COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) A Securitization Financing Order; And (5) All Other Required Approvals And Relief	)))))))	Case No. 2023-00159

DIRECT TESTIMONY OF

ALEX E. VAUGHAN

ON BEHALF OF KENTUCKY POWER COMPANY

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TABLE OF CONTENTS

SECTION **PAGE**

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Alex E. Vaughan. I am employed by AEPSC as Managing Director-Renewables & Fuel Strategy. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. AEPSC is a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"), the parent Company of Kentucky Power Company (the "Company" or "Kentucky Power").

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCES.

A. I graduated from Bowling Green State University with a Bachelor of Science degree in Finance in 2005. Prior to joining AEPSC, I worked for a retail bank and a holding company where I held various underwriting, finance, and accounting positions. In 2007, I joined AEPSC as a Settlement Analyst in the RTO Settlements Group. I later became the PJM Settlements Lead Analyst, and in that role, I was responsible for reconciling AEP's settlement of its activities in the PJM Interconnection, LLC ("PJM") market with the monthly PJM invoices and for resolving issues with PJM. In 2010, I transferred to Regulatory Services as a Regulatory Analyst and was later promoted to the position of Regulatory Consultant. My responsibilities included supporting regulatory filings across AEP's eleven state jurisdictions and at the FERC. I also performed financial analyses related to AEP's generation resources and loads, power pools, and PJM. In September 2012, I was promoted to Manager, Regulatory Pricing and Analysis, where I was responsible for cost of service, rate design, and special contract analysis for the AEP east operating companies. In September 2018, I was promoted to Director of Regulated Renewables and Pricing, at which time oversight of regulated renewable and fuel filings across the AEP operating companies was added to my responsibilities. I was promoted to my current position in June 2022.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES.

A. I am responsible for assisting Kentucky Power and the other AEP electric utility operating companies in the preparation of their regulatory filings before this and other commissions under whose jurisdiction these companies provide electric service. My responsibilities include the oversight of cost of service analyses, rate design, special contracts, energy supply costs, and renewables for the AEP System operating companies.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have presented testimony on behalf of the AEP operating companies numerous times before the regulatory bodies in Virginia, West Virginia, Kentucky, Tennessee, Indiana, Michigan, and Oklahoma. In Kentucky, I have testified before the Kentucky Public Service Commission (the "Commission") in several cases, most notably in Kentucky Power's past four base rate case proceedings (Case Nos. 2013-00197, 2014-

00396, 2017-00179, and 2020-00174), and the proposed transfer of ownership of Kentucky Power in Case No. 2021-00481.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is threefold:

- To support the prudence of the approximately $11.5 million winter storm Elliott Peaking Unit Equivalent ("PUE") purchased power expense and $3.2 million of other PUE expense Kentucky Power incurred during the test year;
- To describe and outline the Company's proposed financial power hedging framework for which it is seeking approval; and
- To describe and support the Company's proposed distributed solar program.

IV. PUE EXPENSE

Q. PLEASE DESCRIBE THE SITUATION THAT CAUSED THE APPROXIMATELY $11.5 MILLION WINTER STORM ELLIOTT PUE EXPENSE.

A. Winter Storm Elliott ("Elliott") was an extreme cold weather event that included blizzards, high winds, snowfall and record cold temperatures across much of the United States. Elliott occurred December 23, 2022 through December 26, 2022, in the PJM region (the "Winter Storm Elliott Period").[1] The resulting load during this period of time was an extreme outlier in both magnitude and timing, with the Christmas Eve load

[1] PJM defined the Winter Storm Elliott Period as December 23, 2022 through December 26, 2022, and this is the time period used for purposes of this testimony. The Company also has referred to the Winter Storm Elliott Period when describing its generation performance as December 23, 2022 through December 27, 2022 (see Direct Testimony of Timothy C. Kerns).

being 40 gigawatts ("GW") higher than the second highest in the past decade.[2] The drastic temperature drop and higher than forecasted load caused PJM to dispatch generation reserves, many of which failed to perform.

The unanticipated high load and rapid load increase combined with generation outages due to cold weather and fuel issues resulted in Performance Assessment Intervals ("PAIs") on December 23, 2022 and December 24, 2022. PAIs are triggered when PJM declares an emergency action in the RTO. During the PAIs, the load weighted LMP reached the system marginal price cap of $3,700/MWh as a result of the supply/demand imbalance during emergency operations. Generation resource outages during Elliott peaked at 48,080 MW on December 24, 2022. Roughly 11,000 MW of those outages were due to a lack of natural gas supply.[3]

Q. DID THE COMPANY EXPERIENCE EXTREME LOAD CONDITIONS DURING ELLIOTT?

A. Yes. The Company's peak load during the Winter Storm Elliott Period was 1,358 MW, 46% higher than the Company's previous 12 month average peak demand ("12CP") of 929 MW. In 85 of the 96 hours during the event, the Company's hourly average load was higher than its most recent 12CP demand.

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[2] https://www.pjm.com/-/media/committees-groups/committees/mic/2023/20230111/item-0x---winter-storm-elliott-overview.ashx

[3] PJM State of the Market Report 2022 – pages 210-211.

Figure AEV-1

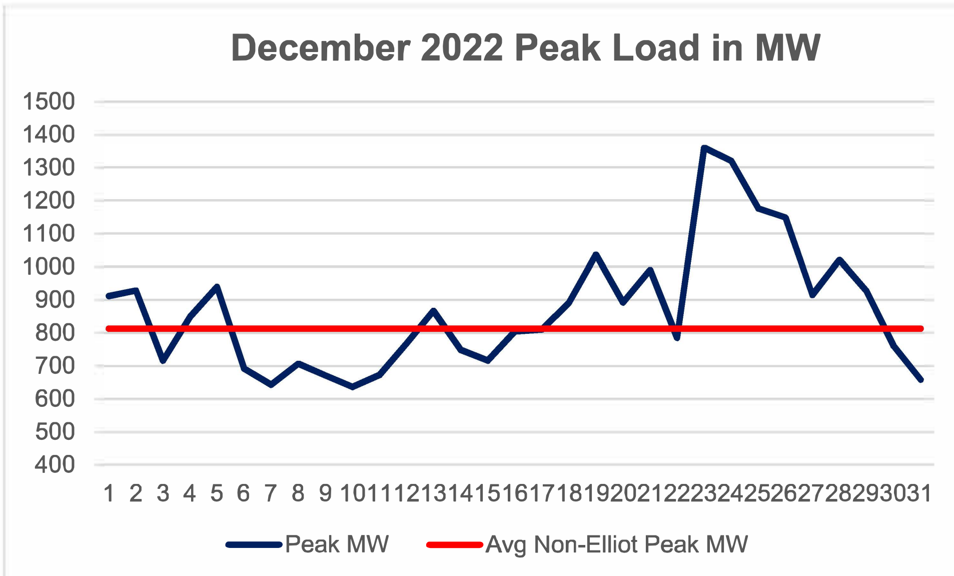


Figure AEV-1 illustrates the Company's daily peak demand during the month of December 2022. As can be seen, there is an extreme increase in demand during Elliott, including the 1,358 MW peak during hour ending 2100 on December 23, 2022. The flat line in Figure AEV-1 is the average peak demand during the non-Elliott days in December (813 MW). The Company's peak demand during Elliott was 545 MW higher than the average peak demand for the other 27 days of December 2022. Before this, one has to go back to January 2018 to find a Company peak higher than what was experienced during Elliott, and the Company has only had eight monthly peaks in the last decade greater than the Elliott peak. This illustrates the magnitude of the demand on the Company's system resulting from Elliott's extreme cold weather. This high load when combined with PJM-wide emergency operations resulted in extremely high system energy pricing at which the Company had to purchase its load obligation, in excess of its available supply, from the PJM spot energy market. Figure AEV-2 below shows the real-time LMPs over the Winter Storm Elliott Period, and Figure AEV-3 shows real-time LMPs over the month of December 2022 to put into context how much of an outlier pricing during Elliott was and provide a narrower view on the hourly pricing during Elliott.

Figure AEV-2

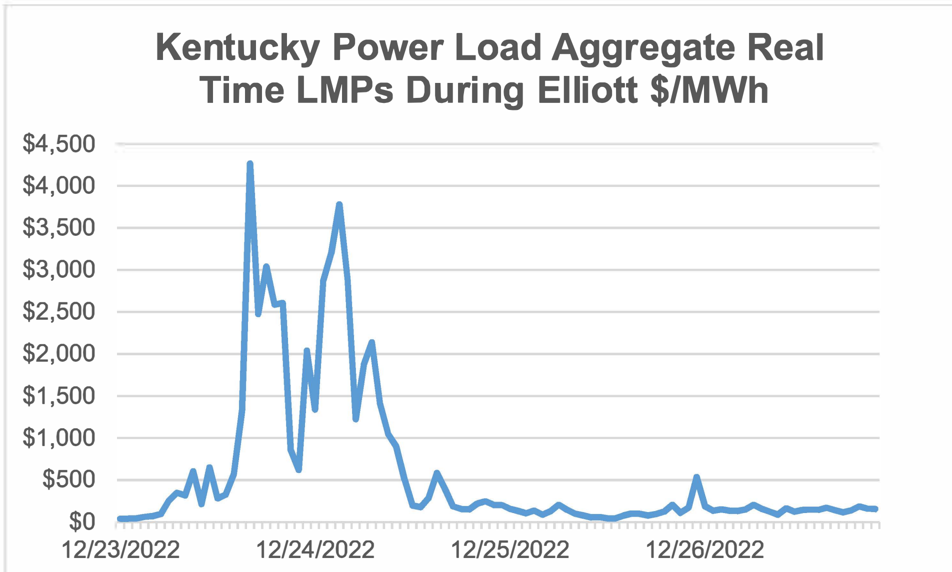
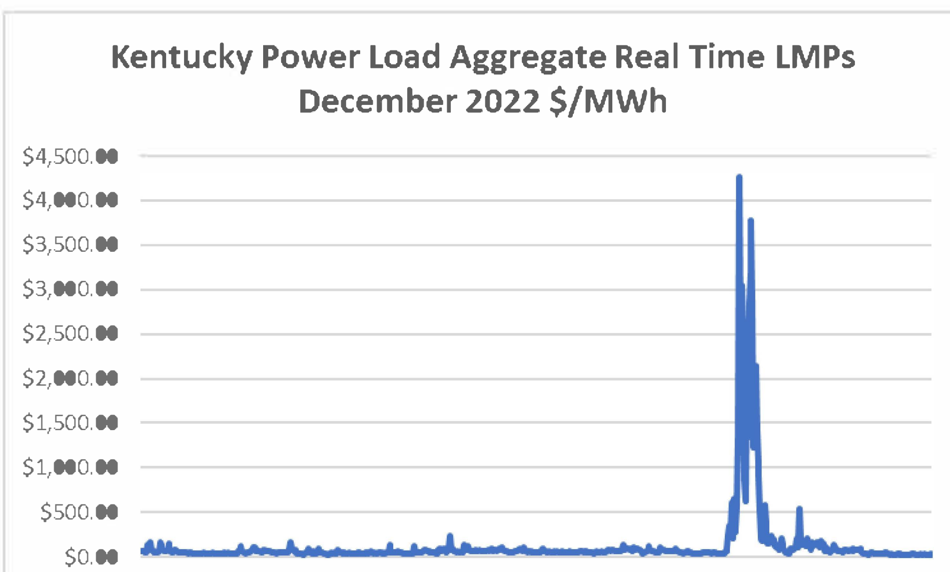


Figure AEV-3



Q. HOW DID THE COMPANY'S GENERATION RESOURCES PERFORM DURING THE WINTER STORM ELLIOTT EVENT?

A. During Elliott, none of the Company's generating units were forced out of service. Both Mitchell Units operated continuously throughout Elliott. Mitchell Units 1&2 operated at 80.31% and 74.11% net capacity factors,[4] respectively. The Mitchell Units performed at a level above the total PJM coal fleet which achieved a net capacity factor of 73.03%[5] during the same period of time. Big Sandy Unit 1 was in the midst of a PJM-approved planned outage during Winter Storm Elliott. Company Witness Kerns provides a more detailed description of the performance of the Company's generation resources during the Winter Storm Elliott Period.

Q. HAD THE COMPANY'S GENERATION RESOURCES RUN AT A 100% CAPACITY FACTOR DURING THE WINTER STORM ELLIOTT PERIOD, WOULD THERE STILL HAVE BEEN A NEED TO PURCHASE ENERGY FROM THE PJM SPOT ENERGY MARKET?

A. Yes. The Company's generation resources at 100% of their installed capacities ("ICAP") can produce approximately 1,076 MWh. As discussed earlier, the Company's load was extremely high during Elliott because of the extreme cold. In many instances, the Company's customers rely on electricity for heating their homes, which caused extremely high load conditions during Elliott. Thus, even had the Company's generators run at 100% of their ICAPs, the Company would have still

[4] December 23-27 period to be consistent with Company Witness Kerns's testimony.
[5] Source: PJM Dataminer2 and PJM State of the Market Report for 2022.

purchased roughly 8,400 MWh from the PJM spot market during the Winter Storm Elliott Period.

Q. DID THE COMPANY INCUR A CAPACITY PERFORMANCE PENALTY DURING THE ELLIOTT PAIs?

A. No, due to the Company's prudent management of its available coal supplies during 2022, the Mitchell Plant was available to run and, as previously discussed, operated continuously during Elliott and the PAIs called by PJM. Furthermore, the larger AEP Companies FRR plan, in which Kentucky Power participates, also did not incur a penalty as it benefited from the diversity of generation resource types and locations utilized by the Companies in the plan.

Q. WHAT OTHER OPTIONS WERE AVAILABLE TO THE COMPANY DURING THE WINTER STORM ELLIOTT EVENT TO SERVE THE HOURLY ENERGY NEEDS OF ITS CUSTOMERS?

