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	)	CASE NO.
AND INCREMENTAL AUCTION CONSTRUCT FOR THE	)	2024-00285
2027/2028 DELIVERY YEAR AND FOR NECESSARY	)	
ACCOUNTING AND TARIFF CHANGES	)	

DIRECT TESTIMONY OF

JOHN D. SWEZ

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

September 6, 2024

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Attachments:

I. INTRODUCTION

Q. STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John D. Swez, and my business address is 525 S. Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as Managing Director, Trading and Dispatch, by Duke Energy Carolinas, LLC, a utility affiliate of Duke Energy Kentucky, Inc. (Duke Energy Kentucky or Company).

Q. PLEASE DESCRIBE BRIEFLY YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Mechanical Engineering from Purdue University in 1992. I received a Master of Business Administration degree from the University of Indianapolis in 1995. I joined PSI Energy, Inc. in 1992 and have held various engineering positions with the Company or its affiliates in the generation dispatch or power trading departments. In 2003, I assumed the position of Manager, Real-Time Operations, on January 1, 2006, became the Director of Generation Dispatch and Operations, and finally assumed my current role on November 1, 2019.

Q. HAVE YOU EVER TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes, I have testified before the Kentucky Public Service Commission (Commission) on several occasions.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AS MANAGING DIRECTOR, TRADING & DISPATCH.

A. As Managing Director, Trading and Dispatch of Duke Energy, I am responsible for Power Trading on behalf of Duke Energy's regulated utilities in the Carolinas and Florida and Generation Dispatch on behalf of Duke Energy's regulated utilities in Indiana, Ohio, and Kentucky. I am responsible for Duke Energy Kentucky's participation as a member of PJM Interconnection LLC (PJM) as it relates to the Company's generation dispatch, unit commitment, 24-hour real-time operations, and short-term maintenance planning. I am also responsible for the Company's submittal of supply offers in PJM's day-ahead and real-time electric energy (collectively Energy Markets) and ancillary services markets (ASM), as well as managing the Company's short-term supply position to ensure that the Company has adequate economic resources committed to serve its retail customers' electricity needs. I also work closely with the teams responsible for managing the Company's capacity position with respect to meeting its Fixed Resource Requirement (FRR) obligation as a member of PJM.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to discuss the Company's current participation in the PJM capacity market construct as a FRR member, the cost-benefit analysis Duke Energy Kentucky performed regarding its continued participation as an FRR entity and the benefits that support a move to changing its participation status to the auction-based Reliability Pricing Model (RPM) Base Residual (BRA) and Incremental Auction (IA) capacity market construct. In doing so, I explain the difference between the two capacity market participation alternatives and explain the reasons why a move to the RPM participation is for a proper purpose, is in the public interest, and more importantly, in the best interests of customers. I also discuss recent structural changes in the PJM capacity market implemented by PJM as approved by the Federal Energy Regulatory Commission (FERC) that influenced this decision, and that now makes this move to RPM beneficial to the Duke Energy Kentucky customer and in the overall public interest. I further discuss risks of remaining an FRR entity, which support this transition, including impacts from potential new customer demand additions in the Duke Energy Kentucky service territory, overall supply and demand projections both within the Duke Energy Ohio Kentucky (DEOK) zone, the PJM Locational Delivery Area (LDA) where the Company operates, and in PJM as a whole. Finally, I also describe how such a transition will occur, its timing, and explain the new PJM Billing Line Item (BLI) credits and charges that will be received after such a move.

II. OVERVIEW OF PJM AND DUKE ENERGY KENTUCKY'S PARTICIPATION

Q. PLEASE GENERALLY DESCRIBE PJM AND DUKE ENERGY KENTUCKY'S MEMBERSHIP.

A. PJM is the nation's first fully functioning Regional Transmission Organization (RTO). PJM operates the power grid and wholesale electric market for all or parts of thirteen states and the District of Columbia. This electric market consists of an energy market, capacity market, ASM, and a Financial Transmission Rights (FTR) market. PJM's operation is governed by agreements and tariffs approved by the

FERC including the Operating Agreement,[1] Open Access Transmission Tariff (OATT),[2] and the Reliability Assurance Agreement (RAA).[3] Effective January 1, 2012, Duke Energy Kentucky became a member of PJM, and as a PJM member, Duke Energy Kentucky is subject to these agreements, which among other things, require Duke Energy Kentucky to offer its available generation to PJM and to purchase its energy to serve customer load from the PJM Day-Ahead or Real-Time Energy Markets.

Pursuant to the Commission's December 22, 2010, Order in Case No. 2010-00203 (PJM Realignment Order),[4] Duke Energy Kentucky currently participates in the PJM capacity construct as a self-supply FRR entity. As an FRR entity, Duke Energy Kentucky uses its own generation assets located in the DEOK LDA, Company demand response programs, and any necessary bilateral capacity purchases to satisfy its PJM capacity demand requirements. The Company effectively matches its PJM determined load/demand obligation, including sufficient reserves with Megawatts (MW) of unit-specific[5] capacity resources and demand response programs to meet supply reliability requirements.

[1] Available at: https://agreements.pjm.com/oa/4541
[2] Available at: https://agreements.pjm.com/oatt/3897
[3] Available at: https://agreements.pjm.com/raa/17427
[4] *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. PSC Order) (December 22, 2010).
[5] Unit specific capacity means that the Company can directly point to specific generating unit as supplying needed MWs.

Q. PLEASE DESCRIBE HOW PJM MEMBERS PARTICIPATE IN THE PJM CAPACITY CONSTRUCT.

A. As I previously mentioned, there are two ways for a PJM member to participate in the PJM capacity construct, either through PJM's RPM capacity market, or as a FRR entity.

Q. PLEASE DESCRIBE PJM'S CAPACITY MARKET.

A. PJM's capacity market, also known as the RPM, is designed to secure enough power supplies in a cost-effective manner to maintain resource adequacy three years into the future. Put simply, the market pays participants for the promise to produce electricity when called upon by PJM. Capacity resources include generators that produce electricity and other resources, such as demand response, which incentivizes consumers to reduce electricity use and help operators keep the supply and demand for electricity in balance. To meet PJM FERC-approved reliability requirements, a utility that delivers electricity to end-use customers must have the resources available to meet customers' demand. Utilities must also secure reserves necessary for emergencies. PJM utilities meet these mandates with capacity they own, capacity purchased elsewhere, or capacity procured from the capacity market.

