COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. TO BECOME A FULL PARTICIPANT IN THE PJM INTERCONNECTION LLC, BASE RESIDUAL AND INCREMENTAL AUCTION CONSTRUCT FOR THE 2027/2028 DELIVERY YEAR AND FOR NECESSARY ACCOUNTING AND TARIFF CHANGES	)	CASE NO. 2024-00285

DUKE ENERGY KENTUCKY, INC.'S REPLY BRIEF

I. Introduction

Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company) made its application in this proceeding because the Company believes it is in the best interests of customers to exit the Fixed Resource Requirement (FRR) and transition to full participation in the PJM Interconnection LLC (PJM) Reliability Pricing Model (RPM) Base Residual Auction (BRA)/ Incremental Auction (IA) construct (collectively referred to as RPM). The change to RPM only impacts the method that the Company uses to satisfy its PJM Reliability Assurance Agreement (RAA) obligation. Switching to RPM will not impact Duke Energy Kentucky's participation in the PJM energy or ancillary services markets (ASM). The primary difference between the RPM participation and the FRR participation is that as an FRR participant, Duke Energy Kentucky must submit an annual plan to PJM to meet its customer demand, as determined by PJM, including sufficient reserves, with unit-specific capacity, meaning dedicated Megawatts (MWs) from identified resources that have not already been committed to meeting other load or that have not cleared the PJM BRA/IAs for that delivery year. Conversely, as a full RPM -auction participant, 100 percent of demand is purchased from the market, and 100 percent of generation is sold into the market. The transition to RPM is an all-or-nothing decision insofar as there is no FRR/RPM hybrid where the Company can elect which rules to follow or ignore, and which charges it will receive. It is impossible to have one-foot in and one-foot out of RPM. A transition to RPM means that the Company must follow PJM's Tariffed rules for RPM participation, just as it does today for FRR participation.

In sum, there are six primary reasons that this transition is in customers' best interests: 1) RPM provides greater flexibility to meet sudden large customer load growth that could come online faster than the Company can build or acquire baseload generation; 2) the risk of change in the balance between supply and demand in the Duke Energy Ohio/Kentucky delivery zone in PJM (DEOK Zone); 3) the risk that available bilateral capacity is becoming constrained in the DEOK Zone due to announced retirements; 4) the likelihood PJM further changes the FRR construct that adversely affects the Company's continued FRR participation; 5) PJM market risks including, the overall energy transition in PJM due to fossil generation retirements, PJM's shrinking reserve margin, and higher capacity prices; and 6) the already enacted PJM changes to the FRR shortfall penalty.[1]

Further, the Company discussed the risks of remaining an FRR participant, which include the risk of FRR deficiency penalties and high-priced bilateral capacity purchases that will occur if a large new load comes online before the Company can timely build or acquire new and owned capacity. Additionally, the Company pointed out that remaining an FRR participant creates additional risks should the DEOK Zone becomes constrained

[1] Rebuttal Testimony of John D. Swez, p. 2 (Swez Rebuttal).

once again, including 1) scarcity of in-zone capacity;[2] 2) inability to purchase competitively-price bilateral capacity;[3] 3) premiums in capacity costs due to the PJM minimum internal requirement for FRR participants;[4] and 4) increased risks of FRR deficiency charges.[5]

The Company presented testimony explaining each of these risks and how a transition to RPM mitigates or resolves each one. Additionally, the Company presented detailed cost-benefit analysis, including a "Heat Map" that compared participation in the RPM to that of the FRR, showing that in the vast majority of scenarios, a transition to RPM produced the best results for customers.[6] Significantly, the Attorney General of the Commonwealth of Kentucky (KYAG)'s consulting witness Hayet confirmed the Company's analysis.[7]

The Company's Application and supporting testimony proposed reasonable changes to the Company's profit sharing mechanism, Rider PSM, in order to effectuate a smooth transition to RPM that 1) appropriately provides customers with *all* of the benefits of the rate-based generation dedicated to meet demand, which should provide additional value through capacity revenues that are restricted as an FRR; and 2) provides the Company with timely recovery of costs that will be incurred if the Commission approves this transition. These charges and credits are established through FERC-approved rates embedded in PJM's tariffs through Billing Line Items (BLIs). The Company has no choice

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[2] Direct Testimony of John D. Swez, p. 23 (Swez Direct).

[3] *Id.*

[4] *Id.*

[5] *Id.,* p. 22.

[6] Swez Direct, pp 11-19.

