COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of: An Electronic Examination of the Application of the Fuel Adjustment Clause of Kentucky Power Company from May 1, 2021 through October 31, 2021.	: : :	**Case No 2022-00036**

BRIEF OF
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

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TABLE OF CONTENTS

APPENDIX

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Kentucky Industrial Utility Customers, Inc. ("KIUC") submits this Brief in support of its recommendations to the Kentucky Public Service Commission ("Commission" or "KPSC"). As discussed in detail below, Kentucky Power Company's ("Kentucky Power" or "Company") application of the Fuel Adjustment Clause ("FAC") during the six-month period under review was improper and contrary to the requirements of 807 KAR 5:056 and KRS 278.030.

INTRODUCTION

Kentucky has a long tradition of setting utility rates based on actual costs. But there is one (perhaps the only) exception to cost-based ratemaking within the Commonwealth - the determination of whether energy purchases made by AEP and assigned to Kentucky Power are "*economic*" and therefore recoverable in the Company's FAC. This determination is made through a *hypothetical* ratemaking methodology called the peaking unit equivalent ("PUE"). Under the PUE methodology, the hypothetical energy production cost associated with a hypothetical gas-fired combustion turbine ("CT") serves as the cap on Kentucky Power's FAC purchased power recovery.

During the six-month period under review, Kentucky Power improperly applied the PUE methodology by assuming that the hypothetical peaking unit started and stopped *every hour* of the entire review period at a cost of $30.00/MWh. Kentucky Power's assumption that a hypothetical CT would start and stop 8,760 times per year was not reasonable or realistic.[1] Yet this unrealistic assumption led to almost all purchases assigned to the Company by AEP, no matter how costly, being treated as "*economic*" and therefore recoverable in the FAC.

The improper application of the PUE also provided little incentive for Kentucky Power to run its own power plants since it allowed for overreliance on market purchases. This lack of incentive is borne out by the poor capacity factors of Kentucky Power's generation resources during the review period.

To address these issues, the Commission should order Kentucky Power to re-run its FAC calculation using a reasonable startup cost assumption. KIUC's recommended approach is to amortize the $3,000 startup cost over the 6.49-hour average runtime per start of Appalachian Power's Ceredo Unit 1 in 2021 since that unit served as the basis for Kentucky Power's PUE calculation.[2] That would reduce the start-up cost adder from $30.00/MWh to $4.62/MWh. Alternatively, the Commission could use updated EIA data to develop a reasonable total energy cost of a new CT.

BACKGROUND

On March 31, 2022, the Commission initiated this proceeding in accordance with 807 KAR 5:056, Section 3(3) to review Kentucky Power's application of its FAC from May 1, 2021 through October 31, 2021.

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[1] It was not until the Company's August 18, 2022 Response to Staff's Post-Hearing Data Request 2, Attachment 1 that the hypothetical startup cost calculation was disclosed. Using Appalachian Power's Ceredo Unit 1 as the hypothetical proxy, Kentucky Power assumed a $3,000 startup cost for a 100 MW unit with a runtime of one hour. $3,000/100 MW/1 hour equals a cost of $30.00/MWh. As discussed *infra*, in 2021, Ceredo Unit 1 had an actual average runtime of 6.49 hours per start. This means that the startup cost should be amortized over 6.49 hours, not one hour. This yields a startup cost of $4.62/MWh ($3,000/100MW/6.49 hours) (Appendix 1).

[2] Company Response to Staff's Post-Hearing Data Request 2, Attachment 1 (Appendix 1).

807 KAR 5:056 was promulgated in the early 1980s pursuant to KRS 278.030, which requires all utility rates to be fair, just, and reasonable. It was modeled upon the Federal Energy Regulatory Commission ("FERC") fuel adjustment clause regulation in effect at the time.[3] Under 807 KAR 5:056, Section 1, an electric utility is permitted to recover through its FAC the costs of fuel consumed in the utility's owned or leased plants (excluding the costs of substitute fuel related to forced outages) as well as the net energy cost of energy purchases "*if the energy is purchased on an economic dispatch basis.*" This exact same "*economic dispatch*" language was included in the FERC FAC.