A. The Company had to purchase power from the PJM spot energy market during Elliott because the Company's load obligations were in excess of the supply available from its resources. The Company's plan for covering load obligations in excess of available generation supply is to purchase the balance of its energy requirements from the PJM spot energy markets. The Company's customers receive the lower of cost to generate or market energy prices as determined by PJM's FERC approved tariff and economic dispatch model. To the extent that the Company may be adding additional owned or contracted capacity and energy resources in the future to replace the energy and capacity from the recently expired Rockport Unit Power Agreement ("UPA"), those resources would contribute in the future to reducing the Company's amount of spot market energy purchases from PJM. However, it should be noted that resource acquisitions are generally informed by long-range integrated resource planning and forecasting that utilizes normative forecasts that do not account for extreme outlier events like Elliott. The weather and resulting conditions in the PJM energy market during Elliott were an outlier; it is highly unlikely that traditional resource planning would result in the Company being insulated from all possible PJM energy market fluctuations.

Q. WAS THERE ANOTHER SOURCE OF PURCHASED POWER AVAILABLE TO THE COMPANY AT A LOWER COST DURING THE ELLIOTT EMERGENCY?

A. No. It was a PJM system emergency; if excess power was available in the market, then scarcity pricing and emergency conditions would not have occurred. Additionally, it is fundamental under economic principles of supply and demand that a willing market seller of energy would not sell available energy during such an event for less than the transparent spot market price of energy.

Q. HYPOTHETICALLY, WHAT WOULD HAVE BEEN THE FINANCIAL RESULT HAD THE COMPANY PURCHASED TERM FINANCIAL POWER DURING 2022 IN AN AMOUNT TO COVER THE COMPANY'S PEAK LOAD DURING THE ELLIOTT EXTREME COLD EVENT?

A. Hypothetically speaking, had the Company known it would need 283 MW[6] of additional purchased power during Elliott, and had it purchased financial power[7] in

[6] Peak Kentucky Power load during Elliott minus generation resource (Mitchell and Big Sandy 1) ICAP.
[7] The reference to financial power is referring to any purchase that is not asset specific.

advance of December 2022, customers' resulting fuel costs would have been significantly higher. This is due to the high natural gas and power prices during 2022, which caused the forward prices of financial power to be very high during 2022. Had the Company transacted for this hypothetical amount of purchased power in any of the five months leading up to December of 2022, purchased power expenses for December would have been higher than what the Company actually experienced in three out of the five months. Based on this information, the only way a hypothetical financial power transaction would have potentially benefitted the Company's customers would have been based on arbitrary market timing. Said another way, if the Company by luck alone had transacted based on October forward prices having perfect knowledge of the unknown Winter Storm Elliott to come, purchased power expense could have been lower than what was realized.

Had the Company bought that same amount of financial purchased power for the balance of the winter (January-March in addition to December), rather than settling its net load requirements at the spot market energy prices, total fuel costs would have been materially higher under every scenario as can be seen in Figure AEV-4. Furthermore, as discussed later in the financial power hedging portion of my testimony, these types of extreme load spikes are not what a hedging program is meant to insulate against. In fact, the Company's proposed hedging program will utilize weather normal load levels (which do not include extreme cold or heat events that materially impact retail load) and would leave one standard deviation of the total position open to the spot energy market.

Figure AEV-4 - Hypothetical Forward Purchased Power Transactions

MW Needed to Cover Elliott Peak	283				
July Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$87.96	$113.72	$106.52	$76.42	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	$864,103	$16,293,909	$14,946,855	$10,011,819	$42,116,685
August Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$108.04	$136.92	$126.07	$78.07	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	$5,085,802	$21,171,569	$18,659,357	$10,358,721	$55,275,449
September Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$94.97	$126.51	$111.50	$75.71	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	$2,337,913	$18,982,929	$15,892,546	$9,862,545	$47,075,934
October Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$73.45	$106.30	$91.27	$67.17	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	($2,186,537)	$14,733,898	$12,050,914	$8,067,062	$32,665,337
November Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$80.90	$99.41	$91.97	$67.02	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	($620,220)	$13,285,317	$12,183,842	$8,035,525	$32,884,465

A similar fact pattern would be true if the Company had purchased a block of financial power to replace Big Sandy Unit 1's 295 MW of generation when it became known that the emergent generator issue with Big Sandy Unit 1[8] would keep the unit in a planned outage for all of December 2022. Had the Company purchased that block of power[9] for the remainder of the month of December after the equipment issue was discovered on December 2, 2022, total purchased power costs realized would not have changed materially. Forward pricing for the balance of December 2022 was

[8] As discussed in more detail by Company Witness Kerns, the issue was discovered on December 2, 2022.
[9] 295 x 696 hours in the balance of the month = 205,320 MWh of hypothetical purchased power transaction.

$82.93/MWh and the average December 2022 liquidated price was $83.85. Therefore, less than a dollar per MWh (or roughly $190,000 in total) of savings was hypothetically possible. It should be noted that making such a transaction at a single point in time, rather than layering in over time as the Company is proposing in its hedging program, can be financially risky. This is very evident when looking out just a single month from December of 2022 to January of 2023, when the average PJM spot market price shown in Figure 4 dropped to just $36.22/MWh.

Q. DID THE COMPANY CURTAIL ITS NON-FIRM OR INTERRUPTIBLE CUSTOMERS DURING ELLIOTT TO REDUCE THE AMOUNT OF PURCHASED POWER IT INCURRED?

A. Yes, the Company called for curtailments of its interruptible customers[10] on December 23, 2022 and December 24, 2022, and those customers reduced their operations to their contracted firm service level during these events.

Q. DID THE COMPANY HAVE TO ENGAGE IN ROLLING BLACKOUTS DURING WINTER STORM ELLIOTT?

A. No. The Company was able to provide reliable service to its customers during the Winter Storm Elliott and had no power supply-related outages.

Q. DOES THE COMPANY MEET ITS CAPACITY OBLIGATIONS AND RESERVE MARGIN REQUIREMENTS IN PJM?

A. Yes it does. The Company plans for and meets its generation capacity obligations in PJM, which is the balancing authority to which the Company belongs. The current

[10] Tariff DRS and special contract.

capacity obligation is determined using a summer 5CP measurement. The Company's customers have benefited from this market design because the Company's winter peak is higher than its summer peak. The Company sources the additional winter energy requirements for its customers from the PJM energy markets, which is an option available to it as a member of the PJM RTO. The matter of securing the excess winter energy requirements from the PJM energy market is a matter of economics, and not reliability, which is why the Company did not have any firm load shedding events during Elliott.

Q. IS THE CURRENT STRATEGY OF MAKING BILATERAL MARKET PURCHASES OF CAPACITY AND UTILIZING THE PJM SPOT ENERGY MARKET FOR EXCESS ENERGY NEEDS IN LINE WITH THE COMPANY'S PREVIOUS IRP?[11]

A. Yes it is. Both the Attorney General and Kentucky Industrial Utility Customers, Inc. ("KIUC") (collectively, "AG-KIUC") advocated for the use of short-term bilateral market capacity purchases and the PJM spot energy market in lieu of the Company owning long-term assets to fill the same need. In their joint comments on Kentucky Power's 2019 IRP Preferred Plan AG-KIUC stated: "This is further evidence that the Company should adjust its Preferred Plan to include additional MPs [market purchases], and it should not be overlooked that we have been in a low-cost

[11] *In The Matter Of: Electronic 2019 Integrated Resource Planning Report Of Kentucky Power Company*, Case No. 2019-00443.

environment for more than ten years with no indication this will change any time soon."[12] The joint comments also state:

> In its response to Staff's Post Hearing Request No. 2, the Company noted that when its winter peak demand is greater than its summer peak demand obligation, it buys energy from the pool. When this situation occurs, it does not mean that Kentucky Power suffers from a reliability issue, but instead it means it is more economic for Kentucky Power to purchase energy from within the PJM market than for Kentucky Power to construct new resources, especially since there is sufficient capacity available in PJM to meet Kentucky Power's winter peak. As long as Kentucky Power meets its PJM summer peak demand obligation, and PJM ensures that the entirety of the PJM System is reliable on a year round basis, then it would become an economic matter as to whether Kentucky Power should construct additional capacity to avoid having to purchase during the winter period. Even if the Company were to construct physical assets such as combustion turbine units to satisfy its winter peak, Kentucky Power possibly would still purchase energy from the PJM market during the winter as opposed to running its newly built resources since PJM market resources could be cheaper to operate than Kentucky Power's new resources.[13]

This concept is exactly what the Company has been doing since the end of the Rockport UPA and will continue to do until a long-term replacement solution is proposed by the Company and approved by this Commission.

Q. DID THE COMPANY ACT PRUDENTLY WHEN IT INCURRED THE WINTER STORM ELLIOTT PUE EXPENSE?

A. Yes. The Company took all reasonable efforts available to it to reduce the total amount of purchased power expense during the extreme winter storm Elliott event. This includes operating the Mitchell Plant through the event and curtailing interruptible

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[12] Joint Review of Kentucky Power's 2019 Integrated Resource Plan at 9, *In The Matter Of: Electronic 2019 Integrated Resource Planning Report Of Kentucky Power Company*, Case No. 2019-00443 (February 25, 2021).
[13] *Id.* at 16.

customers during peak periods. The Company's actions in response to Winter Storm Elliott were reasonable and prudent.

The entire PJM region, and much of the United States as the storm made its way from west coast to east coast, was impacted by Elliott. Elliott was not just a Kentucky Power issue, as it financially and operationally impacted many utilities in the region. There was no reasonable and foreseeable way for the Company to avoid the resulting PJM energy market exposure in a way that would have materially changed the realized costs.

Q. PLEASE DESCRIBE WHAT CAUSED THE APPROXIMATELY $3.2 MILLION OF NON-WINTER STORM ELLIOTT TEST YEAR PUE EXPENSE.

A. Purchased power costs are excluded from FAC recovery when they are in excess of the Company's highest cost source of internal generation, including the approved hourly PUE calculation. It is not a cap on the level of costs that are recoverable, but rather on what level of costs can be recovered in the monthly FAC rate updates. These instances where purchased power costs exceed the PUE calculation are generally occurring because the implied heat rate of the PJM energy market is higher than that of the hypothetical combustion turbine used in the PUE calculation, the locational natural gas price of the marginal unit in PJM's hourly economic dispatch solution is higher than that of the price used in the PUE calculation, or some combination thereof. These purchased power costs are still reasonably incurred as they are the product of hourly economic dispatch which is optimized across the PJM RTO pursuant to PJM's FERC approved tariff. They are next cheapest spot source of energy available to serve customers.

Q. WHAT IS THE COMPANY'S PROPOSAL FOR RECOVERY OF THE PUE EXPENSE INCURRED SINCE THE COMPANY'S LAST BASE RATE CASE?

A. As described by Company Witness West, the Company respectfully requests, based upon the evidence supporting the prudency of the Winter Storm Elliott PUE expense presented in this case, that the Commission find those costs were prudently incurred. The Company further requests that the Commission include the Winter Storm Elliott PUE expense in the revenue requirement approved in its final order in this case, up to the noticed total revenue requirement. To be clear, the Company is not requesting recovery of revenue above the amount included in its public notice in this case. The Company proposes to amortize incremental non-Winter Storm Elliott PUE expense incurred since the Company's last base rate case over three years, as detailed by Company Witness Whitney.

V. FINANCIAL POWER HEDGING PROPOSAL

Q. PLEASE DESCRIBE THE COMPANY'S CURRENT ENERGY POSITION GIVEN ITS HISTORIC LOAD CHARACTERISTICS AND CURRENT SUPPLY RESOURCES.

A. The Company has been backstopped from an energy standpoint by a pooling arrangement since 1951. Until December 31, 2013[14] the Company was a member of the AEP Interconnection Agreement ("AEP East Pool"), where any energy shortfall

[14] The AEP East Pool terminated on this date by mutual notice.

was first met by the other Companies in the East Pool. After the AEP East Companies joined the PJM RTO in 2004, any additional energy requirements beyond what could be provided by the East Pool were sourced from the PJM spot energy market. This included economic dispatch of the East Pool generating resources by PJM, so if it were more economic to purchase energy from PJM than to generate energy from the East Pool resources, the Companies did so, and customers benefited from the lower of cost to produce or what could be purchased on the market. Beginning in 2014, the East Pool was no longer a source of energy for the Company and its energy requirements were sourced from the PJM RTO spot energy market with that same economic dispatch concept applying. In December 2022 the Company became shorter from an energy perspective (load requirements are greater than available economic generation resources over some period of time) relative to its load requirements when the Rockport UPA expired. To be clear, purchasing energy from the market to meet its requirements is not something new for the Company, it just now finds itself in a larger energy deficit than it has had previously.

Q. HOW DO THE COMPANY'S GENERATING RESOURCES HEDGE CUSTOMER MARKET RISK?

A. Because the Company sells all of its available generation resources into PJM's spot energy market and purchases all of its load from the same market, the net position if short is what is actually exposed financially to the spot energy market. Thus, the Company's generating resources provide a physical hedge on the spot energy market. During times of planned or forced outages, absent taking on additional resource hedge positions, the physical hedge position provided by the Mitchell and Big Sandy plants will decline, leaving Customers more exposed to PJM's spot energy market price volatility. However, the Company can reduce this exposure by purchasing financial hedges to replace the generation.

Q. DEFINE THE COMPANY'S OPEN ENERGY POSITION SUBJECT TO PJM SPOT ENERGY MARKET VOLATILITY.

A. The Company's Open Energy Position exposed to PJM spot energy market volatility is defined as its hourly retail load less the generation from Mitchell and Big Sandy generation plants.

Q. CAN THE COMPANY REDUCE THE IMPACT THAT PJM'S SPOT ENERGY MARKET HAS ON ITS OPEN ENERGY POSITION?

A. Yes. Although no entity can accurately predict future energy prices, a structured program that layers in financial hedges over time will help smooth out the impact of PJM's spot energy market price volatility on the Company's Open Energy Position resulting in greater fuel cost certainty for customers.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED FINANCIAL HEDGING PLAN.

