COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Investigation of the	)	
Service, Rates and Facilities of	)	Case No. 2021-00370
Kentucky Power Company	)	

REBUTTAL TESTIMONY OF

ALEX E. VAUGHAN

ON BEHALF OF KENTUCKY POWER COMPANY

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EXHIBITS

EXHIBIT	DESCRIPTION
Confidential EXHIBIT AEV-R1	Excerpt from Guggenheim Report on Fuel Deferrals

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I. INTRODUCTION

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

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

Q. ARE YOU THE SAME ALEX E. VAUGHAN THAT PROVIDED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

II. PURPOSE OF REBUTTAL TESTIMONY

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

A. The purpose of my testimony is to :

a) Rebut the Office of the Attorney General of the Commonwealth of Kentucky's and Kentucky Industrial Utility Customers, Inc's (jointly, "AG-KIUC") witness Lane Kollen's allegation of poor performance of the Mitchell Plant;

b) Refute the claim that the Company is "capacity short"; and

c) Refute Mr. Kollen's reliance on transmission costs to the exclusion of overall cost of service.

Q. ARE YOU SPONSORING ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes, I am sponsoring the following exhibits:

Exhibit	Description
Confidential Exhibit AEV-R1	Excerpt from Guggenheim Report on Fuel Deferrals

III. COAL-FIRED PLANT PERFORMANCE

Q. DO YOU AGREE WITH AG-KIUC WITNESS KOLLEN'S ACCUSATION THAT THE MITCHELL PLANT "OPERATED POORLY"?

A. No. Mr. Kollen claims the Company's coal-fired generating units operated "at low or extremely low capacity factors or didn't operate at all" during the two-year review period established in the Company's two-year Fuel Adjustment Clause ("FAC") review case, Case No. 2023-00008.[1] Mr. Kollen also presents a side-by-side comparison of capacity factors for the Mitchell Plant and East Kentucky Power Cooperative's "EKPC" Spurlock Plant over the last five calendar years, on which he bases the claim that the Mitchell Plant "operated very poorly compared to the EKPC Spurlock units."[2]

AG-KIUC Witness Kollen incorrectly assumes that low capacity factors necessarily equate to poor performance, but that is incorrect. A unit's capacity factor is simply a comparison of its actual output compared to its maximum potential output. A generating unit's output is a function of that unit's economics, availability, and fuel supply. Thus, there are many reasonable reasons why a generating unit will run less than

[1] Kollen Direct Test. at 8.
[2] *Id*.

its maximum potential output, and therefore have a low capacity factor, other than "poor performance."

Q. CAN ECONOMICS AFFECT A UNIT'S CAPACITY FACTOR?

A. Yes. Economics can directly and significantly affect a unit's capacity factor. Kentucky Power offers all of its available generating resources into the PJM Day-Ahead energy market. Kentucky Power submits considerable data to PJM as part of its bids including offer curves and operating parameters, which are linked largely to the economics of the unit. PJM uses the offer information provided by all market participants to "stack" the available units in economic order from least cost to highest cost. The PJM model dispatches generation to provide the least-cost solution to meet load.

Through this process, the Mitchell Plant is only selected to generate if it is part of the least cost, pool-scheduled solution. If the Mitchell Plant is not selected to operate by PJM because it is not part of PJM's least-cost solution to serve customers, as Mr. Kerns explains, it enters a reserve shutdown, during which its capacity factor is 0%.

Q. DO YOU AGREE WITH AG-KIUC WITNESS KOLLEN THAT THE MITCHELL PLANT IS A "BASE LOAD" GENERATOR?

A. No. In fact, this apparent misunderstanding helps to explain Mr. Kollen's incorrect perception that the Mitchell Plant has underperformed.

In large, economically dispatched RTO energy markets, the distinction of being a "base load" resource is no longer driven only by a generating resource's design and fuel type. Instead, the timing and duration of a resource's operation, and its resulting net capacity factor, is a function of relative economics, regardless of its original design and technology. Because many newer resources have lower variable costs, especially combined-cycle natural gas plants, coal plants that were traditionally thought of as being "base load" resources—and even designed for that purpose—no longer fill a "base load" role in RTOs' day-to-day economic dispatch stacks. The Mitchell Plant falls squarely into this group.

