

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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I. INTRODUCTION

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

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

II. BACKGROUND

7 **Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND**
8 **BUSINESS EXPERIENCES.**

9 A. I graduated from Bowling Green State University with a Bachelor of Science degree in
10 Finance in 2005. Prior to joining AEPSC, I worked for a retail bank and a holding
11 company where I held various underwriting, finance, and accounting positions. In
12 2007, I joined AEPSC as a Settlement Analyst in the RTO Settlements Group. I later
13 became the PJM Settlements Lead Analyst, and in that role, I was responsible for
14 reconciling AEP’s settlement of its activities in the PJM Interconnection, LLC (“PJM”)
15 market with the monthly PJM invoices and for resolving issues with PJM. In 2010, I
16 transferred to Regulatory Services as a Regulatory Analyst and was later promoted to

1 the position of Regulatory Consultant. My responsibilities included supporting
2 regulatory filings across AEP's eleven state jurisdictions and at the FERC. I also
3 performed financial analyses related to AEP's generation resources and loads, power
4 pools, and PJM. In September 2012, I was promoted to Manager, Regulatory Pricing
5 and Analysis, where I was responsible for cost of service, rate design, and special
6 contract analysis for the AEP east operating companies. In September 2018, I was
7 promoted to Director of Regulated Renewables and Pricing, at which time oversight of
8 regulated renewable and fuel filings across the AEP operating companies was added to
9 my responsibilities. I was promoted to my current position in June 2022.

10 **Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES.**

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

17 **Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY**
18 **PROCEEDINGS?**

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

1 00396, 2017-00179, and 2020-00174), and the proposed transfer of ownership of
2 Kentucky Power in Case No. 2021-00481.

III. PURPOSE OF TESTIMONY

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

4 A. The purpose of my testimony is threefold:

- 5 • To support the prudence of the approximately \$11.5 million winter storm
6 Elliott Peaking Unit Equivalent (“PUE”) purchased power expense and \$3.2
7 million of other PUE expense Kentucky Power incurred during the test year;
- 8 • To describe and outline the Company’s proposed financial power hedging
9 framework for which it is seeking approval; and
- 10 • To describe and support the Company’s proposed distributed solar program.

IV. PUE EXPENSE

11 **Q. PLEASE DESCRIBE THE SITUATION THAT CAUSED THE**
12 **APPROXIMATELY \$11.5 MILLION WINTER STORM ELLIOTT PUE**
13 **EXPENSE.**

14 A. Winter Storm Elliott (“Elliott”) was an extreme cold weather event that included
15 blizzards, high winds, snowfall and record cold temperatures across much of the United
16 States. Elliott occurred December 23, 2022 through December 26, 2022, in the PJM
17 region (the “Winter Storm Elliott Period”).¹ The resulting load during this period of
18 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).

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

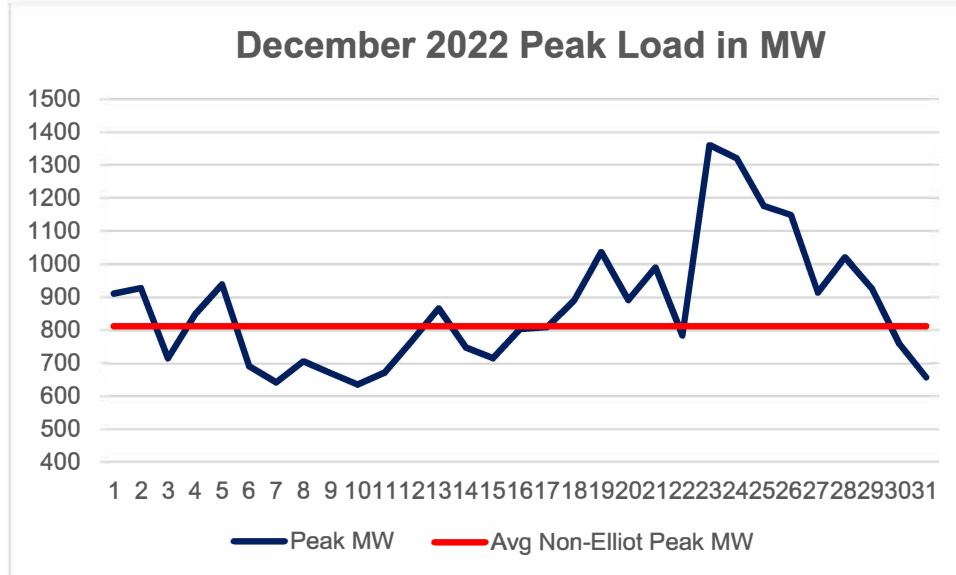
4 The unanticipated high load and rapid load increase combined with generation
5 outages due to cold weather and fuel issues resulted in Performance Assessment
6 Intervals (“PAIs”) on December 23, 2022 and December 24, 2022. PAIs are triggered
7 when PJM declares an emergency action in the RTO. During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

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

14 A. Yes. The Company’s peak load during the Winter Storm Elliott Period was 1,358
15 MW, 46% higher than the Company’s previous 12 month average peak demand
16 (“12CP”) of 929 MW. In 85 of the 96 hours during the event, the Company’s hourly
17 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

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

1 shows real-time LMPs over the month of December 2022 to put into context how much
2 of an outlier pricing during Elliott was and provide a narrower view on the hourly
3 pricing during Elliott.

