COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC JOINT APPLICATION OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND SITE COMPATIBILITY CERTIFICATES AND APPROVAL OF A DEMAND SIDE MANAGEMENT PLAN	))))))))	**CASE NO. 2022-00402**

DIRECT TESTIMONY OF
DAVID S. SINCLAIR
VICE PRESIDENT, ENERGY SUPPLY AND ANALYSIS
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: December 15, 2022

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Section 1 – Introduction and Overview

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

A. My name is David S. Sinclair. I am Vice President, Energy Supply and Analysis for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively "Companies"), and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky 40202. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before the Kentucky Public Service Commission ("Commission")?

A. Yes, I have testified before the Commission numerous times in a variety of cases.[1] I testified most recently in the Companies' 2021 integrated resource plan proceeding.[2]

Q. Please describe your job responsibilities.

A. I have four primary areas of responsibility: (i) fuel procurement (coal and natural gas) and coal combustion residual marketing for the Companies' generating stations, (ii)

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[1] *See, e.g.,* Case No. 2020-00016, *Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Solar Power Contract and Two Renewable Power Agreements to Satisfy Customer Requests for a Renewable Energy Source Under Green Tariff Option #3;* Case No. 2015-00194, *In the Matter of: Investigation of Kentucky Utilities Company's and Louisville Gas and Electric Company's Respective Need for and Cost of Multiphase Landfills at the Trimble County and Ghent Generating Stations;* Case No. 2011-00161, *In the Matter of: The Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery By Environmental Surcharge*; Case No. 2011-00162, *In the Matter of: The Application of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery By Environmental Surcharge*; Case No. 2011-00375, *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and a Site Compatibility Certificate for the Construction of a Combined Cycle Combustion Turbine at the Cane Run Generating Station and the Purchase of Existing Simple Cycle Combustion Turbine Facilities From Bluegrass Generation Company, LLC in La Grange, Kentucky*; Case No. 2014-00002, *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of a Combined Cycle Combustion Turbine at the Green River Generating Station and a Solar Photovoltaic Facility at the E.W. Brown Generating Station*.

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

real-time dispatch optimization of the generating stations to meet the Companies' native load obligations, (iii) wholesale electricity market activities, and (iv) sales and energy market analysis, and generation planning. Also, the Project Engineering group reports to me through the Vice President, Project Engineering. Among other things, they are responsible for the development and construction of major generation-related capital projects such as coal combustion residual pond closures, water treatment facilities, and new generation assets.

Q. Did persons reporting to you prepare any of the analysis presented in the Companies' application in this proceeding?

A. Yes. As it pertains to this proceeding:

- the Sales Analysis and Forecasting group prepared the 2022 CPCN Load Forecast sponsored by Tim A. Jones (see Exhibit TAJ-1),
- the Power Supply group administered the June 2022 request for proposals ("RFP") for new supply-side resource options and is negotiating all power purchase agreements ("PPA") with third parties (see the testimony and exhibits of Charles R. Schram),
- the Generation Planning group evaluated the RFP responses and prepared the 2022 Resource Assessment sponsored by Stuart A. Wilson (see Exhibit SAW-1), and
- the Project Engineering group prepared all of the cost estimates and other development work for the self-build responses to the RFP.

All of this work was done under my direction and overall supervision.

Q. What are the purposes of your testimony?

A. The purposes of my testimony are to: (1) provide an overview of the supply-side resources in this filing and how they address the Companies' need to comply with the Good Neighbor Plan as well as fit into the Companies' future generation portfolio; (2) discuss the implications of the Companies' plan to retire three coal units and the need for reliable technology to serve customers' load throughout the year; (3) summarize the process the Companies used to obtain proposals for supply-side resources, discuss the responses received to the RFP, and the resulting PPAs that are being negotiated; (4) address the benefits of the Companies' utility-owned solar and battery proposals; (5) discuss several options the Companies did not pursue, including nuclear and pumped hydro; and (6) discuss the financial and reliability benefits to customers of the resulting recommended supply-side and demand-side resources and how they move the Companies in a significant direction toward a lower CO_2 emitting future.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibit to my direct testimony:

Exhibit DSS-1 Contrasting Key Attributes of a Solar PPA and Asset Ownership

Section 2 – The Need to Act Now to Reliably and Economically Address New Regulations and Aging Coal Plants

Q. Why are the Companies applying for certificates of public convenience and necessity ("CPCNs") for new generating resources and for approval of a proposed 2024-2030 Demand-Side Management and Energy Efficiency ("DSM-EE") Program Plan at this time?

A. First and foremost, as discussed in Philip A. Imber's testimony, the U.S. Environmental Protection Agency ("EPA") issued a draft regulation in April this year (the Good

Neighbor Plan) that will require the Companies to reduce their nitrogen oxides ("NOx") emissions at the 297 MW Mill Creek Unit 2 ("Mill Creek Unit 2") and the 485 MW Ghent Unit 2 ("Ghent Unit 2"). In order to continue to operate those units in compliance with the Good Neighbor Plan during the five-month ozone season (May through September), Selective Catalytic Reduction ("SCR") equipment would need to be installed on those units as early as May 2026 and certainly no later than May 2027 at significant cost: $110 million and $126 million, respectively.

Second, at the E.W. Brown Generating Station ("Brown"), coal-fired Unit 3 ("Brown Unit 3") is due for a major maintenance outage in 2027 if it is to operate safely and reliably beyond 2028. The major outage comes with a significant cost: $26 million.

The timing of either making these potential investments or determining the best means to continue providing reliable service in the absence of making these investments drives the need to act now.

Q. What would happen if the Companies did not act other than simply retiring these units?

A. The three units at issue have a combined capacity of 1,194 MW. This represents 27 percent of the Companies' remaining coal-fired generating units, and about 16% of the Companies total fuel-dispatchable generating fleet, after the retirement of the 300 MW Mill Creek Unit 1 in 2024. Collectively, as shown in Table 1 below, these units typically produce 15% or more of customers' annual energy requirements, and they produce just over half of their annual energy during non-daylight hours:

Table 1: Operational Data for Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3

Year	Total Energy (GWh)	Non-Daylight Energy	Daylight Energy	Max Hourly Output (MW)	Average Hourly Output (MW)	% of Total Energy Requirements
2017	5,698	52%	48%	1,235	772	17%
2018	6,230	51%	49%	1,238	842	18%
2019	5,407	51%	49%	1,250	785	16%
2020	4,512	52%	48%	1,229	729	15%
2021	4,610	51%	49%	1,219	752	15%

As the Companies' 2022 Resource Assessment shows, even assuming significant amounts of energy efficiency and distributed generation—including that incentivized by the Inflation Reduction Act ("IRA") and the full effect of the 2024-2030 DSM-EE Program Plan—having these three units retire or be unavailable May through September without having additional resources to replace their energy would almost certainly result in rolling blackouts.[3] Indeed, even with the addition of the proposed DSM-EE programs, in 2028 the system would have a loss of load expectation ("LOLE") in excess of 130 days in 10 years, far exceeding the industry standard of 1 day in 10 years.[4] Such unreliable service would be unacceptable to customers, the Commission, and the Companies.

