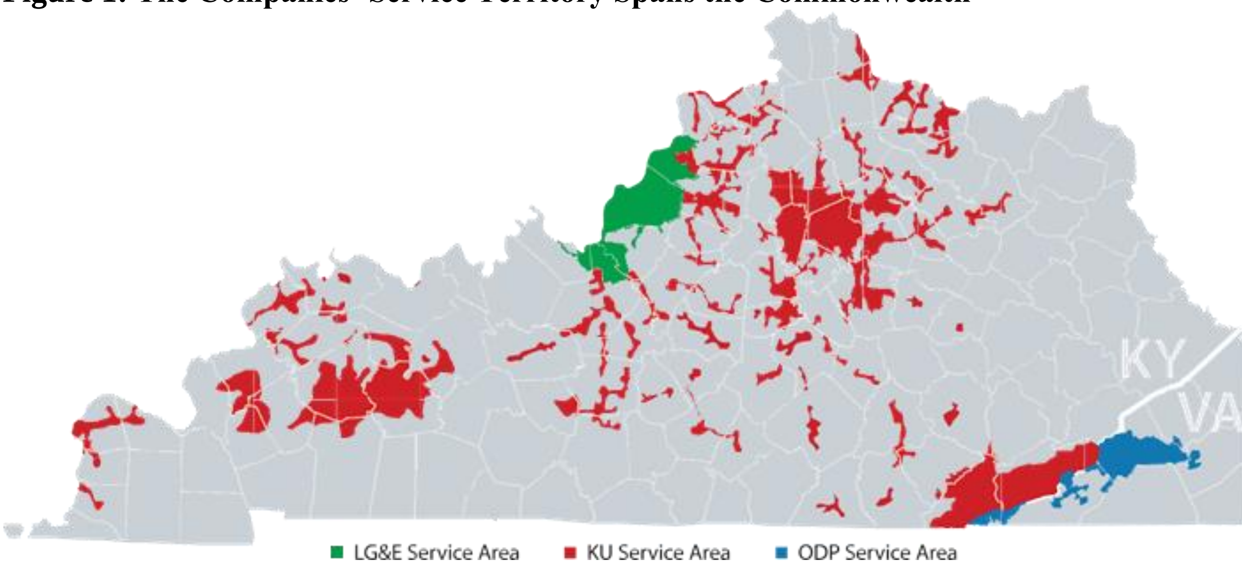
2024 IRP Executive Summary

Profile of Louisville Gas and Electric Company and Kentucky Utilities Company

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 more than 570,000 customers across two time zones in 77 Kentucky counties and five counties in Virginia, where KU operates under the name Old Dominion Power Company. In addition, KU provides wholesale power to two municipalities in Kentucky.

Figure 1: The Companies' Service Territory Spans the Commonwealth



The Companies' customers consume energy fairly equally across residential, commercial, and industrial classes: For the 12 months ending in June 2024, electricity consumption by class was approximately 35% residential, 25% commercial, 30% industrial, and 10% other.

Over the last ten years, the Companies have supplied from just over 30,000 GWh to over 35,500 GWh of energy to their customers each year, and they have experienced seasonal peak customer energy demands as high as 6,500 MW in the summer and 7,100 MW in the winter.

The Companies' Current and Recently Approved Resource Portfolio

In November 2023, the Kentucky Public Service Commission ("Commission") approved several new supply-side and demand-side management and energy efficiency ("DSM-EE") resources for the Companies, as well as the retirement of two coal-fired units, Mill Creek Units 1 and 2. Specifically, the Commission approved: a new natural gas combined cycle ("NGCC") unit, Mill Creek Unit 5, expected to be in service by the end of 2027; a new 125 MW four-hour battery energy storage system ("BESS") to be installed at the E.W. Brown Generating Station; the Mercer

County and Marion County Solar Facilities to be owned by the Companies; four solar power purchase agreements ("PPAs"); and a new comprehensive portfolio of DSM-EE programs.