Kentucky's FAC regulation, and the FERC FAC regulation upon which it was modeled, are both aimed at producing the lowest reasonable cost for customers. While the state and federal FAC regulations permit utilities to purchase energy from third parties to meet native load needs, they also anticipate doing so when the cost of the purchase is lower than generating the energy with the utility's own resources. FERC stated that its objective was to *"cast the regulations in a form that would provide an incentive to the utilities to purchase energy…**when the total energy charge is less than the cost of the purchaser's own generation."***[4] FERC explained this *"will benefit consumers by permitting the purchaser to pass on the entire energy costs when it will replace the purchaser's higher cost energy, **thus reducing the costs to the consumer."***[5]

Likewise, the Kentucky Commission has found that *"economy energy purchases that are recoverable through an electric utility's FAC"* under 807 KAR 5:056, Section 1(3) are *"purchases that an electric utility makes to serve native load, that displace its higher cost of generation, and that have an energy cost less than the avoided variable generation cost of the utility's*

[3] Federal Register Description of 18 C.F.R. 35.14 (Nov. 19, 1974) (Appendix 2).
[4] Id. at 2 (emphasis added) (Appendix 2).
[5] Id. (emphasis added) (Appendix 2).

highest cost generating unit available to service native load during that FAC expense month."[6] The Commission noted that *"such transactions are generally considered beneficial to utility ratepayers by permitting purchasing utilities to obtain lower cost power to meet their native load requirements while allowing selling utilities the opportunity to earn additional revenues by the sale of excess power."*[7]

The Commission contrasted this with *"non-economic energy purchases,"* which it defined as *"purchases made to serve native load that have an energy cost greater than the avoided variable cost of the utility's highest cost generating unity available to serve native load during that FAC expense month."*[8] According to the Commission, 807 KAR 5:056 permits an electric utility to recover through its FAC *"only the lower of the actual energy cost of the non-economy purchased energy or the fuel cost of its highest cost generating unit available to be dispatched to serve native load during the reporting expense month."*[9]

While most Kentucky electric utilities use their actual generating unit costs when calculating the FAC cost cap for economic energy purchases, Kentucky Power uses a unique hypothetical generating cost methodology approved by the Commission almost twenty years ago. In the early 2000s, Kentucky Power was unlike the other Kentucky electric utilities in that its generating resource mix consisted solely of low energy cost base load units and did not include a high energy cost peaking unit.[10] Because of its fuel mix, Kentucky Power argued that applying the actual cost methodology to the Company would be unfair, resulting in a much lower purchased power cost cap for Kentucky Power as compared to other utilities.[11]

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[6] Order, Case No. 2000-00495-B (May 2, 2002) at 4 (Appendix 3).
[7] Id. at 4, fn 6 (Appendix 3).
[8] Id. at 4 (Appendix 3).
[9] Id. at 5 (Appendix 3).
[10] Order, Case No. 2000-00495-B (October 3, 2002) at 1-2 (Appendix 3).
[11] Id. at 2 (Appendix 3).

The Commission ultimately agreed with Kentucky Power and permitted the Company to use a hypothetical peaking unit cost methodology - the PUE - instead of an actual cost methodology.[12] That energy cost of the hypothetical peaking unit was based upon a daily market price for natural gas multiplied by a General Electric simple cycle gas turbine heat rate of 10,400 Btu/kWh in winter and 10,800 Btu/kWh in summer.[13]