Q. Even if it is necessary to act to address the future of these units to ensure reliable service, why is it necessary to act *now*?

A. I am aware from the minutes of the DSM-EE Advisory Group meetings and communications the Companies received from certain participants in that group that there are those who perceive that this application could wait.

[3] *See* Exhibit SAW-1, 2022 Resource Assessment Sec. 4.5.1.
[4] See Exhibit SAW-1, 2022 Resource Assessment Appendix. C.

As the officer responsible for ongoing reliable service, I can assure the Commission it could *not* wait.

As the responses to the June 2022 RFP show, the earliest start date for a new fully dispatchable generating unit is April 2026, just before the Good Neighbor Plan (in its current form) would require Mill Creek Unit 2 and Ghent Unit 2 to severely curtail or cease operating altogether during the summer months.[5]

Thus, due to the need to comply with the impending Good Neighbor Plan, this is the time to make real-world resource decisions to ensure reliable service for the Companies' nearly one million retail electric customers.

Q. The 2022 Resource Assessment has a study period that runs through 2050. Are the Companies proposing a portfolio of all resources the Companies propose to retain or add through 2050?

A. No. It is neither practicable nor prudent to attempt to decide now what the Companies' resources in <u>total</u> should be for almost 30 years. The resource decisions that the Companies are recommending in this case likely will not be the last resource decisions to be made for even the next ten years. Assuming the Commission grants the Companies' CPCN requests and the new solar PPA projects are constructed, the Companies will still have seven coal units totaling over 3,200 MW of generation capacity that will need to be retired over time, as well as a number of simple cycle gas turbine peaking units. Those retirement decisions will be informed by the future state of technology development and regulations. What should be decided now—and must

[5] *See* Exhibit SAW-1, 2022 Resource Assessment Appx. B.

be decided now—is the future of Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 and which resources will fill the energy gap resulting from their retirement.

Section 3 – Summary of the Companies' Proposed Resource Portfolio

Q. What steps did the Companies take to ensure their recommended resource portfolio to address this pressing need would result in reliable service at the lowest reasonable cost?

A. To make these resource decisions and take the necessary actions, I directed Mr. Schram and his team to issue the Companies' June 2022 RFP for generation capacity and energy, and I directed our Project Engineering group to prepare cost estimates for SCRs on Mill Creek Unit 2 and Ghent Unit 2. I also directed our Project Engineering group to evaluate alternative generation and storage technologies that could be installed at the Mill Creek and Brown sites to take advantage of existing infrastructure to reduce future costs and identify potential new sites for solar generation. All of this information has been evaluated from the perspective of:

- cost for customers (i.e., present value of future revenue requirements),
- reliability of the system (e.g., loss of load expectations), and
- ability to execute in a timely manner (i.e., comply with timing requirements of the Good Neighbor Plan and maintenance planning for Brown Unit 3).

At the same time these supply-side alternatives were being developed and evaluated, the Companies were evaluating current and new DSM-EE programs in light of the likely need for new capacity. As John Bevington discusses in his testimony, the Companies engaged with their DSM-EE Advisory Group and worked with a reputable third-party consultant, Cadmus, to conduct financial analysis to identify and propose new DSM-EE programs to help offset the need for future supply-side resources.

Q. How did the Companies ensure that their decision-making process will benefit customers?

A. I have been directly responsible for generation planning since 2007 and have been involved in the Companies' generation acquisition decisions since Trimble County Unit 2 in the mid-2000s. During that time, the Companies' decisions have always been informed by certain principles that benefit customers:

- Safely operating their facilities for employees, customers, and the public,
- Ensuring reliable generation supply 8,760 hours a year in all weather conditions,
- Working to comply with all laws and regulations,
- Investing in generation assets based on long-run economics for customers,
- Avoiding speculative technologies that would create unnecessary financial and reliability risks for our customers,
- Making decisions based on a thorough and thoughtful analysis of the alternatives and risks, and
- Having a clear, executable plan to implement (primarily through construction) new generation decisions on time and on budget.

The same principles that have demonstrably resulted in a reliable, cost-effective portfolio of supply-side and demand-side resources over the last several decades underlay the Companies' recommendations in this case. The application of these principles significantly reduces the risk that the Companies' recommended DSM-EE and generation portfolio will create "regrets" for our customers at some point in the future due to material changes in circumstances (e.g., regulations, technology, and load).

Q. What is the Companies' recommended resource portfolio to address Good Neighbor Plan compliance and Brown Unit 3's long-term economics?

A. Considering customers' projected needs in the 2022 Load Forecast, the results of the June 2022 RFP, and the Companies' proposed 2024-2030 DSM-EE Program Plan, the Companies' 2022 Resource Assessment analysis indicated that it was not in our customers' long-term financial interest to invest in SCRs on Mill Creek Unit 2 and Ghent Unit 2 and that the pending major maintenance investment in Brown Unit 3 was not warranted if the alternative portfolio proposed in this filing, particularly the construction of two natural gas-fired combined cycle units, is implemented. Therefore, assuming the resources requested in this filing are approved, the Companies will retire Mill Creek Unit 2 in 2027 and Ghent Unit 2 and Brown Unit 3 in 2028. To maintain reliable service when these units retire, the Companies are requesting certificates of public convenience and necessity ("CPCNs") for:

- two new 1-on-1 natural gas-fired combined cycle ("NGCC") generation units (621 MW summer-net each)
    - one to be built by the Companies and on-line by summer 2027 at the Mill Creek Generating Station ("Mill Creek") and named Mill Creek Unit 5 ("Mill Creek NGCC") and
    - one to be built by the Companies and on-line by summer 2028 at Brown and named Brown Unit 12 ("Brown NGCC");

- a 120 MWac solar photovoltaic facility to be built by the Companies and on-line in 2026 in Mercer County (“Mercer County Solar Facility”);
- the purchase of a 120 MWac solar photovoltaic facility to be developed and constructed by BrightNight, LLC, and on-line in 2027 in Marion County and named the Marion County Solar Facility; and
- a 125 MW, 500 MWh lithium-ion battery storage facility to be built by the Companies and on-line in 2026 at Brown and named the Brown Battery Electric Storage System (“Brown BESS”).

The Companies are also pursuing four solar Purchase Power Agreements (“PPAs”), which they presently expect to finalize and execute by the end of January 2023:

- a 138 MW 30-year PPA with ibV Energy Partners for a project to be built in Hopkins County (“Grays Branch PPA”);
- a 280 MW 30-year PPA with ibV Energy Partners for a project to be built in Hardin County (“Nacke Pike PPA”);
- a 104 MW 20-year PPA with Clearway Energy for a project to be built in Ballard County (“Song Sparrow PPA”); and
- a 115 MW 20-year PPA with BrightNight, LLC for a project to be built in Ballard County (“Gage Solar PPA”).