A. The Company proposes to use financial hedge products to mitigate the volatility of its PJM spot energy market energy purchases for its Open Energy Positions. PJM AD HUB fixed-for-floating price swaps, also known as contracts for differences, will be used to reduce customer exposure to the volatility in market prices. These forward contracts will be purchased in layers over time to match the Company's target hedge position and smooth out the impact of price volatility in the market. The hedging plan would provide the flexibility to modify or unwind executed forward contracts, as necessary, when adjustments or changes are made to the forecasted load or planned outage schedules at the Mitchell and Big Sandy generation plants. If the PJM AD HUB forward future market is not liquid enough to purchase the target hedge position, the Company may purchase financial future contracts from adjacent zones or other liquid trading hubs, such as the PJM West Hub, to fill in the short position.

Q. WHAT IS THE PROPOSED TIME HORIZON FOR THE FINANCIAL HEDGING PLAN?

A. The Company proposes a financial hedge time horizon of a rolling 36-month period so it can layer purchases of forward contract positions in equal one-third tranches, with the first purchase at 36 months, the second at 18 months, and the third at 6 months, in advance of the respective hedge period.

Q. WHAT IS THE PROPOSED START DATE OF THE FINANCIAL HEDGING PLAN?

A. Upon Commission approval of the financial hedging plan.

Q. HOW WILL THE COMPANY DETERMINE THE APPROPRIATE MWH TO HEDGE IN A GIVEN PERIOD?

A. For each hedge interval, the Company will calculate its Interval Hedge Percent by taking the forecasted generation from the Mitchell and Big Sandy plants based on the fuel purchased in MWh plus any purchased forward hedge contracts (intervals 2 and 3) divided by the forecasted weather normalized retail load in MWh less one standard deviation of its forecasted weather normalized retail load in MWh. Since forecasts are never perfect, a portion of the Open Energy Position will be left exposed to the PJM spot energy market, one standard deviation represents that amount.

$$\text{Interval Hedge Percent (\%)} = \frac{\text{Forecasted Big Sandy and Mitchell Generation (MWh)} + \text{Purchased Forward Hedge Contracts (MWh)}}{\text{Forecasted Load (MWh)} - 1\sigma\ \text{Forecasted Load (MWh)}}$$

The Target Hedge Percent in Figure AEV-5 below represents the targeted amount of the Company's Open Energy Position to be hedged for a given hedge interval. When the Interval Hedge Percent is less than the Target Hedge Percent, the Company will calculate the Target Hedge Position for that interval and purchase forward energy contracts to hedge its Open Energy Position up to the Target Hedge Percent.

Figure AEV-5

Hedge Interval	Target Hedge Percent
Interval 1 (36-months prior to flow)	33%
Interval 2 (18 months prior to flow)	67%
Interval 3 (6-months prior to flow)	100%

The Target Hedge Position in MW is calculated by taking the generation in MWh from Mitchell and Big Sandy plus any purchased forward hedge contracts (intervals 2 and 3) less the Company's forecasted weather normalized retail load in MWh as reduced by one standard deviation of its forecasted weather normalized retail load in MWh times the Target Hedge Percent, divided by the number of hours in the period.

$$\text{Target Hedge Position (MW)} = \frac{\begin{array}{c}\text{Forecasted Big Sandy and Mitchell Generation (MWh)} + \\ \text{Purchased Forward Hedge Contracts (MWh)} - [(\text{Forecasted Load (MWh)} - 1\sigma\ \text{Forecasted Load (MWh)}] \times \text{Target Hedge Percent (\%)}\end{array}}{\text{Number of Hours in Hedge Period (Hrs)}}$$

In the event that the forward future market is not liquid enough to purchase the number of MWh of financial energy needed to reach the Target Hedge Percent for a given hedge interval, hedges will be purchased off-cycle to fill in the short positions.

Q. WILL THE COMPANY PURCHASE FUTURE ENERGY CONTRACTS TO HEDGE ITS OPEN ENERGY POSITION IN ALL THREE HEDGE INTERVALS?

A. The Big Sandy and Mitchell plants should provide enough generation to cover the Target Hedge Percent during the first two intervals in most scenarios. During the third interval, six months prior to the hedge period, future energy contracts may be needed to reach the Target Hedge Percent. This may change over time as operating and outage schedules change.

Q. UNDER THE PROPOSED FINANCIAL HEDGING PLAN, HOW MANY MWH OF THE COMPANY'S OPEN ENERGY POSITION WOULD BE HEDGED IN 2024?

A. Based on the current weather normalize load forecast and outage schedules for the Michell and Big Sandy Plants, the Company would purchase approximately 600,000 MWh of forward energy contracts to cover the Target Hedge Position in 2024. Once purchased, the Company's current forecasted load less one standard deviation would be hedged at 10067%. The forward energy contract purchase timeline would be condensed given the limited number of months between the proposed program start date and the hedge period.

Q. PLEASE PROVIDE A HISTORICAL EXAMPLE OF THE PROPOSED FINANCIAL HEDGING PLAN AND ITS IMPACT ON CUSTOMER FUEL COSTS?

A.

Figure AEV-6

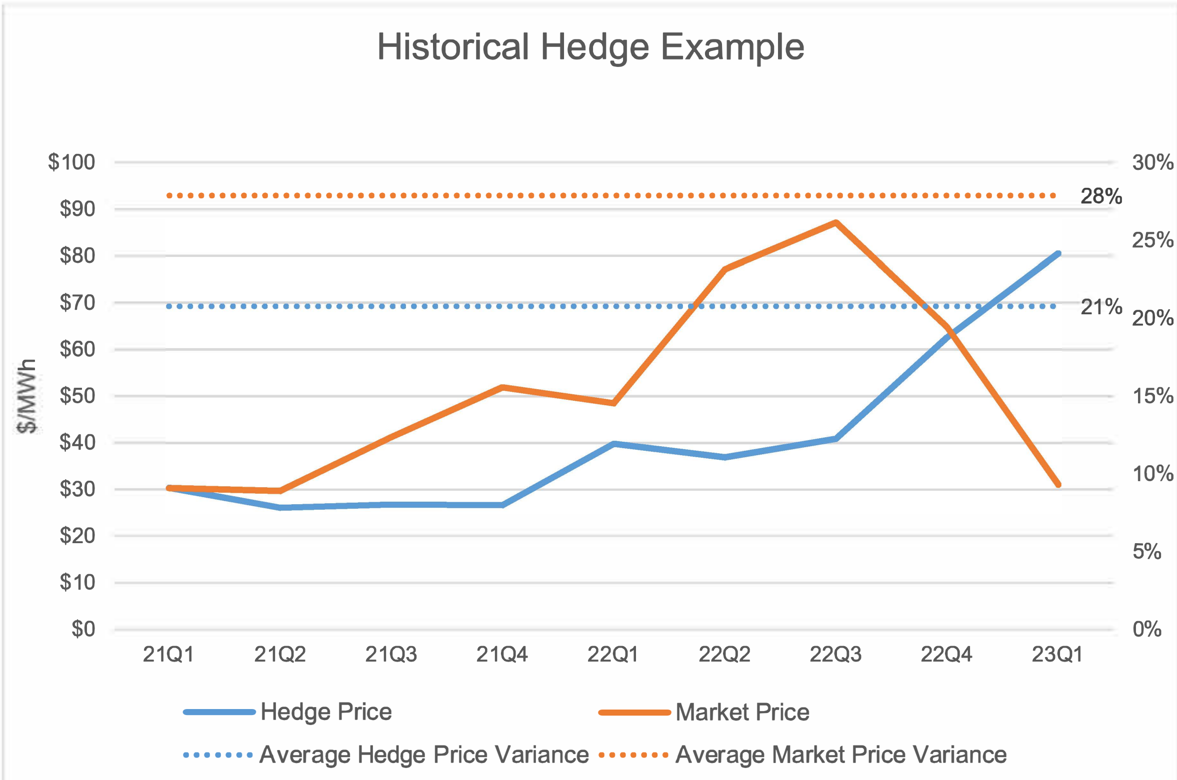
Historical Example Hedge Transactions

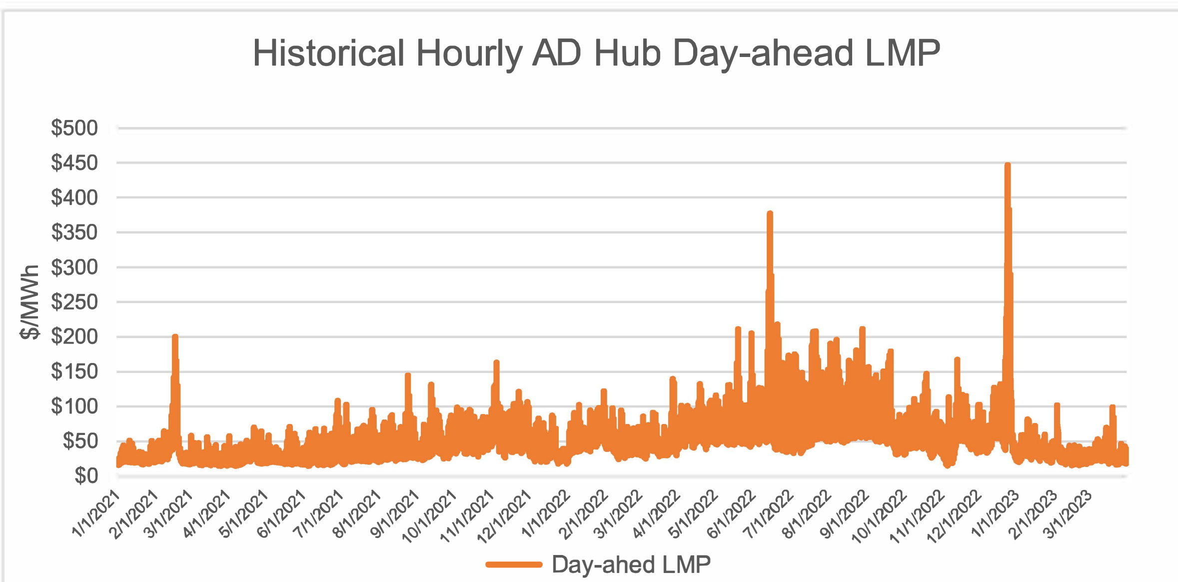
Hedge Interval 3									
Purchase Date	**21Q1**	**21Q2**	**21Q3**	**21Q4**	**22Q1**	**22Q2**	**22Q3**	**22Q4**	**23Q1**
7/1/2020	$ 30.38								
10/1/2020		$ 26.10							
1/2/2021			$ 26.79						
4/1/2021				$ 26.66					
7/1/2021					$ 39.79				
10/1/2021						$ 36.91			
1/2/2022							$ 40.87		
4/1/2022								$ 62.58	
7/1/2022									$ 80.47
Day-Ahead Settle Price	$ 30.33	$ 29.71	$ 41.22	$ 51.88	$ 48.46	$ 77.06	$ 87.06	$ 64.70	$ 31.05
Credit/(Charge)	**$ (0.05)**	**$ 3.61**	**$ 14.43**	**$ 25.22**	**$ 8.67**	**$ 40.15**	**$ 46.19**	**$ 2.12**	**$ (49.42)**

It is estimated that for all nine hedging periods, the Company would have had sufficient generation from the Big Sandy and Mitchell plants to cover the Target Hedge Percent during the first two hedge intervals; therefore, all hedge transactions would have been purchased for the third hedge interval. For the hedging period beginning in January and ending in March of 2021 (21Q1), the forward energy contract pricing during the third hedging period was $30.38/MWh and the average PJM spot energy market price of energy for the hedge period was $30.33MWh. In this example the average hedge contract price was greater than the PJM spot energy market price creating a hedging loss of $0.05/MWh for customers. The $0.05/MWh hedging loss would have been charged to the FAC, thereby increasing customer's fuel costs. Similarly, For the hedging period beginning in April and ending in June of 2021 (21Q2), the forward energy contract pricing during the third hedging period was $26.10/MWh and the average PJM spot energy market price of energy for the hedge period was $29.71/MWh. In this example the average hedge contract price was less than the PJM spot energy market price creating a hedging gain of $3.61/MWh for customers. The $3.61/MWh hedging gain would have been credited to the FAC, thereby reducing customer's fuel costs.

The goal of the proposed hedging plan is not to reduce customer's fuel costs over time; rather, it is to reduce their exposure to the volatility of the PJM spot energy market, especially when the Company's generating facilities have scheduled outages, leaving customers more exposed to PJM's Day-ahead market. The proposed hedging plan will reduce customer's sensitivity to PJM's spot market price volatility by creating more predictable fuel costs over time. The graphs in Figure AEV-7 below illustrate how hedging can help smooth out customer fuel costs. Had the Company incorporated a structured hedging program between January 2021 and March 2023, Customers would have been exposed to an average 21% price variance between their monthly fuel charges rather than the 28% variance seen in the spot market.

Figure AEV-7


Historical Hedge Example
$/MWh
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
30%
25%
20%
15%
10%
5%
0%
28%
21%
21Q1
21Q2
21Q3
21Q4
22Q1
22Q2
22Q3
22Q4
23Q1
Hedge Price
Market Price
Average Hedge Price Variance
Average Market Price Variance


Historical Hourly AD Hub Day-ahead LMP
$/MWh
$500
$450
$400
$350
$300
$250
$200
$150
$100
$50
$0
1/1/2021
2/1/2021
3/1/2021
4/1/2021
5/1/2021
6/1/2021
7/1/2021
8/1/2021
9/1/2021
10/1/2021
11/1/2021
12/1/2021
1/1/2022
2/1/2022
3/1/2022
4/1/2022
5/1/2022
6/1/2022
7/1/2022
8/1/2022
9/1/2022
10/1/2022
11/1/2022
12/1/2022
1/1/2023
2/1/2023
3/1/2023
Day-ahed LMP

Q. WHAT RATE RECOVERY TREATMENT IS THE COMPANY SEEKING REGARDING ITS PROPOSED FINANCIAL POWER HEDGING PROGRAM?

A. The Company proposes that all Commission-approved financial power hedging program-related contract settlements (gains and losses) and related contract costs be recovered through the FAC. A gain will be realized when the contracted price of financial power is less than the realized LMP value at the time of settlement. A loss will be realized when the opposite is true. The Company proposes that the financial power hedging program transactions will not be subject to the PUE FAC limitation as they are forward financial contracts entered into to reduce fuel rate volatility and market exposure, not to necessarily produce the absolute lowest purchased power cost in any hour.