In its 2017 rate case, Kentucky Power requested that the Commission approve a major change to the hypothetical peaking unit calculation, asking to include three more cost components: 1) firm gas transportation costs; 2) startup costs; and 3) variable operations and maintenance ("O&M") expenses. Kentucky Power witness Vaughan explained that those types of costs *"would be incurred to operate an actual natural gas combustion turbine generating unit (CT)"* and that *"the peaking unit equivalent cost calculation seeks to mimic the costs of operating an actual CT…"*[14] As support for this change, Company witness Vaughan also provided an exhibit reflecting monthly (not hourly) startup costs of $30.00/MWh and variable O&M costs of $3.48/MWh.[15] On January 18, 2018, the Commission approved two of the Company's proposed changes, finding that *"Kentucky Power's proposal to include startup costs and variable O&M expense is reasonable and should be approved."*[16] That was the extent of the Commission's discussion. There was no detail regarding how startup costs should be applied.

Not until the Company's August 18, 2022 Response to Staff's Post-Hearing Data Request 2, Attachment 1 was the basis for the hypothetical startup cost calculation disclosed. Using Appalachian Power's Ceredo Unit 1 as the hypothetical proxy, Kentucky Power assumed a $3,000 startup cost for a 100 MW unit with a runtime of one hour. $3,000/100 MW/1 hour

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[12] Order, Case No. 2000-00495-B (October 3, 2002) at 3 (Appendix 3).

[13] Id. at 3 (Appendix 3).

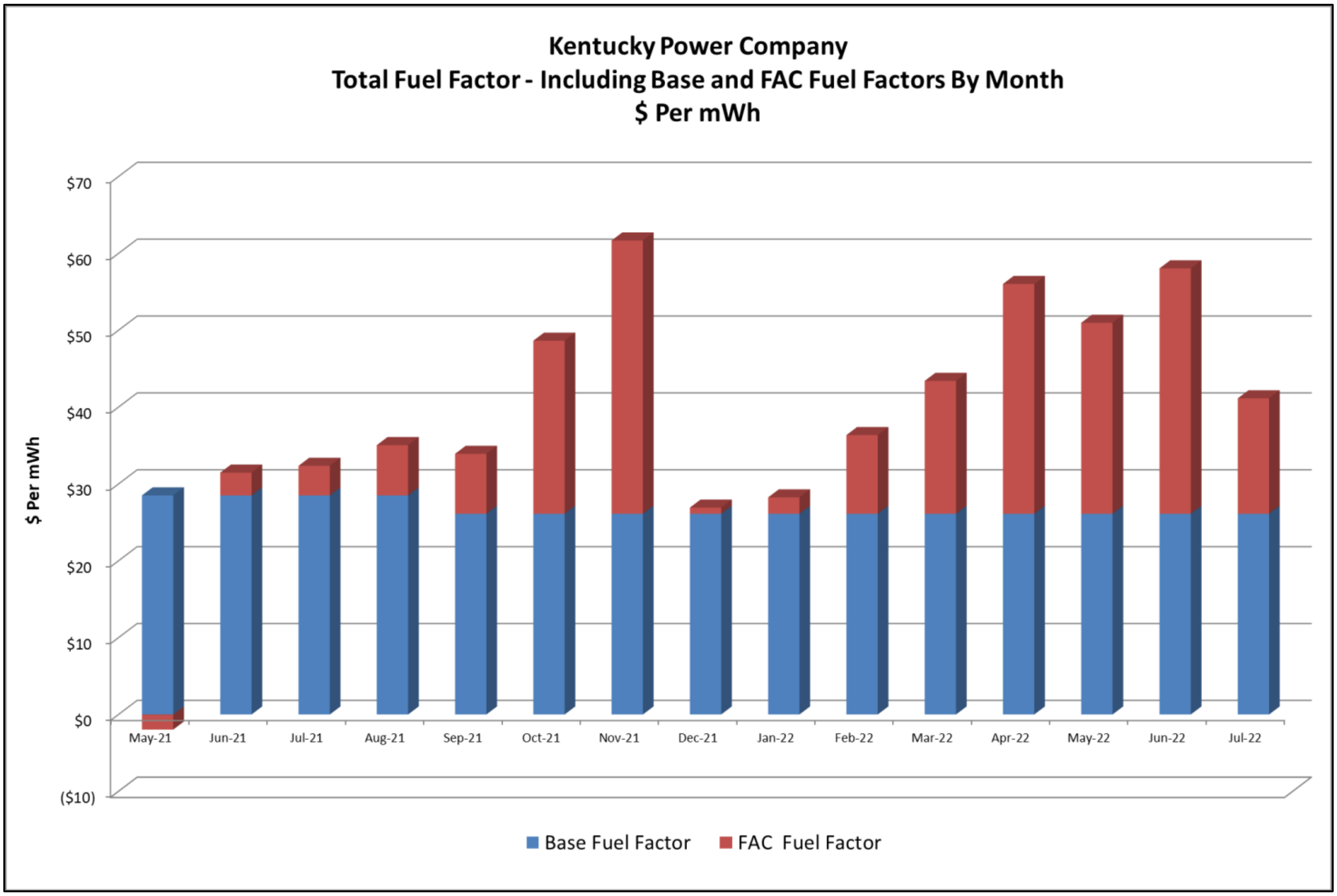
[14] Direct Testimony of Alex E. Vaughan, Case No. 2017-00179 (June 28, 2017) at 34:3-6 (Appendix 3).