[7] KY AG Initial Brief, p. 3.

but to receive these charges and credits once it transitions from FRR to RPM. And these individual BLIs can and do become both costs and revenues, depending upon reconciliations and resettlements in PJM. Put another way, what may be a credit in one month could become a "negative credit" or charge the next due to PJM's resettlements. The same goes with charges. These charges could turn into "negative charges" or credits in any given month. Therefore, it is important to include all the BLIs for accounting and reconciliation purposes.

The Company has remained an FRR participant since first joining PJM, as was ordered by the Commission and none of the restrictions advocated by the KYAG currently exist.[8] Through the years, the Commission has asked and in response, the Company has analyzed, whether or not continued FRR participation was in the customers' best interests.[9] Historically, FRR was, indeed, the best choice for customers. Now, the Company believes that is no longer the case as fully explained in its application and direct and rebuttal testimonies. Nonetheless, if the Commission determines that transitioning to RPM is "too risky" for customers, it should simply deny the Company's application and it will remain an FRR participant. The Commission should not, however, impose unreasonable and unnecessary restrictions or conditions on such a transition that constrain the Company's

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[8] *In the Matter of the Application of Duke Energy Kentucky, Inc., for Approval to Transfer Functional Control of its Transmission Assets from the Midwest Independent Transmission System Operator to the PJM Interconnection Regional Transmission Organization and Request for Expedited Treatment,* Case No. 2010-00203, p. 18, (Ky. P.S.C. Order) (Dec. 22, 2010).

[9] *See e.g. In the Matter of the Electronic Application of Duke Energy Kentucky, Inc. for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief,* Case No. 2017-00321, Responses to Commission Staff's Second Request for Information, Item 76 (Nov. 13, 2017)*;* and *In the Matter of the Electronic 2018 Integrated Resource Plan of Duke Energy Kentucky, Inc.,* Case No. 2018-00195, Responses to Commission Staff's First Request for Information, Item 2 (Feb. 25, 2019).

ability to successfully manage its rate-based generation assets in the capacity markets. Likewise, the Commission should not limit the Company's ability to effectively and cost-efficiently manage serving customer demand or transfer additional costs on the Company and its shareholders. If the Commission does not believe the identified risks and the cost-benefit analysis justify the transition to RPM, then the Company should remain an FRR participant as previously directed. Duke Energy Kentucky will continue to manage the capacity position as it always has, through submittal of an annual FRR plan using unit-specific capacity and manage any shortfalls through bilateral purchases to the extent it is available.

II. Reply to the Attorney General's Initial Brief

A. Overview

In its Initial Brief, the KYAG confirms that it does not oppose the Company's proposal to transition from FRR to full RPM auction participation and in fact, its own consulting witness confirmed the results of the Company's cost-benefit analysis. However, the KYAG advocates for limitations, or as the KYAG puts it, "guard rails" that if adopted, unnecessarily restricts the Company's ability to effectively manage the capacity position in PJM for the benefit of customers and pushes costs of participating in the PJM market to Duke Energy Kentucky and its shareholders. Such a result is unreasonable and antithetical to fundamental rate-making principles where utilities are allowed an opportunity to recover their costs of providing service and an opportunity to earn a reasonable return.[10]

[10] *See In the Matter of Kentucky Industrial Utility Customers, Inc., v. Kentucky Utilities Company, Louisville Gas and Electric Company, Kentucky Power Company, and Duke Energy Kentucky, Inc.,* Case No. 2017-0477, p. 2 (Ky. P.S.C. Order) (Dec. 27, 2017); finding "*Rates must be set at a level to allow a utility to recover all of its reasonable expenses, including taxes, and to provide its shareholders an opportunity to earn a fair return on invested capital.*"

Placing unreasonable constraints on the Company, particularly on how it can manage the generating portfolio capacity to the benefit of ratepayers, as explained in the Company's Initial Brief, and herein, will most likely force the Company to make sub-optimal, higher cost decisions because more efficient and flexible solutions would be precluded. Unreasonable restrictions such as a limitation on annual capacity purchases in the BRA may mean the Company is unable to respond quickly enough to acquire a resource to match customer demand prior to its inclusion in PJM's load forecast, resulting in an imbalance between capacity and demand. In order to serve this large customer load, the Company would be required to enter into above-market bilateral capacity agreements, which if geographic restrictions are layered on top of the RPM capacity purchases, could place the Company in a position where there are zero options available to cure this imbalance. Restrictions such as limiting the amount of net capacity purchases in the auctions and creating arbitrary timelines for curing imbalances, which may be impossible to achieve, erodes the benefits of an RPM transition, and depending on the details of the ultimate requirements, could mean remaining in FRR is the better choice for customers.