In addition to these supply-side generation resources, the Companies are seeking approval of their 2024-2030 DSM-EE Program Plan, which greatly expands the Companies’ DSM-EE offerings for all customers, as Mr. Bevington and Lana Isaacson describe in their testimony.

Q. Are the Companies forecasting changes in customers' future energy needs compared to the current year?

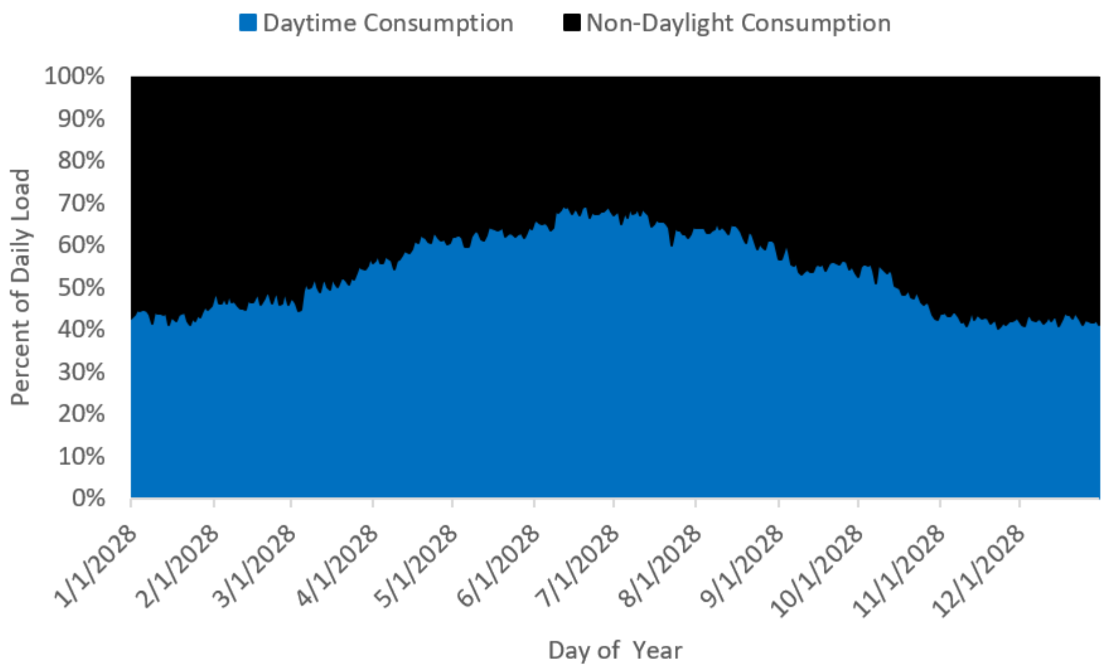
A. Yes. The 2022 Load Forecast shows there are three main contributors to higher future load: i) the construction of the BlueOval SK Battery Park in Hardin County to be on-line beginning 2026 and the potential for ancillary supporting load growth, ii) the forecast for growing energy requirements for charging electric vehicles ("EVs"), and iii) anticipated growth in winter heating load as more customers move to heat pumps. The 2022 Load Forecast further shows that some of this load growth will be offset by the new DSM-EE programs described by Mr. Bevington and Ms. Isaacson, accelerated customer-initiated energy efficiency driven by incentives in the IRA, and during daylight hours by growth in customer distributed energy resources ("DER") such as rooftop solar. In total, compared to weather normal 2021 actual peak and energy, by 2028 system summer peak is forecasted to be 179 MW higher and system winter peak 246 MW higher. Similarly, weather-normalized energy requirements are forecasted to be 1.8 million MWh higher by 2028.

Q. How does understanding customers' hourly energy needs inform the Companies' proposed resource portfolio?

A. Although it is important to understand customers' annual energy requirements as I discussed above, it is also vitally important to understand that customers need that energy when they need it—in every hour of the year—not just when particular generating resources might best produce it. Thus, the Companies must have a resource portfolio that can supply all the energy customers demand at all times and in all seasons, weather, and daylight conditions.

To illustrate this, consider Figure 1 below, which shows the forecasted proportion of energy customers will require in daylight versus non-daylight hours in 2028:

Figure 1: 2028 Proportion of Energy Consumed During Daylight and Non-Daylight Hours

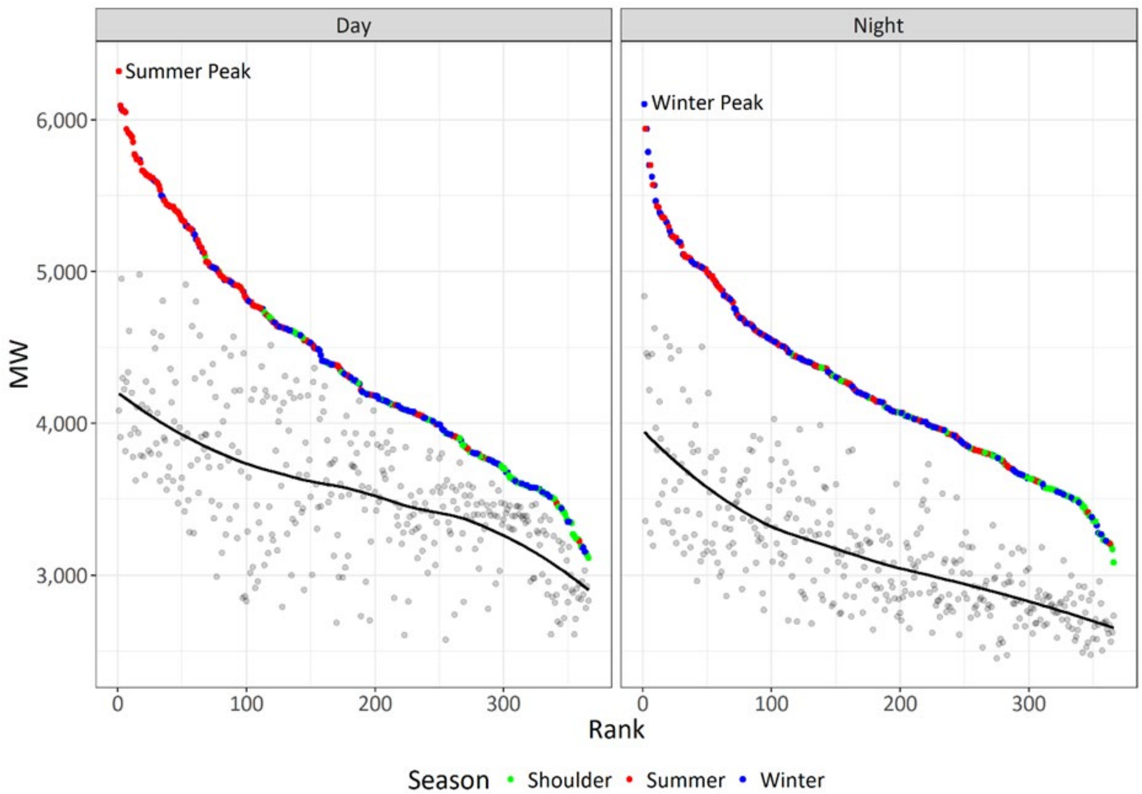


Note that, on an annual basis, approximately 50 percent of electricity demand is during daylight hours and 50 percent is during non-daylight hours. Due to both the length of daylight and temperatures, during summer months the daylight energy requirements grow to around 60 percent of the total and shrink to around 45 percent in winter months.[6]

Furthermore, from a daily load perspective, the similarity in absolute daily maximum and minimum load during daylight and non-daylight hours over the course of the year requires a generation portfolio that can ramp up and down both during daylight and non-daylight hours as shown in Figure 2 below:

[6] See Figure 8 in Exhibit TAJ-1.