[15] KIUC Ex. 1 at 21 (Direct Testimony of Alex E. Vaughan, Case No. 2017-00179 (June 28, 2017), Ex. AEV 8 (Appendix 3).

[16] Order, Case No. 2017-00179 (January 18, 2018) at 56 (Appendix 3).

equals a cost of $30.00/MWh. In 2021, Ceredo Unit 1 had an actual average runtime of 6.49 hours per start. If the startup cost is amortized over 6.49 hours, not one hour, then the startup cost would be $4.62/MWh ($3,000/100MW/6.49 hours).

For years after the Commission's 2017 rate case decision market energy prices remained relatively low and the PUE was not of great concern. But in October 2021, at the end of the six-month review period, market energy prices began spiking dramatically. Kentucky Power's FAC charges followed suit, as the following chart reflects:[17]



[17] Appendix 4.

In light of this dramatic increase in Kentucky Power's FAC rates during the six-month review period, it is important that the Commission carefully scrutinize Kentucky Power's FAC practices to ensure that the charges ultimately passed through to customers were fair, just and reasonable.

ARGUMENT

I. Kentucky Power's PUE Startup Cost Assumption Of $30.00/MWh Every Hour Of The Year Was Unreasonable And Does Not Mimic The Cost To Operate An Actual Combustion Turbine.

A. Assuming That The Hypothetical Peaking Unit Starts and Stops 8,760 Times A Year Is Unrealistic And Creates An Unreasonably High Economic Energy Purchase Price Cap.

While the Commission approved the inclusion of startup costs in Kentucky Power's hypothetical peaking unit cost calculation, Kentucky Power's application of the startup cost calculation during the review period was improper. Rather than using monthly startup costs of $30.00/MWh as depicted in Company witness Vaughan's Exhibit AEV-8 in Case No. 2017-00179, Kentucky Power applied the $30.00/MWh startup cost (plus the $3.48 variable O&M cost) to *every hour* of the review period. The Company confirmed that it did so in response to discovery, explaining *"[t]he $33.48 cost added to every hour…is comprised of a $30.00 adder for fixed start-up costs plus a $3.48 adder for variable O&M pursuant to the Commission's January 18, 2018 and February 27, 2018 order in Case No. 2017-00179 approving the inclusion of variable O&M and fixed start-up costs in the PUE."*[18]

Applying $30.00/MWh in startup costs ($3,000 per start) to every hour of the review period does not *"mimic the costs of operating an actual CT"* since an actual CT does not start and stop 8,760 times per year. For example, in Louisville Gas & Electric/Kentucky Utilities Company's most recent Integrated Resource Plan case, the Companies stated that in 2019, 85%