The KYAG's Initial Brief recites its eight proposed "guardrails" on pages 5 and 6, but only focuses on a few of these restrictions in its discussion. Duke Energy Kentucky fully addressed all of the KYAG's restrictions through the Rebuttal Testimony of John D. Swez and Lisa D. Steinkuhl, and more fully explained why they are unnecessary and unreasonable in the Company's Initial Brief.[11] In the interest of brevity and not clouding the record with unnecessary repetition, the Company incorporates its arguments as if fully

[11] Duke Energy Kentucky, Inc.'s Initial Brief.

rewritten herein, and focuses on addressing those concerns raised by the KYAG in its Initial Brief, Section III Argument.

B. Restriction on Replacing Capacity with Owned or Bilaterally Purchased Capacity, which is Located in Zone, and preferably, in Kentucky.

As the KYAG accurately points out in its Initial Brief,[12] Duke Energy Kentucky generally agrees that it should, and under Kentucky law, must, as part of the requirements replace fossil capacity with more dispatchable capacity prior to its retirement. KRS 278.264 requires the Company to come forward with a replacement plan as part of the analysis necessary to request the retirement of fossil generation. The KYAG agrees.[13]

Similarly, the Company agrees with the KYAG insofar as the KYAG believes that locating new replacement capacity within the DEOK Zone, appears facially, to be the optimal strategy for customers. Indeed, the Company has no current intention to build or acquire any new base-load capacity outside of its delivery zone. However, where the Company and the KYAG diverge is whether or not such a regulatory restriction should be made now, before the Company is in the position of having to evaluate such replacement. First, the DEOK Zone, as the name implies, includes portions of Ohio. And Duke Energy Kentucky's Woodsdale Generating unit is geographically located in Southwestern Ohio, but just north of Cincinnati. Further, as this Commission is aware, Duke Energy Kentucky actually has a small amount of load, served off the Long Branch circuit, which is located outside of the DEOK Zone and in that of East Kentucky Power Cooperative. Therefore, an instate or an "in-zone" restriction on the geographic location of any future capacity may

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[12] KY AG Initial Brief, p. 6.

[13] *Id.*

impact Duke Energy Kentucky's ability to effectively plan for serving its load. Further, in the coming years, it may be possible for Duke Energy Kentucky to acquire an interest or construct new capacity for a significantly cheaper cost outside of the state of Kentucky or even in a different, but contiguous zone in PJM. Placing a restriction on the Company's ability to examine potential future capacity options, even if only to confirm the value of an in-state or in-zone asset, is unnecessary and not in customer's best interests. Such a limitation could eliminate the possibility for the Company to partner with other Kentucky utilities for new capacity construction simply because a jointly owned asset, while geographically in the Commonwealth, may not be in the DEOK Zone.

Additionally, in order to pursue any replacement capacity, built or bought, the Company must receive Commission approval through either a Certificate of Public Convenience or Necessity (CPCN) or a financing application to enter into a long-term purchase power agreement (PPA). In either event, the Company will have the burden of proof to explain why it believes such a strategy is in the best interests of customers, most likely through the due diligence of requests for proposals and analysis of alternative proposals. The Commission will have the opportunity, at that time, to evaluate whether a particular strategy is reasonable, and the KYAG, or any other interested stakeholder, will have an opportunity to evaluate any such proposal. It is an unnecessary restriction to pre-judge any potentially reasonable strategy now, limiting the scope of potential supply-side resources that may be available, when nothing has even been brought forth for the Commission to evaluate.

The Commission does not need to limit itself or the Company now. The Commission's existing regulations and years of experience and precedent provide adequate due process and protections for all stakeholders to guide the Company and this Commission on future resource evaluation. Additional restrictions are not necessary and unreasonably limit potential reasonable supply alternatives.

C. Restriction on Market Capacity Purchases to No More than Nine Percent of the Company's Annual Capacity Requirement and a Six Year Cure for Capacity Imbalances.

The KYAG correctly points out that Duke Energy Kentucky agrees that owned generating resources are the best hedge against potentially volatile capacity market prices and that the Company does not intend to ever be in a position that it must rely solely upon the PJM capacity auctions to meet long-term capacity needs.[14] However, the KYAG misinterprets the Company's reasoning for wanting the flexibility to meet capacity needs in the short and medium-term planning horizons. Indeed, the Company wishes to maintain the flexibility to procure needed capacity in the markets where it is economic to do so.