Q. WILL THE COMPANY MAKE ANY FINANCIAL GAINS FROM THE PROPOSED FINANCIAL HEDGING PROGRAM?

A. No. The Company's proposed financial hedging program is designed to smooth out the impact of PJM's spot energy market price volatility on the Company's Open Energy Position and provide greater fuel cost certainty for customers. The hedging plan effectively locks-in or caps the price of future energy purchases for customers. If the actual energy price in the future turns out to be lower than the hedged price, customers will end up paying more for energy than they would have if the Company had purchased its Open Energy Position from the PJM spot energy market. This incremental cost will flow through the FAC as a hedge charge. Conversely, when the actual energy price turns out to be greater than the hedge price, customers will pay less than they would have if the Company had purchased its Open Energy Position from the PJM spot energy market. Any credits or charges (gains and losses) associated with the hedging program will be passed back to customers through the FAC. The potential for realized hedge charges from this program is essentially the cost of reducing volatility in customers' monthly fuel rates.

Q. HOW WOULD THE FINANCIAL POWER HEDGING PROGRAM BE ACCOUNTED FOR?

A. The financial power product being employed is expected to be a derivative, which would be subject to mark to market ("MTM") treatment. Should the Commission authorize the Company to pass back any credits or charges (gains and losses) associated with the hedging program to customer through the FAC, the Company would defer MTM gains or losses prior to hedge liquidation to a regulatory asset or liability which would unwind when the financial power contracts are liquidated at the time of settlement. The net gain or loss from liquidation would flow through the FAC as discussed earlier.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE COMPANY'S PROPOSAL.

A. PJM's energy market is susceptible to market volatility largely driven by the underlaying and interrelated fuel markets, operating conditions, and has been exacerbated over the years by extreme weather disturbances. A significant portion of the Company's load is subject to the day-to-day volatility of PJM's spot market and becomes even more magnified during times of planned outages at the Mitchell and Big Sandy plants. To help mitigate the exposure to the daily market volatility, the Company is proposing a rolling 36-month financial hedging plan to provide customers with greater fuel cost certainty over time. Although the monthly results of the Company's proposed hedging plan may not result in net fuel cost savings for customers, it will reduce their exposure to the fluctuations in the PJM Day-ahead energy market by creating more predictable fuel costs over time. This will leave customers better positioned to budget for and manage their monthly energy bills.

VI. DISTRIBUTED SOLAR PROPOSAL (SOLAR GARDEN PROGRAM)

i. Proposed Ownership and Accounting Structure

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S PROPOSED SOLAR GARDEN PROGRAM AND THE PROGRAM'S GENERAL COST RECOVERY STRUCTURE.

A. The Company proposes to own and operate one or more solar facilities, not to exceed 10 MW in individual size, to be located on the Company's distribution system. The aggregate capacity of all the solar sites will not exceed 25 MW. This program will help establish solar generation within the Company's service territory and fill a capacity need that starts in 2026. Projects will be considered a prudent investment if the Net Present Value[15] ("NPV") of the benefits and costs of the project do not exceed the NPV of the equivalent avoided capacity costs, an example of the items considered in the analysis is shown in Figure AEV-8 below, and Figure AEV-9 is an illustrative example of the economic test. The Company is seeking approval of this program so it can solicit through requests for proposals and acquire the projects without further Commission approvals if a project meets the proposed requirements.

[15] The discount rate would be equal to the Company's approved after tax weighted average cost of capital.

Figure AEV-8

Inputs of NPV Economic Prudency Test

Cost of Service Build Up	**Years 1-35**	
O&M	(x)	
Property Taxes	(x)	
Insurance	(x)	
Land Lease	(x)	
ARO Depreciation	(x)	
Accretion Expense	(x)	
Depreciation Expense	(x)	
Income and Property Taxes	(x)	
PTC Revenue	x	
Return on Rate Base	(x)	
Total Cost of Service	(xx)	
Test Input	**Value**	
NPV of Cost of Service	(xx)	**a**
NPV of Energy Value	MWh x Energy Price	**b**
NPV of Ancillary Charges	MWh x Ancillary Charge	**c**
NPV of OATT	Average 12 CP reduction x Annual Transmission Revenue Requirement $/MW-yr	**d**
NPV of REC Value	MWh x REC Price	**e**
NPV of Capacity Value	FRR 5CP Reduction x Capacity Price	**f**
Total NPV		**g = a-b-c-d-e-f**
NPV of Avoided Capacity Cost	Capacity MW x Capacity Price	**h**
Is (g) greater than (h)?	Prudency Test	

Figure AEV-9

Prudent Investment Example

NPV of Cost of Service	(64,904,189)	(63,595,882)
NPV of Benefits (Energy, OATT, Ancilary Service, REC Values)	49,500,986	70,342,556
Total NPV (a)	(15,403,203)	6,746,673
NPV of Capacity Cost (b)	(13,387,086)	(17,219,757)
Is a greater than b?	FALSE	TRUE

The Company is proposing to recover the net costs of these solar facilities acquired through the solar gardens program through Tariff PPA until they can be manifest as a reduction in FAC costs. The benefits and costs associated with these solar facilities are discussed later in my testimony.

Q. IS THIS PROPOSAL IN LINE WITH THE COMPANY'S RECENTLY FILED 2022 IRP?

A. Yes. The Company's going in capacity positions shows a 115MW shortfall in 2026, which grows even larger through 2037. The Preferred Plan shows 250MW of new solar being added in 2027 and further solar additions in 2028 and 2029.

Q. HOW WILL THE SOLAR GARDEN FACILITIES INTERACT WITH PJM?

A. The solar facilities will be connected to the Company's distribution system. They will act as a load reducer for PJM settlement purposes. This means that the Company's internal distribution load will be reduced by the output of the solar facilities, which will provide the Company and its customers with various PJM benefits. The solar facilities will not be market-facing generation resources and will not participate in PJM's energy, ancillary service, or capacity markets.

Q. WHAT OPERATIONS AND MAINTENANCE COSTS ARE ASSOCIATED WITH THE SOLAR FACILITIES?

A. Outside of general operating and maintenance costs, there are property taxes, insurance expenses and if the Company has to lease the land that the facilities reside on, land lease payments to the lessors of the land.

Q. WHAT IS THE DEPRECIABLE LIFE OF THE PROPOSED SOLAR FACILITIES?

A. The depreciable life of the proposed solar facilities is 35 years. This life is based upon the Company's current accounting policies related to solar generation technology. The

35 year life would also be supported by incremental capital additions over the life of the plant to lengthen the life of inverters.

Q. ARE THERE ANY ASSET RETIREMENT OBLIGATIONS ("AROs") ASSOCIATED WITH THE COMPANY'S PROPOSED SOLAR FACILITY?

A. Yes, if the Company leases the land, then at the end of the solar facilities' useful life, and the corresponding end of the land lease, the Company has the legal obligation to remove the solar generating equipment from the lessors' land. As such, the Company will recognize ARO depreciation expense in an amount equal to the estimated demolition cost 35 years after the solar facilities begin commercial operation and an estimate of the salvage value associated with the racking equipment and other salvageable items.

Q. DOES THE FEDERAL PRODUCTION TAX CREDIT APPLY TO THE PROPOSED SOLAR GARDENS?

A. Yes, it is expected that the solar gardens will qualify and generate the Production Tax Credit ("PTC"), at 100%. The Inflation Reduction Act ("IRA") was signed into law by President Biden on August 16, 2022, which created a new technology-neutral Clean Electricity PTC. The realized value of PTCs generated will be passed back to customers as a reduction to the cost of service of the facilities. Depending on where the facilities are ultimately sited, there is a possibility that they could qualify for a 110% PTC based on the "Energy Communities" portion of the IRA.

Prior to the passage of the IRA, the facilities would have only qualified for the Solar Investment Tax Credit ("ITC"). Every solar facility within this program, will be individually evaluated to ensure max benefits are being recognized for customers.

ii. Customer Benefit Analysis

Q. WHAT FINANCIAL BENEFITS WILL ALL OF THE COMPANY'S CUSTOMERS RECEIVE FROM THE SOLAR GARDEN PROGRAM?

A. As mentioned earlier, the solar facilities will reduce the Company's wholesale load that it purchases from PJM each hour that the solar facilities are producing solar power and injecting it into the Company's distribution system. Because of this, the Company will realize energy, ancillary service, and capacity benefits related to both its generation and transmission obligations in PJM.

Energy Benefits

The energy benefits will manifest by the Company purchasing approximately 33,500 fewer MWh of on-peak energy (49,008 MWh of energy in total) from the PJM RTO annually. This is because the Company purchases all of its load requirements from the hourly energy markets of PJM and sells its generation resources into those same markets. The monthly cost reconstruction/economic dispatch and deferred fuel accounting process ensures that customers receive the lowest cost resources and the resulting monthly average costs through a combination of the Company's base fuel rates and the fuel adjustment clause. The proposed solar facilities will reduce the Company's on-peak load[16] that it purchases from PJM, thus avoiding on-peak purchases and the higher hourly pricing associated with them.

[16] While solar produces energy during "on-peak" daytime hours, weekend days are considered off-peak for pricing purposes.

Ancillary Service Benefits

Also due to the reduction of the Company's PJM load, customers will receive a benefit by avoiding hourly PJM ancillary service load charges.

Capacity Benefits

To the extent that the solar facilities are producing energy during the Company's capacity cost-causing hours in PJM, Kentucky Power will have a lower generation capacity obligation, which will result in lower generation capacity costs.

LSE OATT Charges

Similar to the generation capacity peak reduction, the facilities will also reduce the Company's 12CP used to allocate PJM load serving entity Open Access Transmission Tariff charges to the Company.

The solar facilities also produce one renewable energy certificate ("REC") per MWh of energy generated. These RECs can then be sold bilaterally into the marketplace to offset the cost of the solar facilities.

Q. ARE THERE ADDITIONAL NON-COST OF SERVICE BENEFITS RELATED TO THE COMPANY'S PROPOSED SOLAR FACILITIES?

A. Yes. The solar facilities will pay property taxes to the Commonwealth and the localities where they are built. There will also be local jobs created during the construction and operation of the facilities, all within the Company's service territory.

Q. ARE YOU PROPOSING THAT ANY OF THE NON-COST OF SERVICE BENEFITS BE PRICED INTO THE PROPOSED SOLAR GARDEN PROGRAM?

A. No. The Company's rates are based on cost of service ratemaking. They do not consider non-cost of service economic factors or other externalities. Although these things may exist and may provide positive economic and societal benefits, they do not belong in the Company's rates.

iii. Low-Income Benefit Option

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S PROPOSED LOW-INCOME BENEFIT OPTION IN RELATION TO THE SOLAR GARDEN PROGRAM.

A. The Company has approximately 11,500 customers that are participating in government assistance programs, such as the Federal Low Income Home Energy Assistance Program ("LIHEAP"). The Company is proposing to provide 50 percent of the energy benefits from the Solar Gardens to these customers through a yearly bill credit, to be credited in their January billing when customer bills are generally higher due to heating usage. The customers will not have to sign up for the option, they will be automatically enrolled.

Q. HOW WILL THE ENERGY CREDIT BE CALCULATED?

A. The Company is proposing to use the hourly MWh produced from the solar facilities for the previous 12 months and multiply that by the Day Ahead Local Marginal Price ("DA LMP") for the corresponding hour. The total will then be multiplied by 50 percent and divided by the number of customers identified as low-income through their participation in LIHEAP as of December 31. Based on high-level estimates, this credit could amount to approximately $66 per customer annually.

Q. IS THE 50 PERCENT ENERGY BENEFIT THE ONLY BENEFIT THESE CUSTOMERS WILL RECEIVE FROM THE SOLAR GARDEN PROGRAM?

A. No. These customers will also still receive all of the other the benefits mentioned in the customer benefit analysis portion of my testimony.

iii. Summary

Q. PLEASE SUMMARIZE THE ACCOUNTING FOR THE PROPOSED SOLAR GARDEN FACILITIES AND THE LOW INCOME OPTION.

A. The Company is proposing to flow all non-energy benefits and all costs through Tariff PPA and will be subject to the normal true-up process for Tariff PPA. Energy benefits will flow through the FAC in the form of reduced load requirements being purchased from the PJM spot energy market. The Company is also proposing to provide 50 percent of the energy benefits from the Solar Gardens to low-income customers through a yearly bill credit, as discussed above. The 50 percent of the energy benefit being credited to low-income customers would also be recovered through Tariff ~~PPA~~FAC.

Q. SHOULD THE PROPOSED SOLAR GARDEN PROGRAM BE APPROVED?

A. Yes, because of the benefits to customers, the proposed built in customer protections, and the need for solar identified in the Company's 2022 IRP, the proposed solar garden program should be approved.

VII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED TESTIMONY?

A. Yes, it does.

VERIFICATION

The undersigned, Alex E. Vaughan, being duly sworn, deposes and says he is the Managing Director for Renewables and Fuel Strategy for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief after reasonable inquiry.

Alex E. Vaughan

Franklin County)
Ohio)
)

Case No. 2023-00159

Subscribed and sworn to before me, a Notary Public in and before said County and State, by <u>Alex E. Vaughan</u>, on 12/7/23.