The Companies' 2024 IRP analysis assumes that nearly all of the new resources and retirements approved in the 2022 CPCN and DSM-EE case will be deployed or occur as planned.[1] Therefore, by 2028 the Companies anticipate having supply-side resources consisting of 4,313 MW of coal-fired generation,[2] 3,672 MW of natural gas-fired generation, 134 MW of hydroelectric generation, and 254 MW of solar generation, as well as 125 MW of BESS.[3] The Companies also deploy the most robust demand-side management and energy efficiency ("DSM-EE") program portfolio in Kentucky, projected to provide 110 MW of demand response in 2028, as well as a Curtailable Service Rider ("CSR") program providing over 100 MW of curtailable customer load during times of system stress.[4]

The Continuing Importance of Solar in the Companies' Resource Planning

Solar continues to play an important role in the Companies' resource planning. Although solar PPA pricing has risen significantly in recent years, resulting in the Companies' current expectation that the approved solar PPAs will not advance under their approved terms, current projections by the National Renewable Energy Laboratory ("NREL") suggest that solar pricing may decrease over the IRP planning period, potentially allowing for additional solar development. Also, both existing and potential customers, such as data centers, may have an increasing interest in carbon-free energy and seek to have additional amounts of solar added through the Companies' Green Tariff Option #3. Thus, as discussed below and at length in IRP Volume I and the Resource Assessment included in Volume III, the 2024 IRP Recommended Resource Plan and the Enhanced Solar Resource Plan contain significant amounts of new solar.

Moreover, both plans include hundreds of megawatts of new battery storage, which could help facilitate increased amounts of renewable energy generation in the future. Therefore, both solar and solar-enabling technologies continue to figure prominently in the Companies' resource planning.

<u>Three Key Drivers and Uncertainties in the Companies' 2024 IRP Analysis</u>

The Companies' 2024 IRP analysis identifies three key drivers of change and uncertainty over the 15-year IRP planning horizon: (1) potentially large new load from data centers; (2) significant

[1] 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.

[2] This includes the Companies' 158 MW share of the coal-fired generating capacity owned and operated by the Ohio Valley Electric Corporation ("OVEC").

[3] Renewable generation capacity values are nameplate, not contributions to seasonal peak.

[4] All values are winter capacity values.

increases in supply-side resource costs and changes in relative costs of certain supply-side resources; and (3) uncertainty in federal environmental regulations.

Data Centers Are an Economic Development Opportunity and Key Load Forecast Driver

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).

Although prior IRPs have sought to account for economic development activity, that issue is particularly important to this IRP. 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 1 below, to study what the lowest-cost portfolios might be across a reasonable range of possible future load scenarios:

Table 1: 2024 IRP Load Forecast Scenarios—Important Differences

Load Scenario	Data Centers in 2032	Distributed Generation in 2032	Energy Efficiency, CVR, AMI, and Other Energy Reductions in 2032[5]
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

As shown in Figure 2 and Figure 3 below, annual energy requirements and seasonal peaks in the Low load scenario will gradually decrease over the planning horizon due to energy efficiency and distributed generation in combination with minimal economic development load growth. In contrast, by 2032 in the Mid and High load scenarios annual energy requirements increase by over 30% to over 60%, respectively, relative to the Low load forecast scenario. Likewise, by 2032

[5] 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.

seasonal peak demands in the Mid and High load scenarios increase by about 1,000 MW to 2,000 MW, respectively, relative to the Low load forecast scenario.

Figure 2: 2024 IRP Annual Energy Requirements (GWh)[6]