In the RPM, a participant is required to purchase all its demand (*i.e.,* customer load plus a reserve requirement) in the market and also sell (offer) all of its resources, including generation capacity and demand response, through the market. The "hedge" takes place through the Company being able to offer the same or greater amount of capacity into the market for sale, than it needs to purchase back to serve the demand. The Company, per PJM's tariffs, must buy all demand, and offer to sell its resources. By selling the same amount or more capacity into the market at the same price that the demand must pay, customers remain neutral or net positive in revenues, thereby reducing overall costs for electricity. If all resources that were offered cleared the market at the maximum offer amount, the only scenario where a customer would pay more than the amount of revenue

[14] *Id.,* p. 7.

received is when there is more demand than the available amount of capacity to be sold. This can be due to an increase in additional demand, or a significant or permanent loss of existing capacity through a forced or planned retirement.[15]

As Mr. Swez explained in both his Direct and Rebuttal Testimony, it is possible that new and significant load/demand may appear at a rate faster than the Company's ability to construct or acquire bilaterally, additional capacity. As an FRR participant, if the Company cannot procure unit specific capacity to meet its FRR demand obligation, the Company faces penalties. However, through RPM participation, the Company can cure any deficiency through the market. This maintains reliability for all customers. If, however, the Company were subject to an arbitrary limitation on the amount of capacity it is able to procure through the capacity auctions, then the Company may be forced to either obtain higher-priced resources, that did not or cannot clear the BRA, to meet this need or purchase bilaterial capacity prior to the auction at a premium price. Again, under PJM tariffs, the Company must buy all and sell all available capacity into RPM.

If the Company was forced to procure uneconomic bilateral capacity because of a Commission-imposed limit on annual capacity purchases, customers may be paying a higher price for this capacity since sellers would have an advantage knowing (1) the Company was required to make a purchase to stay within a limit, and (2) the purchase was required to be made inside the DEOK Zone and preferably in Kentucky. Further, customers could be facing even greater costs because per PJM's rules, the Company would still be

[15] If an auction cleared at a point low enough that did not allow some or all Company resources to clear, there could be a situation where there were higher costs to purchase demand than the revenue received. These resources would not clear if the revenues that would have been received in the lower price scenario were not enough to offset the capacity performance risk of having cleared the market. In the given example where all resources clear at the highest amount possible (100% of the offered UCAP), this short capacity position could occur only either with additional load or through though a significant or permanent loss of existing capacity through a forced or planned retirement.

required to procure capacity to meet its total demand through the BRA. A bilateral capacity purchase does not reduce the amount of demand that must be purchased in the auction. Put another way, having 1 MW of bilateral capacity does not result in a 1 MW reduction of demand to be purchased in the auction. It just results in 1 additional MW of capacity that could potentially be sold. The Company would offer the contracted bilateral capacity into the auction, but the dollar amount received could be less than the bilateral amount paid. Customers could easily pay more if the Company were forced to use in-zone, in-Kentucky, bilateral purchases to cure any imbalance between customer demand and owned capacity.

Likewise, a six-year limitation on imbalance between capacity and demand, may seem like a consumer protection, but it in fact limits the Company's ability to provide long-term cost-effective solutions for customers. In the hypothetical scenario where the Company becomes capacity-short, the long-term, cost-effective solution may be to construct a new combined cycle or even a small modular reactor. The design, permitting, interconnection, and other regulatory approvals for either of these solutions will exceed a six-year horizon. The Company's most recent IRP presumes that a combined-cycle generator will take approximately eight years from siting to commercial operation.[16]

A reasonable solution to meet large load additions is best evaluated through the rigor of the IRP planning process. Depending upon when such new load appears, that planning may not occur or conclude for a year or more. And if bilateral capacity is not available or cost effective, the Company may indeed need to procure additional capacity through the RPM, for several years, until it can effectively analyze, plan, obtain necessary regulatory approvals, obtain interconnection rights and easements, construct and

[16] *See In the Matter the Electronic 2024 Integrated Resource Plan of Duke Energy Kentucky, Inc.,* Case No. 2024-00197, Response to AG-DR-02-008 (Oct. 16, 2024).

commence commercial operation of a generating asset. Layering in potential natural gas pipeline construction, the timeline for new generation could easily exceed eight years or more.

The Commission should not be concerned that the Company will not keep it apprised of changes in load or generation capacity. The Company annually reports on potential retirements as well as additions in capacity as part of the Commission's Admin 387 updates. These reports, the Company's triannual IRP filings, and the Commission's authority over CPCNs and long-term purchase power agreements through fuel proceedings, provide regular reporting to the Commission of the Company's ability to meet customer demand. And as proposed, the Company's changes to its Rider PSM will provide further evidence of costs and revenues to customers.