Figure AEV-2

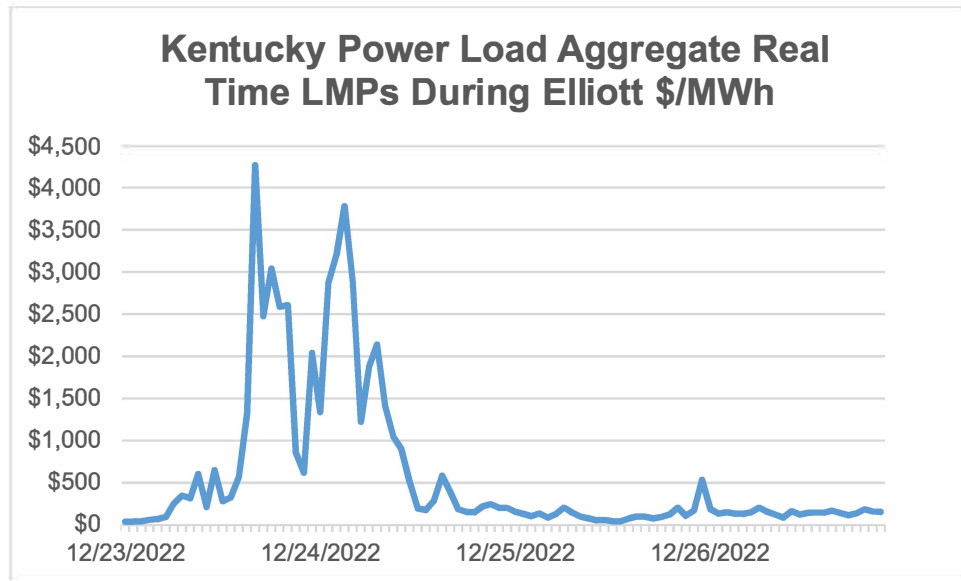
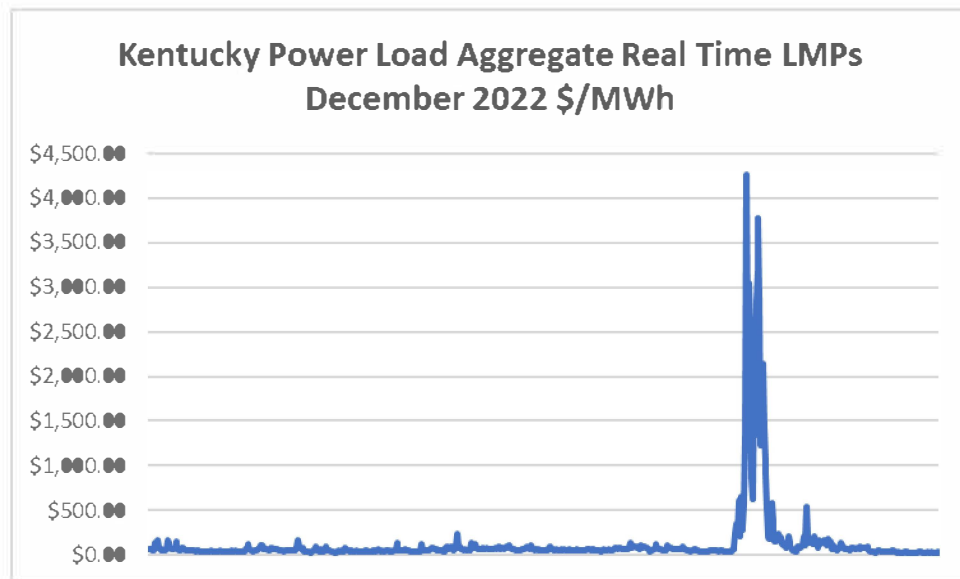


Figure AEV-3



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

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

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

15 A. Yes. The Company's generation resources at 100% of their installed capacities
16 ("ICAP") can produce approximately 1,076 MWh. As discussed earlier, the
17 Company's load was extremely high during Elliott because of the extreme cold. In
18 many instances, the Company's customers rely on electricity for heating their homes,
19 which caused extremely high load conditions during Elliott. Thus, even had the
20 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.

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

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

5 A. No, due to the Company's prudent management of its available coal supplies during
6 2022, the Mitchell Plant was available to run and, as previously discussed, operated
7 continuously during Elliott and the PAIs called by PJM. Furthermore, the larger AEP
8 Companies FRR plan, in which Kentucky Power participates, also did not incur a
9 penalty as it benefited from the diversity of generation resource types and locations
10 utilized by the Companies in the plan.

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

14 A. The Company had to purchase power from the PJM spot energy market during Elliott
15 because the Company's load obligations were in excess of the supply available from
16 its resources. The Company's plan for covering load obligations in excess of available
17 generation supply is to purchase the balance of its energy requirements from the PJM
18 spot energy markets. The Company's customers receive the lower of cost to generate
19 or market energy prices as determined by PJM's FERC approved tariff and economic
20 dispatch model. To the extent that the Company may be adding additional owned or
21 contracted capacity and energy resources in the future to replace the energy and
22 capacity from the recently expired Rockport Unit Power Agreement ("UPA"), those
23 resources would contribute in the future to reducing the Company's amount of spot

1 market energy purchases from PJM. However, it should be noted that resource
2 acquisitions are generally informed by long-range integrated resource planning and
3 forecasting that utilizes normative forecasts that do not account for extreme outlier
4 events like Elliott. The weather and resulting conditions in the PJM energy market
5 during Elliott were an outlier; it is highly unlikely that traditional resource planning
6 would result in the Company being insulated from all possible PJM energy market
7 fluctuations.

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

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

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

20 A. Hypothetically speaking, had the Company known it would need 283 MW⁶ of
21 additional purchased power during Elliott, and had it purchased financial power⁷ 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.

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

13 Had the Company bought that same amount of financial purchased power for
14 the balance of the winter (January-March in addition to December), rather than settling
15 its net load requirements at the spot market energy prices, total fuel costs would have
16 been materially higher under every scenario as can be seen in Figure AEV-4.
17 Furthermore, as discussed later in the financial power hedging portion of my testimony,
18 these types of extreme load spikes are not what a hedging program is meant to insulate
19 against. In fact, the Company's proposed hedging program will utilize weather normal
20 load levels (which do not include extreme cold or heat events that materially impact
21 retail load) and would leave one standard deviation of the total position open to the spot
22 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 | |

1 A similar fact pattern would be true if the Company had purchased a block of
2 financial power to replace Big Sandy Unit 1's 295 MW of generation when it became
3 known that the emergent generator issue with Big Sandy Unit 1⁸ would keep the unit
4 in a planned outage for all of December 2022. Had the Company purchased that block
5 of power⁹ for the remainder of the month of December after the equipment issue was
6 discovered on December 2, 2022, total purchased power costs realized would not have
7 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.

1 \$82.93/MWh and the average December 2022 liquidated price was \$83.85. Therefore,
2 less than a dollar per MWh (or roughly \$190,000 in total) of savings was hypothetically
3 possible. It should be noted that making such a transaction at a single point in time,
4 rather than layering in over time as the Company is proposing in its hedging program,
5 can be financially risky. This is very evident when looking out just a single month
6 from December of 2022 to January of 2023, when the average PJM spot market price
7 shown in Figure 4 dropped to just \$36.22/MWh.