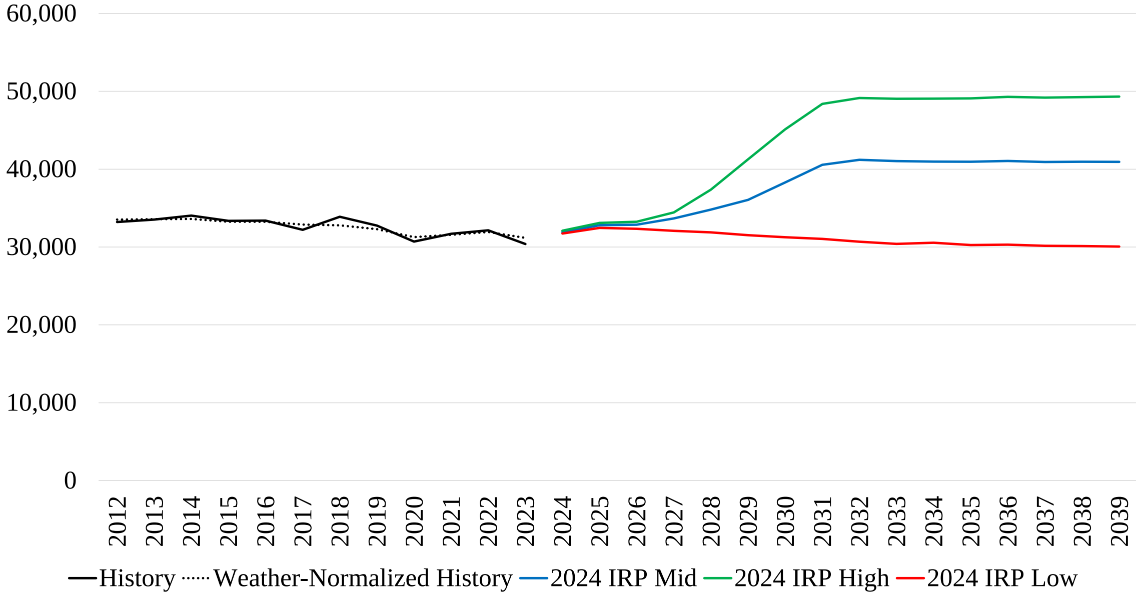
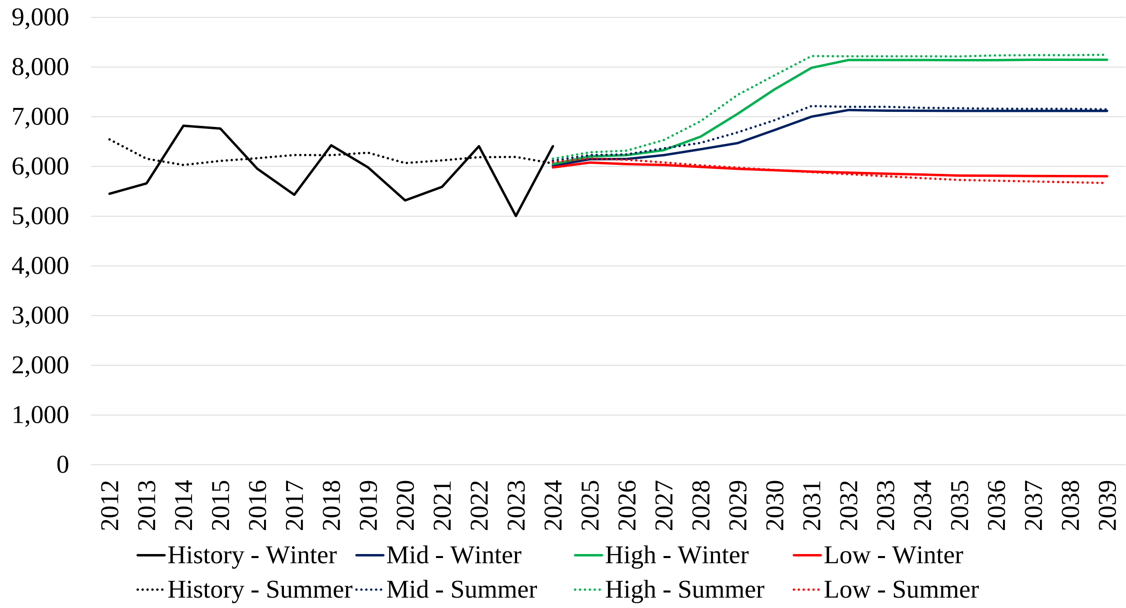


Figure 3: 2024 IRP Winter and Summer Peak Demands (MW)[7]



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.

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[6] History excludes municipal customers that departed in 2019.
[7] History excludes municipal customers that departed in 2019.

Two other load forecast items are particularly noteworthy:

- **The Companies' system is now consistently dual-peaking.** Figure 3 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 1 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.

New Supply-Side Resource Costs Have Increased Markedly Since the 2021 IRP

Other than the change in load forecast driven by potential data center load, the primary driver of change in the 2024 IRP compared to the 2021 IRP is the marked increase in the cost all new supply-side resources. As shown in Table 2 below, although the costs of all supply-side resources have increased since 2021, they have not all increased proportionally. Importantly, although 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.