Again, the scenario where the Company is in a short capacity position due to sudden load increases, while feasible, is nonetheless today, a theoretical exercise. The Company neither intends for, nor incorporates into its resource planning, scenarios where it is short capacity to satisfy demand for several years. Nonetheless, there is such a possibility, should a large load, like a data center appear. The Company and this Commission should have all available tools to respond to such a scenario should it occur, at the time it occurs.

The Company commits to use its best efforts to maintain sufficient capacity, including reserves to meet customer demand over the long-term planning horizon, and further commits to come to the Commission if and when such a shift in its long-term capacity position changes. But arbitrary limitations established now, without full analysis of scenarios that could exist at the time of any such shortfall, could unreasonably restrict the available alternatives to reliably serve customers, forcing sub-optimal and more costly decisions. The Commission should not impose unreasonable restrictions on the Company's ability to cost-effectively manage customer demand and reliably serve their needs in the future as a condition to transitioning to RPM. If the Commission is concerned with the potential for the market-exposure to customers through RPM, then it can deny the Company's Application and Duke Energy Kentucky will remain an FRR participant and operate as it does today under PJM's rules for FRR entities.

Placing arbitrary time and volume constraints on the Company's ability to satisfy demand can make the benefits of the RPM less attractive for customers and indeed, remaining an FRR participant a potential better strategy. If the Commission feels the need to create such limitations, depending on the requirements imposed, remaining an FRR PJM capacity member may be a better option for customers.

D. Double Recovery of Capacity Costs

Duke Energy Kentucky and the KYAG agree in principle, that there should not be double recovery of capacity costs. The differences between the two positions are simply a matter of timing and applicability of Kentucky law. The KYAG would have the Commission make restrictive rate-making decisions now, before the Company has actually made any request to retire an asset, to adjust the Company's Rider PSM to include offsets for non-fuel operational costs included in base rates if and when, the Company actually retires capacity. Deciding this issue now, when the Company has not sought Commission approval to retire an asset under KRS 278.264, and there is no evidence of any over collections, is speculative and premature. Moreover, as this Commission recently held in Duke Energy Kentucky's most recent electric base rate case, per KRS 278.264, the Commission is prohibited from "taking any other action which authorizes or allows for the recovery costs for the retirement of an electric generating unit… unless the presumption created by this section is rebutted."[17] Duke Energy Kentucky has not sought approval to retire any fossil asset. Unless or until the Company seeks Commission-authorization to retire its generation, addressing what costs, if any, need to be adjusted for recovery or for cessation of recovery, is unnecessary. The Commission will have the opportunity to evaluate whether Rider PSM is or is not the appropriate mechanism to ensure there is no double recovery. The Company is merely saying that the Commission should simply wait until the appropriate time, where it has the ability to consider all relevant information, including actual costs, not theoretical costs, which should be adjusted.

Additionally, the KYAG clarifies that its consulting witness is only opining upon non-fuel operating expenses and not addressing the recovery or form of recovery for the remaining net book value of the Company's generating assets, and those assets are not an issue at this time.[18] The Company respectfully submits that so too, the non-fuel operating expenses should not be an issue at this time. The issues of both any remaining net book value and any non-fuel operating expenses, if any, that may exist in base rates can be examined at a later date, when the retirement of a generator, its replacement, and any costs are before the Commission.

E. Modification of the Rider PSM Off-System Sharing of Capacity Revenues

The Company's generating portfolio was and will continue to be designed to meet its Kentucky customer demand. The costs of these assets are included in base rates paid for

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[17] *In the Matter of the Electronic Application of Duke Energy Kentucky, Inc. for (1) An adjustment of Electric Rates; (2) Approval of Net Tariffs; (3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and (5) All Other Required Approvals and Relief,* Case No. 2022-00372, p. 14 (Ky. P.S.C. Order) (Oct. 12. 2023).

[18] Ky AG Initial Brief, p. 8.

by customers. Duke Energy Kentucky's application to transition to RPM is not driven by any benefit that accrues to Duke Energy Kentucky or its shareholders. The request to transition to RPM is based solely upon the Company's belief that such a move is the right choice for customers. Company witness Swez explained this fact in his Direct and Rebuttal testimonies and nothing in the KYAG consulting witness testimony says otherwise.[19] The Company proposed to use Rider PSM to net these capacity costs and revenues because that mechanism already exists and traditionally has been used to provide customers with the benefits of participation in regional transmission organizations and the off-system sales that are enabled therein.