Q. HOW DOES A UTILITY'S PRUDENT MAINTENANCE OF ITS PLANTS AFFECT THE RESULTING NET CAPACITY FACTOR?

A. As Company Witness Kerns explains more fully, a plant's or unit's net capacity factor during a planned or maintenance outage will be 0%, even when the outage is reasonable and prudent.

Take, for example, the planned outages at the Mitchell Plant during the review period in Case No. 2023-00008, to which Mr. Kollen's testimony refers. Those planned outages were approved by PJM and included work needed to construct or install approved environmental projects, including work associated with implementing the Coal Combustion Residuals Rule (approved by this Commission in Case No. 2021-00004), and the Effluent Limitations Guidelines Rule (approved by the West Virginia Public Service Commission). The Company prudently took these outages to maintain the plant as a reliable source of capacity and energy now and in the future. Moreover, older plants generally require more maintenance.

In addition, planned and maintenance outages often are required to span full months. For one, PJM market rules prohibit planned outages during the majority of the months of June through September. And furthermore, the Company seeks to avoid planned and maintenance outages during the winter peak season of December through early March, as that is historically a time of high power demand with the potential for power price spikes. As a result, the Company tries to limit necessary outage work at the plant to the months of April, May, October, and November when possible.

In sum, that the Mitchell Plant had approved planned outages during the review period is not a sign of "poor" performance, as Mr. Kollen claims. Rather, it is evidence of good maintenance practices that show the Company's commitment to providing least-cost, reliable service to its customers.

Q. HOW DOES FUEL AVAILABILITY AFFECT A PLANT'S NET CAPACITY FACTOR?

A. The inability of coal mine operators to ramp up production to meet increased demand from generators can lead to scarcity in coal supply, and result in a plant operating at a level below its maximum output or shutting down.

Because of the COVID-19 pandemic, during 2021 through 2022, the Company faced many unforeseen events that led to fluctuations in energy demand, inventory, and market dynamics. These included the drop in electricity demand in 2020, which led to increased and excess coal inventories, followed by the rapid increase in demand for coal-fired generation in the latter part of 2021, through the balance of 2022, ending in January of 2023. Most notably, as the economy began to recover in mid- to late-2021 and electricity demand increased, coal production lagged demand. In response, the Company worked to operate the Mitchell Plant in a manner that mitigated fuel supply constraints. In addition, the Company issued four coal RFPs to adjust to the changing market dynamics and forecasted demand. Through those efforts, the Company responded to the challenges reasonably, prudently, and within the competitive market construct to deliver the lowest reasonable cost, reliable energy to its customers.

Q. DID THE COMPANY HAVE, OR COULD IT HAVE HAD, FOREKNOWLEDGE OF THE UNPRECEDENTED INCREASE IN COMMODITY COSTS THAT OCCURRED AND THAT LED TO HIGHER PJM LMPs AND AN INCREASED DEMAND FOR COAL GENERATION?

A. No, it did not; nor could it have. The Company's normal forecasting process did not predict the anomalous pricing events that occurred during the review period. Nor would it have been reasonable to expect the Company's normal forecasting process to identify in advance such anomalous pricing events. As evidenced by the decline in total coal fleet realized capacity factors in PJM from 2021 to 2022, no one, especially the fleet as a whole, knew that anomalous commodity pricing and extreme rise in demand for coal fired generation was going to occur in 2022. This, coupled with the decline in coal mining output, made it impossible for the coal fleet to generate more MWh on average (achieve higher capacity factors) during 2022 as energy market economics would have allowed for. Thus, the fleet in total was constrained by the amount of coal it had already contracted for and the amount mining sector could produce. Coal plant operators were then left with few options besides maximizing the economic gain they could realize with the finite amount of coal they had available to them.

Q. DID THIS ENERGY, GAS, AND COAL MARKET ANOMALY IMPACT OTHER COMPANIES IN THE SAME WAY KENTUCKY POWER WAS IMPACTED?

A. Yes. The macroeconomic factors impacting energy markets affected many utilities across the RTO, region, and nation, including the other Kentucky utilities that are PJM members. This is not an indicator of imprudence, nor does it indicate that the Company was an outlier from other utilities. A report from Guggenheim Securities reported

December 31, 2022 deferred balances for fuel and purchased power for some thirty-plus traditional electric operating companies, including some of the Company's affiliates. As can be seen on Confidential Exhibit AEV-R1, which is a table from that report, the Company was not unique in being impacted by the unprecedent run-up in fuel prices. Unrecovered fuel and purchase power deferrals for some electric utilities in the report exceed $2 billion dollars by year end 2022 and are over $14 billion in aggregate for those utilities shown. Just to be clear, the deferred amount is the amount that actual costs exceeded previously approved fuel rates for those utilities.