The RPM construct and the associated rules regarding how PJM members participate in the PJM capacity market are described within the PJM OATT and RAA. The PJM capacity market operates on a planning period that spans twelve months beginning June 1st and ending May 31st of each year (delivery year). In PJM, the capacity market structure is intended to provide transparent forward market signals that support generation and infrastructure investment. The BRA is the baseline procurement process. BRAs are typically conducted three years in advance of the actual delivery year to allow bidders to complete construction of projects that clear the BRA. The PJM capacity market is designed to provide incentives for the development of generation, demand response, energy efficiency, and transmission solutions through capacity market payments. Another key component of RPM is that price signals are locational and designed to recognize and quantify the geographical value of capacity. PJM divides the RTO into multiple LDA sub-regions to model the locational value of generation. On a MW basis, in the 2025/2026 BRA, 92.5% of PJM members are RPM participants and 7.5% are FRR participants[6].

Q. HOW IS THE CAPACITY MARKET AUCTION PRICE ESTABLISHED?

A. In a capacity market auction, PJM first accepts offers to provide capacity at the lowest cost. As the auction progresses, PJM accepts progressively higher-priced offers until enough capacity is assembled to meet the projected demand plus reserve requirement for the future delivery year. At that point, when the auction clears, all sellers receive the last or "marginal" offer price. This marginal price is also known as the auction clearing price.

Q. PLEASE FURTHER EXPLAIN PJM'S FRR PROCESS.

A. The FRR process is the alternative to the RPM that allows PJM Load Serving Entities (LSE), such as Duke Energy Kentucky, to satisfy its customer capacity obligation under the PJM RAA. Under the FRR construct, an LSE must annually

[6] In the 2025/2026 PJM Base Residual Auction planning parameters, the PJM peak load was 153,883 MW and the Total Peak Load of FRR Entities was 11,597.3 MW, or 7.5% of the total.

submit two self-supply plans (FRR Plan): 1) a preliminary or "initial" three-year forward capacity plan, and 2) a final or "current year" FRR capacity plan. Each plan must meet a PJM defined customer capacity obligation. The FRR Plan must identify the unit-specific generating or demand response resources that will be providing the capacity that will fulfill the LSE's customer demand obligation. FRR allows the LSE to match its customer reliability requirement to its own generation, demand response, energy efficiency and/or transmission resources, while still being permitted to sell some excess supply, subject to certain defined limitations, into RPM.[7]

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE RESOURCES THAT DUKE ENERGY KENTUCKY USES TO MEET ITS CAPACITY LOAD OBLIGATION.

A. Duke Energy Kentucky currently owns and operates approximately 1,076 MW of summer generating capacity. East Bend Unit 2 Generating Unit (East Bend) supplies the portfolio's base load requirements. East Bend is a 600 MW (net rating) coal-fired base load unit located along the Ohio River in Boone County, Kentucky. The Company meets its peaking requirements with the Woodsdale Generating Station (Woodsdale). Woodsdale is a 476 MW (net summer rating) six-unit natural gas-fired combustion turbine (CT) facility with fuel oil back-up located in Trenton, Ohio. The net ratings represent the amount of power that the Company can dispatch

[7] FRR entities are limited in the amount of excess capacity they can sell into the capacity auctions. As an FRR entity, Duke Energy Kentucky is subject to the lesser of 450 MW or a 3 percent collar or hold back on its ability to sell excess in the BRA. The hold back requirement is relaxed only in the 3rd IA, at which time the capacity can be sold in the auction.

from the plants after a portion of the gross power output is used to power the plant machinery.

Additionally, the Company has 9.3 MW of solar assets consisting of the nameplate ratings of Walton 1 (2 MW), Walton 2 (2 MW), Crittenden (2.8 MW), and Aero Solar (2.5 MW) site with the combined net firm summer capacity at all four solar sites of 3.9 MW. These assets are connected at the distribution level and thus, from PJM's perspective are behind the meter, meaning these generating assets reduce the customer demand as seen from PJMs perspective but are not separately dispatched into the market.

All these resources, East Bend, Woodsdale, and the solar facilities, along with the Company's demand response programs and potential bilateral capacity purchases are utilized to meet the capacity load obligation from the Company's customers under the FRR.

Q. PLEASE EXPLAIN WHAT BEING AN FRR ENTITY MEANS FOR DUKE ENERGY KENTUCKY AND ITS CUSTOMERS.

A. As a FRR entity, Duke Energy Kentucky must secure and commit unit-specific resources to meet the peak load capacity requirements for all its customers in advance of the PJM's annual BRA through its FRR Plan. As the FRR Plan timeline follows the RPM auction timeline, the Company recently submitted its initial 2025/2026 FRR Plan for the delivery year spanning June 1, 2025, through May 31, 2026, and its final 2024/2025 FRR plan for the delivery year spanning June 1, 2024, through May 31, 2025. Note that the 2025/2026 auction timing period was delayed and is on a compressed schedule, as is discussed later in this testimony, and would have normally occurred prior to now.

Q. WHAT WOULD HAPPEN IF DUKE ENERGY KENTUCKY'S FRR PLAN IS INSUFFICIENT TO SATISFY ITS DEMAND OBLIGATION?

A. Duke Energy Kentucky would face severe penalties and limitations on its ability to choose the FRR option if PJM were to deem the Company's initial or final FRR Plans to be insufficient or its generation otherwise non-compliant with PJM requirements. If the Company does not have sufficient unit-specific capacity to meet its demand obligation in either its initial or final FRR Plans, PJM could assess significant monetary penalties for the deficient delivery year, require the Company to procure additional capacity going forward, and remove the Company's ability to participate as a FRR entity. The two FRR plans submitted each year by Duke Energy Kentucky are consistent with the Commission's Order in Case No. 2010-00203 whereby the Commission required the Company to participate in the PJM capacity market as a FRR entity until such time as it received Commission approval to participate in the PJM capacity auctions. To date, Duke Energy Kentucky has not requested such permission, but now is doing so since it has determined that a change would be in the best interests of its customers and should be made at this time.

Q. PLEASE BRIEFLY SUMMARIZE WHY REMAINING A FRR ENTITY IS NO LONGER IN THE BEST INTERESTS OF CUSTOMERS.

A. Transitioning from the FRR participation to the RPM BRA/IA construct is in the best interest of customers due to the following factors: 1) the risk of and potential for large and sudden load growth at a rate faster than the Company can construct or acquire additional baseload generation; 2) uncertainty and change in the balance between demand and supply in the DEOK zone in PJM driven by announced generating asset retirements; 3) the lack of available bilateral capacity in the DEOK zone should future zonal separation occur and Duke Energy Kentucky find itself in a position where it needed additional bilateral capacity to meet its FRR plan;[8] 4) anticipated changes to PJM's FRR construct that would negatively impact the Company's participation as a FRR entity; 5) the energy transition in PJM due to retirements of fossil generation and PJM's own prediction of shrinking reserve margins and higher capacity prices; and 6) the change in the FRR shortfall penalty to the greater of 1.75 x Net Cost of New Entry (Net Cone) or Gross CONE.