The Rider PSM sharing mechanism was something created when Duke Energy Kentucky first acquired its generation from its parent, Duke Energy Ohio, Inc., in the early part of this century.[20] Since joining PJM in 2012 as an FRR participant, the capacity from this portfolio has been used directly to serve customer demand, with any available excess, subject to the FRR hold-back limitation, sold into the PJM auctions.[21] PJM's rules for FRR participation limit the amount of capacity that can be made available to sell into the PJM BRA auctions, where the greatest value typically lies. This FRR holdback, limits Duke Energy Kentucky's ability to sell excess capacity into the BRA to a small amount.[22] Maintaining a cost and revenue sharing mechanism for capacity between customers and the Company was reasonable historically when the amount of capacity that could be sold

[19] *See* Swez Direct, pp. 11-36; Swez Rebuttal, pp. 5-6, 14, 30.

[20] *In the Matter of the Application of the Union Light Heat and Power Company for a Certificate of Public Convenience To Acquire Certain Generation Resources and Related Property; For Approval of Certain Purchase Power Agreements; For Approval of Certain Accounting Treatment, and for Approval of Deviation from Requirements of KRS* 278.2207 and 278.2213(9); (Ky.P.S.C. Interim Order, pp. 18-20) (Dec. 5, 2003).

[21] Swez Direct, p. 20.

[22] *Id.*

was small. The risks and the rewards available for the capacity were relatively small as an FRR participant.

In this case, the Company proposed to modify the Rider PSM sharing of capacity revenues to make sure customers receive 100 percent of the benefits of that capacity in PJM, whether through meeting their demand, or in excess of demand through additional sales margins that reduce the total electric bill. As a full RPM auction participant, all of the demand is purchased and all of the available generation is offered into the BRA, a benefit that does not exist today. With having a net long position, Duke Energy Kentucky's customer will have the opportunity to receive the benefit of up to 30 MWs of additional capacity that can be monetized in the BRA that could not occur as an FRR participant. Likewise, under the PJM RPM auction construct, because the Company must also purchase all of its Kentucky customer demand in the PJM BRA and IAs under PJM's rules, it is reasonable and justifiable that customers should also be responsible for the costs. The fact that the Company is currently net-long capacity is a benefit to customers and Duke Energy Kentucky proposed in its Application that customers experience 100 percent of that benefit in the transition to RPM.

The KYAG justifies its opposition to the proposed change in Rider PSM, stating that "capacity purchases and expense recoverable through the PSM are incremental to the owned resource capacity resources and costs recoverable through base rates."[23] However this argument belies how operating in PJM as a full RPM participant works under the FERC-approved PJM tariffs. As previously stated, if the Commission approves the Company's transition to RPM, the Company would be required to offer *all* available

[23] KY AG Initial Brief, p. 9.

generation and purchase *all* its Kentucky load/demand in the PJM RPM. The Company will receive costs through PJM BLIs for *all* of the load to be served in PJM, meaning these BLIs are all costs incurred to serve Kentucky load. And, in turn, for selling its available generation, Duke Energy Kentucky will receive revenues for generation that clears the market through the PJM BLIs. While there is no guarantee, the Company does believe that the capacity for its fossil generation fleet will clear the PJM RPM, and so long as the Company's available capacity exceeds customer demand, customers will receive a net revenue that effectively lowers their energy costs.

The KYAG argues that the current 90/10 sharing for capacity costs and revenues under the FRR construct and maintaining the 90/10 sharing on energy sales belies the argument that customers should receive 100 percent of the capacity costs and revenues through PJM RPM participation. The KYAG's position, again, shows a misunderstanding of the PJM markets. First, as it relates to capacity, the cost of these assets is fixed and not subject to variability like fuel. Under the FRR construct, Duke Energy Kentucky must annually submit its FRR Plan, where specific MWs of generation are used to meet the PJM determined FRR load obligation. Therefore, customers receive 100 percent of the Duke Energy Kentucky-owned capacity first, to meet their FRR Plan demand. Only after that demand is satisfied can excess available capacity, subject to the FRR holdback, be monetized in the RPM.

Conversely, as an RPM auction participant, 100 percent of the load must be purchased in the PJM RPM, meaning the Company must purchase all capacity in RPM to satisfy that demand. The Company also must offer to sell 100 percent of available capacity into RPM. To the extent that capacity clears, and the amount of cleared capacity meets or exceeds the load, then customers will receive positive net capacity revenues. However, if for some reason, the amount of capacity that clears does not meet or exceed the demand, then as an RPM participant, customers would receive a net charge for capacity, because more capacity must be purchased to meet demand. Therefore, it makes sense that customers should receive all of the benefit and all of the costs.