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

11 A. Yes, the Company called for curtailments of its interruptible customers¹⁰ on December
12 23, 2022 and December 24, 2022, and those customers reduced their operations to their
13 contracted firm service level during these events.

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

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

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

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

¹⁰ Tariff DRS and special contract.

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

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

13 A. Yes it is. Both the Attorney General and Kentucky Industrial Utility Customers, Inc.
14 ("KIUC") (collectively, "AG-KIUC") advocated for the use of short-term bilateral
15 market capacity purchases and the PJM spot energy market in lieu of the Company
16 owning long-term assets to fill the same need. In their joint comments on Kentucky
17 Power's 2019 IRP Preferred Plan AG-KIUC stated: "This is further evidence that the
18 Company should adjust its Preferred Plan to include additional MPs [market
19 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.*

1 environment for more than ten years with no indication this will change any time
2 soon.”¹² The joint comments also state:

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

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

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

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

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.

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

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

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

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

1 approved tariff. They are next cheapest spot source of energy available to serve
2 customers.

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

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

V. FINANCIAL POWER HEDGING PROPOSAL

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

18 A. The Company has been backstopped from an energy standpoint by a pooling
19 arrangement since 1951. Until December 31, 2013¹⁴ the Company was a member of
20 the AEP Interconnection Agreement ("AEP East Pool"), where any energy shortfall

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

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

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

18 A. Because the Company sells all of its available generation resources into PJM's spot
19 energy market and purchases all of its load from the same market, the net position if
20 short is what is actually exposed financially to the spot energy market. Thus, the
21 Company's generating resources provide a physical hedge on the spot energy market.
22 During times of planned or forced outages, absent taking on additional resource hedge
23 positions, the physical hedge position provided by the Mitchell and Big Sandy plants

1 will decline, leaving Customers more exposed to PJM's spot energy market price
2 volatility. However, the Company can reduce this exposure by purchasing financial
3 hedges to replace the generation.

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

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

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

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

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

17 A. The Company proposes to use financial hedge products to mitigate the volatility of its
18 PJM spot energy market energy purchases for its Open Energy Positions. PJM AD
19 HUB fixed-for-floating price swaps, also known as contracts for differences, will be
20 used to reduce customer exposure to the volatility in market prices. These forward
21 contracts will be purchased in layers over time to match the Company's target hedge
22 position and smooth out the impact of price volatility in the market. The hedging plan
23 would provide the flexibility to modify or unwind executed forward contracts, as

1 necessary, when adjustments or changes are made to the forecasted load or planned
2 outage schedules at the Mitchell and Big Sandy generation plants. If the PJM AD HUB
3 forward future market is not liquid enough to purchase the target hedge position, the
4 Company may purchase financial future contracts from adjacent zones or other liquid
5 trading hubs, such as the PJM West Hub, to fill in the short position.

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

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

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

14 A. Upon Commission approval of the financial hedging plan.

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

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

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

1 The Target Hedge Percent in Figure AEV-5 below represents the targeted
 2 amount of the Company’s Open Energy Position to be hedged for a given hedge
 3 interval. When the Interval Hedge Percent is less than the Target Hedge Percent, the
 4 Company will calculate the Target Hedge Position for that interval and purchase
 5 forward energy contracts to hedge its Open Energy Position up to the Target Hedge
 6 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% |

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

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

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

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

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

12 **Q. UNDER THE PROPOSED FINANCIAL HEDGING PLAN, HOW MANY MWH**
13 **OF THE COMPANY'S OPEN ENERGY POSITION WOULD BE HEDGED IN**
14 **2024?**

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

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

A.

Figure AEV-6
 Historical Example Hedge Transactions

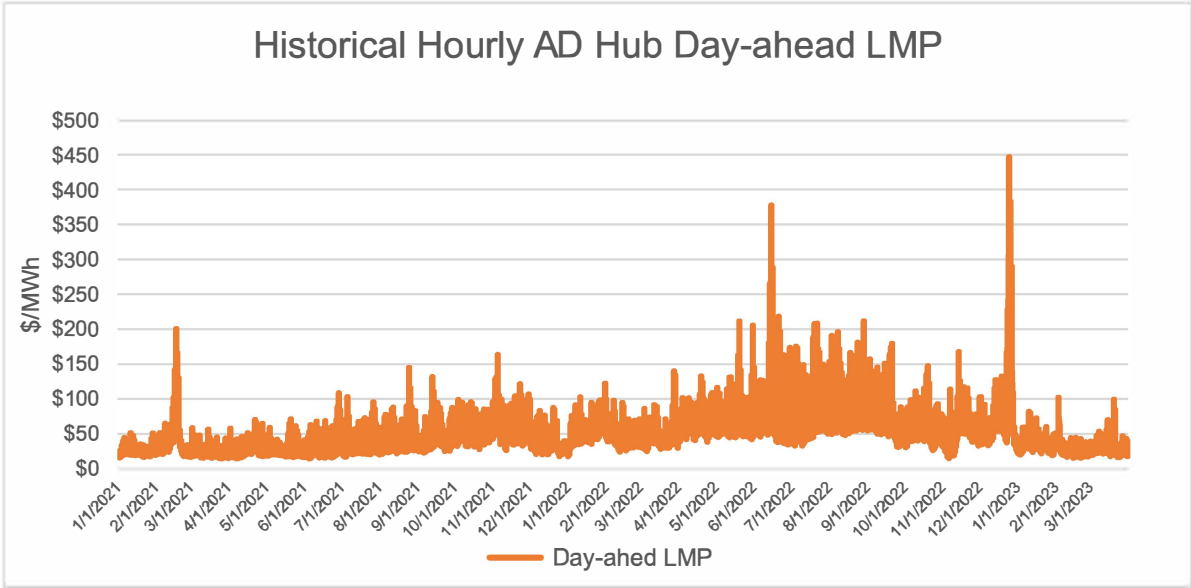
| Hedge Interval 3 | | | | | | | | | |
|------------------------|-----------|----------|----------|----------|----------|----------|----------|----------|------------|
| Purchase Date | 21Q1 | 21Q2 | 21Q3 | 21Q4 | 22Q1 | 22Q2 | 22Q3 | 22Q4 | 23Q1 |
| 7/1/2020 | \$ 30.38 | | | | | | | | |
| 10/1/2020 | | \$ 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) |

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

1 average PJM spot energy market price of energy for the hedge period was
2 \$29.71/MWh. In this example the average hedge contract price was less than the PJM
3 spot energy market price creating a hedging gain of \$3.61/MWh for customers. The
4 \$3.61/MWh hedging gain would have been credited to the FAC, thereby reducing
5 customer's fuel costs.