Over its time in PJM, the Company has periodically analyzed whether remaining a FRR entity continues to be in the best interests of customers. And although previous analysis supported remaining in the FRR construct, such is no longer the case, and the Company believes a change is justified and in the public interest.

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[8] The DEOK zone has separated in three (3) of the last six (6) PJM BRAs demonstrating that the zone is capacity constrained and with future announced retirements, will likely continue to be going forward.

III. FINANCIAL ANALYSIS SUPPORTS PARTICIPATING IN THE RPM

A. SUMMARY OF ANALYSIS

Q. PLEASE EXPLAIN THE COMPANY'S COST-BENEFIT ANALYSIS THAT NOW SUPPORTS EXITING THE FRR AND BECOMING AN RPM AUCTION PARTICIPANT.

A. The Company recently performed a cost-benefit analysis examining the customer benefits from participation in the PJM capacity market as an RPM member as opposed to a FRR member and included this as Attachment JDS- 1. As I explain below, the conclusion is that since 2012 when first entering PJM as a FRR entity, participating as a FRR was the logical choice and has benefited customers. However, going forward, such is no longer the case. This is due to the potential for sudden and large customer load growth, especially those loads that can be added quicker than generation supply, announced and likely PJM capacity market structural changes, the risk of continued zonal separation for the DEOK zone and an inability to import, projected increases in PJM market clearing prices, and changes to the PJM supply/demand balance. Based upon these factors, the Company has determined through its analysis that a move to a full RPM auction participant is in the customer's best interest.

Q. PLEASE SUMMARIZE THE RESULTS OF THIS ANALYSIS.

A. Referring to Attachment JDS- 1, the results of this analysis created a "Heat Map" showing the annual net financial impact comparing participation as a FRR with that of RPM under four possible yet different scenarios. These four scenarios included evaluation of 1) Capacity in excess of demand (Long Capacity Position) coupled with a low auction clearing price (Low Price); 2) Insufficient capacity to meet demand (Short Capacity Position) coupled with a Low Price; 3) Long Capacity Position couple with a high-capacity auction clearing price (High Price); and 4) Short Capacity Position coupled with a High Price. In the three most likely of the four scenarios, moving to the RPM was the better alternative for customers going forward.

Q. PLEASE FURTHER EXPLAIN THIS ANALYSIS.

A. Attachment JDS-1, Tab 3, Labeled Heat Map depicts the results of these four scenarios. Starting with the "X-axis," a range of potential BRA clearing prices is shown, starting from low BRA prices on the left and moving to higher BRA prices on the right. The scenarios on the "Y-axis" are a range of the Company's supply-demand balance, with a Long Capacity Position on the top and a Short Capacity Position on the bottom. In this Heat Map, if a positive value is shown in a cell, this means that the FRR created that much more annual value for the customer as opposed to the RPM, whereas if a negative value is shown it means that staying in the FRR caused that much more annual loss for the customer than moving to the RPM.

The Heat Map can also be viewed as the opposite; thus, a positive value means that moving to the RPM would result in that much less annual net revenue as opposed to participation under FRR, and that a negative value means that the RPM would have resulted in that much additional value for the customer. A copy of the Heat Map from this analysis is shown as Table 1 below.

Table 1: “Heat Map” - Annual Financial Impact of FRR vs. RPM Participation

FRR - RPM

Length

DEK Portfolio Length

Long (Positive) or Short (Negative) Position

(Position = Length before Holdback or Short divided by Load Obligation)

Length	BRA Clearing Price, $/MW-Day 50	100	150	200	250	300	350	400	450	500
9%	$ 584,584	$ 855,998	$ 814,242	$ 459,316	$ (334,918)	$ (1,644,143)	$ (2,145,504)	$ (2,711,820)	$ (3,343,090)	$ (4,039,313)
8%	$ 591,008	$ 865,405	$ 823,190	$ 464,363	$ (338,598)	$ (1,662,210)	$ (2,169,081)	$ (2,741,620)	$ (3,379,827)	$ (4,083,701)
7%	$ 597,432	$ 874,811	$ 832,137	$ 469,411	$ (342,279)	$ (1,680,278)	$ (2,192,658)	$ (2,771,421)	$ (3,416,564)	$ (4,128,089)
6%	$ 603,856	$ 884,218	$ 841,085	$ 474,458	$ (345,959)	$ (1,698,345)	$ (2,216,235)	$ (2,801,221)	$ (3,453,301)	$ (4,172,477)
5%	$ 610,280	$ 893,624	$ 850,033	$ 479,506	$ (349,640)	$ (1,716,413)	$ (2,239,812)	$ (2,831,021)	$ (3,490,039)	$ (4,216,865)
4%	$ 616,704	$ 903,031	$ 858,981	$ 484,553	$ (353,320)	$ (1,734,480)	$ (2,263,389)	$ (2,860,821)	$ (3,526,776)	$ (4,261,253)
3%	$ 623,128	$ 912,437	$ 867,928	$ 489,601	$ (357,000)	$ (1,752,548)	$ (2,286,966)	$ (2,890,622)	$ (3,563,513)	$ (4,305,641)
2%	$ 649,846	$ 962,432	$ 937,758	$ 575,824	$ (259,211)	$ (1,648,851)	$ (2,168,485)	$ (2,758,070)	$ (3,417,604)	$ (4,147,089)
1%	$ 777,523	$ 1,214,345	$ 1,310,465	$ 1,065,883	$ 343,374	$ (939,401)	$ (1,343,291)	$ (1,817,846)	$ (2,363,065)	$ (2,978,948)
0%	$ 905,200	$ 1,466,257	$ 1,683,171	$ 1,555,943	$ 945,958	$ (229,950)	$ (518,097)	$ (877,622)	$ (1,308,525)	$ (1,810,806)
-1%	$ 543,387	$ 1,158,752	$ 1,426,534	$ 1,346,731	$ 779,344	$ (359,625)	$ (601,956)	$ (916,379)	$ (1,302,893)	$ (1,761,498)
-2%	$ (53,167)	$ 582,973	$ 868,087	$ 802,175	$ 243,852	$ (891,713)	$ (1,121,762)	$ (1,424,616)	$ (1,800,276)	$ (2,248,741)
-3%	$ (649,721)	$ 7,193	$ 309,640	$ 257,619	$ (291,640)	$ (1,423,801)	$ (1,641,568)	$ (1,932,854)	$ (2,297,659)	$ (2,735,983)
-4%	$ (1,246,274)	$ (568,587)	$ (248,807)	$ (286,937)	$ (827,133)	$ (1,955,889)	$ (2,161,374)	$ (2,441,092)	$ (2,795,042)	$ (3,223,226)
-5%	$ (1,842,828)	$ (1,144,366)	$ (807,255)	$ (831,493)	$ (1,362,625)	$ (2,487,977)	$ (2,681,180)	$ (2,949,329)	$ (3,292,425)	$ (3,710,468)
-6%	$ (2,439,382)	$ (1,720,146)	$ (1,365,702)	$ (1,376,049)	$ (1,898,117)	$ (3,020,065)	$ (3,200,986)	$ (3,457,567)	$ (3,789,809)	$ (4,197,711)
-7%	$ (3,035,935)	$ (2,295,926)	$ (1,924,149)	$ (1,920,605)	$ (2,433,609)	$ (3,552,153)	$ (3,720,791)	$ (3,965,805)	$ (4,287,192)	$ (4,684,953)
-8%	$ (3,632,489)	$ (2,871,705)	$ (2,482,596)	$ (2,465,160)	$ (2,969,102)	$ (4,084,241)	$ (4,240,597)	$ (4,474,042)	$ (4,784,575)	$ (5,172,196)
-9%	$ (4,229,043)	$ (3,447,485)	$ (3,041,043)	$ (3,009,716)	$ (3,504,594)	$ (4,616,328)	$ (4,760,403)	$ (4,982,280)	$ (5,281,958)	$ (5,659,439)