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[18] Company Response to KIUC First Set of Data Requests, Item No. 1-6(c) (May 9, 2022); *See also* KIUC Ex. 2 at 2 (reflecting a PUE cost cap of $71.172/MWh in every hour of August 2, 2021) (Appendix 5).

of the runs of the Trimble County Simple Cycle CTs were greater than four hours and 71% of the runs were greater than eight hours.[19] Additionally, in 2021, the average runtime per start for East Kentucky Power Cooperative's Bluegrass CTs were 7.16 hours.[20] Kentucky Power's own witness, admitted that an actual CT does not start and stop 8,760 times per year:[21]

> *Q: Is it reasonable to assume that a gas combustion turbine peaking unit would start and stop 8,760 times per year?*
>
> *A: No.*

In Response to Staff Post-Hearing Data Request No. 2 Attachment 1, Kentucky Power provided Excel sheets which formed the basis of the $3.48/MWh variable O&M cost and the $30.00/MWh startup cost calculations. Those sheets reflect that Kentucky Power used 2013-2015 data from Appalachian Power's Ceredo Unit 1 in West Virginia as the basis for the $3.48/MWh variable O&M cost assumption and November 2016 - May 2017 data from the same unit to set the $30.00/MWh startup cost assumption ($3,000 per start/100 MW unit/1 hour run time). But Ceredo Unit 1 did not start and stop every hour during the November 2016-May 2017 period. For most hours, Ceredo Unit 1 did not operate at all.[22] In fact, Ceredo Unit 1 only started and stopped 18 times during that period. It was therefore improper for Kentucky Power to assume that Ceredo's $3,000 startup cost per start was incurred in every single hour.

Seemingly anticipating this criticism, Kentucky Power now attempts to retreat from its 2017 claim that *"the peaking unit equivalent cost calculation seeks to mimic the costs of operating an actual CT…"*[23] Instead, in Post-Hearing Data Responses, the Company claims that *"the peaking unit equivalent value …is not intended to simulate the dispatch of a combustion*

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[19] Responsive Comments of Louisville Gas & Electric Company and Kentucky Utilities Company, Case No. 2021-00393 (May 20, 2022) at 23 (Appendix 6).

[20] EPA Continuous Emissions Monitoring System ("CEMS") Data and EIA 923 Data (Appendix 6).

[21] Hearing Tr. (Aug. 4, 2022) at 10:13:55.

[22] EPA CEMS Data (Appendix 7).

[23] Direct Testimony of Alex E. Vaughan, Case No. 2017-00179 (June 28, 2017) at 34:3-6 (Appendix 3).

turbine unit.”[24] This stunning change of position undermines Kentucky Power’s arguments for engaging in hypothetical ratemaking in the first place.

Utilizing a hypothetical calculation that does not mimic the operations of an actual CT produces an arbitrary cost cap and does not result in reasonable rates. The Commission should therefore require Kentucky Power to recalculate the hypothetical peaking unit cost cap using a reasonable startup assumption.

B. Using An Unreasonably High Startup Cost Assumption Creates A Disincentive For Kentucky Power To Run Its Own Units And Results In Overreliance On Market Purchases

Kentucky Power’s unrealistic startup cost assumption disincentivizes the Company from running its own lower cost baseload generation rather than having AEP assign it PJM market purchases. Of course, running Kentucky Power’s low-cost baseload coal generation runs counter to AEP’s CO2 ESG goals, whereas purchases are booked as having a zero CO2 impact. For example, in hour nine of October 27, 2021, 658.19 MW of 670 MW (or 98.24%) of Kentucky Power’s native load was served by non-Rockport purchased power rather than by the Company’s own generating units.[25]