Notary Public

KIM WOLFENBERGER · NOTARY PUBLIC
MY COMMISSION EXPIRES
STATE OF OHIO

My Commission Expires 5/4/2028

Notary ID Number 2013-RE-707303

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) A Securitization Financing Order; And (5) All Other Required Approvals And Relief	)))))))	Case No. 2023-00159

DIRECT TESTIMONY OF

ALEX E. VAUGHAN

ON BEHALF OF KENTUCKY POWER COMPANY

DIRECT TESTIMONY OF
ALEX E. VAUGHAN ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

TABLE OF CONTENTS

SECTION **PAGE**

DIRECT TESTIMONY OF
ALEX E. VAUGHAN ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Alex E. Vaughan. I am employed by AEPSC as Managing Director-Renewables & Fuel Strategy. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. AEPSC is a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"), the parent Company of Kentucky Power Company (the "Company" or "Kentucky Power").

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCES.

A. I graduated from Bowling Green State University with a Bachelor of Science degree in Finance in 2005. Prior to joining AEPSC, I worked for a retail bank and a holding company where I held various underwriting, finance, and accounting positions. In 2007, I joined AEPSC as a Settlement Analyst in the RTO Settlements Group. I later became the PJM Settlements Lead Analyst, and in that role, I was responsible for reconciling AEP's settlement of its activities in the PJM Interconnection, LLC ("PJM") market with the monthly PJM invoices and for resolving issues with PJM. In 2010, I transferred to Regulatory Services as a Regulatory Analyst and was later promoted to the position of Regulatory Consultant. My responsibilities included supporting regulatory filings across AEP's eleven state jurisdictions and at the FERC. I also performed financial analyses related to AEP's generation resources and loads, power pools, and PJM. In September 2012, I was promoted to Manager, Regulatory Pricing and Analysis, where I was responsible for cost of service, rate design, and special contract analysis for the AEP east operating companies. In September 2018, I was promoted to Director of Regulated Renewables and Pricing, at which time oversight of regulated renewable and fuel filings across the AEP operating companies was added to my responsibilities. I was promoted to my current position in June 2022.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES.

A. I am responsible for assisting Kentucky Power and the other AEP electric utility operating companies in the preparation of their regulatory filings before this and other commissions under whose jurisdiction these companies provide electric service. My responsibilities include the oversight of cost of service analyses, rate design, special contracts, energy supply costs, and renewables for the AEP System operating companies.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have presented testimony on behalf of the AEP operating companies numerous times before the regulatory bodies in Virginia, West Virginia, Kentucky, Tennessee, Indiana, Michigan, and Oklahoma. In Kentucky, I have testified before the Kentucky Public Service Commission (the "Commission") in several cases, most notably in Kentucky Power's past four base rate case proceedings (Case Nos. 2013-00197, 2014-

00396, 2017-00179, and 2020-00174), and the proposed transfer of ownership of Kentucky Power in Case No. 2021-00481.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is threefold:

- To support the prudence of the approximately $11.5 million winter storm Elliott Peaking Unit Equivalent ("PUE") purchased power expense and $3.2 million of other PUE expense Kentucky Power incurred during the test year;
- To describe and outline the Company's proposed financial power hedging framework for which it is seeking approval; and
- To describe and support the Company's proposed distributed solar program.

IV. PUE EXPENSE

Q. PLEASE DESCRIBE THE SITUATION THAT CAUSED THE APPROXIMATELY $11.5 MILLION WINTER STORM ELLIOTT PUE EXPENSE.

A. Winter Storm Elliott ("Elliott") was an extreme cold weather event that included blizzards, high winds, snowfall and record cold temperatures across much of the United States. Elliott occurred December 23, 2022 through December 26, 2022, in the PJM region (the "Winter Storm Elliott Period").[1] The resulting load during this period of time was an extreme outlier in both magnitude and timing, with the Christmas Eve load

[1] PJM defined the Winter Storm Elliott Period as December 23, 2022 through December 26, 2022, and this is the time period used for purposes of this testimony. The Company also has referred to the Winter Storm Elliott Period when describing its generation performance as December 23, 2022 through December 27, 2022 (see Direct Testimony of Timothy C. Kerns).

being 40 gigawatts ("GW") higher than the second highest in the past decade.[2] The drastic temperature drop and higher than forecasted load caused PJM to dispatch generation reserves, many of which failed to perform.

The unanticipated high load and rapid load increase combined with generation outages due to cold weather and fuel issues resulted in Performance Assessment Intervals ("PAIs") on December 23, 2022 and December 24, 2022. PAIs are triggered when PJM declares an emergency action in the RTO. During the PAIs, the load weighted LMP reached the system marginal price cap of $3,700/MWh as a result of the supply/demand imbalance during emergency operations. Generation resource outages during Elliott peaked at 48,080 MW on December 24, 2022. Roughly 11,000 MW of those outages were due to a lack of natural gas supply.[3]

Q. DID THE COMPANY EXPERIENCE EXTREME LOAD CONDITIONS DURING ELLIOTT?

A. Yes. The Company's peak load during the Winter Storm Elliott Period was 1,358 MW, 46% higher than the Company's previous 12 month average peak demand ("12CP") of 929 MW. In 85 of the 96 hours during the event, the Company's hourly average load was higher than its most recent 12CP demand.

[2] https://www.pjm.com/-/media/committees-groups/committees/mic/2023/20230111/item-0x---winter-storm-elliott-overview.ashx
[3] PJM State of the Market Report 2022 – pages 210-211.

Figure AEV-1

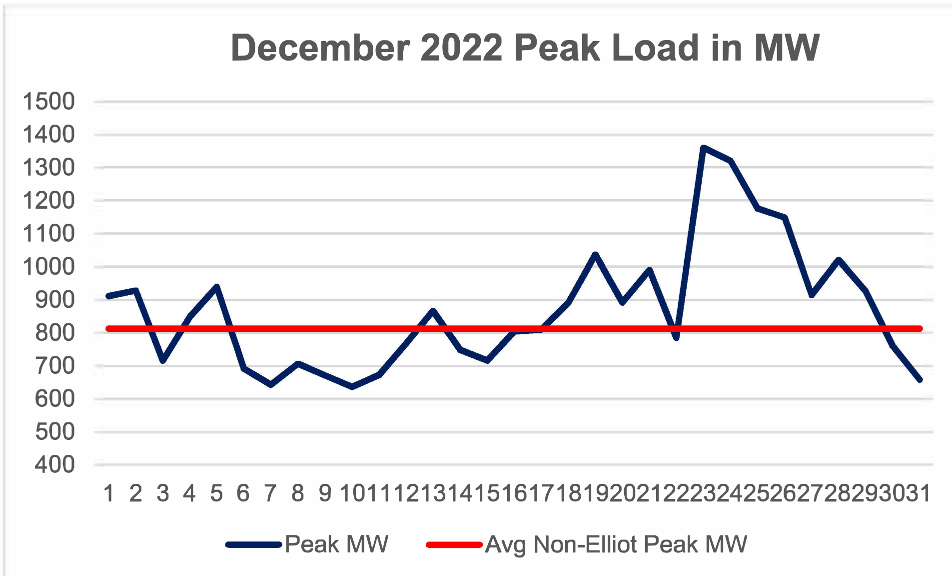


Figure AEV-1 illustrates the Company's daily peak demand during the month of December 2022. As can be seen, there is an extreme increase in demand during Elliott, including the 1,358 MW peak during hour ending 2100 on December 23, 2022. The flat line in Figure AEV-1 is the average peak demand during the non-Elliott days in December (813 MW). The Company's peak demand during Elliott was 545 MW higher than the average peak demand for the other 27 days of December 2022. Before this, one has to go back to January 2018 to find a Company peak higher than what was experienced during Elliott, and the Company has only had eight monthly peaks in the last decade greater than the Elliott peak. This illustrates the magnitude of the demand on the Company's system resulting from Elliott's extreme cold weather. This high load when combined with PJM-wide emergency operations resulted in extremely high system energy pricing at which the Company had to purchase its load obligation, in excess of its available supply, from the PJM spot energy market. Figure AEV-2 below shows the real-time LMPs over the Winter Storm Elliott Period, and Figure AEV-3 shows real-time LMPs over the month of December 2022 to put into context how much of an outlier pricing during Elliott was and provide a narrower view on the hourly pricing during Elliott.

Figure AEV-2

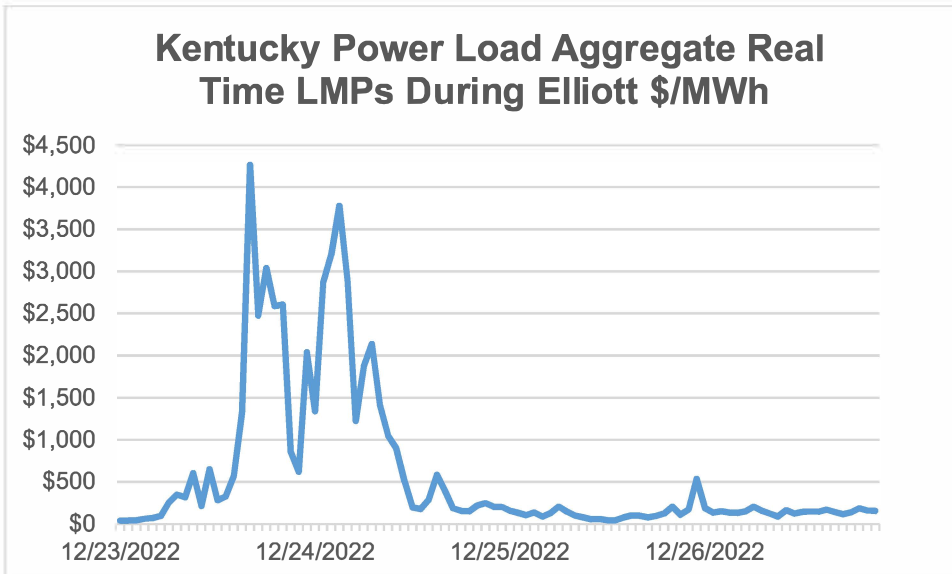
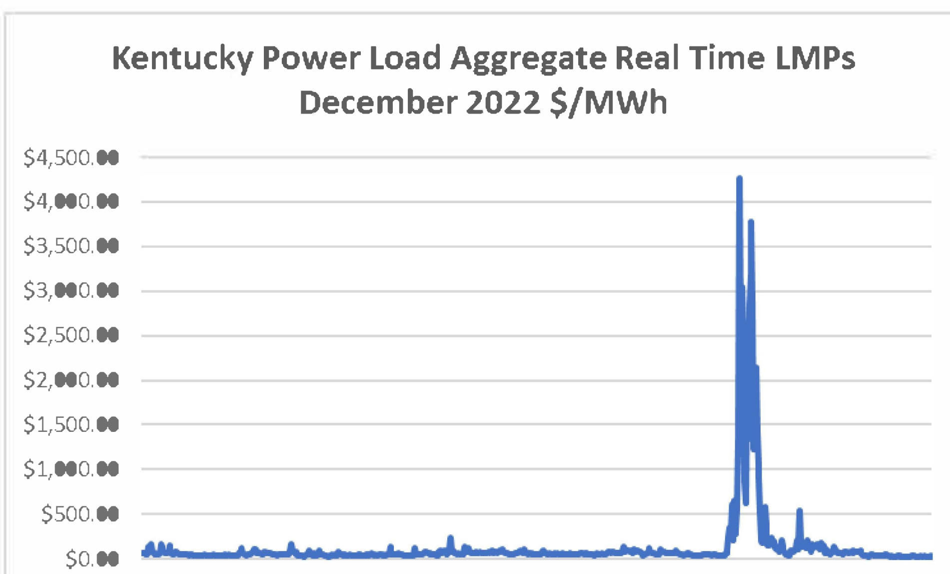


Figure AEV-3



Q. HOW DID THE COMPANY'S GENERATION RESOURCES PERFORM DURING THE WINTER STORM ELLIOTT EVENT?

A. During Elliott, none of the Company's generating units were forced out of service. Both Mitchell Units operated continuously throughout Elliott. Mitchell Units 1&2 operated at 80.31% and 74.11% net capacity factors,[4] respectively. The Mitchell Units performed at a level above the total PJM coal fleet which achieved a net capacity factor of 73.03%[5] during the same period of time. Big Sandy Unit 1 was in the midst of a PJM-approved planned outage during Winter Storm Elliott. Company Witness Kerns provides a more detailed description of the performance of the Company's generation resources during the Winter Storm Elliott Period.

Q. HAD THE COMPANY'S GENERATION RESOURCES RUN AT A 100% CAPACITY FACTOR DURING THE WINTER STORM ELLIOTT PERIOD, WOULD THERE STILL HAVE BEEN A NEED TO PURCHASE ENERGY FROM THE PJM SPOT ENERGY MARKET?

A. Yes. The Company's generation resources at 100% of their installed capacities ("ICAP") can produce approximately 1,076 MWh. As discussed earlier, the Company's load was extremely high during Elliott because of the extreme cold. In many instances, the Company's customers rely on electricity for heating their homes, which caused extremely high load conditions during Elliott. Thus, even had the Company's generators run at 100% of their ICAPs, the Company would have still

[4] December 23-27 period to be consistent with Company Witness Kerns's testimony.
[5] Source: PJM Dataminer2 and PJM State of the Market Report for 2022.

purchased roughly 8,400 MWh from the PJM spot market during the Winter Storm Elliott Period.

Q. DID THE COMPANY INCUR A CAPACITY PERFORMANCE PENALTY DURING THE ELLIOTT PAIs?

A. No, due to the Company's prudent management of its available coal supplies during 2022, the Mitchell Plant was available to run and, as previously discussed, operated continuously during Elliott and the PAIs called by PJM. Furthermore, the larger AEP Companies FRR plan, in which Kentucky Power participates, also did not incur a penalty as it benefited from the diversity of generation resource types and locations utilized by the Companies in the plan.

Q. WHAT OTHER OPTIONS WERE AVAILABLE TO THE COMPANY DURING THE WINTER STORM ELLIOTT EVENT TO SERVE THE HOURLY ENERGY NEEDS OF ITS CUSTOMERS?