Figure 2: 2028 Daily Maximum and Minimum Loads during Daylight and Non-Daylight Hours[7]



The Companies' 2028 hourly load profile and 2028 annual hourly load duration curve (Figures 10 and 11 in the 2022 Load Forecast, respectively) further demonstrate both the variability of load from hour to hour and the magnitude of demand in every hour. In particular, the load duration curve shows that total customers' hourly energy requirements are forecasted to be at least 3,000 MW over 7,700 hours a year and 2,450 MW every single hour of the year. Furthermore, Figure 12 in the 2022 Load Forecast, which shows the Companies' hourly load profiles during the 2014 polar vortex, demonstrates that customers' demand can—and actually has—changed by nearly 3,000 MW in less than 24 hours, with a peak demand of over 7,100 MW at 8:00 p.m.

[7] Data points in color represent daily maximum values; those in light grey represent daily minimums. The solid black line is a smoothed curve fit through the daily minimums.

Therefore, the Companies' resources must be able to provide significant quantities of energy at all times, day and night, and must be able to adjust quickly as customers' needs change.

Importantly, the Companies' proposed resource portfolio is capable of serving customers' significant and varying needs in all hours, and it is capable of rapidly moving within the hour (i.e., ramping) to both follow load and the sizable real-time intermittency that will result from the large expansion of solar resources proposed in this filing. The Companies know from experience that their current generating fleet is capable of meeting such ramping needs reliably day-in, day-out throughout the year across a broad range of weather events. Table 2 below shows the total minimum and maximum generation operating range of the Companies' non-peaking generation fleet in 2025—which is the same as today's proven and reliable non-peaking generation fleet—but without Mill Creek Unit 1, which compares favorably to the minimum and maximum generation operating range of the Companies' proposed non-peaking generation fleet in 2028:

Table 2 Generation Operating Range (MW)

	2025		2028	
	Minimum	Maximum	Minimum	Maximum
MC - NGCC	-	-	226	621
BR - NGCC	-	-	226	621
BR3	140	412	-	-
CR7	338	662	338	662
TC1	141	370	141	370
TC2 - Full load	549	549	549	549
MC2	115	297	-	-
MC3	170	391	170	391
MC4	175	477	175	477
GH1	218	475	218	475
GH2	225	485	-	-
GH3	210	481	210	481
GH4	215	478	215	478
OVEC	50	174	50	174
Total	2,546	5,251	2,518	5,299

This, as well as the reliability analysis in the 2022 Resource Assessment, shows that the Companies' proposed resource portfolio will be able to serve customers' projected needs in all hours, seasons, weather, and daylight conditions. The addition of incremental dispatchable DSM programs and solar in the resource portfolio will indeed provide resources that can be statistically predicted to be available under certain load and weather conditions that are correlated with load. But those resources are not controllable from the system dispatcher's perspective in the same way as fuel-dispatchable generation technologies to ensure reliable real-time operations. The Companies' proposed portfolio optimally blends both kinds of resources to ensure reliability and reasonable cost.

Q. What demonstrates that the Companies' proposed resource portfolio is preferable to other possible portfolios?

A. Mr. Wilson's testimony and the 2022 Resource Assessment he sponsors details the rigorous economic and reliability analyses the Companies conducted of the RFP responses and the dispatchable DSM programs from the Companies' 2024-2030 DSM-EE Program Plan to arrive at their proposed optimal resource portfolio. As he explains, the analysis involved using sophisticated modeling tools, including PLEXOS, PROSYM and SERVM, to evaluate thousands of possible portfolios and to develop and screen least-cost portfolios across six different fuel-price cases and three CO_2 price cases, while also accounting for reliability and other uncertainties, including solar PPA execution risk.[8] The Companies did not test only model-created portfolios, but also analyzed a number of portfolios formulated by the Companies to evaluate the economics and reliability of other portfolio configurations, including replacing the retiring coal units with only renewable resources, battery storage, and dispatchable DSM programs from the 2024-2030 DSM-EE Program Plan.

The Companies gained important insights from this exercise of comparing portfolios to see key differences and understand what was driving optimal economics:

- Retaining the coal units (Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3) was always costlier than retiring them and replacing them with the Mill Creek and Brown NGCC units, particularly as CO_2 prices rose.
- Retiring the three coal units and replacing them with portfolios of only dispatchable DSM from the 2024-2030 DSM-EE Program Plan, renewables, and batteries (or even adding SCCT to that resource mix) was much higher cost than a portfolio consisting of NGCC units and solar PPAs because such

[8] *See* Resource Assessment at Section 4.5.2.

portfolios require considerably more renewable resources (and batteries or SCCT) to meet minimum reserve margins, particularly in non-daylight hours.

- Perhaps counterintuitively at first glance, a renewables-only portfolio had higher CO_2 emissions than the portfolio with the Mill Creek NGCC, Brown NGCC, and solar PPAs because the Companies' remaining coal units serve non-daylight energy requirements in an all-renewables replacement portfolio, whereas NGCCs serve a significant amount of non-daylight energy requirements in the two-NGCC portfolio, and NGCCs have about 65% lower CO_2 emissions than coal.[9]

From the information produced by the Resource Assessment and the application of the resource decision principles that I described, it is clear why the Companies' proposed portfolio is optimal: it blends the reliability and non-daylight energy production benefits of NGCC technology with the fuel-price and CO_2 price benefits of solar, to which the Companies added the reliability enhancements of dispatchable DSM and the Brown BESS. The result is a reliability-, cost-, and risk-optimized resource portfolio that can be executed in time to address the Good Neighbor Plan and Brown Unit 3 maintenance schedule while also positioning the Companies to effectively address future generation unit retirements.

Section 4 – The Benefits and Challenges of Solar

Q. Why would the Companies not depend on new solar resources to ensure system reliability?

[9] *See* Resource Assessment Tables 14 and 15.