Table 2: Sum of Capital and Non-Fuel O&M ($/kW-yr) for Selected Resources

Resource	2021 IRP 2022 $ Capital + Non-Fuel O&M ($/kW-yr)	2022 CPCN[8] 2026/2027 $ Capital + Non-Fuel O&M ($/kW-yr)	2024 IRP 2030 $ Capital + Non-Fuel O&M ($/kW-yr)
SCCT	127	83	182
NGCC	140	117	222
Solar No ITC/PTC	126	136	183
Solar with ITC/PTC	101	90	133
4-hr BESS No ITC	172	300	265
4-hr BESS with ITC	N/A	138	138

These significant increases in the cost of all new supply-side resources tend to increase the relative value of existing resources, and changes in the relative costs of new resources affect the ultimate composition of the 2024 IRP Recommended Resource Plan.

Environmental Regulations Continue to Drive Uncertainty

The impact of environmental regulations remains a key uncertainty in the 2024 IRP. Since the Companies' 2021 IRP, the U.S. Environmental Protection Agency ("EPA") has finalized three major, impactful regulations, all of which have been the subject of federal court challenges, and the ultimate fate of which remains uncertain: the 2023 Good Neighbor Plan relating to the 2015 National Ambient Air Quality Standards ("NAAQS") for ozone ("Ozone NAAQS"); the 2024 updates to the Effluent Limitation Guidelines ("ELG"); and the 2024 Clean Air Act Section 111(b) and (d) Greenhouse Gas Rules ("GHG Rules").

To address this uncertainty, the 2024 IRP modeled four different environmental regulatory scenarios: (1) a No New Regulations scenario in which none of the recent regulations becomes enforceable, and only existing enforceable environmental regulations continue throughout the IRP planning horizon; (2) an Ozone NAAQS-only scenario; (3) an Ozone NAAQS and ELG scenario; and (4) a scenario in which all three of the recent major regulations (or their equivalents) become enforceable.

The Companies believe the third scenario, i.e., regulatory constraints roughly equivalent to the Ozone NAAQS and ELG scenario, is the most likely of the four scenarios, and the No New Regulations scenario appears least likely, though the upcoming federal elections could significantly affect the regulatory landscape over the IRP planning horizon.

As shown in Tables 25-28 of the 2024 IRP Resource Assessment, the potential effects of these environmental regulations are significant, particularly with respect to the GHG Rules. Unlike all of the least-cost portfolios in the non-GHG Rules scenarios, which retain the Ghent and Trimble County coal-fired units through the end of the IRP planning period, all of the least-cost portfolios

[8] 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.

in the GHG Rules scenarios retire *all* coal-fired capacity by the end of the planning period. Moreover, the lifetime cost of the least-cost Mid load GHG Rules portfolio (shown in the middle column of Resource Assessment Table 28) is about $5.6 billion PVRR *more* than the comparable least-cost portfolio in the Ozone NAAQS and ELG scenario (i.e., the portfolio shown in the Base Resource Costs, Mid Load column of Resource Assessment Table 27).[9]

<u>The Companies' 2024 IRP Analysis Is Robust and Results in a Reasonable Recommended Resource Plan</u>

In addition to accounting for the three key drivers and uncertainties addressed above, the Companies' IRP analysis considered a wide range of fuel price scenarios, multiple supply-side resource options, and new demand-side dispatchable resource options (beyond existing or approved dispatchable DSM and Curtailable Service Rider programs), as well as new modeling parameters and constraints relative to previous IRP analyses, including updated seasonal reserve margin requirements to ensure reliability. The Companies' robust modeling efforts resulted in 60 different resource portfolios being evaluated across five different fuel price scenarios (i.e., 300 different resource portfolio and fuel-price combinations), resulting in a final 2024 IRP Recommended Resource Plan that is a robust solution across a range of possible future scenarios.

The Companies' 2024 IRP Recommended Resource Plan

Table 3 below contains the least-cost resource plans across all fuel scenarios for the Mid load, Ozone NAAQS + ELG scenario and the High load, Ozone NAAQS + ELG scenario, as well as the Companies' 2024 IRP Recommended Resource Plan and an Enhanced Solar Resource Plan.[10]

The Mid load, Ozone NAAQS + ELG scenario includes new dispatchable DSM measures, two NGCCs, 900 MW of battery storage, a Ghent 2 SCR, the retirement of Brown 3, and ELG compliance at the Ghent and Trimble County stations via zero liquid discharge.