A. The Company had to purchase power from the PJM spot energy market during Elliott because the Company's load obligations were in excess of the supply available from its resources. The Company's plan for covering load obligations in excess of available generation supply is to purchase the balance of its energy requirements from the PJM spot energy markets. The Company's customers receive the lower of cost to generate or market energy prices as determined by PJM's FERC approved tariff and economic dispatch model. To the extent that the Company may be adding additional owned or contracted capacity and energy resources in the future to replace the energy and capacity from the recently expired Rockport Unit Power Agreement ("UPA"), those resources would contribute in the future to reducing the Company's amount of spot market energy purchases from PJM. However, it should be noted that resource acquisitions are generally informed by long-range integrated resource planning and forecasting that utilizes normative forecasts that do not account for extreme outlier events like Elliott. The weather and resulting conditions in the PJM energy market during Elliott were an outlier; it is highly unlikely that traditional resource planning would result in the Company being insulated from all possible PJM energy market fluctuations.

Q. WAS THERE ANOTHER SOURCE OF PURCHASED POWER AVAILABLE TO THE COMPANY AT A LOWER COST DURING THE ELLIOTT EMERGENCY?

A. No. It was a PJM system emergency; if excess power was available in the market, then scarcity pricing and emergency conditions would not have occurred. Additionally, it is fundamental under economic principles of supply and demand that a willing market seller of energy would not sell available energy during such an event for less than the transparent spot market price of energy.

Q. HYPOTHETICALLY, WHAT WOULD HAVE BEEN THE FINANCIAL RESULT HAD THE COMPANY PURCHASED TERM FINANCIAL POWER DURING 2022 IN AN AMOUNT TO COVER THE COMPANY'S PEAK LOAD DURING THE ELLIOTT EXTREME COLD EVENT?

A. Hypothetically speaking, had the Company known it would need 283 MW[6] of additional purchased power during Elliott, and had it purchased financial power[7] in

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[6] Peak Kentucky Power load during Elliott minus generation resource (Mitchell and Big Sandy 1) ICAP.
[7] The reference to financial power is referring to any purchase that is not asset specific.

advance of December 2022, customers' resulting fuel costs would have been significantly higher. This is due to the high natural gas and power prices during 2022, which caused the forward prices of financial power to be very high during 2022. Had the Company transacted for this hypothetical amount of purchased power in any of the five months leading up to December of 2022, purchased power expenses for December would have been higher than what the Company actually experienced in three out of the five months. Based on this information, the only way a hypothetical financial power transaction would have potentially benefitted the Company's customers would have been based on arbitrary market timing. Said another way, if the Company by luck alone had transacted based on October forward prices having perfect knowledge of the unknown Winter Storm Elliott to come, purchased power expense could have been lower than what was realized.

Had the Company bought that same amount of financial purchased power for the balance of the winter (January-March in addition to December), rather than settling its net load requirements at the spot market energy prices, total fuel costs would have been materially higher under every scenario as can be seen in Figure AEV-4. Furthermore, as discussed later in the financial power hedging portion of my testimony, these types of extreme load spikes are not what a hedging program is meant to insulate against. In fact, the Company's proposed hedging program will utilize weather normal load levels (which do not include extreme cold or heat events that materially impact retail load) and would leave one standard deviation of the total position open to the spot energy market.

Figure AEV-4 - Hypothetical Forward Purchased Power Transactions

MW Needed to Cover Elliott Peak	**283**				
July Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$87.96	$113.72	$106.52	$76.42	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**$864,103**	**$16,293,909**	**$14,946,855**	**$10,011,819**	**$42,116,685**
August Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$108.04	$136.92	$126.07	$78.07	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**$5,085,802**	**$21,171,569**	**$18,659,357**	**$10,358,721**	**$55,275,449**
September Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$94.97	$126.51	$111.50	$75.71	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**$2,337,913**	**$18,982,929**	**$15,892,546**	**$9,862,545**	**$47,075,934**
October Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$73.45	$106.30	$91.27	$67.17	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**($2,186,537)**	**$14,733,898**	**$12,050,914**	**$8,067,062**	**$32,665,337**
November Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$80.90	$99.41	$91.97	$67.02	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**($620,220)**	**$13,285,317**	**$12,183,842**	**$8,035,525**	**$32,884,465**

A similar fact pattern would be true if the Company had purchased a block of financial power to replace Big Sandy Unit 1's 295 MW of generation when it became known that the emergent generator issue with Big Sandy Unit 1[8] would keep the unit in a planned outage for all of December 2022. Had the Company purchased that block of power[9] for the remainder of the month of December after the equipment issue was discovered on December 2, 2022, total purchased power costs realized would not have changed materially. Forward pricing for the balance of December 2022 was

[8] As discussed in more detail by Company Witness Kerns, the issue was discovered on December 2, 2022.
[9] 295 x 696 hours in the balance of the month = 205,320 MWh of hypothetical purchased power transaction.

$82.93/MWh and the average December 2022 liquidated price was $83.85. Therefore, less than a dollar per MWh (or roughly $190,000 in total) of savings was hypothetically possible. It should be noted that making such a transaction at a single point in time, rather than layering in over time as the Company is proposing in its hedging program, can be financially risky. This is very evident when looking out just a single month from December of 2022 to January of 2023, when the average PJM spot market price shown in Figure 4 dropped to just $36.22/MWh.

Q. DID THE COMPANY CURTAIL ITS NON-FIRM OR INTERRUPTIBLE CUSTOMERS DURING ELLIOTT TO REDUCE THE AMOUNT OF PURCHASED POWER IT INCURRED?

A. Yes, the Company called for curtailments of its interruptible customers[10] on December 23, 2022 and December 24, 2022, and those customers reduced their operations to their contracted firm service level during these events.

Q. DID THE COMPANY HAVE TO ENGAGE IN ROLLING BLACKOUTS DURING WINTER STORM ELLIOTT?

A. No. The Company was able to provide reliable service to its customers during the Winter Storm Elliott and had no power supply-related outages.

Q. DOES THE COMPANY MEET ITS CAPACITY OBLIGATIONS AND RESERVE MARGIN REQUIREMENTS IN PJM?

A. Yes it does. The Company plans for and meets its generation capacity obligations in PJM, which is the balancing authority to which the Company belongs. The current

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[10] Tariff DRS and special contract.

capacity obligation is determined using a summer 5CP measurement. The Company's customers have benefited from this market design because the Company's winter peak is higher than its summer peak. The Company sources the additional winter energy requirements for its customers from the PJM energy markets, which is an option available to it as a member of the PJM RTO. The matter of securing the excess winter energy requirements from the PJM energy market is a matter of economics, and not reliability, which is why the Company did not have any firm load shedding events during Elliott.

Q. IS THE CURRENT STRATEGY OF MAKING BILATERAL MARKET PURCHASES OF CAPACITY AND UTILIZING THE PJM SPOT ENERGY MARKET FOR EXCESS ENERGY NEEDS IN LINE WITH THE COMPANY'S PREVIOUS IRP?[11]

A. Yes it is. Both the Attorney General and Kentucky Industrial Utility Customers, Inc. ("KIUC") (collectively, "AG-KIUC") advocated for the use of short-term bilateral market capacity purchases and the PJM spot energy market in lieu of the Company owning long-term assets to fill the same need. In their joint comments on Kentucky Power's 2019 IRP Preferred Plan AG-KIUC stated: "This is further evidence that the Company should adjust its Preferred Plan to include additional MPs [market purchases], and it should not be overlooked that we have been in a low-cost

[11] *In The Matter Of: Electronic 2019 Integrated Resource Planning Report Of Kentucky Power Company*, Case No. 2019-00443.

environment for more than ten years with no indication this will change any time soon."[12] The joint comments also state:

> In its response to Staff's Post Hearing Request No. 2, the Company noted that when its winter peak demand is greater than its summer peak demand obligation, it buys energy from the pool. When this situation occurs, it does not mean that Kentucky Power suffers from a reliability issue, but instead it means it is more economic for Kentucky Power to purchase energy from within the PJM market than for Kentucky Power to construct new resources, especially since there is sufficient capacity available in PJM to meet Kentucky Power's winter peak. As long as Kentucky Power meets its PJM summer peak demand obligation, and PJM ensures that the entirety of the PJM System is reliable on a year round basis, then it would become an economic matter as to whether Kentucky Power should construct additional capacity to avoid having to purchase during the winter period. Even if the Company were to construct physical assets such as combustion turbine units to satisfy its winter peak, Kentucky Power possibly would still purchase energy from the PJM market during the winter as opposed to running its newly built resources since PJM market resources could be cheaper to operate than Kentucky Power's new resources.[13]

This concept is exactly what the Company has been doing since the end of the Rockport UPA and will continue to do until a long-term replacement solution is proposed by the Company and approved by this Commission.

Q. DID THE COMPANY ACT PRUDENTLY WHEN IT INCURRED THE WINTER STORM ELLIOTT PUE EXPENSE?

A. Yes. The Company took all reasonable efforts available to it to reduce the total amount of purchased power expense during the extreme winter storm Elliott event. This includes operating the Mitchell Plant through the event and curtailing interruptible

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[12] Joint Review of Kentucky Power's 2019 Integrated Resource Plan at 9, *In The Matter Of: Electronic 2019 Integrated Resource Planning Report Of Kentucky Power Company*, Case No. 2019-00443 (February 25, 2021).

[13] *Id.* at 16.

customers during peak periods. The Company's actions in response to Winter Storm Elliott were reasonable and prudent.

The entire PJM region, and much of the United States as the storm made its way from west coast to east coast, was impacted by Elliott. Elliott was not just a Kentucky Power issue, as it financially and operationally impacted many utilities in the region. There was no reasonable and foreseeable way for the Company to avoid the resulting PJM energy market exposure in a way that would have materially changed the realized costs.

Q. PLEASE DESCRIBE WHAT CAUSED THE APPROXIMATELY $3.2 MILLION OF NON-WINTER STORM ELLIOTT TEST YEAR PUE EXPENSE.

A. Purchased power costs are excluded from FAC recovery when they are in excess of the Company's highest cost source of internal generation, including the approved hourly PUE calculation. It is not a cap on the level of costs that are recoverable, but rather on what level of costs can be recovered in the monthly FAC rate updates. These instances where purchased power costs exceed the PUE calculation are generally occurring because the implied heat rate of the PJM energy market is higher than that of the hypothetical combustion turbine used in the PUE calculation, the locational natural gas price of the marginal unit in PJM's hourly economic dispatch solution is higher than that of the price used in the PUE calculation, or some combination thereof. These purchased power costs are still reasonably incurred as they are the product of hourly economic dispatch which is optimized across the PJM RTO pursuant to PJM's FERC approved tariff. They are next cheapest spot source of energy available to serve customers.

Q. WHAT IS THE COMPANY'S PROPOSAL FOR RECOVERY OF THE PUE EXPENSE INCURRED SINCE THE COMPANY'S LAST BASE RATE CASE?

A. As described by Company Witness West, the Company respectfully requests, based upon the evidence supporting the prudency of the Winter Storm Elliott PUE expense presented in this case, that the Commission find those costs were prudently incurred. The Company further requests that the Commission include the Winter Storm Elliott PUE expense in the revenue requirement approved in its final order in this case, up to the noticed total revenue requirement. To be clear, the Company is not requesting recovery of revenue above the amount included in its public notice in this case. The Company proposes to amortize incremental non-Winter Storm Elliott PUE expense incurred since the Company's last base rate case over three years, as detailed by Company Witness Whitney.

V. FINANCIAL POWER HEDGING PROPOSAL

Q. PLEASE DESCRIBE THE COMPANY'S CURRENT ENERGY POSITION GIVEN ITS HISTORIC LOAD CHARACTERISTICS AND CURRENT SUPPLY RESOURCES.

A. The Company has been backstopped from an energy standpoint by a pooling arrangement since 1951. Until December 31, 2013[14] the Company was a member of the AEP Interconnection Agreement ("AEP East Pool"), where any energy shortfall

[14] The AEP East Pool terminated on this date by mutual notice.

was first met by the other Companies in the East Pool. After the AEP East Companies joined the PJM RTO in 2004, any additional energy requirements beyond what could be provided by the East Pool were sourced from the PJM spot energy market. This included economic dispatch of the East Pool generating resources by PJM, so if it were more economic to purchase energy from PJM than to generate energy from the East Pool resources, the Companies did so, and customers benefited from the lower of cost to produce or what could be purchased on the market. Beginning in 2014, the East Pool was no longer a source of energy for the Company and its energy requirements were sourced from the PJM RTO spot energy market with that same economic dispatch concept applying. In December 2022 the Company became shorter from an energy perspective (load requirements are greater than available economic generation resources over some period of time) relative to its load requirements when the Rockport UPA expired. To be clear, purchasing energy from the market to meet its requirements is not something new for the Company, it just now finds itself in a larger energy deficit than it has had previously.

Q. HOW DO THE COMPANY'S GENERATING RESOURCES HEDGE CUSTOMER MARKET RISK?

A. Because the Company sells all of its available generation resources into PJM's spot energy market and purchases all of its load from the same market, the net position if short is what is actually exposed financially to the spot energy market. Thus, the Company's generating resources provide a physical hedge on the spot energy market. During times of planned or forced outages, absent taking on additional resource hedge positions, the physical hedge position provided by the Mitchell and Big Sandy plants will decline, leaving Customers more exposed to PJM's spot energy market price volatility. However, the Company can reduce this exposure by purchasing financial hedges to replace the generation.

Q. DEFINE THE COMPANY'S OPEN ENERGY POSITION SUBJECT TO PJM SPOT ENERGY MARKET VOLATILITY.

A. The Company's Open Energy Position exposed to PJM spot energy market volatility is defined as its hourly retail load less the generation from Mitchell and Big Sandy generation plants.