A. There are two main reasons: i) the current state of the solar PPA market, as discussed later in my testimony, makes it very uncertain that the solar PPA projects will get built in a timely manner, if at all, and ii) there is growing evidence around the country that moving away from fuel-dispatchable generation technologies too quickly is putting the grid at risk for blackouts due to lack of generation. The North American Electric Reliability Corporation ("NERC") has, on numerous occasions in the last year or so, expressed concerns about generation shortfall during high load conditions in California, Texas, part of MISO, and New England.[10] Also, FERC Commissioner Mark Christie stated in a recent Bloomberg interview that, "The red lights are flashing everywhere. We're not going to have sufficient power supply." According to that same article, "The sweeping push to replace fossil fuel plants with clean energy is forcing US power grids to the brink of a twin crisis, making electricity unaffordable while raising the specter of more frequent blackouts."[11]

As the utilities responsible for serving our customers' electricity needs every day, the Companies must ensure that adequate supply will be available at all times. Thus, the Companies' generation portfolio proposed in this filing maintains minimum summer and winter reserve margins with fuel-dispatchable generation technology (which includes batteries since they would be charged with fuel-dispatchable generation at this time) while at the same time significantly increases the volume of solar generation on the system to hedge future natural gas price volatility and reduce

[10] See, for example, 2022 Summer Reliability Assessment, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf, and 2023-23 Winter Reliability Assessment, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2022.pdf

[11] "High Costs, Low Reliability Imperil US Grid, Regulator Warns", Bloomberg, November 21, 2022.

exposure to future CO_2 regulations. It is important to note that this result, i.e., maintaining minimum summer and winter reserve margins with fuel-dispatchable technology is the output of the modeling described in the Resource Assessment and not an input into the modeling. In other words, given customers' hourly load demands and the technology and economic performance characteristics of the various RFP responses, the optimal portfolio selected has the reliability attribute of maintaining minimum summer and winter reserve margins with fully dispatchable technology.

But not depending on solar to maintain reliability does not mean it is unimportant. Indeed, if the Companies' existing two solar PPAs, the four proposed new PPAs, and the two owned solar projects in this filing become operational, in 2028 approximately 8 percent of the Companies' system energy requirements would be met by utility-scale solar, which compares very favorably to a national level of approximately 3 percent today. This would be a significant movement toward renewable generation by the Companies over the next five years.

Q. Why does the current state of the solar PPA market raise questions about whether or not the projects that will supply the Companies' solar PPAs will be built?

A. For the last decade, the cost of solar generation has been declining and interest rates have been stable at very low levels. Neither condition exists today. Prior to this year, developers could quote a fixed price per MWh for a PPA assuming low, stable interest rates and that key solar equipment prices would be cheaper (or technology would be better or both) by the time the project moved to construction which is probably at least two years from the time the PPA is signed.

These projects are typically highly leveraged (70 to 80 percent debt financed), making the Federal Reserve's recent increase in interest rates materially impactful on current PPA pricing. This increase in interest rates further calls into question the ability of the projects that will support the Companies' two existing solar PPAs to get financed should they receive all of their necessary permits as discussed by Mr. Schram because they are priced well below the four PPAs being addressed in this case.[12]

Second, the cost of key solar components has also been increasing as illustrated by the price of polysilicon, the primary foundational material in a solar panel. In mid-2020, spot polysilicon prices were around $7/kg, while recent prices are around $45/kg. Typically, solar panels use around 3,000 kg of polysilicon per MW, which would increase project costs by around $114/kW.[13] Additionally, solar developers are having to deal with general inflation that is significantly greater than in the last decade.

Q. Do these economic changes create new execution risks for solar PPAs?

A. Yes. This general rising cost environment brings into question the ability of the Companies to count on executed solar PPAs being developed. It is helpful to understand that the PPA structure is essentially a type of "put" option. A put option owner (the solar developer) is entitled to require the put option seller (the Companies) to purchase an item (solar energy) if the market price (the cost of building and financing the new solar project) at the time of option expiration is less than the strike price (PPA

[12] When the Companies received responses to their generation RFP in June 2019, the interest rate on 10-year Treasury bonds (a key benchmark rate for pricing debt associated with solar PPAs) was 2.07% and had declined to 1.86% by December 2019 when the Rhudes Creek solar PPA was executed with ibV Energy Partners. This interest rate had declined to 1.58 percent by October 2021 when the solar PPA was executed with BrightNight. As of November 2022, this interest rate had risen to 3.69%.

[13] "Polysilicon Prices Remain High, No Moderation Until 2023", EnergyTrend, September 2, 2022. [https://m.energytrend.com/news/20220902-29845.html#:~:text=While future polysilicon prices are,per kilogram polysilicon price drop.]

price per MWh). Although the Companies are entitled to limited financial damages if a developer breaches a PPA, failing to obtain financing is not a breach. Regardless, the Companies will not get energy to serve customers if the project is not built. Thus, as long as the total cost of actually building and financing a solar project is increasing, the likelihood that developers will execute their put option and deliver energy at the agreed PPA price is highly uncertain. Ironically, negotiating lower PPA pricing lowers the likelihood that the project will be "in the money" and result in actual energy to serve customers.

Q. What steps did the Companies take to address this "put option" risk?

A. As Mr. Schram discusses in his testimony, to help address this "put option" risk the Companies attempted to insert a future price re-opener clause into the four proposed PPAs and were successful in two of them. These two PPAs contain a 60-day price re-opener period that can be initiated by either party just prior to the project moving to the financing stage in order to set the PPA to the then current market. This mechanism will allow the Companies to request a lower price should solar costs and interest rates decline and the solar developer to request a higher price should solar costs or interest rates or both increase such that the project would not be financeable at the price agreed to at PPA execution. If the parties cannot agree on a new price by the end of the 60-day period, the original PPA price would stay in place and either party would have 30 days to terminate the PPA. The Companies believe that this mechanism will allow customers to benefit should future solar project costs decline from today's levels and increases the ability of the Companies to ensure that electricity will be supplied in the future should solar project costs continue to escalate. Of course, the Companies would need to be prepared to justify the prudency of their decision in future Commission proceedings just as they do with coal and natural gas contracts today.

Despite the Companies' best efforts, both of the other two PPAs continue with the past fixed price structure (and thus implied put option feature). Thus, it simply has not been possible to eliminate this aspect of solar PPA execution risk.

Q. Assuming all of the solar PPAs do come to fruition, how will the Companies' energy mix for meeting customers' energy needs change in the future with these proposed new generation resources?

A. Table 3 compares the Companies' annual energy mix by fuel type in 2021 with the proposed portfolio in 2030. It shows that by 2030 the expected share of energy from coal declines from 81 percent 49 percent while the expected percentage of energy coming from natural gas grows from 18 percent to 42 percent. Also, assuming the existing 225 MW of executed solar PPAs come on-line combined with the additional 877 MW of new solar, the amount of energy coming from renewables grows from 1 percent to 9 percent by 2030.

Table 3: Energy Mix[14]

	2021	**2030**
Coal	81%	49%
Natural Gas	18%	42%
Renewable	1%	9%

Q. What will be the implications for the Companies' future CO_2 emissions of the proposed new generation portfolio?

[14] Note that 2030 data is based on the mid gas, mid-coal price forecast scenario.