***Positive** value means FRR is a **better** financial outcome than RPM Capacity Construct annually for the amount shown.*
***Negative** value means FRR is a **worse** financial outcome than RPM Capacity Construct annually for the amount shown.*

Q. WHAT COULD CAUSE DUKE ENERGY KENTUCKY TO BECOME SHORT ON CAPACITY?

A. A short position could be caused by multiple reasons, including a.) a large, energy intensive customer, such as a data center or large factory, locating in the Duke Energy Kentucky service territory, b.) a reduction in the Company’s generation capacity value, as would be the case with a planned or forced unit retirement, c.) the Company’s generation becomes devalued due to performance (de-rates or outages), or d.) by PJM action where any or all of the following occur: 1) PJM increases the Company’s planning reserve margin; or 2) PJM makes other market rule/tariff changes that affect the Company’s FRR status or capacity position. This is sometimes referred to as a “stroke of pen risk,” as was recently the case with the transition to the PJM Effective Load Carrying Capability (ELCC) as discussed later in this testimony. While these four capacity-impacting scenarios have not yet occurred, nonetheless, they are possible and likely, and it is in the public interest to proactively act in the best interests of customers to protect them from such risks.

Q. EXPLAIN HOW TO READ AND UNDERSTAND THE RESULTS OF THIS HEAT MAP.

A. The four corners of the Heat Map show the four scenarios I previously described and depict the comparison of remaining an FRR participant versus RPM participation:

Scenario 1- (Upper left corner) Low Prices & Long Capacity Position): The green corner of the Heat Map shows where Duke Energy Kentucky has historically resided since joining PJM in 2012; in the lower range of PJM cleared capacity prices[9] and a Long Capacity position. This scenario resulted in the only scenario where FRR was the best choice for the customer, with this corner showing all positive values of up to approximately $1 million annually. This confirms that under the historical Low Price, Long Capacity scenario, the FRR has benefitted customers.

As an example, the historical average BRA clearing price has been $89.89/MW-Day.[10] Using the closest auction price on the Heat Map of $100/MW-Day as a proxy for comparison and a typical Duke Energy Kentucky 9% long capacity position, the value shown in the second column, first row of $855,998, would be the approximate value of the annual FRR benefit.

[9] Available at https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx, p. 5.
[10] The average BRA clearing price from the 2007/2008 to 2024/2025 auctions was $89.89/MW-Day.

<u>Scenario 2- (Lower left corner) Low Prices & Short Capacity Position</u>: This corner of the Heat Map shows the negative financial consequences to customers if, as a FRR entity, the Company lacks sufficient resources to meet its customer demand in a Low-Price environment. In this hypothetical, the Company is unable to construct or acquire a new, generating unit(s) with sufficient uncommitted,[11] unit-specific capacity within that timeframe needed to a serve load(s) within the FRR plan delivery year. Such a scenario could occur given that large customer loads can appear faster than a utility can design, site, receive construction approval, and build a large generating resource.

As Table 1 shows, even in a Low Price environment, due to a Short Capacity Position, the Company would need to purchase replacement capacity at a premium, assuming it is even available and deliverable into the DEOK zone, resulting in net costs to customers.[12] The impact of this shortfall of capacity could be in the millions of dollars, which includes the cost of replacement capacity and the PJM FRR penalty.[13]

<u>Scenario 3- (Upper right corner) High Prices & Long Capacity Position</u>: This corner of the Heat Map shows the negative financial consequences to the customer if the Company stays a FRR entity under a

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[11] As an FRR entity, the Company can only procure capacity that is unit-specific and has not already been committed to the PJM RPM. Capacity purchases in the RPM auctions are not unit specific and are unable to be used to meet an FRR obligation. Therefore, an FRR entity must rely upon the bilateral market to procure uncommitted capacity.

[12] If the shortfall of capacity occurs in a delivery year where the DEOK zone has separated from the rest of RTO, it may restrict the Company's ability to contract for bilateral, unit-specific capacity that is uncommitted, *i.e.* has not already been bid in, and cleared in the PJM auction.

[13] For example, even at a low-capacity price of $50/MW-Day with a 9 percent capacity shortfall, the impact to customers would be approximately $4.38 million in capacity costs.

High-Price, Long Capacity scenario. As stated, the historical average BRA clearing price was $89.89/MW-Day. However, as PJM undergoes a transition to lower emitting resources and lower reserve margins,[14] capacity prices are expected, and are more likely than not, to increase.

