit retirements would implicate other Kentucky statutes, including KRS 278.264. These concerns create a critical path schedule issue for submitting a presumptively approvable SIP on schedule.

Subsequent to EPA finalizing the EGU GHG rule, several petitions for review have been filed.[109] Additionally, on May 13, 2024, motions for stay of the final rule were filed by a coalition of states, including Kentucky, and several industry and trade groups. The D.C. Circuit agreed to hear arguments on the motions for stay. Briefings on the stay motions were completed on June 18, 2024. On July 19, 2024, the D.C. Circuit issued a ruling denying the motions for stay of the EGU GHG rule. In response, EPA suggested that the court case regarding the petitions for review of the EGU GHG rule should be expedited. On August 9, 2024, the D.C. Circuit issued the briefing schedule with a date of November 1, 2024 for final briefs and the date for oral arguments still to be determined.

With the D.C. Circuit's denial of the stay motion, a coalition of states, including Kentucky, filed an emergency stay application in the U.S. Supreme Court on July 23, 2024.[110] Several industry groups have also submitted similar applications. The basic assertion is that the final EGU GHG rule "shift[s] electricity generation" and "reshape[s] America's power grid" without statutory authorization, pointing to the Supreme Court's decision in *West Virginia v. EPA.*[111] On October 16, 2024, the Court denied the petition.[112] Justice Thomas stated he would have granted the stay, and Justices Kavanaugh and Gorsuch opined, "[T]he applicants have shown a strong likelihood of success on the merits as to at least some of their challenges to the Environmental Protection Agency's rule."[113] The Companies will continue to follow all these GHG issues and assess their impacts on operating facilities.

Clean Water Act - 316(b): Regulation of Cooling Water Intake Structures

Clean Water Act Section 316(b) requires the reduction of adverse environmental impact upon aquatic populations by using Best Available Control Technology for water withdrawn from a water source for cooling purposes. EPA published final 316(b) regulations on August 15, 2014, which became effective on October 14, 2014. The regulation addresses both impingement and entrainment impacts for aquatic species. All coal-fired generating units meet the impingement standard by utilizing the closed-cycle cooling compliance option, except the Companies' Mill Creek Unit 1. For the entrainment standard, only the combined units of Mill Creek Station exceed the withdrawal threshold for entrainment, which required a series of aquatic studies to be conducted and a final report submitted to the Kentucky Division of Water. The final report was

---

[109] *West Virginia, et al. v. EPA*, No. 24-01120 (D.C. Cir.)
[110] *West Virginia v. EPA*, No. 24A95 (U.S.).
[111] *West Virginia v. EPA*, 597 U.S. 697 (2022).
[112] *West Virginia v. EPA*, 604 U.S. ___ (Oct. 16, 2024), available at https://www.supremecourt.gov/opinions/24pdf/24a95_n7ip.pdf.
[113] *Id.*

submitted in 2022 along with the Mill Creek NPDES permit renewal application. Due to the retirement of Mill Creek Unit 1 in 2024, no additional 316 compliance actions are necessary for the Mill Creek coal units.

Clean Water Act: Steam Electric Power Generating ELG

EPA published final effluent limitation guidelines ("ELG") on November 3, 2015, which became effective on January 4, 2016. The revised regulations require major changes to wastewater treatment systems at existing coal-fired plants that generate both bottom and fly ash wastewaters, and for facilities that generate gypsum wastes from flue-gas desulfurization ("FGD") scrubbers. The regulations impose a prohibition on the discharge of ash transport waters by no later than 2023. The new regulations also include greatly reduced the discharge limits from FGD wastewaters on mercury, arsenic, selenium, and nitrates.