A. Because the proposed Mill Creek NGCC and Brown NGCC will emit approximately 65 percent less CO_2 per MWh than a coal unit, CO_2 emissions by 2030 will be significantly less than in 2021. In addition to offsetting the emissions from the retiring coal units, Mill Creek NGCC and Brown NGCC will be able to displace energy from the remaining coal units under certain fuel price scenarios. From a CO_2 emission perspective, the ability to replace energy production from not only the retired units but also from the remaining units makes both proposed NGCC units extremely valuable. Also, the addition of all of the solar generation by 2030 would replace both coal and natural gas energy, further reducing CO_2 emissions. In total by 2030, with the build-out of the full solar portfolio, CO_2 emissions would decrease by approximately 6 million metric tons annually or 23 percent compared to 2021.

Section 5 – The Importance of Solar Owned by the Companies

Q. How would customers benefit if the Companies owned solar (such as the Mercer County Solar Facility and the Marion County Solar Facility) rather than relying solely on PPAs for solar energy?

A. As I have previously discussed, the "put option" nature of a PPA makes the actual future receipt of energy very uncertain in today's market. The Companies' self-build solar project is not subject to the same financial structure as an independently developed project. In the Companies' case, if the Commission determines the cost of the Companies' self-build solar project to be reasonable and actual construction costs are prudently incurred, the Companies can reasonably expect to recover such costs. The Companies' build-transfer arrangement for the Marion County Solar Facility has many of the same cost-based attributes as the self-build project, thus, both of these solar projects are much more likely to be actually built than any of the solar PPA projects.

A second key feature that distinguishes a solar PPA from an owned solar project is that with a PPA the Companies will have contractual rights related to the generating asset, whereas with ownership the Companies will have total control of the generation asset. Exhibit DSS-1 illustrates the similarities and differences between PPA contractual rights and ownership control across a number of attributes such as project development, permitting, economics, operations, and maintenance. Although the Companies have done their best both in past solar PPAs and with the four solar PPAs in this case to include language that protects our interests and those of our customers, it is important to recognize that all long-term contracts can have issues in the future that may lead to disagreements. Unlike contract disputes involving the Companies' long-term fuel contracts where the Companies can seek delivery of coal and natural gas from others should the dispute result in a cessation of performance by the counterparty, a non-performing solar PPA counterparty would result in the Companies not receiving any energy from that PPA resource.

Section 6 – The Value of the Brown BESS

Q. What are the benefits of the Brown BESS?

A. If the nation and Companies are going to transition to a lower CO_2 emitting future with large quantities of wind and solar generation, then it will be necessary and essential to utilize battery storage to move electricity from when it can be produced to when customers actually need it. Based on our research, moving beyond approximately 20 percent annual energy from intermittent generation will require battery storage or the curtailment of renewable energy to avoid overproducing such energy when customers are not consuming it. If all of the solar generation previously contracted and contemplated in this filing becomes operational, on an annual basis the Companies would get approximately 8 percent of their energy from solar. This means that adding renewables in the context of the next retirement of coal units will likely push up against that 20 percent threshold. Thus, it is essential that the Companies have day-to-day operational experience at scale with the technology before they transition to relying on batteries for system reliability. Also, a battery of this size could be a useful resource in managing the Companies' operating reserve requirements due to a battery's ability to instantly respond when called upon (assuming it is charged) and avoid fast starting a simple cycle combustion turbine. Furthermore, the 125 MW size of the Brown BESS approximates the unit size of the Companies existing 11N2 gas turbine fleet that is also located at Brown. Thus, a successful operational experience with the Brown BESS asset would potentially enable the retirement of one of these machines in the coming years without replacement.

Q. Why are the Companies seeking approval for the Brown BESS rather than developing a storage contract with one of the RFP respondents who offered battery storage services?

A. There are several reasons, many identical to those associated with the financial development and contractual risks of solar PPAs.

Additionally, the proposed Brown BESS is much like the Brown solar facility in that it will allow the Companies to learn at scale about the issues associated with operating a battery asset. The Companies' experience with the Brown solar project was extremely instructive in identifying issues that were later addressed in their solar PPAs such as the energy availability guarantee. The Companies' ability to have real-world operational experience at scale will greatly facilitate their development of future energy storage contracts with third parties. Though the Companies have had a 1 MW, 2 MWh Li-ion battery research project at Brown for a number of years, this asset is not controlled by the generation dispatch group and is too small to have a meaningful impact on real-time unit commitment and energy planning. We have learned from the existing battery about issues to monitor, such as state of charge, container temperatures, and the importance of safety protocols in case of fire (something that the entire industry has been focused on given the number of events both domestically and internationally), but the research battery's small size has not provided the Companies an opportunity to gain important operational experience.

Finally, a battery project is fundamentally a reliability project because it does not generate electricity on its own, it only moves electricity in time. The sole reason for that time shift is to serve load reliably because the system in a highly intermittent generation future is not likely to have the ability to generate energy in real-time to meet customers' needs. It would be unwise for the Companies to outsource this important reliability function at this time when storage remains in its infancy.

Section 7 – RTO Membership as a Resource Solution

Q. Did the Companies consider joining an RTO as an alternative to building and/or acquiring new generation assets?

A. Yes, but as the Companies' recently filed RTO study demonstrates, even if the Companies were to join PJM, two new NGCC units would be the preferred generation technology to replace retiring coal units and additional solar generation would be useful to hedging PJM energy prices. As the RTO study discusses in-depth, the decision to join an RTO is about much more than just future capacity and energy costs. RTOs are in the early stages of addressing energy transition issues related to the retirement of coal units and the addition of large quantities of intermittent generation and energy storage. Thus, before the Companies turn over the responsibility of serving the real-time electricity needs of our customers to an RTO, it is important to let the RTOs further evolve their market design and associated rules and tariffs so that the Companies have a better understanding of what they would be joining. Having a reliable energy supply at a reasonable cost is too important to our customers to join an RTO at this time and hope it works out in the future.

<u>Section 8 – Nuclear Generation</u>

Q. Did the Companies receive any RFP responses for new nuclear generation?

A. No. Though there is a lot of industry interest in the potential for new nuclear generation, particularly associated with small modular reactors ("SMR"), the technology risk remains large and the Nuclear Regulatory Commission's ("NRC") permitting process is long and expensive. For example, in February 2022, TVA announced that it was authorizing spending $200 million on a plant design, an NRC license application, and a robust project plan for an SMR at its Clinch River site.[15] TVA emphasized that they have not committed to build the project but are taking a "disciplined, phased approach."