In its February 24, 2023 whitepaper, "Energy Transition in PJM: Resource Retirements, Replacements & Risks," PJM, as part of its multiphase effort to study the potential impacts of the energy transition, examined four trends that it perceives as presenting increasing reliability risks.[15] Under each of the four scenarios presented by PJM in its whitepaper, PJM is projecting reserve margins of 5%, 3%, 15%, and 12% by 2030,[16] well below the current PJM reserve margin in the mid-20% range.[17] As shown in the Heat Map I provided in JDS-1, in the High-Price, Long Capacity scenario, remaining in the FRR is a more costly alternative for customers, in excess of $4 million annually. Customers will receive a lower value for excess capacity due to the PJM requirement that FRR entities withhold 3% of its capacity before selling excess into the BRA. This withheld capacity would, however, be allowed to be sold in the 3rd incremental auction at a lower price assumption, as is discussed later in this testimony.

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[14] https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx (Table 1, p. 16).
[15] *Id*., p. 1.
[16] *Id*.. Table 1, p. 16.
[17] *Id.*

<u>Scenario 4- (Lower right corner) High-Prices & Short-Capacity Position</u>: This corner of the Heat Map shows the negative financial consequences to the Duke Energy Kentucky customers if the Company has a short capacity position as an FRR entity due to additional customer demand or less generating unit capacity or demand response, as discussed previously, but under a higher capacity price scenario. As shown in the lower right corner of the Heat Map, the customer could experience the largest risk in this corner, as it would be forced to purchase replacement capacity at a premium and have an increased risk of a FRR penalty associated with failing to meet its FRR plan.

B. CALCULATIONS SUPPORTING THE COMPANY BECOMING AN RPM PARTICIPANT

Q. PLEASE EXPLAIN IN DETAIL HOW YOU PERFORMED THE CALCULATIONS IN ATTACHMENT JDS-1.

A. To perform these calculations, the Company used existing PJM rules or market assumptions that defined (1) the amount of holdback required for FRR members prior to selling excess capacity into the BRA, (2) the Company's current required FRR reserve margin, (3) the slope of the PJM capacity demand curve, (4) the cost of the replacement capacity when experiencing a short FRR position, and (5) the relationship between the BRA and subsequent incremental auctions clearing prices. The above five factors were defined as the following:

1) Capacity holdback required prior to FRR entities selling into the BRA = 3%

2) Required FRR reserve margin = 18% (Installed Capacity, or ICAP basis)

3) Slope of the PJM capacity demand curve and corresponding reserve margin:
   - Low BRA Price RPM Reserve Margin = 22.5%
   - Mid BRA Price RPM Reserve Margin = 19.5%
   - High BRA Price RPM Reserve Margin = 18%
   - Maximum BRA Price RPM Reserve Margin = 17%

   Table 2 below shows a graphical representation of the reserve margin.

4) Estimated cost of replacement capacity under short FRR position:
   - 75% of the short position assumed to be purchased under bilateral contract equal to a price of 1.25 x BRA.
   - 25% of short position assumed to be charged FRR replacement penalty of 1.75 x Net CONE Price, where CONE = Cost of New Entry

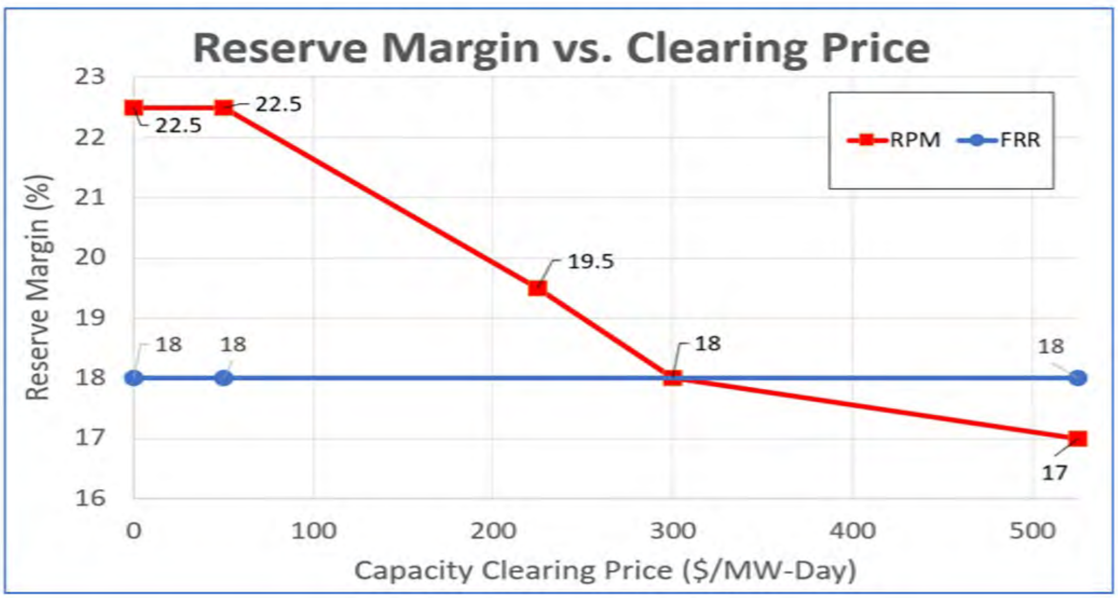
5) Relationship between the BRA and subsequent incremental auctions:
   - Incremental auction clearing price = 50% x BRA clearing price

The Company made realistic assumptions regarding the cost of the replacement capacity, but it is possible that under certain scenarios the financial consequence of failing to meet its FRR plan could cost Kentucky customers more than what is shown in the bottom right and left corners of the Heat Map. For example, if Duke Energy Kentucky is 100 MW short and there is no replacement capacity available, under the FRR construct, Duke Energy Kentucky would incur a FRR Deficiency Penalty equal to the shortfall amount multiplied by the greater of either the Gross Cost of New Entry (CONE)[18] or 1.75 multiplied by Net CONE.

[18] CONE represents the total annual net revenue (net of variable operating costs) that a new generation resource would need to recover its capital investment and fixed costs, given reasonable expectations about future cost recovery over its economic life. CONE is the starting point for estimating the Net Cost of New Entry (Net CONE). Net CONE represents the first-year revenues that a new resource would need to earn in the capacity market, after netting out Energy and Ancillary (E&AS) margins from CONE. CONE and Net CONE of the simple-cycle combustion turbine (CT) reference resource are used to set the prices on PJM's Variable Resource Requirement (VRR) curve.