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

Figure AEV-7



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

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

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

14 A. No. The Company's proposed financial hedging program is designed to smooth out the
15 impact of PJM's spot energy market price volatility on the Company's Open Energy
16 Position and provide greater fuel cost certainty for customers. The hedging plan
17 effectively locks-in or caps the price of future energy purchases for customers. If the
18 actual energy price in the future turns out to be lower than the hedged price, customers
19 will end up paying more for energy than they would have if the Company had
20 purchased its Open Energy Position from the PJM spot energy market. This incremental
21 cost will flow through the FAC as a hedge charge. Conversely, when the actual energy
22 price turns out to be greater than the hedge price, customers will pay less than they
23 would have if the Company had purchased its Open Energy Position from the PJM spot

1 energy market. Any credits or charges (gains and losses) associated with the hedging
2 program will be passed back to customers through the FAC. The potential for realized
3 hedge charges from this program is essentially the cost of reducing volatility in
4 customers' monthly fuel rates.

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

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

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

17 A. PJM's energy market is susceptible to market volatility largely driven by the
18 underlying and interrelated fuel markets, operating conditions, and has been
19 exacerbated over the years by extreme weather disturbances. A significant portion of
20 the Company's load is subject to the day-to-day volatility of PJM's spot market and
21 becomes even more magnified during times of planned outages at the Mitchell and Big
22 Sandy plants. To help mitigate the exposure to the daily market volatility, the Company
23 is proposing a rolling 36-month financial hedging plan to provide customers with

1 greater fuel cost certainty over time. Although the monthly results of the Company's
2 proposed hedging plan may not result in net fuel cost savings for customers, it will
3 reduce their exposure to the fluctuations in the PJM Day-ahead energy market by
4 creating more predictable fuel costs over time. This will leave customers better
5 positioned to budget for and manage their monthly energy bills.

VI. DISTRIBUTED SOLAR PROPOSAL (SOLAR GARDEN PROGRAM)

i. Proposed Ownership and Accounting Structure

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

9 A. The Company proposes to own and operate one or more solar facilities, not to exceed
10 10 MW in individual size, to be located on the Company's distribution system. The
11 aggregate capacity of all the solar sites will not exceed 25 MW. This program will help
12 establish solar generation within the Company's service territory and fill a capacity
13 need that starts in 2026. Projects will be considered a prudent investment if the Net
14 Present Value¹⁵ ("NPV") of the benefits and costs of the project do not exceed the NPV
15 of the equivalent avoided capacity costs, an example of the items considered in the
16 analysis is shown in Figure AEV-8 below, and Figure AEV-9 is an illustrative example
17 of the economic test. The Company is seeking approval of this program so it can solicit
18 through requests for proposals and acquire the projects without further Commission
19 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, Ancillary 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 |

- 1 The Company is proposing to recover the net costs of these solar facilities
- 2 acquired through the solar gardens program through Tariff PPA until they can be

1 manifest as a reduction in FAC costs. The benefits and costs associated with these
2 solar facilities are discussed later in my testimony.

3 **Q. IS THIS PROPOSAL IN LINE WITH THE COMPANY'S RECENTLY FILED**
4 **2022 IRP?**

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

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

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

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

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

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

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

1 35 year life would also be supported by incremental capital additions over the life of
2 the plant to lengthen the life of inverters.

3 **Q. ARE THERE ANY ASSET RETIREMENT OBLIGATIONS (“AROs”)**
4 **ASSOCIATED WITH THE COMPANY’S PROPOSED SOLAR FACILITY?**

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

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

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

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

ii. Customer Benefit Analysis

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

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

8 **Energy Benefits**

9 The energy benefits will manifest by the Company purchasing approximately 33,500
10 fewer MWh of on-peak energy (49,008 MWh of energy in total) from the PJM RTO
11 annually. This is because the Company purchases all of its load requirements from the
12 hourly energy markets of PJM and sells its generation resources into those same
13 markets. The monthly cost reconstruction/economic dispatch and deferred fuel
14 accounting process ensures that customers receive the lowest cost resources and the
15 resulting monthly average costs through a combination of the Company's base fuel
16 rates and the fuel adjustment clause. The proposed solar facilities will reduce the
17 Company's on-peak load¹⁶ that it purchases from PJM, thus avoiding on-peak
18 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.

1 Ancillary Service Benefits

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

4 Capacity Benefits

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

8 LSE OATT Charges

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

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

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

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

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

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

iii. Low-Income Benefit Option

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

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

18 **Q. HOW WILL THE ENERGY CREDIT BE CALCULATED?**

19 A. The Company is proposing to use the hourly MWh produced from the solar facilities
20 for the previous 12 months and multiply that by the Day Ahead Local Marginal Price
21 ("DA LMP") for the corresponding hour. The total will then be multiplied by 50 percent
22 and divided by the number of customers identified as low-income through their

1 participation in LIHEAP as of December 31. Based on high-level estimates, this credit
2 could amount to approximately \$66 per customer annually.

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

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

iii. Summary

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

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

16 **Q. SHOULD THE PROPOSED SOLAR GARDEN PROGRAM BE APPROVED?**

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


VII. CONCLUSION

1 **Q. DOES THIS CONCLUDE YOUR PRE-FILED TESTIMONY?**

2 **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

State of Ohio)
_____))
Franklin County)

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 12.4.22.