It is bad enough for Kentucky Power to not run its low-cost units because of planned, forced, or maintenance outages. But it is inexplicable why Kentucky Power did not run its two Mitchell Units when they were available to run and were much lower in cost than market purchases. After factoring all known outages, in October 2021 Mitchell Units 1 and 2 (with generation costs of $30.01/MWh and $20.74/MWh) operated during only 63% and 67% of the hours when they were available to run.[26] PJM is not to blame. PJM would have dispatched the low-cost Mitchell Units during all hours they were available in October 2021 unless AEP bid

[24] Company Response to Staff Post-Hearing Data Request No. 2.
[25] KIUC Ex. 3 (Appendix 8).
[26] KIUC Ex. 5 (Appendix 9).

them in at prices well above cost. It appears that AEP did not want the Mitchell Units to run. Perhaps to conserve coal inventory. But whatever the reason, customers suffered through the recovery of expensive market purchases in the FAC.

The average cost of non-Rockport purchased power costs assigned to native load in October 2021 was $57.37/MWh, or $12,923,530.[27] Kentucky Power's hypothetical PUE cost cap of $86.49/MWh resulted in a disallowance of only $29,766 despite significantly increased FAC charges to retail customers that month.[28] These expensive purchases caused the FAC to skyrocket to $22.52/MWh, resulting in the average residential ratepayer incurring a rate increase of approximately $28 in December 2021 (October FAC costs are charged on December bills). Were Kentucky Power required to adopt a reasonable startup cost assumption, the disallowance would be greater.

C. The Commission Should Require Kentucky Power to Recalculate Its FAC Charges Using A Reasonable Startup Cost Assumption.

Kentucky Power's *every hour* approach to calculating startup costs was an improper application of 807 KAR 5:056 and an improper interpretation of the Commission's Order in Case No. 2017-00179, which produced unjust and unreasonable rates in violation of KRS 278.030. Accordingly, the Commission should require Kentucky Power to recalculate startup costs during the six-month review period using reasonable assumptions.

One reasonable metric would be to use the actual Ceredo Unit 1 operations data to calculate startup costs. In 2021, Ceredo 1 started up 121 times with an average runtime of 6.49 hours per start.[29] It would therefore be reasonable to change Kentucky Power's startup cost calculation from the current method:

[27] KIUC Ex. 4 (Appendix 10).
[28] Id. (Appendix 10)
[29] EPA CEMS Data (Appendix 11).

$3,000 startup cost ÷ 100 MW unit size ÷ 1 hour runtime = $30.00/MWh

To a method based upon Ceredo Unit 1's actual operations:

$3,000 startup cost ÷ 100 MW unit size ÷ 6.49 hour runtime = $4.62/MWh

Another reasonable metric to establish an economic purchase price cap is recent EIA data addressing the cost and performance characteristics of a new CT. According to EIA's 2022 Annual Energy Outlook, a new 237 MW CT has a fixed O&M cost of $1,737,210 per year, or $2.57/MWh, including startup costs.[30] Given that EIA fixed O&M costs includes startup costs, it is unnecessary to calculate startup costs separately under this approach.

The impact of adopting these alternatives is set forth in the chart below.

Comparison of PUE As Filed, Modified PUE Based On August 2, 2021 Data Included On Exhibit KIUC Ex. 2 And CT Energy Costs Based On 2023 EIA Data

	Reference	Current AEP Calculated PUE	Modified AEP Calculated PUE Utilizing Ceredo Unit 1 Startup Costs	EIA 2023 Combustion Turbine Calculated PUE
Average Size Unit (kW)	1			237,000
Fixed O&M per kW Year	2			$7.33
Annual Fixed O&M	3 = 1 x 2			$1,737,210
Average Annual Capacity Factor	4			32.6%
Annual Hours	5 = 365 x 24			8,760
Annual mWh	6 = 1 / 1000 x 4 x 5			676,815
Fixed O&M ($/mWh) - Startup	7 = 3 / 6 for EIA	$30.00	$4.62	$2.57
Gas Price ($/mWh)	8	$3.49	$3.49	$3.49
Heat Rate (Btu/mWh)	9	10.800	10.800	9.905
Variable O&M ($/mWh)	10	$3.48	$3.48	$4.71
PUE Calculation	11 = (8 x 9) + 7 +10	$71.172	$45.792	$41.845

[30] EIA Annual Energy Outlook 2022, C*ost and Performance Characteristics of New Generating Technologies* (March 2022) at 2, *available at:* https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf (Appendix 12).