Q. PUTTING ASIDE YOUR VIEWS ON USING REALIZED CAPACITY FACTOR TO ASSESS PLANT PERFORMANCE, IS MR. KOLLEN'S COMPARISON OF THE MITCHELL PLANT TO EKPC'S SPURLOCK PLANT APPROPRIATE?

A. No. As stated above, capacity factor is not the right parameter to evaluate plant performance, but even if it were, comparing two plants' capacity factors to draw conclusions about their relative performance is inappropriate.

Plant owners manage the operation and resulting dispatch of their plants by considering various factors, such as equipment age, market economics, fuel and reagent availability, as well as preserving its accredited capacity value. Because the inputs to the calculus will naturally vary for different plants—not to mention be affected by the prudent judgments of their operators—there is no way to assess prudence by comparing the resulting capacity factors.

Mr. Kollen's attempt to compare the capacity factor for EKPC's coal-fired Spurlock Plant against the Mitchell Plant's capacity factor for the years 2018-2022 is especially problematic. Mr. Kollen shows that for those years, the Spurlock units have capacity factors in the low to upper 60% while the Mitchell Plant's units are in the low to mid 30% range.[3] But this is explainable in large part, however, because Spurlock is committed by its operator on a self-schedule (also referred to as must run) basis.[4] Units that are committed on a must-run basis will tend to have higher capacity factors than units that are committed only when it is economic to run; but the former's higher capacity factor is due to its operator's decision to run the plant regardless of the economics, not due to better performance.

EKPC's chosen self-schedule commitment strategy is different than the Company's economic commitment strategy in that self-schedule ensures the Spurlock units remain online and available at least at minimum load levels regardless of economic scenarios where market prices for purchased power are less than the cost to generate. This leads to the Spurlock units being dispatched at consistently high levels regardless of whether it is more costly to their customers.

Kentucky Power's economic commitment strategy,[5] on the other hand, is more likely to produce an outcome where Kentucky Power's customers will not bear the cost to generate for the Mitchell units if that cost is greater than the price of market purchased power. This strategy therefore benefits Kentucky Power customers, but will result in a lower net capacity factor for the Mitchell units. Because of this fundamental difference in commitment strategy over time, one cannot draw any meaningful conclusions about the prudency and reasonableness of the Mitchell Plant's operational performance simply by comparing its net capacity factor to Spurlock's.

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[3] *Id.* at 8.
[4] This differs from a unit that is a reliability must run.
[5] The Company does commit the Mitchell Plant as self-scheduled in some instances, but the general commitment strategy is that of economic commitment.

Q. IS THE COMPANY'S ULTIMATE GOAL OF OPERATING ITS GENERATION RESOURCES TO MINIMIZE CUSTOMERS' FUEL AND CAPACITY COSTS?

A. Yes. This is why the Company generally employs an economic commitment strategy for the Mitchell Plant versus a self-schedule strategy. Actions taken and decisions made by the Company are done to benefit customers by ensuring, to the extent reasonably possible given the knowledge it has at the time decisions are made, that the Company is providing lower-cost generation when market prices are expected to be high. On pages 13-14 of my recent Direct Testimony in Case No. 2022-00008, I explain how the strategy the Company took with regard to the Mitchell Plant during the review period in that case benefited customers by generating during higher market priced times, preserving the capacity value of the Mitchell Plant, and avoiding 234 unit forced outage days.

Q. HOW DOES THE MITCHELL PLANT'S NET CAPACITY FACTOR COMPARE TO THE PJM COAL FLEET AS A WHOLE?

A. As discussed above, net capacity factor is not an appropriate measure for a plant's performance because it is also a function of economics, plant availability, and fuel availability. Nevertheless, by way of comparison, the Mitchell Plant's net capacity factor is comparable to the average net capacity factor for the PJM coal fleet. During the 2018-2022 time period referenced by Mr. Kollen, the annual average capacity factor values for the entire PJM coal fleet ranged between 30.1% and 44.4%. The Mitchell Plant's annual average annual capacity factors for the same time period ranged between 25.6% and 40.3% respectively. Over the past decade, the entire PJM coal fleet[6] has operated at an

[6] Currently the PJM coal fleet is roughly 52GW of installed capacity.

average annual capacity factor of 42.9%, similar to the Mitchell Plant (42.2%). These capacity factor data points are summarized in Table AEV-R1.