Using the current Gross CONE of $444.26/MW-Day (UCAP Price) since it is currently the greater, the estimated penalty for only a 100 MW FRR shortfall would be $16.2 million.[19] This amount is a much larger value than shown on the two bottom corners of the Heat Map, since it was assumed that the Company would be able to satisfy 75% of this short position with replacement capacity, something that is likely to become increasingly difficult given a potentially changing PJM minimum internal requirement [20] and limited availability of bilateral capacity in the DEOK zone, both of which will be explained later.

Table 2: Graphical display of the FRR versus RPM reserve margin (ICAP basis)



[19] Penalty = 100 MW x $444.26/MW-Day x 365 days
[20] Defined in PJM RAA under the term "Percentage Internal Resources Required." This is the percentage of the LDA Reliability Requirement for an LDA that must be satisfied with Capacity Resource located in such LDA.

IV. RISK FACTORS SUPPORTING THE COMPANY BECOMING AN RPM PARTICIPANT

Q. PLEASE IDENTIFY ANY RISKS OF REMAINING AN FRR ENTITY AS OPPOSED TO TRANSITIONING TO THE RPM AUCTION CONSTRUCT.

A. There are several risks with remaining a FRR entity, which I explain further below. In summary they include: 1) the FRR capacity holdback requirement; 2) the difference in the reserve margin that PJM requires (*i.e.,* differential) between FRR and RPM participants; 3) deficiency penalties; and 4) the minimal internal requirement for FRR capacity.

Q. PLEASE FURTHER EXPLAIN THE RISKS AND COSTS OF REMAINING A FRR DUE TO THE FRR CAPACITY HOLDBACK REQUIREMENT, VERSUS TRANSITIONING TO THE RPM AUCTION CONSTRUCT.

A. FRR entities are restricted by PJM, pursuant to the RAA, to hold back, or not monetize their generation capacity in an amount equivalent to the lower of 450 MW or 3 percent of their load in the BRA. This means that Duke Energy Kentucky (or any FRR entity) are unable to fully take advantage of the benefit of having excess generation capacity until the 3rd IA of a delivery year. For Duke Energy Kentucky, as an FRR participant, it must hold back (cannot offer nor sell) approximately 30 MW of excess capacity in the BRA and first two incremental auctions. This restriction would not exist if the Company became a full RPM participant. By moving to RPM, Duke Energy Kentucky will be able to monetize more capacity than it has previously been permitted as a FRR entity. Because the Company includes capacity sales in its Profit Sharing Mechanism (Rider PSM), customers will receive additional value for this capacity. This ability to avoid the capacity holdback in the RPM construct is a significant advantage over the FRR. For the recently completed 2025/2026 BRA, with a clearing price of $269.92/MW-Day and 24 MW of required hold back, this resulted in $2.364 million in less revenue sold into the BRA and shared with customers.[21]

Q. PLEASE EXPLAIN THE RISKS AND COSTS OF REMAINING A FRR ENTITY DUE TO THE RESERVE MARGIN DIFFERENTIAL, VERSUS TRANSITIONING TO THE RPM AUCTION CONSTUCT.

A. As shown in Table 2, the reserve margin for FRR entities is a constant amount (currently approximately 18%), but for RPM entities, the reserve margin is as high as 22.5% at very low-capacity prices, but as low as 17% at the highest capacity prices. Thus, this reserve margin differential produces different costs and benefits for both the FRR and RPM participant, depending upon the price of capacity. As capacity prices rise, as they are predicted to do, the benefit of RPM increases. For reliability, FRR LSEs must self-supply an incremental fixed reserve margin of capacity equal to 100% of the Reliability Requirement of the FRR load obligation or the target Installed Reserve Margin (IRM).[22] However, RPM entities purchase capacity reserves on a sloped demand curve, with an annual reserve margin requirement keyed off the price of capacity determined in the RPM for the delivery year. In periods of low-capacity prices, the RPM sloped demand curve can cause additional purchases as the price of the auction moves lower, meaning that at lower prices, loads purchase more capacity to ensure greater reliability. However, the

[21] In the 2025/2026 BRA; 24 MW x $269.92/MW-Day x 365 days = $2,364,499.
[22] In the 2025/2026 BRA; the target installed reserve margin for FRR 17.8%.

opposite is also true that in periods of higher capacity prices, the required reserve purchases are lower for RPM participants. For Duke Energy Kentucky, and in turn, its customers, the reserve margin differential only provides a benefit to the FRR participant when capacity prices are low. However, as capacity prices trend higher, the benefit to being a FRR entity starts to decrease. This is because in periods of higher capacity prices, FRR entities, with a flat target IRM, end up holding a higher reserve margin than those in RPM. This means that there is a financial advantage to being in RPM at high-capacity prices. This benefit is shown as a savings to being in the RPM in the Heat Map calculation at the upper right and lower right corners. Based upon this analysis, there is significant advantage to customers with the Company becoming an RPM entity.

Q. PLEASE FURTHER EXPLAIN THE RISKS AND COSTS OF REMAINING A FRR DUE TO FRR DEFICIENCY PENALTIES, VERSUS TRANSITIONING TO THE RPM AUCTION CONSTUCT.

A. As the name implies, FRR deficiency penalties are only applicable to FRR entities. The potential magnitude of a deficiency penalty can be severe if Duke Energy Kentucky is unable to meet its FRR plan as submitted prior to the BRA. As I previously stated, a FRR plan deficiency can occur due to a sudden increase in customer demand, planned or unplanned unit retirements, or through a reduction in Duke Energy Kentucky's generation capacity value. The deficiency penalty is equal to the capacity shortfall amount multiplied by the greater of either the Gross CONE or 1.75 multiplied by Net CONE, in $/MW-day. Thus, depending upon the size of the deficiency and ability to cure this shortfall, a penalty could be very costly. A move to RPM eliminates the risk potential for a large FRR deficiency penalty charge.

Q. PLEASE DESCRIBE THE RISK ASSOCIATED WITH THE PJM MINIMUM INTERNAL REQUIREMENT FOR THE DEOK ZONE IF THE COMPANY REMAINS A FRR, VERSUS TRANSITIONING TO THE RPM AUCTION CONSTUCT.