II. The Commission Should Address Several Outstanding Issues Surrounding Kentucky Power's Fuel and Purchased Power Practices in the Upcoming Two-Year Review Proceeding.

Given the compressed procedural timeline for this six-month review, it is difficult to address every issue surrounding Kentucky Power's FAC practices. But the Commission should not allow those significant issues to fall by the wayside and should expressly state that it will explore them in the Company's upcoming two-year FAC proceeding.

A. The Capacity Factors Of Kentucky Power's Units Are Substantially Lower Than The Other Utilities In Kentucky.

Data provided by Kentucky Power in this case reflects that the Company's generating units were frequently offline for forced, planned, and maintenance outages. For example, in October 2021, Rockport Units 1 and 2 and Big Sandy were down for the entire 744 hours of the month.[31] Mitchell Unit 1 was down for 629.43 of those hours and Mitchell Unit 2 was down for 240 of those hours.[32] Thus, in the midst of a dramatic market price spike, Kentucky Power's own generating units were rarely running. The monthly capacity factors during the review period for each of the Company's generating units are shown below.

Generating Unit Net Capacity Factor (%)[33]

	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21
Big Sandy 1	17.33	29.72	44.62	17.23	30.74	0.00
Mitchell 1	0.00	55.90	54.13	45.20	47.19	9.64
Mitchell 2	65.03	51.02	71.11	77.10	55.23	45.54
Rockport 1	47.70	62.92	37.70	26.72	0.00	0.00
Rockport 2	0.00	29.20	45.65	54.43	8.56	0.00

[31] KIUC Ex. 5 (Appendix 9).

[32] Id. Appendix 9).

[33] Staff First Set of Data Requests, Item No. 17 at 1; KIUC Second Set of Data Requests (June 8, 2022) Item No. 6, Attachment 1 at 1.

Further, when compared to the base load coal generating units of other Kentucky electric utilities, Kentucky Power's units had significantly lower capacity factors.[34] For example, in 2021 the capacity factor for Mitchell 1 was 26.39% and for Mitchell 2 was 43.19%. In contrast, in 2021 the capacity factors for EKPC's Spurlock Station were: Unit 1 74.96%, Unit 2 58.77%, Unit 3 80.08%, and Unit 4 83.20%.[35]

The Company's ability to recover substitute fuel costs resulting from forced outages through its Purchase Power Adjustment ("PPA Rider") may be contributing to this issue. 807 KAR 5:056, Section 1(3) provides that electric utilities cannot recover the cost of substitute fuel related to forced outages through FAC charges. But Kentucky Power recovers those substitute fuel costs dollar for dollar through its PPA Rider pursuant to the Commission's Order in Case No. 2017-00179. During the six-month review period, Kentucky Power recovered a total of $46,395,868 million in purchased power costs (including Rockport purchases) through the FAC and $2,399,061 in purchased power costs through the PPA Rider.[36] Kentucky Power is therefore insulated from risk with respect to fuel costs resulting from forced outages.

B. Kentucky Power's Units Were Not Running When Available To Run During High Market Price Periods.

Even after factoring in forced, planned, and maintenance outages, Kentucky Power's generating units were often not running during high market price periods even when they were available to run. For instance, in October 2021, the Company's low-cost Mitchell Units 1 and 2 were only running during 63% and 67% of hours they were available to run.[37] This resulted in customers paying for higher cost purchased power instead, an outcome that merits greater scrutiny in the upcoming two-year review case.