A fundamental tenant of utility ratemaking is that the utility recovers its reasonable costs of serving customers through rates. If there is a net short capacity position because of a sudden increase in load, the costs of serving that load should be recoverable in full. Yet under the KYAG's scenario where capacity costs and revenues remain under a 90/10 sharing split, the Company and its shareholders would be paying costs of serving customer load. This Company and shareholder subsidy will adversely impact Duke Energy Kentucky's balance sheet and cash flows needed to invest in its system and could adversely affect its credit metrics and ability to attract investors. This will result in increases of the Company's costs and ultimately impact customer rates.

As an example of this potential impact, suppose a new, desirable 1,000 MW customer load decides to expand or locate in the Duke Energy Kentucky service territory, bringing with it, new high-paying jobs, and significant incremental tax-base. This customer would be a tremendous boon to the development of the region. If the Company were in a flat capacity position before the new customer comes online, to no fault of its own planning process, under the KYAG's proposal, the Company would find itself in the position of subsidizing the costs of serving this load because it must purchase capacity until a new generation facility could be built. At the current expected capacity price of $325/MW-Day, the cost to the Company of 100 MW (10% of 1,000 MW) would be approximately $12 million annually.[24] Thus, the Company would not be able to recover all of the costs to serve the new customer. This subsidy amount could be exacerbated with a limitation on capacity purchases through the RPM auctions and geographic restrictions on bilateral capacity transactions.

It should be additionally noted that since entering PJM in 2012, the Company has typically had a net long capacity position and has predominantly sold additional capacity resources to PJM. Customers have received the majority benefit of these net sales. The Company is now proposing to credit customers with 100 percent of the net capacity sales proceeds, and for so long as the net capacity position remains long, will be a significant benefit to customers over the current 90/10 sharing split.

A transition to the FRR construct has absolutely no impact on how the Company participates in the PJM Day-Ahead and Real-Time energy markets where the Company has the opportunity to sell its economic energy, including amounts in excess of customer load, on a daily basis, thereby generating non-native revenues. The ability to be cleared in either the Day-Ahead or Real-Time energy markets lies solely upon the unit's variable costs, which the Company has some control over through effective management of fuel, purchased power, offer strategy, and environmental compliance. PJM determines the dispatch of the units in the real-time markets in five-minute increments to meet reliability in the most economic means possible. And if the Company is able to keep its costs low relative to the market, then these assets produce revenues for customers. This provides a distinction between how energy revenues are treated and how capacity should be treated through the PSM.

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[24] $325/MW-Day x 100 MW x 365 days = $11.862,500

Again, if the Commission is concerned about participation in the RPM and that customers should not pay for the costs of meeting customer demand in the auctions, then the Commission has the choice to deny the Company's Application and Duke Energy Kentucky will remain an FRR participant. The Commission should not require Duke Energy Kentucky or its shareholders to bear the costs of meeting Kentucky demand in the event available generation does not clear, or load exceeds the amount of capacity that is available. This is especially the case if the Company is also restricted in its ability to manage the capacity portfolio due to limitations on capacity purchases or arbitrary time limits on satisfying capacity imbalances. These restrictions make the transition to RPM onerous and remaining an FRR participant the better option for both customers and the Company.

F. All BLIs for PJM Expenses Related to RPM Participation Should Be Recoverable

In its Initial Brief, the KYAG concedes that the benefits and expenses of RPM participation should be recoverable and netted through the PSM. However, the KYAG also argues that BLIs attributed to compliance or performance failures should not be automatically included for recovery unless the costs are prudent and reasonable. The Commission has the experience and expertise to conduct hindsight reviews of prudence and routinely does so through its Fuel Adjustment Clause and Environmental Surcharge Mechanism proceedings for electric rates and the Company's Pipeline Modernization Mechanism for natural gas. The Commission could conduct similar such reviews for transactions associated with RPM participation through Rider PSM. What the Company proposes herein is no different, namely that the BLIs for costs be netted against corresponding BLIs for credits and the Commission use its plenary rate-making authority to consider and determine the reasonableness.