A. A challenge of meeting the Company's FRR plan is the PJM minimum internal resource requirement. Under this requirement, Duke Energy Kentucky must locate a certain, PJM-determined, percentage of its unit-specific generation that is included in its FRR Plans within the DEOK zone. This percentage varies from year to year and can be volatile. While the Company's owned generation at East Bend and Woodsdale stations are located within the DEOK zone, if a FRR plan required a purchase of additional capacity, such capacity may also need to meet those zone limitations. While the current year's requirement is a low 4.4% percent, this percentage can have substantial changes year to year, with the previous yearly required value at 29.3%. With recent and announced merchant generation retirements located within the DEOK zone,[23] there is a significant risk that bilateral capacity within the DEOK zone will be scarce and potentially unavailable. Because PJM's minimum internal requirement is responsive to and influenced by additional load added within the zone, as well as changes in generating unit capacity within the zone, and changes in local transmission capability, the Company and its

[23] *See e.g.,* Vistra announces retirement of Zimmer Power Plant in Moscow Ohio and Miami Fort Power Plant in North Bend Ohio by 2027: available at https://investor.vistracorp.com/2020-09-29-Vistra-Accelerates-Pivot-to-Invest-in-Clean-Energy-and-Combat-Climate-Change.

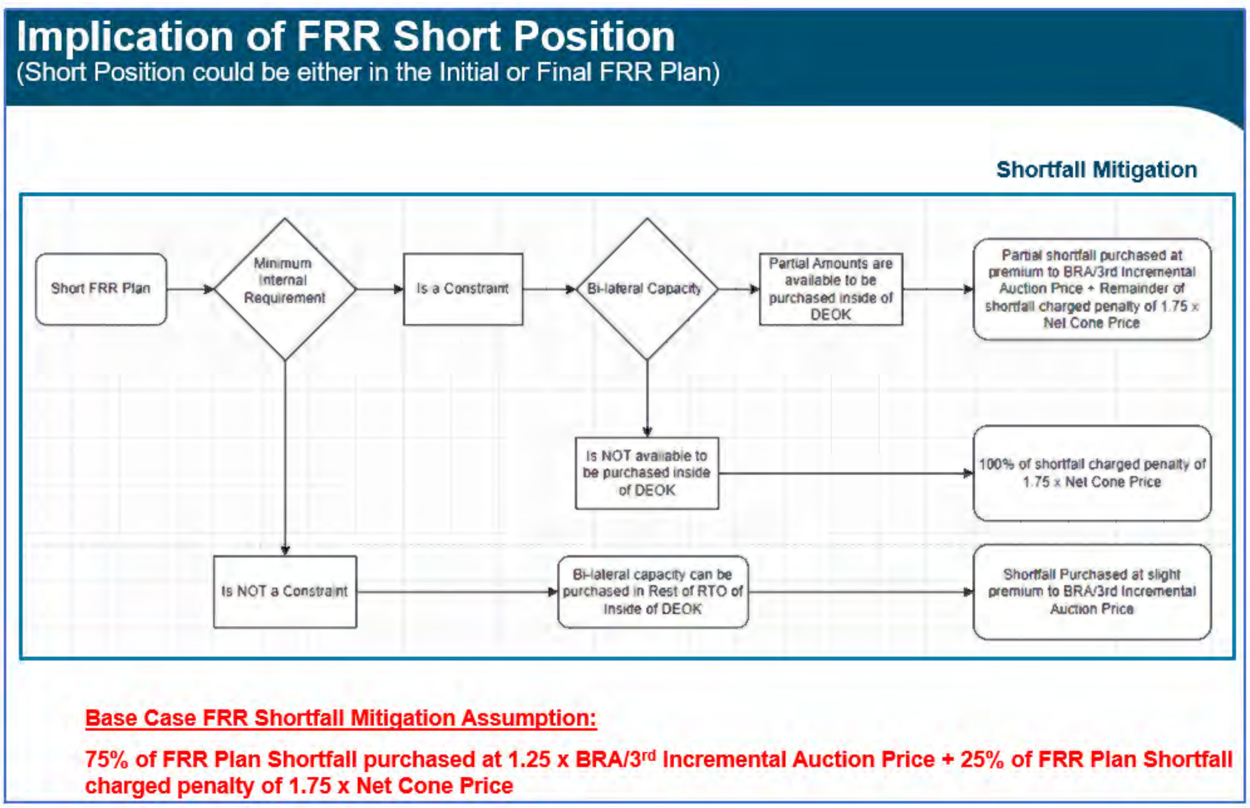
customers are exposed to a significant reliability and cost risk if additional capacity is needed but not available within the DEOK zone. This PJM minimum internal resource requirement risk is not present as an RPM participant.

Q. PLEASE DESCRIBE THE AVAILABILITY OF REPLACEMENT BILATERAL CAPACITY IN THE DEOK ZONE AND HOW THIS IMPACTS THESE CALCULATIONS.

A. In the event of a short capacity position, a FRR participant can only purchase unit specific capacity through bilateral contracts, as required by the FRR construct. This is because the BRA and IAs do not procure unit-specific capacity. Thus, the RPM auctions are not a viable compliance alternative for a FRR entity.

As a further FRR complication, the geographic location of bilateral capacity can be outside the LSE's zone only to the extent that the FRR entity satisfies the minimal internal requirement. Again, the risk is what happens when the Company cannot satisfy its minimum internal requirement in the bilateral market. Remaining an FRR creates a risk through the potential limited available bilateral capacity options available for the Duke Energy Kentucky customer. Capacity owners are not obligated to participate in the bilateral market, or potential sellers may only be willing to sell excess capacity in advance of the BRA/IA at prices higher than expected auction clearing prices. If a seller anticipates a higher auction price, then there is no incentive for them to offer bilateral capacity. Moreover, if unit-specific capacity is available following an auction, it did not clear the BRA/IA for the delivery year, meaning its costs were higher than the clearing price produced. If potential bilateral capacity sellers realize that Duke Energy Kentucky needs to purchase capacity within the DEOK zone due to a short fall, the Company would be in a weak bargaining position and sellers may try to raise the offer price of capacity to capitalize on their long and unique locational position (like a "short squeeze" in stock market trading). For these reasons, in the Heat Map calculations I previously described, the calculations assume that 75% of a capacity shortfall will be able to be purchased bilaterally at a slight auction clearing price premium, but that 25% of the shortfall will not be available for purchase resulting in a FRR deficiency penalty assessment. Table 3 below shows a flowchart describing the implications of an FRR short position and replacement capacity values.

Table 3: Flowchart - FRR Short Position and Replacement Capacity Value



Transitioning to the RPM avoids this risk entirely as all capacity will be procured through the competitive BRA and IA constructs.

Q. PLEASE EXPLAIN THE RISK OF ZONAL SEPARATION AND WHETHER THE DEOK DELIVERY ZONE PREVIOUSLY SEPARATED AS A CONSTRAINED ZONE.