Q. CAN THE COMPANY REDUCE THE IMPACT THAT PJM'S SPOT ENERGY MARKET HAS ON ITS OPEN ENERGY POSITION?

A. Yes. Although no entity can accurately predict future energy prices, a structured program that layers in financial hedges over time will help smooth out the impact of PJM's spot energy market price volatility on the Company's Open Energy Position resulting in greater fuel cost certainty for customers.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED FINANCIAL HEDGING PLAN.

A. The Company proposes to use financial hedge products to mitigate the volatility of its PJM spot energy market energy purchases for its Open Energy Positions. PJM AD HUB fixed-for-floating price swaps, also known as contracts for differences, will be used to reduce customer exposure to the volatility in market prices. These forward contracts will be purchased in layers over time to match the Company's target hedge position and smooth out the impact of price volatility in the market. The hedging plan would provide the flexibility to modify or unwind executed forward contracts, as necessary, when adjustments or changes are made to the forecasted load or planned outage schedules at the Mitchell and Big Sandy generation plants. If the PJM AD HUB forward future market is not liquid enough to purchase the target hedge position, the Company may purchase financial future contracts from adjacent zones or other liquid trading hubs, such as the PJM West Hub, to fill in the short position.

Q. WHAT IS THE PROPOSED TIME HORIZON FOR THE FINANCIAL HEDGING PLAN?

A. The Company proposes a financial hedge time horizon of a rolling 36-month period so it can layer purchases of forward contract positions in equal one-third tranches, with the first purchase at 36 months, the second at 18 months, and the third at 6 months, in advance of the respective hedge period.

Q. WHAT IS THE PROPOSED START DATE OF THE FINANCIAL HEDGING PLAN?

A. Upon Commission approval of the financial hedging plan.

Q. HOW WILL THE COMPANY DETERMINE THE APPROPRIATE MWH TO HEDGE IN A GIVEN PERIOD?

A. For each hedge interval, the Company will calculate its Interval Hedge Percent by taking the forecasted generation from the Mitchell and Big Sandy plants based on the fuel purchased in MWh plus any purchased forward hedge contracts (intervals 2 and 3) divided by the forecasted weather normalized retail load in MWh less one standard deviation of its forecasted weather normalized retail load in MWh. Since forecasts are never perfect, a portion of the Open Energy Position will be left exposed to the PJM spot energy market, one standard deviation represents that amount.

Interval Hedge Percent (%) =

$$\frac{\text{Forecasted Big Sandy and Mitchell Generation (MWh)} + \text{Purchased Forward Hedge Contracts (MWh)}}{\text{Forecasted Load (MWh)} - 1\sigma \text{ Forecasted Load (MWh)}}$$

The Target Hedge Percent in Figure AEV-5 below represents the targeted amount of the Company's Open Energy Position to be hedged for a given hedge interval. When the Interval Hedge Percent is less than the Target Hedge Percent, the Company will calculate the Target Hedge Position for that interval and purchase forward energy contracts to hedge its Open Energy Position up to the Target Hedge Percent.

Figure AEV-5

Hedge Interval	Target Hedge Percent
Interval 1 (36-months prior to flow)	33%
Interval 2 (18 months prior to flow)	67%
Interval 3 (6-months prior to flow)	100%

The Target Hedge Position in MW is calculated by taking the generation in MWh from Mitchell and Big Sandy plus any purchased forward hedge contracts (intervals 2 and 3) less the Company's forecasted weather normalized retail load in MWh as reduced by one standard deviation of its forecasted weather normalized retail load in MWh times the Target Hedge Percent, divided by the number of hours in the period.

Target Hedge Position (MW) =

$$\frac{\begin{array}{c}\text{Forecasted Big Sandy and Mitchell Generation (MWh)} + \\ \text{Purchased Forward Hedge Contracts (MWh)} - [(\text{Forecasted Load (MWh)} - 1\sigma \text{ Forecasted Load (MWh)}] \times \text{Target Hedge Percent (\%)}\end{array}}{\text{Number of Hours in Hedge Period (Hrs)}}$$

In the event that the forward future market is not liquid enough to purchase the number of MWh of financial energy needed to reach the Target Hedge Percent for a given hedge interval, hedges will be purchased off-cycle to fill in the short positions.

Q. WILL THE COMPANY PURCHASE FUTURE ENERGY CONTRACTS TO HEDGE ITS OPEN ENERGY POSITION IN ALL THREE HEDGE INTERVALS?

A. The Big Sandy and Mitchell plants should provide enough generation to cover the Target Hedge Percent during the first two intervals in most scenarios. During the third interval, six months prior to the hedge period, future energy contracts may be needed to reach the Target Hedge Percent. This may change over time as operating and outage schedules change.

Q. UNDER THE PROPOSED FINANCIAL HEDGING PLAN, HOW MANY MWH OF THE COMPANY'S OPEN ENERGY POSITION WOULD BE HEDGED IN 2024?

A. Based on the current weather normalize load forecast and outage schedules for the Michell and Big Sandy Plants, the Company would purchase approximately 600,000 MWh of forward energy contracts to cover the Target Hedge Position in 2024. Once purchased, the Company's current forecasted load less one standard deviation would be hedged at 100%. The forward energy contract purchase timeline would be condensed given the limited number of months between the proposed program start date and the hedge period.

Q. PLEASE PROVIDE A HISTORICAL EXAMPLE OF THE PROPOSED FINANCIAL HEDGING PLAN AND ITS IMPACT ON CUSTOMER FUEL COSTS?

A.

Figure AEV-6

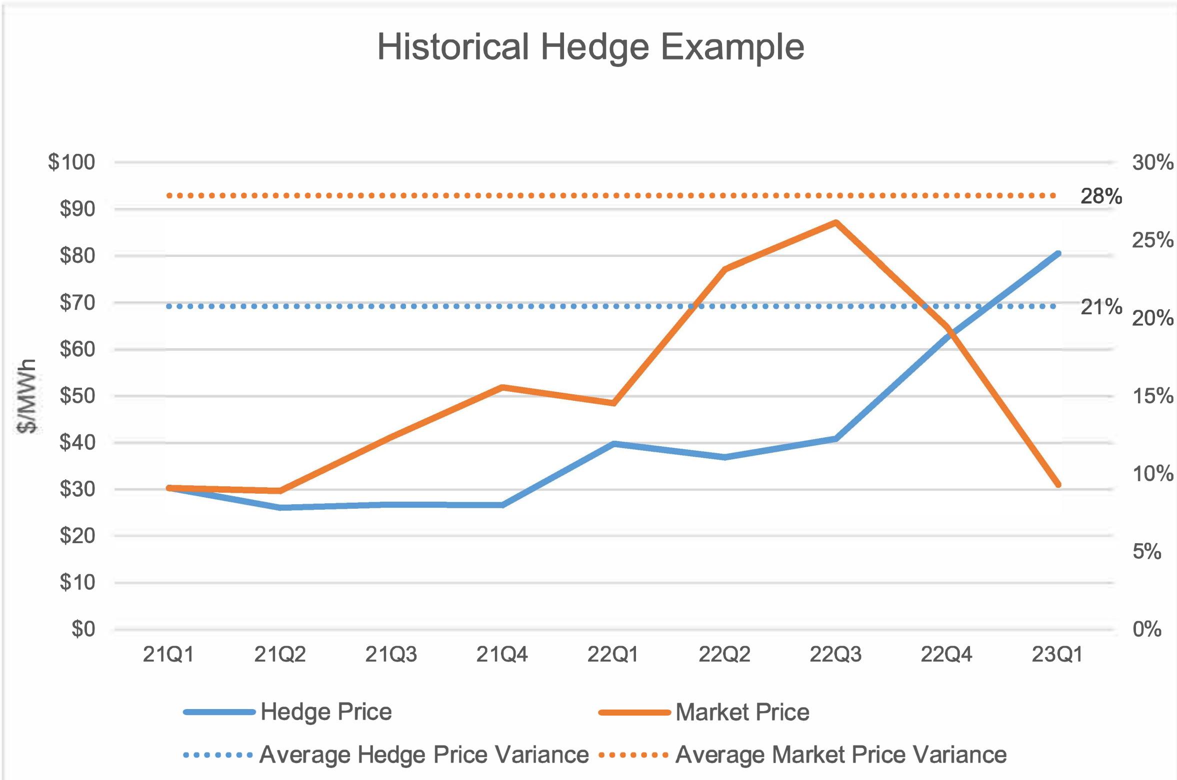
Historical Example Hedge Transactions

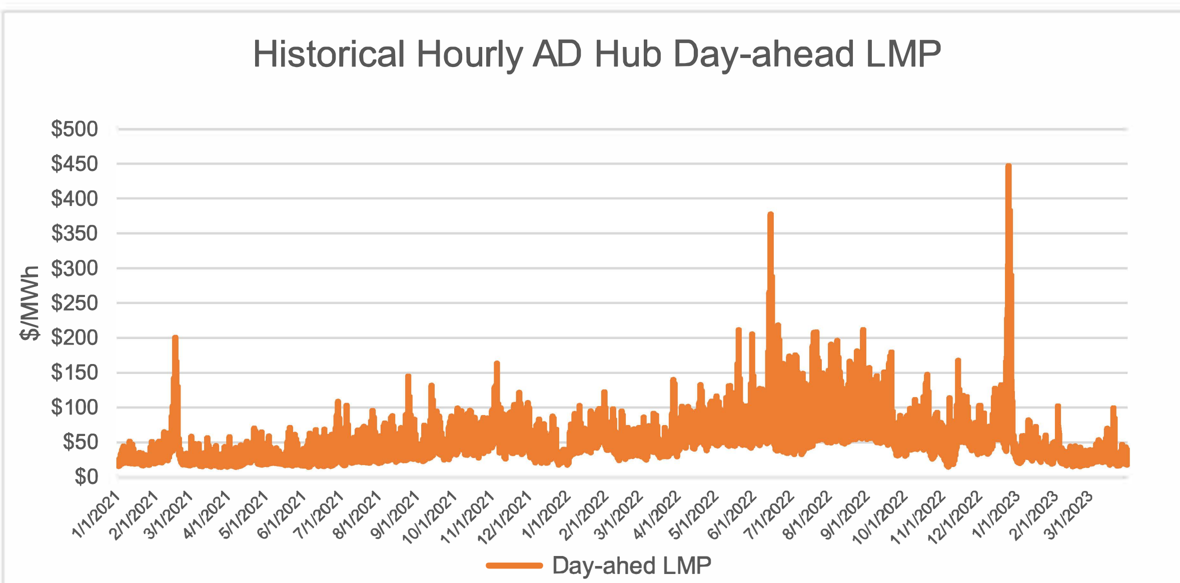
Hedge Interval 3									
Purchase Date	21Q1	21Q2	21Q3	21Q4	22Q1	22Q2	22Q3	22Q4	23Q1
7/1/2020	$ 30.38								
10/1/2020		$ 26.10							
1/2/2021			$ 26.79						
4/1/2021				$ 26.66					
7/1/2021					$ 39.79				
10/1/2021						$ 36.91			
1/2/2022							$ 40.87		
4/1/2022								$ 62.58	
7/1/2022									$ 80.47
Day-Ahead Settle Price	$ 30.33	$ 29.71	$ 41.22	$ 51.88	$ 48.46	$ 77.06	$ 87.06	$ 64.70	$ 31.05
Credit/(Charge)	$ (0.05)	$ 3.61	$ 14.43	$ 25.22	$ 8.67	$ 40.15	$ 46.19	$ 2.12	$ (49.42)

It is estimated that for all nine hedging periods, the Company would have had sufficient generation from the Big Sandy and Mitchell plants to cover the Target Hedge Percent during the first two hedge intervals; therefore, all hedge transactions would have been purchased for the third hedge interval. For the hedging period beginning in January and ending in March of 2021 (21Q1), the forward energy contract pricing during the third hedging period was $30.38/MWh and the average PJM spot energy market price of energy for the hedge period was $30.33MWh. In this example the average hedge contract price was greater than the PJM spot energy market price creating a hedging loss of $0.05/MWh for customers. The $0.05/MWh hedging loss would have been charged to the FAC, thereby increasing customer's fuel costs. Similarly, For the hedging period beginning in April and ending in June of 2021 (21Q2), the forward energy contract pricing during the third hedging period was $26.10/MWh and the average PJM spot energy market price of energy for the hedge period was $29.71/MWh. In this example the average hedge contract price was less than the PJM spot energy market price creating a hedging gain of $3.61/MWh for customers. The $3.61/MWh hedging gain would have been credited to the FAC, thereby reducing customer's fuel costs.

The goal of the proposed hedging plan is not to reduce customer's fuel costs over time; rather, it is to reduce their exposure to the volatility of the PJM spot energy market, especially when the Company's generating facilities have scheduled outages, leaving customers more exposed to PJM's Day-ahead market. The proposed hedging plan will reduce customer's sensitivity to PJM's spot market price volatility by creating more predictable fuel costs over time. The graphs in Figure AEV-7 below illustrate how hedging can help smooth out customer fuel costs. Had the Company incorporated a structured hedging program between January 2021 and March 2023, Customers would have been exposed to an average 21% price variance between their monthly fuel charges rather than the 28% variance seen in the spot market.

Figure AEV-7


Historical Hedge Example
$/MWh
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
30%
25%
20%
15%
10%
5%
0%
28%
21%
21Q1
21Q2
21Q3
21Q4
22Q1
22Q2
22Q3
22Q4
23Q1
Hedge Price
Market Price
Average Hedge Price Variance
Average Market Price Variance


Historical Hourly AD Hub Day-ahead LMP
$/MWh
$500
$450
$400
$350
$300
$250
$200
$150
$100
$50
$0
1/1/2021
2/1/2021
3/1/2021
4/1/2021
5/1/2021
6/1/2021
7/1/2021
8/1/2021
9/1/2021
10/1/2021
11/1/2021
12/1/2021
1/1/2022
2/1/2022
3/1/2022
4/1/2022
5/1/2022
6/1/2022
7/1/2022
8/1/2022
9/1/2022
10/1/2022
11/1/2022
12/1/2022
1/1/2023
2/1/2023
3/1/2023
Day-ahed LMP

Q. WHAT RATE RECOVERY TREATMENT IS THE COMPANY SEEKING REGARDING ITS PROPOSED FINANCIAL POWER HEDGING PROGRAM?

A. The Company proposes that all Commission-approved financial power hedging program-related contract settlements (gains and losses) and related contract costs be recovered through the FAC. A gain will be realized when the contracted price of financial power is less than the realized LMP value at the time of settlement. A loss will be realized when the opposite is true. The Company proposes that the financial power hedging program transactions will not be subject to the PUE FAC limitation as they are forward financial contracts entered into to reduce fuel rate volatility and market exposure, not to necessarily produce the absolute lowest purchased power cost in any hour.