Notary Public

My Commission Expires _____



CRAIG CARLSON
ATTORNEY AT LAW
NOTARY PUBLIC, STATE OF OHIO
MY COMMISSION HAS NO EXPIRATION DATE

Notary ID Number _____

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

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**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

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

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

II. BACKGROUND

7 **Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND**
8 **BUSINESS EXPERIENCES.**

9 A. I graduated from Bowling Green State University with a Bachelor of Science degree in
10 Finance in 2005. Prior to joining AEPSC, I worked for a retail bank and a holding
11 company where I held various underwriting, finance, and accounting positions. In
12 2007, I joined AEPSC as a Settlement Analyst in the RTO Settlements Group. I later
13 became the PJM Settlements Lead Analyst, and in that role, I was responsible for
14 reconciling AEP’s settlement of its activities in the PJM Interconnection, LLC (“PJM”)
15 market with the monthly PJM invoices and for resolving issues with PJM. In 2010, I
16 transferred to Regulatory Services as a Regulatory Analyst and was later promoted to

1 the position of Regulatory Consultant. My responsibilities included supporting
2 regulatory filings across AEP's eleven state jurisdictions and at the FERC. I also
3 performed financial analyses related to AEP's generation resources and loads, power
4 pools, and PJM. In September 2012, I was promoted to Manager, Regulatory Pricing
5 and Analysis, where I was responsible for cost of service, rate design, and special
6 contract analysis for the AEP east operating companies. In September 2018, I was
7 promoted to Director of Regulated Renewables and Pricing, at which time oversight of
8 regulated renewable and fuel filings across the AEP operating companies was added to
9 my responsibilities. I was promoted to my current position in June 2022.

10 **Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES.**

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

17 **Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY**
18 **PROCEEDINGS?**

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

1 00396, 2017-00179, and 2020-00174), and the proposed transfer of ownership of
2 Kentucky Power in Case No. 2021-00481.

III. PURPOSE OF TESTIMONY

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

4 A. The purpose of my testimony is threefold:

- 5 • To support the prudence of the approximately \$11.5 million winter storm
6 Elliott Peaking Unit Equivalent (“PUE”) purchased power expense and \$3.2
7 million of other PUE expense Kentucky Power incurred during the test year;
- 8 • To describe and outline the Company’s proposed financial power hedging
9 framework for which it is seeking approval; and
- 10 • To describe and support the Company’s proposed distributed solar program.

IV. PUE EXPENSE

11 **Q. PLEASE DESCRIBE THE SITUATION THAT CAUSED THE**
12 **APPROXIMATELY \$11.5 MILLION WINTER STORM ELLIOTT PUE**
13 **EXPENSE.**

14 A. Winter Storm Elliott (“Elliott”) was an extreme cold weather event that included
15 blizzards, high winds, snowfall and record cold temperatures across much of the United
16 States. Elliott occurred December 23, 2022 through December 26, 2022, in the PJM
17 region (the “Winter Storm Elliott Period”).¹ The resulting load during this period of
18 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).

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

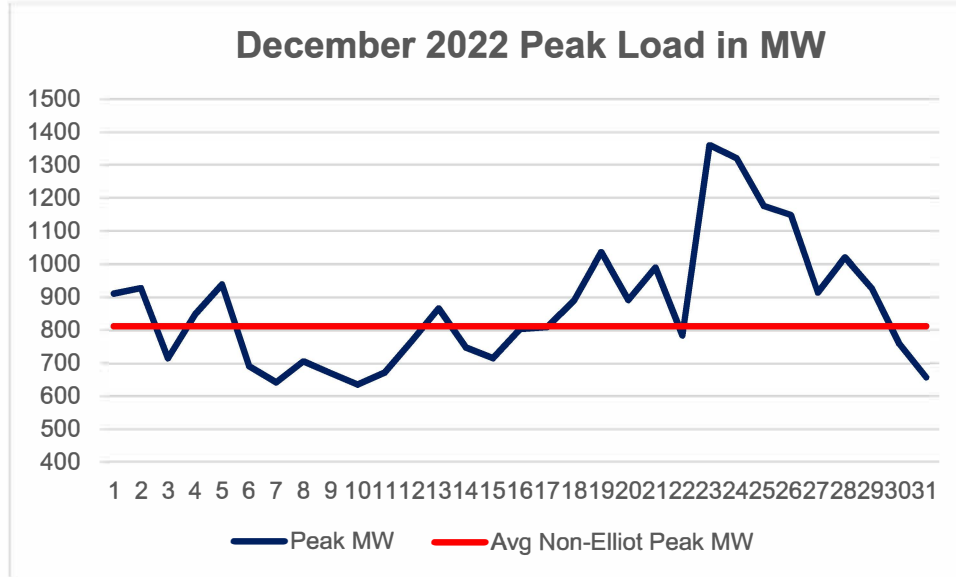
4 The unanticipated high load and rapid load increase combined with generation
5 outages due to cold weather and fuel issues resulted in Performance Assessment
6 Intervals (“PAIs”) on December 23, 2022 and December 24, 2022. PAIs are triggered
7 when PJM declares an emergency action in the RTO. During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

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

14 A. Yes. The Company’s peak load during the Winter Storm Elliott Period was 1,358
15 MW, 46% higher than the Company’s previous 12 month average peak demand
16 (“12CP”) of 929 MW. In 85 of the 96 hours during the event, the Company’s hourly
17 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

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

1 shows real-time LMPs over the month of December 2022 to put into context how much
2 of an outlier pricing during Elliott was and provide a narrower view on the hourly
3 pricing during Elliott.