In the 2024 IRP 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, the retirement of Brown 3 is deferred to 2035, and 500 MW of solar is added in 2035 after prices fall to hedge natural gas price volatility and future CO_2 regulation risk. The Companies' 2024 IRP 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. Perhaps most importantly, it would result in reliable service consistent with the 1-in-10 LOLE planning standard.

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[9] PVRR is the present value of revenue requirements.

[10] 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.

Finally, because growth in data center load is driven significantly by customers with aggressive carbon goals, more solar could be added by these customers in the context of the Companies' Green Tariff Option #3 or by the Companies in a scenario where solar prices fall faster than expected.[11] The Enhanced Solar Resource Plan reflects this possibility and includes 1,000 MW of additional solar in 2028 through 2032.

Table 3: The Companies' 2024 IRP Recommended Resource Plan (only years in which changes occur are shown)

Year	Least-Cost Resource Plans Ozone NAAQS + ELG: Mid Load, Solar Cost Sensitivity[10]	Least-Cost Resource Plans Ozone NAAQS + ELG: High Load	2024 IRP Recommended Resource Plan Mid Load	Enhanced Solar Resource Plan Mid Load
2028	+Dispatchable DSM	+Dispatchable DSM; +300 MW 4hr BESS	+Dispatchable DSM; +400 MW 4hr BESS; Add Ghent 2 SCR	+Dispatchable DSM; +400 MW 4hr BESS; Add Ghent 2 SCR; +200 MW Solar
2029		+700 MW 4hr BESS		
2030	Retire Brown 3; Add Ghent 2 SCR; +1 NGCC; ELG @ Ghent, Trimble County; +100 MW 4hr BESS	Add Ghent 2 SCR; +1 NGCC; ELG @ Ghent, Trimble County	+1 NGCC; ELG @ Ghent, Trimble County	+1 NGCC; ELG @ Ghent, Trimble County; +200 MW Solar
2031	+400 MW 4hr BESS	Retire Brown 3; +1 NGCC; +200 MW 4hr BESS	+1 NGCC	+1 NGCC
2032	+200 MW 4hr BESS	+200 MW 4hr BESS		+600 MW Solar
2035	Retire Mill Creek 3-4; +1 NGCC; +200 MW 4hr BESS	Retire Mill Creek 3-4; +1 NGCC; +1 SCCT	Retire Mill Creek 3-4; Retire Brown 3; +500 MW 4hr BESS; +500 MW Solar	Retire Mill Creek 3-4; Retire Brown 3; +500 MW 4hr BESS

IRP Implementation

With any IRP, it is important to note that it is not actionable in the same way a proposal in a CPCN proceeding is actionable. For example, the resource options analyzed here did not result from a request for proposals process that might result in firm pricing for actual resources; rather, they are good-faith estimates taken from reasonable sources. Moreover, the modeling of these decisions cannot fully reflect supply chain constraints or real-world siting and permitting expense and timelines. Fortunately, the IRP contemplates a number of resource decisions over a 15-year planning horizon that do not require immediate action.

But the Companies' 2024 IRP analysis nonetheless provides important insights about the directional impacts of key drivers and which kinds of resources might best serve customers across a broad range of possible futures, particularly in the near term. In particular, despite uncertainty

[11] NREL projects solar prices to fall by more than 30% by 2035. More solar could be added sooner if these reductions occur sooner.

due to load and environmental regulations, the least-cost resource plans in this IRP contain some common elements that will require more immediate attention:

- **NGCC and battery storage are needed to support economic development load growth**. 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.

- **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 provides assurance the unit will be available to support economic development load growth.

Other IRP-Related Issues

Transmission Considerations

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. Also, they would not require any upgrades for long-term winter-season imports of up to 500 MW and only a minor upgrade ($3.1 million) to accommodate up to 1,000 MW. The Companies similarly would not require transmission upgrades to accommodate long-term firm transfers to the Companies during the summer of up to 300 MW from PJM or MISO and up to 100 MW from TVA.[12] 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.

RTO Membership Analysis

The Companies are also filing with their IRP an updated RTO membership analysis, which does not support pursuing RTO membership now, particularly due to the volatility in capacity market rules and capacity auction results in PJM.

[12] MISO is the Midcontinent Independent Transmission System Operator, Inc., which is a Regional Transmission Organization ("RTO"). PJM is PJM Interconnection LLC, which is also an RTO. TVA is the Tennessee Valley Authority.

Natural Gas Fuel Security Analysis

Finally, the Companies are also filing 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.