EPA published revisions to the rule on October 12, 2020 that included minor changes in limits for FGD Wastewater ("FGDW") and an extension on Bottom Ash Transport Water ("BATW") compliance. Permit modification applications were submitted on January 8, 2021 for the Companies Ghent, Mill Creek, Trimble County, and E.W. Brown electric generating facilities to incorporate new discharge limits into each facility's Kentucky Pollutant Discharge Elimination System ("KPDES") water discharge permit. On July 26, 2021, EPA announced a reconsideration of the 2020 revisions to the 2015 ELG standards with review to determine "whether more stringent limitations and standards are appropriate." KPDES permits for E.W. Brown, Ghent, Mill Creek, and Trimble County have 2020 ELG requirements incorporated and each site is implementing controls. On May 9, 2024, EPA published the final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category ("2024 ELG") to revise the 2020 Effluent Limitations Guidelines ("2020 ELG"). The 2024 ELG became effective on July 8, 2024, and sets a compliance period of as-soon-as-possible but no-later-than December 31, 2029 (with the exception of certain subcategories).

The revised regulations require major changes to wastewater treatment systems at existing coal-fired plants that generate FGDW, BATW, Combustion Residual Leachate ("CRL"), and Legacy Waste Water ("LWW"). The regulations impose a prohibition on the discharge of FGDW, BATW, and CRL by no later than December 31, 2029. The new regulations also direct permitting authorities to set Best Professional Judgement ("BPJ") limits for LWW. The rule expands the Notice of Planned Participation ("NOPP") retirement subcategory to include units retiring before January 1, 2034. Upon utilizing the NOPP provision, the final rule retains the 2020 rule requirements for FGD wastewater and BA transport water and the pre-2015 BPJ-based BAT requirements for CRL rather than requiring the new, more stringent zero-discharge requirements for these waste-streams. After the permanent cessation of coal combustion, however, electric generating units (EGU) in this subcategory must meet limitations on arsenic and mercury based on chemical precipitation for CRL.

Coal Combustion Residuals

After several years of review and public comment, EPA issued the coal combustion residuals ("CCR") regulation that was effective on October 14, 2015. The rule is a holistic program outlining federal standards for the storage, management, beneficial use, and long-term care of CCR managed in surface impoundments and landfills.

Following the issuance of the 2015 CCR regulations, the Companies initiated closure of 19 surface impoundments. These processes were accomplished using in-place closure and closure by removal methods-both options were allowed in the rule. The physical closure process has been completed for 17 of the impoundments with the remaining two slated for physical completion in 2025. Of the closures undertaken by the Companies, ten were performed using in-place methods.

Since its effective date, the 2015 rule has continued to evolve through modifications by the EPA. On May 8, 2024, the most recent modification expanded the scope of the regulation to include Legacy CCR surface impoundments and CCR management units (“CCRMU”). While the companies had anticipated the regulation of legacy CCR surface impoundments, the addition of CCRMUs broadens the Companies’ exposure to the rule at each of its owned current and former generating facilities because of the Companies’ past beneficial use of CCR, especially for fill materials. Many of the known CCRMU locations are beneath buildings or infrastructure. This will create challenges during the investigative process and may inhibit the closure process for individual CCRMUs if the removal of CCRs are necessary for rule compliance.

As described previously, the rule added definitions that present risk to compliance strategies that the Companies have already executed. The Companies will continue to assess its compliance strategies so that impacts to units where closure is considered complete will be minimized.

8.(5).(g) Consideration Given to Market Forces and Competition

In the development of the 2024 IRP, the Companies considered market forces and competition. This consideration is reflected in the appropriate sections of the IRP.

9 Financial Information

Annual revenue requirements and the present value of revenue requirements (“PVRR”) are shown in Table 9-1 for the Mid energy requirements, mid gas, mid coal-to-gas ratio fuel price (“Mid Fuel”) case. The discount rate used in the present value calculation is 6.56%. Annual revenue requirements include variable and fixed costs for both new and existing units and capital costs for new units.

Table 9-1: Annual Revenue Requirements (Mid Energy Requirements, Mid Fuel Case)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Revenue Requirements ($M)	2,153	2,120	2,431	2,129	2,781	2,987	3,095	3,103	3,049	3,048	2,508	3,086	3,083	2,939	2,958
PVRR ($M; 2024 Dollars)	13,657														
Mid Energy Requirements (GWh)	32,808	32,867	33,668	34,806	36,057	38,292	40,569	41,200	41,033	40,971	40,949	41,057	40,930	40,949	40,943
cents/kWh	6.56	6.45	7.22	6.12	7.71	7.80	7.63	7.53	7.43	7.44	6.12	7.52	7.53	7.18	7.22