Figure AEV-2

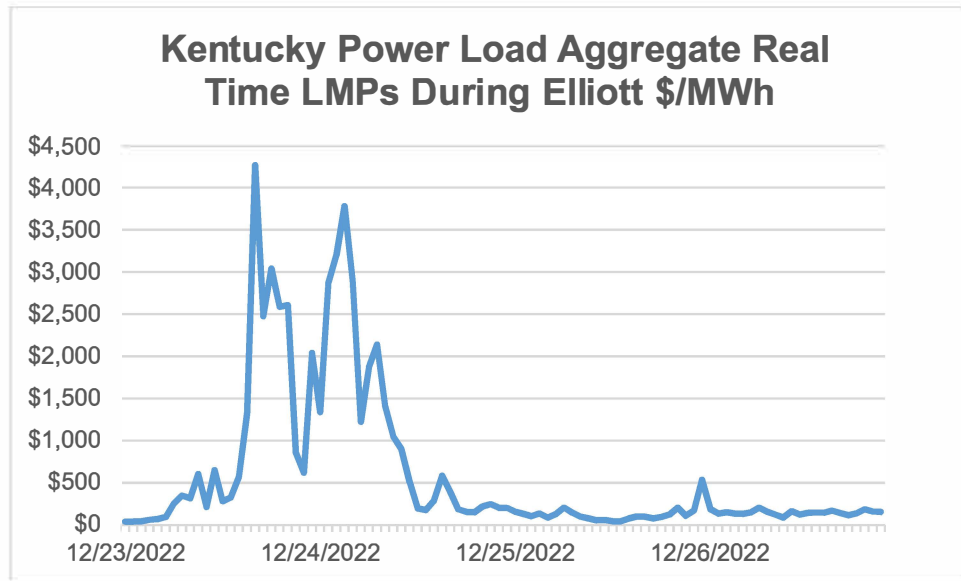
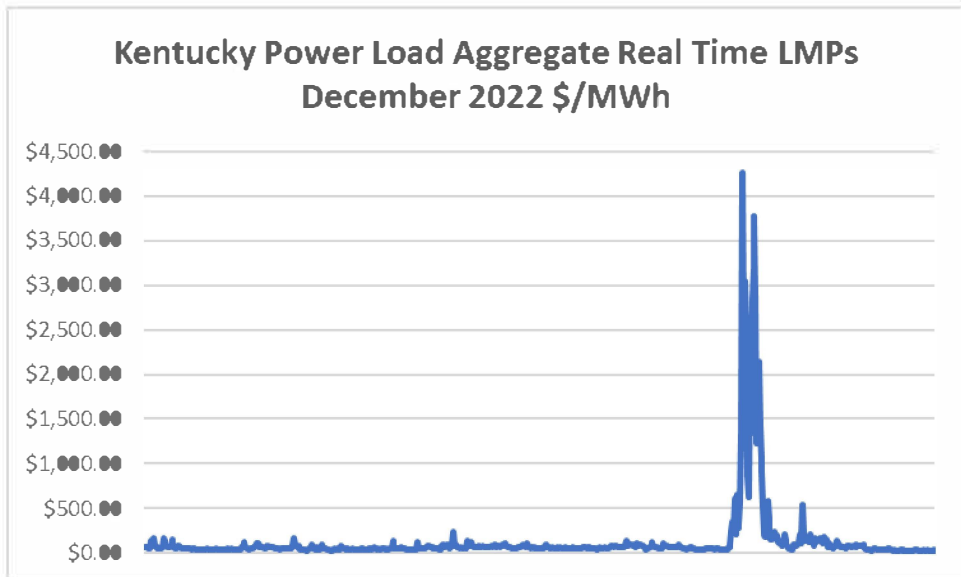


Figure AEV-3



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

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

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

15 A. Yes. The Company's generation resources at 100% of their installed capacities
16 ("ICAP") can produce approximately 1,076 MWh. As discussed earlier, the
17 Company's load was extremely high during Elliott because of the extreme cold. In
18 many instances, the Company's customers rely on electricity for heating their homes,
19 which caused extremely high load conditions during Elliott. Thus, even had the
20 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.

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

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

5 A. No, due to the Company's prudent management of its available coal supplies during
6 2022, the Mitchell Plant was available to run and, as previously discussed, operated
7 continuously during Elliott and the PAIs called by PJM. Furthermore, the larger AEP
8 Companies FRR plan, in which Kentucky Power participates, also did not incur a
9 penalty as it benefited from the diversity of generation resource types and locations
10 utilized by the Companies in the plan.

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

14 A. The Company had to purchase power from the PJM spot energy market during Elliott
15 because the Company's load obligations were in excess of the supply available from
16 its resources. The Company's plan for covering load obligations in excess of available
17 generation supply is to purchase the balance of its energy requirements from the PJM
18 spot energy markets. The Company's customers receive the lower of cost to generate
19 or market energy prices as determined by PJM's FERC approved tariff and economic
20 dispatch model. To the extent that the Company may be adding additional owned or
21 contracted capacity and energy resources in the future to replace the energy and
22 capacity from the recently expired Rockport Unit Power Agreement ("UPA"), those
23 resources would contribute in the future to reducing the Company's amount of spot

1 market energy purchases from PJM. However, it should be noted that resource
2 acquisitions are generally informed by long-range integrated resource planning and
3 forecasting that utilizes normative forecasts that do not account for extreme outlier
4 events like Elliott. The weather and resulting conditions in the PJM energy market
5 during Elliott were an outlier; it is highly unlikely that traditional resource planning
6 would result in the Company being insulated from all possible PJM energy market
7 fluctuations.

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

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

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

20 A. Hypothetically speaking, had the Company known it would need 283 MW⁶ of
21 additional purchased power during Elliott, and had it purchased financial power⁷ 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.

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

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

Figure AEV-4 - Hypothetical Forward Purchased Power Transactions

| MW Needed to Cover Elliott Peak | | 283 | | | | |
|---------------------------------------|----------------------|---------------------|---------------------|---------------------|---------------------|--|
| July Forwards | | | | | | |
| Forward Price | December | January | February | March | Total | |
| | \$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 | | | | | | |
| Forward Price | December | January | February | March | Total | |
| | \$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 | | | | | | |
| Forward Price | December | January | February | March | Total | |
| | \$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 | | | | | | |
| Forward Price | December | January | February | March | Total | |
| | \$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 | | | | | | |
| Forward Price | December | January | February | March | Total | |
| | \$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 | |

1 A similar fact pattern would be true if the Company had purchased a block of
2 financial power to replace Big Sandy Unit 1's 295 MW of generation when it became
3 known that the emergent generator issue with Big Sandy Unit 1⁸ would keep the unit
4 in a planned outage for all of December 2022. Had the Company purchased that block
5 of power⁹ for the remainder of the month of December after the equipment issue was
6 discovered on December 2, 2022, total purchased power costs realized would not have
7 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.

1 \$82.93/MWh and the average December 2022 liquidated price was \$83.85. Therefore,
2 less than a dollar per MWh (or roughly \$190,000 in total) of savings was hypothetically
3 possible. It should be noted that making such a transaction at a single point in time,
4 rather than layering in over time as the Company is proposing in its hedging program,
5 can be financially risky. This is very evident when looking out just a single month
6 from December of 2022 to January of 2023, when the average PJM spot market price
7 shown in Figure 4 dropped to just \$36.22/MWh.