Table AEV-R1

Net Capacity Factor % PJM Coal Fleet Avg. vs Mitchell Plant		
Year	**PJM Coal Fleet**	**Mitchell Plant**
2013	49.5	43.6
2014	49.9	62.2
2015	43.8	39.3
2016	46.2	56.1
2017	46.6	56.3
2018	44.4	40.3
2019	30.1	36.9
2020	34.4	26.4
2021	42.6	34.9
2022	41.8	25.6
Average	42.9	42.2

Accordingly, even if net capacity factor alone were the appropriate measure of good plant performance (which it is not, as discussed above), Mr. Kollen's assertion still would be unsupported by the data. One could not reasonably claim that the Mitchell Plant has performed poorly, as Mr. Kollen does, when the plant's net capacity factor is on par with the average of the PJM coal fleet.

Additionally, the net capacity factor metric only considers energy production, which is only one of the commodities produced by the Mitchell Plant. The other major commodity produced by the Mitchell Plant is capacity. The Company's customers receive the benefits of the Mitchell Plant's unforced capacity (also known as accredited capacity).

Q. PLEASE ADDRESS MR. KOLLEN'S ACCUSATION THAT POOR PLANT PERFORMANCE LED TO HIGHER ENERGY COSTS FOR CUSTOMRS.[7]

A. This issue is a matter of economic prudence which is being litigated in the Company's two year FAC review in Case Number 2023-00008. It is not relevant to the question of adequate service and whether the Company has sufficient capacity to meet customers' energy requirements. As the Company's other witnesses and I demonstrate, Kentucky Power has sufficient capacity to meet its customers' requirements.

Q. IS THE COMPANY "CAPACITY SHORT"?[8]

A. No, it is not. As discussed in Sections IV -VI of my direct testimony, the Company has adequate capacity to meet its reliability requirements. The Company's adequate capacity has resulted in its customers not having a service interruption due to lack of generation supply.

IV. TRANSMISSION PROPOSAL & RATEMAKING

Q. DO YOU AGREE WITH MR. KOLLEN'S RECOMMENDATION REGARDING RTO TRANSMISSION EXPENSE?

A. No, I do not. Mr. Kollen suggests that the alternatives AEP considers include "potential ownership and/or restructuring changes whereby the Company could be merged into or otherwise joined together with a non-AEP LSE and transmission owner in PJM, such as EKPC.. This suggestion is both fundamentally flawed from a ratemaking perspective and ignores how PJM's transmission cost allocation works. Mr. Kollen's assertion that this "would ensure that all the transmission assets, expense, and revenues would be in

[7] Kollen Direct Test. at 9.
[8] *See, e.g.,* Case No. 2023-00159, Order at 32 (Jan. 19, 2024).

Kentucky, avoid transmission investment costs incurred by other AEP affiliates"[9] is simply incorrect. Even in his hypothetical the Company would still be allocated PJM transmission expense from projects that are allocated across multiple zones within PJM such as those that result from the regional transmission expansion plan.

Q. WHY IS MR. KOLLEN'S PROPOSAL FLAWED FROM A RATEMAKING PERSPECTIVE?

A. Mr. Kollen's suggestion misses the forest for the trees; total rates are ultimately what is most important, and it is inappropriate to focus on any individual component without considering the benefits and synergies it achieves. For example, a Company that invests in a robust transmission system may charge higher transmission costs but considerably lower overall rates because it is able to access less expensive energy. In that scenario, a raw comparison of transmission charges would be meaningless, or even misleading.

Here, Kentucky Power's total rates are lower than those of the rural electric co-ops immediately adjacent to the Company's service territory who receive transmission and generation service from EKPC as shown in Table AEV-R2.

Table AEV-R2

Total Average Rates By Year

Source: Public Service Commission of KY Annual Report Statistics

	KPCO	Big Sandy RECC	Grayson RECC	Licking RECC	% Lower than RECCs
2022	0.1263	0.1319	0.1369	0.1402	7%
2021	0.1052	0.1142	0.1323	0.1187	14%
2020	0.0931	0.1068	0.1237	0.1101	18%
2019	0.0893	0.1095	0.1231	0.1122	22%
2018	0.0912	0.1086	0.1192	0.1121	20%

[9] Kollen Direct Test. at 6.