Q. WILL THE COMPANY MAKE ANY FINANCIAL GAINS FROM THE PROPOSED FINANCIAL HEDGING PROGRAM?

A. No. The Company's proposed financial hedging program is designed to smooth out the impact of PJM's spot energy market price volatility on the Company's Open Energy Position and provide greater fuel cost certainty for customers. The hedging plan effectively locks-in or caps the price of future energy purchases for customers. If the actual energy price in the future turns out to be lower than the hedged price, customers will end up paying more for energy than they would have if the Company had purchased its Open Energy Position from the PJM spot energy market. This incremental cost will flow through the FAC as a hedge charge. Conversely, when the actual energy price turns out to be greater than the hedge price, customers will pay less than they would have if the Company had purchased its Open Energy Position from the PJM spot energy market. Any credits or charges (gains and losses) associated with the hedging program will be passed back to customers through the FAC. The potential for realized hedge charges from this program is essentially the cost of reducing volatility in customers' monthly fuel rates.

Q. HOW WOULD THE FINANCIAL POWER HEDGING PROGRAM BE ACCOUNTED FOR?

A. The financial power product being employed is expected to be a derivative, which would be subject to mark to market ("MTM") treatment. Should the Commission authorize the Company to pass back any credits or charges (gains and losses) associated with the hedging program to customer through the FAC, the Company would defer MTM gains or losses prior to hedge liquidation to a regulatory asset or liability which would unwind when the financial power contracts are liquidated at the time of settlement. The net gain or loss from liquidation would flow through the FAC as discussed earlier.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE COMPANY'S PROPOSAL.

A. PJM's energy market is susceptible to market volatility largely driven by the underlaying and interrelated fuel markets, operating conditions, and has been exacerbated over the years by extreme weather disturbances. A significant portion of the Company's load is subject to the day-to-day volatility of PJM's spot market and becomes even more magnified during times of planned outages at the Mitchell and Big Sandy plants. To help mitigate the exposure to the daily market volatility, the Company is proposing a rolling 36-month financial hedging plan to provide customers with greater fuel cost certainty over time. Although the monthly results of the Company's proposed hedging plan may not result in net fuel cost savings for customers, it will reduce their exposure to the fluctuations in the PJM Day-ahead energy market by creating more predictable fuel costs over time. This will leave customers better positioned to budget for and manage their monthly energy bills.

VI. DISTRIBUTED SOLAR PROPOSAL (SOLAR GARDEN PROGRAM)

i. Proposed Ownership and Accounting Structure

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S PROPOSED SOLAR GARDEN PROGRAM AND THE PROGRAM'S GENERAL COST RECOVERY STRUCTURE.

A. The Company proposes to own and operate one or more solar facilities, not to exceed 10 MW in individual size, to be located on the Company's distribution system. The aggregate capacity of all the solar sites will not exceed 25 MW. This program will help establish solar generation within the Company's service territory and fill a capacity need that starts in 2026. Projects will be considered a prudent investment if the Net Present Value[15] ("NPV") of the benefits and costs of the project do not exceed the NPV of the equivalent avoided capacity costs, an example of the items considered in the analysis is shown in Figure AEV-8 below, and Figure AEV-9 is an illustrative example of the economic test. The Company is seeking approval of this program so it can solicit through requests for proposals and acquire the projects without further Commission approvals if a project meets the proposed requirements.

[15] The discount rate would be equal to the Company's approved after tax weighted average cost of capital.

Figure AEV-8

Inputs of NPV Economic Prudency Test

Cost of Service Build Up	**Years 1-35**
O&M	(x)
Property Taxes	(x)
Insurance	(x)
Land Lease	(x)
ARO Depreciation	(x)
Accretion Expense	(x)
Depreciation Expense	(x)
Income and Property Taxes	(x)
PTC Revenue	x
Return on Rate Base	(x)
Total Cost of Service	(xx)

Test Input	**Value**	
NPV of Cost of Service	(xx)	**a**
NPV of Energy Value	MWh x Energy Price	**b**
NPV of Ancillary Charges	MWh x Ancillary Charge	**c**
NPV of OATT	Average 12 CP reduction x Annual Transmission Revenue Requirement $/MW-yr	**d**
NPV of REC Value	MWh x REC Price	**e**
NPV of Capacity Value	FRR 5CP Reduction x Capacity Price	**f**
Total NPV		**g = a-b-c-d-e-f**
NPV of Avoided Capacity Cost	Capacity MW x Capacity Price	**h**
Is (g) greater than (h)?	Prudency Test	

Figure AEV-9

Prudent Investment Example

NPV of Cost of Service	(64,904,189)	(63,595,882)
NPV of Benefits (Energy, OATT, Ancilary Service, REC Values)	49,500,986	70,342,556
Total NPV (a)	(15,403,203)	6,746,673
NPV of Capacity Cost (b)	(13,387,086)	(17,219,757)
Is a greater than b?	FALSE	TRUE

The Company is proposing to recover the net costs of these solar facilities acquired through the solar gardens program through Tariff PPA until they can be manifest as a reduction in FAC costs. The benefits and costs associated with these solar facilities are discussed later in my testimony.

Q. IS THIS PROPOSAL IN LINE WITH THE COMPANY'S RECENTLY FILED 2022 IRP?

A. Yes. The Company's going in capacity positions shows a 115MW shortfall in 2026, which grows even larger through 2037. The Preferred Plan shows 250MW of new solar being added in 2027 and further solar additions in 2028 and 2029.

Q. HOW WILL THE SOLAR GARDEN FACILITIES INTERACT WITH PJM?

A. The solar facilities will be connected to the Company's distribution system. They will act as a load reducer for PJM settlement purposes. This means that the Company's internal distribution load will be reduced by the output of the solar facilities, which will provide the Company and its customers with various PJM benefits. The solar facilities will not be market-facing generation resources and will not participate in PJM's energy, ancillary service, or capacity markets.

Q. WHAT OPERATIONS AND MAINTENANCE COSTS ARE ASSOCIATED WITH THE SOLAR FACILITIES?

A. Outside of general operating and maintenance costs, there are property taxes, insurance expenses and if the Company has to lease the land that the facilities reside on, land lease payments to the lessors of the land.

Q. WHAT IS THE DEPRECIABLE LIFE OF THE PROPOSED SOLAR FACILITIES?

A. The depreciable life of the proposed solar facilities is 35 years. This life is based upon the Company's current accounting policies related to solar generation technology. The

35 year life would also be supported by incremental capital additions over the life of the plant to lengthen the life of inverters.

Q. ARE THERE ANY ASSET RETIREMENT OBLIGATIONS ("AROs") ASSOCIATED WITH THE COMPANY'S PROPOSED SOLAR FACILITY?

A. Yes, if the Company leases the land, then at the end of the solar facilities' useful life, and the corresponding end of the land lease, the Company has the legal obligation to remove the solar generating equipment from the lessors' land. As such, the Company will recognize ARO depreciation expense in an amount equal to the estimated demolition cost 35 years after the solar facilities begin commercial operation and an estimate of the salvage value associated with the racking equipment and other salvageable items.

Q. DOES THE FEDERAL PRODUCTION TAX CREDIT APPLY TO THE PROPOSED SOLAR GARDENS?

A. Yes, it is expected that the solar gardens will qualify and generate the Production Tax Credit ("PTC"), at 100%. The Inflation Reduction Act ("IRA") was signed into law by President Biden on August 16, 2022, which created a new technology-neutral Clean Electricity PTC. The realized value of PTCs generated will be passed back to customers as a reduction to the cost of service of the facilities. Depending on where the facilities are ultimately sited, there is a possibility that they could qualify for a 110% PTC based on the "Energy Communities" portion of the IRA.

Prior to the passage of the IRA, the facilities would have only qualified for the Solar Investment Tax Credit ("ITC"). Every solar facility within this program, will be individually evaluated to ensure max benefits are being recognized for customers.

ii. Customer Benefit Analysis

Q. WHAT FINANCIAL BENEFITS WILL ALL OF THE COMPANY'S CUSTOMERS RECEIVE FROM THE SOLAR GARDEN PROGRAM?

A. As mentioned earlier, the solar facilities will reduce the Company's wholesale load that it purchases from PJM each hour that the solar facilities are producing solar power and injecting it into the Company's distribution system. Because of this, the Company will realize energy, ancillary service, and capacity benefits related to both its generation and transmission obligations in PJM.

Energy Benefits

The energy benefits will manifest by the Company purchasing approximately 33,500 fewer MWh of on-peak energy (49,008 MWh of energy in total) from the PJM RTO annually. This is because the Company purchases all of its load requirements from the hourly energy markets of PJM and sells its generation resources into those same markets. The monthly cost reconstruction/economic dispatch and deferred fuel accounting process ensures that customers receive the lowest cost resources and the resulting monthly average costs through a combination of the Company's base fuel rates and the fuel adjustment clause. The proposed solar facilities will reduce the Company's on-peak load[16] that it purchases from PJM, thus avoiding on-peak purchases and the higher hourly pricing associated with them.

[16] While solar produces energy during "on-peak" daytime hours, weekend days are considered off-peak for pricing purposes.

Ancillary Service Benefits

Also due to the reduction of the Company's PJM load, customers will receive a benefit by avoiding hourly PJM ancillary service load charges.

Capacity Benefits

To the extent that the solar facilities are producing energy during the Company's capacity cost-causing hours in PJM, Kentucky Power will have a lower generation capacity obligation, which will result in lower generation capacity costs.

LSE OATT Charges

Similar to the generation capacity peak reduction, the facilities will also reduce the Company's 12CP used to allocate PJM load serving entity Open Access Transmission Tariff charges to the Company.

The solar facilities also produce one renewable energy certificate ("REC") per MWh of energy generated. These RECs can then be sold bilaterally into the marketplace to offset the cost of the solar facilities.

Q. ARE THERE ADDITIONAL NON-COST OF SERVICE BENEFITS RELATED TO THE COMPANY'S PROPOSED SOLAR FACILITIES?

A. Yes. The solar facilities will pay property taxes to the Commonwealth and the localities where they are built. There will also be local jobs created during the construction and operation of the facilities, all within the Company's service territory.

Q. ARE YOU PROPOSING THAT ANY OF THE NON-COST OF SERVICE BENEFITS BE PRICED INTO THE PROPOSED SOLAR GARDEN PROGRAM?

A. No. The Company's rates are based on cost of service ratemaking. They do not consider non-cost of service economic factors or other externalities. Although these things may exist and may provide positive economic and societal benefits, they do not belong in the Company's rates.

<u>iii. Low-Income Benefit Option</u>

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S PROPOSED LOW-INCOME BENEFIT OPTION IN RELATION TO THE SOLAR GARDEN PROGRAM.

A. The Company has approximately 11,500 customers that are participating in government assistance programs, such as the Federal Low Income Home Energy Assistance Program ("LIHEAP"). The Company is proposing to provide 50 percent of the energy benefits from the Solar Gardens to these customers through a yearly bill credit, to be credited in their January billing when customer bills are generally higher due to heating usage. The customers will not have to sign up for the option, they will be automatically enrolled.

Q. HOW WILL THE ENERGY CREDIT BE CALCULATED?

A. The Company is proposing to use the hourly MWh produced from the solar facilities for the previous 12 months and multiply that by the Day Ahead Local Marginal Price ("DA LMP") for the corresponding hour. The total will then be multiplied by 50 percent and divided by the number of customers identified as low-income through their participation in LIHEAP as of December 31. Based on high-level estimates, this credit could amount to approximately $66 per customer annually.

Q. IS THE 50 PERCENT ENERGY BENEFIT THE ONLY BENEFIT THESE CUSTOMERS WILL RECEIVE FROM THE SOLAR GARDEN PROGRAM?

A. No. These customers will also still receive all of the other the benefits mentioned in the customer benefit analysis portion of my testimony.

iii. Summary

Q. PLEASE SUMMARIZE THE ACCOUNTING FOR THE PROPOSED SOLAR GARDEN FACILITIES AND THE LOW INCOME OPTION.

A. The Company is proposing to flow all non-energy benefits and all costs through Tariff PPA and will be subject to the normal true-up process for Tariff PPA. Energy benefits will flow through the FAC in the form of reduced load requirements being purchased from the PJM spot energy market. The Company is also proposing to provide 50 percent of the energy benefits from the Solar Gardens to low-income customers through a yearly bill credit, as discussed above. The 50 percent of the energy benefit being credited to low-income customers would also be recovered through Tariff FAC.

Q. SHOULD THE PROPOSED SOLAR GARDEN PROGRAM BE APPROVED?

A. Yes, because of the benefits to customers, the proposed built in customer protections, and the need for solar identified in the Company's 2022 IRP, the proposed solar garden program should be approved.

VII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED TESTIMONY?

A. Yes, it does.

VERIFICATION

The undersigned, Alex E. Vaughan, being duly sworn, deposes and says he is the Managing Director for Renewables and Fuel Strategy for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief after reasonable inquiry.

Alex E. Vaughan

Franklin County)
Ohio)
) Case No. 2023-00159

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Alex E. Vaughan, on 12/7/23.

Notary Public

KIM WOLFENBERGER - NOTARY PUBLIC
STATE OF OHIO

My Commission Expires 5/4/2028

Notary ID Number 2013-RE-707303