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

11 A. Yes, the Company called for curtailments of its interruptible customers¹⁰ on December
12 23, 2022 and December 24, 2022, and those customers reduced their operations to their
13 contracted firm service level during these events.

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

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

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

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

¹⁰ Tariff DRS and special contract.

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

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

13 A. Yes it is. Both the Attorney General and Kentucky Industrial Utility Customers, Inc.
14 ("KIUC") (collectively, "AG-KIUC") advocated for the use of short-term bilateral
15 market capacity purchases and the PJM spot energy market in lieu of the Company
16 owning long-term assets to fill the same need. In their joint comments on Kentucky
17 Power's 2019 IRP Preferred Plan AG-KIUC stated: "This is further evidence that the
18 Company should adjust its Preferred Plan to include additional MPs [market
19 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.*

1 environment for more than ten years with no indication this will change any time
2 soon.”¹² The joint comments also state:

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

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

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

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

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.

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

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

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

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

1 approved tariff. They are next cheapest spot source of energy available to serve
2 customers.

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

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

V. FINANCIAL POWER HEDGING PROPOSAL

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

18 A. The Company has been backstopped from an energy standpoint by a pooling
19 arrangement since 1951. Until December 31, 2013¹⁴ the Company was a member of
20 the AEP Interconnection Agreement ("AEP East Pool"), where any energy shortfall

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

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

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

18 A. Because the Company sells all of its available generation resources into PJM's spot
19 energy market and purchases all of its load from the same market, the net position if
20 short is what is actually exposed financially to the spot energy market. Thus, the
21 Company's generating resources provide a physical hedge on the spot energy market.
22 During times of planned or forced outages, absent taking on additional resource hedge
23 positions, the physical hedge position provided by the Mitchell and Big Sandy plants

1 will decline, leaving Customers more exposed to PJM's spot energy market price
2 volatility. However, the Company can reduce this exposure by purchasing financial
3 hedges to replace the generation.

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

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

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

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

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

17 A. The Company proposes to use financial hedge products to mitigate the volatility of its
18 PJM spot energy market energy purchases for its Open Energy Positions. PJM AD
19 HUB fixed-for-floating price swaps, also known as contracts for differences, will be
20 used to reduce customer exposure to the volatility in market prices. These forward
21 contracts will be purchased in layers over time to match the Company's target hedge
22 position and smooth out the impact of price volatility in the market. The hedging plan
23 would provide the flexibility to modify or unwind executed forward contracts, as

1 necessary, when adjustments or changes are made to the forecasted load or planned
2 outage schedules at the Mitchell and Big Sandy generation plants. If the PJM AD HUB
3 forward future market is not liquid enough to purchase the target hedge position, the
4 Company may purchase financial future contracts from adjacent zones or other liquid
5 trading hubs, such as the PJM West Hub, to fill in the short position.

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

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

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

14 A. Upon Commission approval of the financial hedging plan.

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

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

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

1 The Target Hedge Percent in Figure AEV-5 below represents the targeted
 2 amount of the Company’s Open Energy Position to be hedged for a given hedge
 3 interval. When the Interval Hedge Percent is less than the Target Hedge Percent, the
 4 Company will calculate the Target Hedge Position for that interval and purchase
 5 forward energy contracts to hedge its Open Energy Position up to the Target Hedge
 6 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% |

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

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

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

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

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

12 **Q. UNDER THE PROPOSED FINANCIAL HEDGING PLAN, HOW MANY MWH**
13 **OF THE COMPANY'S OPEN ENERGY POSITION WOULD BE HEDGED IN**
14 **2024?**

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

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

A. **Figure AEV-6**
 Historical Example Hedge Transactions

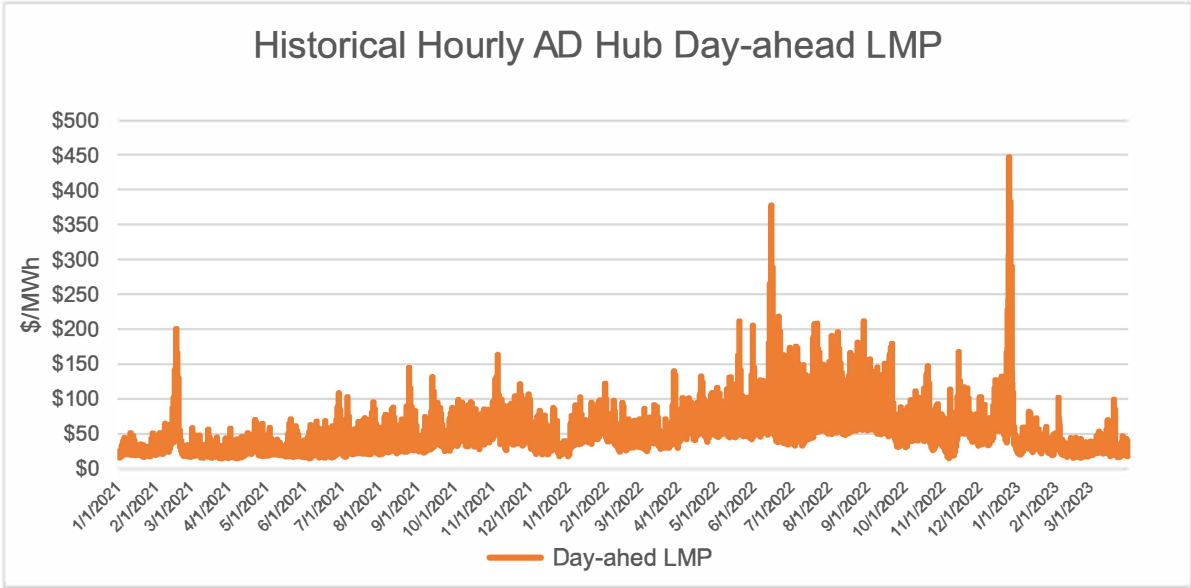
| Hedge Interval 3 | 21Q1 | 21Q2 | 21Q3 | 21Q4 | 22Q1 | 22Q2 | 22Q3 | 22Q4 | 23Q1 |
|------------------------|-----------|----------|----------|----------|----------|----------|----------|----------|------------|
| Purchase Date | | | | | | | | | |
| 7/1/2020 | \$ 30.38 | | | | | | | | |
| 10/1/2020 | | \$ 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) |

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

1 average PJM spot energy market price of energy for the hedge period was
2 \$29.71/MWh. In this example the average hedge contract price was less than the PJM
3 spot energy market price creating a hedging gain of \$3.61/MWh for customers. The
4 \$3.61/MWh hedging gain would have been credited to the FAC, thereby reducing
5 customer's fuel costs.