Mr. Kollen's testimony inappropriately focuses on transmission costs alone without considering customers' total cost of service, or the benefits in excess of transmission costs that customers may receive from Kentucky Power's transmission costs being incurred.

Q. HOW CAN A ROBUST TRANSMISSION SYSTEM DELIVER CUSTOMERS COMPARATIVELY LARGER COST SAVINGS?

A. In modern energy markets, real-time energy prices represent the marginal cost of generating electricity and delivering it to a place on the grid.[10] This reflects the basic principle that transmission capacity is finite, and customers cannot benefit from low-cost electricity that cannot be delivered to them. The robust transmission system that connects Kentucky Power to the broader PJM region has enabled customer benefits in two key respects.

First, as Mr. Plewes and I explained in our respective direct testimonies, on an ongoing basis, Kentucky Power customers enjoy the price and reliability benefits of accessing least-cost electricity generated across the geographically and technologically diverse PJM power pool. Because of Kentucky Power's position on PJM's transmission system, customers rarely see material congestion charges.

Second, PJM's robust transmission system has enabled Kentucky Power to make planning choices that facilitate the same or better reliability outcomes that the Company could achieve on its own, but at lower costs. Throughout this proceeding and in others, the Company's chosen strategy of replacing the Rockport UPA in December of 2022 with short-term capacity purchases and market energy has been criticized. In fact, it was a reasonable strategy, allowing the Company to meet its capacity requirements and providing

[10] PJM Manual 11, § 2.2.

the most economic option for securing the needed increment of capacity and energy for customers.

As Mr. Kerns showed in his direct testimony, Kentucky Power has access to 1,075 MW of installed capacity from Mitchell and Big Sandy, which act as a physical hedge on market prices. If Kentucky Power were a power island, disconnected from PJM, then it would have no choice but to build a new generation resource, or contract with a generation resource, within its service territory to cover the balance of its need up to its reliability requirement. But because Kentucky Power has robust transmission connections to the broader PJM power pool, Kentucky Power has access to reliable capacity and energy from across the region.

Q. HOW DOES ACCESS TO PJM'S SYSTEM BENEFIT CUSTOMERS FROM A PLANNING PERSPECTIVE?

A. Kentucky Power's robust connection with PJM has enabled it to achieve adequate reliability and serve real-time load at least cost to customers.

I reviewed Kentucky Power's hourly load requirements for 2020-2023, which confirmed there were only 87 hours out of a total of 35,064 hours when Kentucky Power's load exceeded its current level of installed capacity that can provide a physical hedge on energy market purchase costs. Of these 87 hours, 66 occurred during the extraordinary conditions during Winter Storm Elliott. To further illustrate what level of physical hedge coverage the Company's post-Rockport UPA generation fleet provides, Table AEV-R3 shows the Company's hourly load distribution over the previous four calendar years.

Table AEV-R3

KPCO Hourly Load Distribution					
MW	**2020**	**2021**	**2022**	**2023**	**Total**
0-500	1,070	1,018	432	511	3,031
501-800	6,689	6,587	6,728	7,362	27,366
801-1075	1,020	1,155	1,520	885	4,580
1076+	5	-	80	2	87
	8,784	8,760	8,760	8,760	35,064
0-500	12.2%	11.6%	4.9%	5.8%	8.6%
501-800	76.1%	75.2%	76.8%	84.0%	78.0%
801-1075	11.6%	13.2%	17.4%	10.1%	13.1%
1076+	0.1%	0.0%	0.9%	0.0%	0.2%

Max Peak	1,166	1,065	1,359	1,085
ML & BS1 MW	1075	1075	1075	1075
Difference	91	(10)	284	10

This analysis shows the number and percentage of annual hours that the Company's total internal load exceeded different thresholds. As the data shows, the Company's load for the vast majority of the annual hours is in the 501-800 MW range, while it fell into the 801-1075 MW range only 13.1% of the time. During only 87 total hours out of the 35,064 observed did the Company's load surpass the 1,075 MW installed capacity and physical energy hedge of Mitchell and Big Sandy 1. Of those 87 occurrences, 66 hours were during Winter Storm Elliot which was an extreme cold weather event. Those 87 hours are equal to two one-thousandths of the time.