To better understand the human and financial resources required for the Companies to seriously consider nuclear as a future resource option, I engaged with colleagues from our technology research department in discussions with utilities that already have nuclear assets and with EPRI. That work indicated that we would likely

[15] "TVA Unveils Major New Nuclear Program, First SMR at Clinch River Site," Power, https://www.powermag.com/tva-unveils-major-new-nuclear-program-first-smr-at-clinch-river-site/

need to hire a staff of five to ten individuals with nuclear permitting and engineering experience and allow them to spend around two years identifying potential sites that would meet NRC permitting requirements, particularly safety, and that would have local acceptance. If such a site or sites could be identified, it would take about two to three years and approximately $50 to $100 million to develop an application to the NRC for what's called an Early Site Permit ("ESP"). Obtaining such a permit would take approximately three years and would mean that the site was suitable for the construction and operation of a nuclear unit. This is the permit that TVA has for the Clinch River site. An ESP would be good for 20 years, but it would not grant the actual construction of a nuclear unit. Seeking a construction and operating permit requires the selection of a specific technology from a specific vendor. This is the step that TVA is currently contemplating. This permitting process would likely take an additional 3+ years before construction could begin. Thus, from the Companies' future generation planning perspective, based on where SRM technology is today, nuclear generation is likely not a resource option until the early 2040s assuming experienced nuclear utilities like TVA are successful in their efforts to develop a project on-time and on-budget.

Section 9 – Pumped Hydro

Q. Why did the Companies opt not to pursue the pumped hydro proposal they received in response to their RFP?

A. First, it is important to recognize that all storage facilities, whether they are chemical such as a lithium-ion battery or hydrological such as pumped storage, are not a source of "new" electricity. An electricity storage facility, which I will generally refer to as a "battery," just moves the electron around in time at a cost of the facility and electricity losses – meaning one gets less electricity out of the battery than it took to charge the battery. In the case of the pumped storage proposal, as Mr. Schram discusses in more detail, the proposal was viewed as not far enough along in its development to be a viable resource to address the timing of the Companies' current energy and capacity needs. Second, as shown in the resource assessment prepared by Mr. Wilson, even if the project was assumed to be viable, the economics as proposed were not competitive with other peaking resources, including lithium-ion batteries. It is important to understand that pumped hydro typically requires approximately 1.25 MWh of energy to pump the water into the reservoir for every one MWh that it produces.[16] Furthermore, because the same piece of equipment is acting as both the motor to drive the pumping and the generator when the water is being released from the upper reservoir, the only way to make up for the energy losses is through time. This means that it will take approximately 1.25 hours of pumping at full load for every one hour of energy generation at full load.

Q. Do the Companies believe that pumped storage could be a useful resource in the future?

A. Yes, but it will depend on its cost and the need for energy storage. The economics of the energy in a storage project depends on the cost of the energy used to pump the water adjusted for energy losses. Typically, because the cost of energy is lower during off-peak periods during the non-daylight hours, the facility is pumped at night and then generated during the peak hours the following day, thus trying to avoid the cost of running natural gas units. As with any storage technology, its value is in the ability to

[16] This is consistent with the pumped hydro proposal to the Companies" RFP.

shift energy in time and so its deployment will depend on the cost of the energy shift and the need for it.

Section 10 – A No-Regrets Portfolio

Q. For purposes of analyzing the Companies' proposals against the possibility that future developments could cause the proposals to be less than optimal, how would you characterize the Companies' future generation portfolio?

A. The Companies' fleet would be markedly different from today. For example:

- In 2030, approximately 49 percent of energy would come from coal compared to 81 percent in 2021,
- Renewable generation, mainly solar, would grow from 1 percent in 2021 to approximately 9 percent by 2030. This value compares favorably to 6 percent utility-scale solar generation in Arizona in 2021 despite their superior solar irradiance compared to Kentucky,[17]
- The choice of two new NGCC units is consistent with technology choices being made by others as illustrated by the approximately 12.3 GW of new NGCCs that are expected to come on-line in the Eastern Interconnect by 2026,[18]
- The construction and operation of a 125 MW Li-ion battery project would be one of the larger projects in the eastern U.S.,[19]
- CO_2 emissions would decrease from around 26 million MT in 2021 to 20 million MT in 2030, and

[17] "Solar Explained", EIA, April 6, 2022, https://www.eia.gov/state/analysis.php?sid=AZ#51
[18] "Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860)", EIA, November 23, 2022, https://www.eia.gov/electricity/data/eia860m/xls/october_generator2022.xlsx
[19] Ibid

- the ramping capability of the new NGCC units supports the increase in volume of intermittent renewables on the system.

In short, by 2028 the generation fleet will have taken major strides in the energy transition and the new resources proposed will lay a strong operational foundation for future coal unit retirements.

Q. Are there any future developments that would cause the Companies to regret their supply-side and DSM-EE recommendations in this case?

A. No. Based on past experience, there are two broad categories of future developments that might impact resource planning decisions: future CO_2 regulations and a major technological innovation. The value of the Companies' proposed DSM-EE programs would only be enhanced under a set of economy-wide CO_2 regulations and they are generally focused on energy uses that are not likely to be revolutionized by new technology during the proposed life of the programs. Thus, I see no potential for material "regrets" for our proposed DSM-EE programs. Similarly, based on everything we know today, there is no reason to believe that the proposed addition of solar PPAs and owned solar will be made obsolete with new generation technology. And it is always the case that the value of renewables is enhanced in a CO_2-constrained world. Likewise, the value of the proposed Brown BESS would be enhanced by broader CO_2 regulations. Though it is true that battery technology continues to evolve, there is no reason to believe that the advances would cause the operating life of the Brown BESS to be artificially shortened.

Finally, the possible impact of future CO_2 regulations and new generation technologies on the Companies' proposed two NGCC units needs to be considered in the context of the rest of the generation fleet. As I have stated, the Companies will still have 3,200 MW of remaining coal capacity that would need to be addressed in a future CO_2 constrained world or that could be replaced by material advances in generation technology (e.g., SMR deployment that I previously discussed). In other words, if material events occurred in one or both of these areas, the Companies' future generation actions would not initially focus on their newest, cleanest, and most economic units but rather their oldest, dirtiest, and least economic units. Thus, given the relatively small size that these two NGCC units would be in terms of overall system capacity (around 20 percent of system peak) and system energy (around 25 percent of annual energy and only 40% of hourly minimum load), it is hard to see how any plausible broad-based CO_2 regulations or new generation technology that would be commercially deployable at scale would cause material regrets any time in the foreseeable future or would justify forgoing the benefits the proposed resource portfolio will provide for decades to come.

<u>Section 10 – Conclusion and Recommendation</u>

Q. In conclusion, how would you summarize the Companies' process in arriving at their recommended resource portfolio?

A. In an effort to ensure the Companies fulfill their primary responsibility to provide reliable electricity at the lowest reasonable cost, they have engaged in a thorough process to:

- understand and forecast customers' future electricity needs;
- reach out to third-parties for new supply-side and storage options;

- develop self-build generation alternatives that repurpose existing generation facilities and take advantage of existing transmission at those sites to reduce costs for customers compared to developing greenfield sites;
- evaluate and develop a suite of new DSM-EE programs;
- evaluate and stress test a large number of possible generation combinations across a broad range of possible future fuel and CO_2 prices to determine the most robust generation fleet to meet our customers' future electricity needs;
- develop four PPAs for new solar generation in addition to two ownership projects that will benefit customers economically and moves the generation fleet in a material way toward renewable energy; and
- position the Companies for future actions as it continues to retire its remaining 3,200 MW of coal generation.