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

Figure AEV-7



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

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

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

14 A. No. The Company's proposed financial hedging program is designed to smooth out the
15 impact of PJM's spot energy market price volatility on the Company's Open Energy
16 Position and provide greater fuel cost certainty for customers. The hedging plan
17 effectively locks-in or caps the price of future energy purchases for customers. If the
18 actual energy price in the future turns out to be lower than the hedged price, customers
19 will end up paying more for energy than they would have if the Company had
20 purchased its Open Energy Position from the PJM spot energy market. This incremental
21 cost will flow through the FAC as a hedge charge. Conversely, when the actual energy
22 price turns out to be greater than the hedge price, customers will pay less than they
23 would have if the Company had purchased its Open Energy Position from the PJM spot

1 energy market. Any credits or charges (gains and losses) associated with the hedging
2 program will be passed back to customers through the FAC. The potential for realized
3 hedge charges from this program is essentially the cost of reducing volatility in
4 customers' monthly fuel rates.

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

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

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

17 A. PJM's energy market is susceptible to market volatility largely driven by the
18 underlying and interrelated fuel markets, operating conditions, and has been
19 exacerbated over the years by extreme weather disturbances. A significant portion of
20 the Company's load is subject to the day-to-day volatility of PJM's spot market and
21 becomes even more magnified during times of planned outages at the Mitchell and Big
22 Sandy plants. To help mitigate the exposure to the daily market volatility, the Company
23 is proposing a rolling 36-month financial hedging plan to provide customers with

1 greater fuel cost certainty over time. Although the monthly results of the Company's
2 proposed hedging plan may not result in net fuel cost savings for customers, it will
3 reduce their exposure to the fluctuations in the PJM Day-ahead energy market by
4 creating more predictable fuel costs over time. This will leave customers better
5 positioned to budget for and manage their monthly energy bills.

VI. DISTRIBUTED SOLAR PROPOSAL (SOLAR GARDEN PROGRAM)

i. Proposed Ownership and Accounting Structure

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

9 A. The Company proposes to own and operate one or more solar facilities, not to exceed
10 10 MW in individual size, to be located on the Company's distribution system. The
11 aggregate capacity of all the solar sites will not exceed 25 MW. This program will help
12 establish solar generation within the Company's service territory and fill a capacity
13 need that starts in 2026. Projects will be considered a prudent investment if the Net
14 Present Value¹⁵ ("NPV") of the benefits and costs of the project do not exceed the NPV
15 of the equivalent avoided capacity costs, an example of the items considered in the
16 analysis is shown in Figure AEV-8 below, and Figure AEV-9 is an illustrative example
17 of the economic test. The Company is seeking approval of this program so it can solicit
18 through requests for proposals and acquire the projects without further Commission
19 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 FRR 5CP Reduction x Capacity | e |
| NPV of Capacity Value | 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, Ancillary 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 |

- 1 The Company is proposing to recover the net costs of these solar facilities
- 2 acquired through the solar gardens program through Tariff PPA until they can be

1 manifest as a reduction in FAC costs. The benefits and costs associated with these
2 solar facilities are discussed later in my testimony.

3 **Q. IS THIS PROPOSAL IN LINE WITH THE COMPANY'S RECENTLY FILED**
4 **2022 IRP?**

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

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

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

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

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

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

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

1 35 year life would also be supported by incremental capital additions over the life of
2 the plant to lengthen the life of inverters.

3 **Q. ARE THERE ANY ASSET RETIREMENT OBLIGATIONS (“AROs”)**
4 **ASSOCIATED WITH THE COMPANY’S PROPOSED SOLAR FACILITY?**

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

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

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

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

ii. Customer Benefit Analysis

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

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

8 **Energy Benefits**

9 The energy benefits will manifest by the Company purchasing approximately 33,500
10 fewer MWh of on-peak energy (49,008 MWh of energy in total) from the PJM RTO
11 annually. This is because the Company purchases all of its load requirements from the
12 hourly energy markets of PJM and sells its generation resources into those same
13 markets. The monthly cost reconstruction/economic dispatch and deferred fuel
14 accounting process ensures that customers receive the lowest cost resources and the
15 resulting monthly average costs through a combination of the Company's base fuel
16 rates and the fuel adjustment clause. The proposed solar facilities will reduce the
17 Company's on-peak load¹⁶ that it purchases from PJM, thus avoiding on-peak
18 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.

1 Ancillary Service Benefits

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

4 Capacity Benefits

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

8 LSE OATT Charges

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

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

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

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

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

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

iii. Low-Income Benefit Option

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

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

18 **Q. HOW WILL THE ENERGY CREDIT BE CALCULATED?**

19 A. The Company is proposing to use the hourly MWh produced from the solar facilities
20 for the previous 12 months and multiply that by the Day Ahead Local Marginal Price
21 ("DA LMP") for the corresponding hour. The total will then be multiplied by 50 percent
22 and divided by the number of customers identified as low-income through their

1 participation in LIHEAP as of December 31. Based on high-level estimates, this credit
2 could amount to approximately \$66 per customer annually.

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

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

iii. Summary

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

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

16 **Q. SHOULD THE PROPOSED SOLAR GARDEN PROGRAM BE APPROVED?**

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

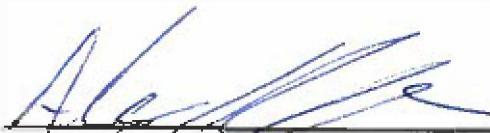
VII. CONCLUSION

1 **Q. DOES THIS CONCLUDE YOUR PRE-FILED TESTIMONY?**

2 **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

State of Ohio)
_____))
Franklin County)

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 12.4.22.



Notary Public

My Commission Expires _____
Notary ID Number _____