The question, then, is this: what is a reasonable, reliable, and economic way to plan to serve a level of load that occurs two one-thousandths of the time? Must the Company build its own generation (or contract with a generator) in its service territory, or can it reasonably obtain a capacity commitment from a unit elsewhere in PJM and rely on energy market purchases?

This is exactly the kind of planning exercise that was done in the Company's 2019 IRP. That analysis showed, and stakeholder input confirmed, that purchasing short-term bilateral capacity and utilizing market energy was the lowest-cost solution for customers. One of the key reasons for this outcome is that the PJM transmission system is sufficiently robust to supply Kentucky Power customers reliably with lower-cost electricity that is largely free of material congestion charges.

Simply put, the Company has access to large amounts of generation resources throughout the PJM RTO on an economic dispatch basis because of the transmission system and the costs it pays for that system.

Q. COULD THE COMPANY RELY ON OWNED OR CONTRACTED RESOURCES TO INCREASE ITS POTENTIAL PHYSICAL HEDGE AGAINST MARKET PRICES DURING THE TWO ONE-THOUSANDTHS OF THE TIME LOAD EXCEEDS KENTUCKY POWER'S CURRENT INSTALLED CAPACITY?

A. Yes, it could—for example by contracting with or building a combustion turbine ("CT")—but one must consider the cost of doing so. Owning or contracting for a resource means paying for its fixed costs across all hours of the year. Using the four-year period referenced above, the Company would have needed a contract with a CT for 284 MW in order to have owned or contracted capacity to cover its maximum requirements in every hour (even though that additional capacity would only be required for two one-thousandths of the time period). Based on recent market information, that contract option would cost the Company over $25 million annually. That amount of annual fixed cost is more than double the amount of non-FAC eligible purchased power cost that the Commission cited in opening this Show Cause proceeding. At a price tag of over $100 million during the four-year period to cover 87 hours in total, this option does not seem reasonable, is much more costly than the strategy employed by the Company, and would not result in a greater level of reliability.

Moreover, it is important to keep in mind that a unit-specific purchase power contract with a CT is not a guarantee of energy production, but rather a means of securing capacity with an energy option. The CT in question might not be dispatched by PJM during some of those 87 hours in question if the heat rate or gas price of the unit or units make it a higher cost resource than the energy market's economic dispatch solution. Thus, the Company could acquire an expensive physical hedge by contracting with or owning a CT, only to find that the market price is still lower than the cost of operating that CT during the very small number of hours for which the CT was contracted or built.

V. CONCLUSIONS

Q. IS MR. KOLLEN'S CLAIM THAT POOR PERFORMANCE AT THE MITCHELL PLANT LED TO MORE NON-ECONOMY POWER PURCHASES FACTUAL?

A. No. Mr. Kollen's claim lacks any factual basis and is not supported by evidence. He ignores factors that affect the capacity factors of generating units, such as planned and approved outages, fuel constraints, and the economics of the unit in a competitive market.

Q. SHOULD THE COMMISSION RELY ON MR. KOLLEN'S ASSERTIONS ?

A. No. Mr. Kollen's assertions are not based on evidence, and do not take into consideration real-world circumstances.

Q. DID THE COMPANY PROVIDE ADEQUATE, RELIABLE, LOWEST REASONABLE COST SERVICE?

A. Yes, it has and continues to do so. As proven in the testimony above, in my affidavit originally filed in this matter, and in my Direct Testimony; the Company's chosen strategy from its 2019 IRP of purchasing short-term capacity and market energy to fill the need left by the expiration of the Rockport UPA has proven to be the most economic for customers and has been reliable. The Company has experienced no outages from a lack of power supply, even during extreme cold weather events like winter storm Elliot. Kentucky Power has provided adequate service to its customers.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

Public Exhibit AEV-R1 has been redacted in its entirety.

VERIFICATION

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

Alex E. Vaughan

Franklin County)
Ohio)
)

Case No. 2021-00370

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Alex E. Vaughan, on 2/21/24.

Notary Public

Paul D. Flory
Attorney At Law
Notary Public, State of Ohio
My commission has no expiration date
Sec. 147.03 R.C.

My Commission Expires Never

Notary ID Number No ID