This has been a comprehensive and thoughtful process that, assuming the requested CPCNs are approved and the assets associated with the PPAs are constructed, will mark a major milestone in the transition Companies' generation fleet away from coal and toward lower CO_2 emitting resources. Most importantly, the realization of this new generation fleet, combined with the new DSM-EE programs, will enable the Companies to continue to provide reliable service at the lowest reasonable cost for decades into the future.

Q. What is your recommendation for the Commission?

A. I recommend the Commission approve the Companies' requested CPCNs as providing valuable, vital resources to ensure the Companies can continue to provide reliable service at the lowest reasonable cost while also positioning the Companies for a lower-carbon future.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **David S. Sinclair**, being duly sworn, deposes and says that he is Vice President, Energy Supply and Analysis for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge, and belief.

David S. Sinclair
David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of December 2022.

Notary Public

Notary Public ID No. KYNP53381

My Commission Expires:

July 11, 2026

APPENDIX A

David S. Sinclair

Vice President, Energy Supply and Analysis
Kentucky Utilities Company
Louisville Gas and Electric Company
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Education
Arizona State University, M.B.A. -1991
Arizona State University, M.S. in Economics – 1984
University of Missouri, Kansas City, B.A. in Economics - 1982

Professional Experience
LG&E and KU Energy, LLC
2008-present – Vice President, Energy Supply and Analysis
2000-2008 – Director, Energy Planning, Analysis and Forecasting

LG&E Energy Marketing, Louisville, Kentucky
1997-1999 – Director, Product Management
1997-1997 (4th Quarter) – Product Development Manager
1996-1996 – Risk Manager

LG&E Power Development, Fairfax Virginia
1994-1995 – Business Developer

Salt River Project, Tempe, Arizona
1992-1994 – Analyst, Corporate Planning Department

Arizona Public Service, Phoenix, Arizona
1989-1992 – Analyst, Financial Planning Department
1986-1989 – Analyst, Forecasts Department

State of Arizona, Phoenix, Arizona
1983-1986 – Economist, Arizona Department of Economic Security

Affiliations
Consensus Forecasting Group (2013-present) - nonpartisan group of economists that sets Kentucky's official revenue budget on behalf of the governor and legislature

Civic Activities
Serve on the Board of Junior Achievement of Kentuckiana
Graduate of Leadership Louisville (2008) and Bingham Fellows (2011)

Contrasts Between a Solar Purchase Power Agreement ("PPA") and Solar Ownership

Key distinction: LKE has <u>contractual rights</u> with PPA and has <u>total control</u> with ownership

Attribute	PPA	Ownership	Implications
Project Development	Under control of PPA Seller. Current PPA market does not support material damages for Seller's failure to complete project in a timely manner or at all.	Under control of LKE.	• PPA Seller effectively has a "put option" to complete a project in a timely manner, if at all. PPA will specify the extent of damages, if any, that LKE may seek. However, success would likely require litigation and would only result in money as it is unlikely that the project would be built. • Money damages is not a substitute for the obligation to provide electric service to customers.
Project Permitting	Subject to local planning and zoning approvals with no condemnation rights.	Not subject to local planning and zoning approvals and have condemnation rights.	• LKE has a greater ability to actually get a project built and limit the delays some independent developers have experienced.
Price and Cost	Customers will pay a fixed PPA price for the term of the PPA.	Customers will pay the actual revenue requirements of the asset for the life of the asset.	• Long-term fixed price agreements have a tendency to produce a winner and loser. This will create incentives for a party to seek a new agreement that reflects the current economic environment or to terminate the agreement. • Asset ownership means that customers pay the actual project cost. LKE will have great deal of influence on how future project costs are managed. KPSC will review those costs to ensure their prudency.

Changes in market conditions prior to commercial operations	PPA Seller may seek to renegotiate price or slow walk development hoping that market conditions improve.	LKE will develop the project on time and will seek to recover prudently incurred costs.	• The current PPA market developed at a time of falling prices and low interest rates so the current environment of rising costs and interest rates is likely impeding progress on developments that support past PPAs. For example, current RFP solar PPAs are being offered at around a $10/MWh premium to the PPA's executed by LKE in 2019 and 2021.
Customer economics	Energy price is collected through FAC based on actual energy delivered. PPA energy price offsets other fuel costs. Net impact on FAC will depend on fuel costs v. PPA price.	Asset capital and O&M costs are collected through base rates and do not depend on plant output. Plant output (which has no fuel costs) will offset other fuel costs so FAC will be lower.	• The annual PPA price is not directly comparable to the annual ownership revenue requirements. The PPA price is akin to a lease where the lease rate depends in part on the residual value of the asset at the end of the lease. The decision on whether to lease or buy will depend on the potential lessee's view of their options when the lease expires. At this time, it is hard for LKE to predict asset and PPA prices beyond the term of the existing PPA.
Renewable Energy Certificates ("RECs")	Registered and created by the PPA Seller and then transferred to LKE. Absent a state RPS, LKE will sell the REC and return proceeds to customers through FAC.	Registered and created by LKE. Absent a state RPS, LKE will sell the REC and return proceeds to customers through FAC.	• Enforcement of REC creation and transfer through PPA contract v. direct control by LKE. • Assuming PPA performance, no economic difference to customer.
Plant O&M	PPA Seller will maintain the plant to optimize return on the PPA.	LKE will maintain the asset to produce energy to reliably serve customers at the lowest reasonable cost.	• LKE has contractual rights in the PPA to require the Seller to maintain the plant to produce energy consistent with solar conditions. Failure to maintain the asset will result in monetary damages at some point. • LKE has total control to repair and maintain equipment to maintain performance and deliver energy to serve customers. Failure to do so could be addressed by KPSC in FAC reviews and rate cases.

Asset Life	LKE receives the energy from the asset for the term of the PPA.	LKE receives the energy for the life of the asset and can make future investment decisions based on customer benefits.	• LKE will need to replace the PPA energy at the end of the PPA which creates cost uncertainty for customers in years 21 to 30. • Assuming traditional ratemaking, the annual capital revenue requirements of asset ownership will be at their lowest point in years 21 to 30, which increases the likelihood that replacement generation for the expiring in that time period will be higher than ownership. • A PPA will have a defined end date that forces LKE to address regardless of other market conditions whereas asset ownership provides flexibility to utilize the asset, including the site, to optimally serve customers, including upgrading technology if that makes economic sense. • The PPA Seller will only invest in the asset if the PPA economics justify the investment or contractually require it. • Any contract disputes regarding asset would likely only result in monetary damages, not physical energy to serve customers.