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[34] S&P Capital IQ Unit Monthly Operations Data (Appendix 13).

[35] Id. (Appendix 13).

[36] KIUC Ex. 1 at 25 (Company Response to Staff Third Set of Data Requests (June 15, 2022), Item No. 2, Attachment 1. (Appendix 3).

[37] KIUC Ex. 5 at 4 (Appendix 9).

C. AEP Service Corp's PJM Bidding Strategy For Kentucky Power's Units Resulted In PJM Not Dispatching Those Units During High Market Price Periods.

As noted above, the costs associated with Kentucky Power generating units, including Mitchell Units 1 and 2, were often lower than PJM Day-Ahead market prices in October 2021. Why those units did not clear in the PJM market more frequently is still uncertain. One answer may be that they were bid in well above cost in an effort to not clear in order to conserve coal inventory. The two-year case should therefore include a detailed examination of AEP's bidding practices with respect to the Kentucky Power units.

D. AEP Service Corp's Assignment of Purchased Power Costs Among The AEP Operating Companies Should Be Reviewed.

Kentucky Power does not bid its generating units into the PJM market itself. AEP Service Corp. does so on behalf of all of the AEP East operating companies and assigns the resulting revenues and costs, including purchased power costs, among the operating companies pursuant to intercompany allocation methodologies. This intercompany allocation may lead to unreasonable or questionable results. For example, in hour 18 of August 2, 2021, AEP assigned 81 MW of market purchases at a cost of $66.50/MWh to Kentucky Power. However, in that hour Kentucky Power had 925 MW of net available generation resources, 816 MW of dispatched generation, and internal load of only 764 MW.[38] In that hour, not only was more Kentucky Power generation running than was needed to serve native load, but all of that generation was much lower cost than the assigned 81 MW market purchase at $66.50/MWh. Why it was necessary to assign so much high cost purchased power to Kentucky Power in that hour is unclear.

[38] KIUC Ex. 2 (Appendix 5).

E. The Exclusion Of The Rockport Units in The FAC Forced Outage Limitation Should Be Reviewed.

Kentucky Power currently treats Rockport as an exception to the requirement under 807 KAR 5:056 that substitute fuel costs resulting from forced outages are not recoverable through the FAC. The Company claims that it does so because Kentucky Power receives its share of Rockport through a Unit Power Agreement.[39] But Kentucky Power treats Rockport like its other generating units in every other way under the FAC. And Rockport is treated as Company-owned generation for base rate and environmental surcharge purposes. The Commission should therefore explore whether to treat Rockport equivalently for purposes of the FAC forced outage cost limitation.

F. All Of The Input Assumptions In Kentucky Power's PUE Calculation Should Be Reviewed.

In addition to requiring Kentucky Power to use a reasonable startup cost assumption for the hypothetical peaking unit calculation during the entire two-year FAC period under review, the Commission should examine the reasonableness of the heat rate assumptions used in that calculation as well. Kentucky Power's current heat rate assumptions were developed nearly twenty years ago. Given technological improvements since that time, those heat rate assumptions are likely dated.

Additionally, Kentucky Power currently assumes that the hypothetical peaking unit is big enough to serve the entirely of Kentucky Power's load. As the amount of Kentucky Power's market purchases grow, the hypothetical peaking unit grows along with it and sets the cap for all purchased power, no matter how big. The hypothetical peaking could grow to 1,000 MW to cover Kentucky Power's winter peak demand. The unlimited size of the hypothetical peaking unit should be examined.

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[39] Company Response to KIUC Data Request 1-3.

CONCLUSION

WHEREFORE, the Commission should require Kentucky Power to reduce the assumed PUE startup cost during the review period from $30.00/MWh to $4.62/MWh, or in the alternative, use current EIA data to develop a reasonable energy cost of a new CT for use in the PUE calculation.

Respectfully submitted,

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