The RPM capacity BLIs proposed to be included in the Rider PSM are, again, FERC-approved and assessed in accordance with PJM tariffs. As the Company explained in Mr. Swez's rebuttal testimony and more fully in its Initial Brief, these BLIs are not necessarily penalties in the sense that the Company did anything imprudent or wrong.[25] The Commission through its general oversight of utility rates, always has the ability to question and disallow any costs that it deems unreasonable or imprudently incurred.[26] Additionally, as Mr. Swez explained, these BLIs can be both a charge or a credit in any given month.[27] And the BLI that is a charge/cost works in tandem with a corresponding BLI that is a credit/revenue. By excluding the charge BLIs from the BLIs credits, the Commission would be creating an asymmetric situation where customers would be receiving all of the benefits of the capacity without paying all of the costs.

The KYAG's proposal to exclude certain BLIs result in the Company being unable to timely recover its costs, if at all. This places the Company in an untenable position. Absent a deferral, the Company must recognize and finance these costs on its ledger upon their assessment by PJM. Further, due to timing of when these charges may be assessed, the Company may be at risk for recovering these costs, even if determined to be prudently incurred due to timing and reconciliation from PJM. PJM can reconcile and restate its billings for several years. This Commission has previously denied the Company the recovery of costs simply because the costs occurred in a previous calendar year absent a

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[25] Swez Rebuttal, p. 26.

[26] *Id.,* pp. 26-28.

[27] *Id.*

deferral.[28] "The Commission has historically not allowed a utility to establish a regulatory asset after a cost has been recorded as an expense and the utility has closed its books for the relevant fiscal year."[29] Unless the Commission grants the Company deferral authority upfront, the Company must, per Generally Accepted Accounting Principles (GAAP) and regulatory accounting, recognize the expense when it is incurred. That means these BLI charges would immediately impact the Company's financial condition because it must recognize the expense upon PJM's inclusion on the bill. And depending upon the timing of PJM's billing, the Company could easily be precluded from even making an application to attempt to demonstrate prudency of these costs.

Duke Energy Kentucky has authorization to include PJM BLIs and bilateral capacity purchases in its Rider PSM to satisfy the Company's FRR requirement. The same should be true for RPM participation. Again, if the Commission does not wish for the Company to be in a position to recover costs that it incurs in managing the Kentucky demand and generation portfolio in RPM, the Commission can simply find the Company remain an FRR participant.

G. PJM's Capacity Crisis

For the first time, the KYAG raises PJM's capacity crisis and PJM's December 9, 2024 announcement of a potential "capacity shortage as soon as the 2026/2027 Delivery Year."[30] This remains especially true in the DEOK Zone due to announced capacity retirements. As the Company's analysis shows, if this comes to fruition resulting in high-

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[28] *In the Matter of the Electronic Application of Duke Energy Kentucky, Inc., for an Order Approving the Establishment of a Regulatory Asset for the Liabilities Associated with the PJM Expenses Related to the Greenhat Energy LLC Default,* Case No 2020-00031 (Ky. P.S.C. Order) (Sept. 30, 2020).

[29] *Id.,* p. 6.

[30] KY AG Initial Brief, p. 11.

capacity prices, customers are better off in RPM, unless the Commission adopts the KYAG's restrictions on capacity purchases and geographic limitations.

The Company admits that the availability of capacity in PJM is a concern, but that customers are better off in RPM in this scenario. Currently, the Company has a net long capacity position, which if transitioned to RPM, and under the Company's proposal, customers would receive 100 percent of all the benefits. As previously stated, the Company agrees that owning, operating, and maintaining generating capacity to meet its Kentucky load is the best hedge against volatile capacity prices. And the Company further intends to continue owning and operating generation to meet its Kentucky customer load requirements. However, arbitrary constraints on how the Company can respond to external forces that impact the system, such as limitations on capacity purchase volumes, geographic locations of resources, limitations on curing capacity imbalances, or inability to recover costs only seek to inject additional risk into the already dynamic market. If the Commission determines that the transition to RPM is in the customers' best interests, the Commission should also determine that allowing the Company to remain nimble to respond to this dynamic market and flexible to adjust its capacity position as prudently needed is in the customers best interest as well.

III. Conclusion

The Company has demonstrated that its request for authorization to transition from operating as an FRR entity in PJM to full participation in the RPM auction construct is both for a proper purpose and is in the public interest and the Commission should approve the Company's Application. The Commission should resist placing misguided, albeit well intentioned restrictions and conditions on the transition to RPM. Such limitations would most likely result in harm to customers or the Company.

Respectfully submitted,

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CERTIFICATE OF SERVICE

This is to certify that the foregoing electronic filing is a true and accurate copy of the document being filed in paper medium; that the electronic filing was transmitted to the Commission on March 21, 2025; and that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding.

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