A. In the BRA/IA, PJM procures capacity for its entire footprint. During these auctions, it is possible for one or more individual zones to separate, or clear at a different, higher price than that of the rest of the PJM footprint. This separation can occur for a number of reasons, but more often than not, due to some constraint within that specific zone. In three of the past six PJM BRAs, the DEOK zone "separated," or cleared at a higher price than the remainder of PJM. See Table 4 below for the specific data related to these past five PJM auctions. Specifically, for the 2020/2021, 2022/2023, and 2024/2025 auctions, the DEOK zone cleared at a higher price than the rest of the RTO, highlighting the "tightness" of capacity in the DEOK zone. The fact that this separation has occurred in multiple delivery years shows the ongoing risk to customers with Duke Energy Kentucky remaining in FRR and facing a short position as depicted in the bottom two corners of the Heat Map. In these two corners, Duke Energy Kentucky would be forced to find bilateral capacity that satisfies the PJM locational requirement, if necessary, or pay an FRR deficiency penalty. This DEOK zone separation could impact market liquidity for capacity, particularly when combined with retirements of other generation in the zone. While this diminished liquidity has not impacted Duke Energy Kentucky to date, the Company is mindful of the potential impacts on capacity planning.

One expected change to the DEOK zone is the announced retirement of the 1,020 MW Miami Fort generating station within the DEOK zone[24] beginning in August 2027. Although the owner of this station can always decide not to retire the unit on this date, this station represents 1,020 MW out of a total of 3,294 MW of generation capacity in the DEOK zone, or approximately one third of the zone's capacity. Thus, accounting for Duke Energy Kentucky's 1,076 MW capacity, there are only 1,198 MW of remaining generating resources within the DEOK zone, with approximately 370 MW of these resources being energy efficiency and demand response.

Table 4: Previous 6 PJM Base Residual Auction results.

Deliery Year	RTO Clearing Price ($/MW-Day)	DEOK Clearing Price ($/MW-Day
2020/2021	76.53	130
2021/2022	140	140
2022/2022	50	71.69
2023/2024	34.13	34.13
2024/2025	28.92	96.24
2025/2026	269.92	269.92

[24] https://www.luminant.com/documents/ccr/Ohio/Miami-Fort/2023/2023-Miami%20Fort-Part%20A%20Annual%20Progress%20Report%202023-Pond%20System.pdf

Q. IN THE EVENT THAT THE DEOK ZONE CONTINUES TO CLEAR AT A HIGHER PRICE THAN THE REMAINDER OF THE PJM RTO, ARE CUSTOMERS HARMED BY A MOVE TO RPM IN THIS SITUATION? PLEASE EXPLAIN.

A. No. In fact, a move to RPM saves customers money under high-capacity price scenarios. As shown in the Heat Map, in both the upper right and lower right corners (the high-capacity price scenarios), if Duke Energy Kentucky is long (upper right) or short (lower right), the customer is better off in RPM than in FRR.

In the case of the upper right corner of the Heat Map, the Company simply sells more capacity than it buys at the higher prices. As a simple example, suppose Duke Energy Kentucky has 1,000 MW of generation capacity and 900 MW of load with the BRA clearing at $400/MW-Day. The amount of capacity sold to PJM would be $146[25] million and the amount purchased from PJM would be $131.4 million.[26] With higher capacity clearing prices and a long position, more money is received than spent. This credit of $146 million would be received by Duke Energy Kentucky through PJM Billing Line Item (BLI) 2600 and the cost of $131.4 million would be charged to Duke Energy Kentucky through PJM BLI 1600.

In the case of the lower right corner of the Heat Map, the Company is short and saves under RPM by avoiding purchasing replacement capacity at a higher price and by also avoiding the FRR deficiency penalty. Taking the inverse of the long example above, suppose Duke Energy Kentucky has 1,000 MW of load and 900 MW of generation capacity with the BRA clearing at $400/MW-Day. The

[25] $146 million = 1,000 MW x $400/MW-Day x 365 Days
[26] $131.4 million = 900 MW x $400/MW-Day x 365 Days

amount of capacity sold would be $131.4 million and the amount bought would be $146 million. Under RPM, a net payment of the difference in the two numbers is paid, or $14.6 million. However, in looking at the Heat Map at the shortest Duke Energy Kentucky position (-9% short) and a $400/MW-Day BRA clearing price, a loss of $4.98 million is shown. Thus, by remaining in FRR, the loss is $4.98 million worse due to replacement capacity and an FRR deficiency penalty, or total FRR losses would be $14.6 million plus $4.98 million, or $19.58 million. If either long or short, under high PJM BRA clearing prices, the customer is better offer under RPM.

Q. AT ONE TIME, CONCERN OVER THE PJM MINIMUM OFFER PRICE RULE (MOPR) PRESENTED RISK THAT DUKE ENERGY KENTUCKY CUSTOMERS COULD "PAY TWICE" FOR CAPACITY IF A MOVE TO THE RPM WAS MADE. IS THIS STILL A CONCERN?

A. No. Recently, PJM has clarified and made changes to the applicability of their MOPR rule impacting new RPM participation. Prior to this rule change, if Duke Energy Kentucky were to switch to an RPM member, there was the potential that Duke Energy Kentucky would be required to offer certain generation resources into the RPM auctions at a minimum price that was potentially high enough that the resource could not clear in the auctions (either the BRA or a subsequent incremental auction). Thus, the potential existed for Duke Energy Kentucky customers to "pay twice" for capacity; once to build/maintain a generation asset and again to purchase capacity for its load in the capacity auctions. If the Company's asset did not clear the auction, there would be no generation revenues to offset the load purchase.

Today, however, with these changes and clarifications, these risks no longer exist, should the Company transition to full RPM participation. There are now two conditions that must be true to eliminate this MOPR risk. The first condition is that Duke Energy Kentucky does not have Buyer-Side Market Power (BSMP), which occurs when an LSE offers generation at a lower price to reduce its overall exposure to the market. This will not occur should Duke Energy Kentucky transition to RPM. The second condition is that Duke Energy Kentucky does not have Conditioned State Support. Conditioned State Support occurs if a state (Kentucky) is giving a unit subsidization based on how the unit is offered (priced) into the capacity market. Again, this is not the case for Duke Energy Kentucky as there is no state subsidization based upon how the unit is priced into the market. For the most recent planning year, Duke Energy Kentucky certified that these two conditions did not occur, and PJM agreed with that determination. The new MOPR rule clarifications eliminate the MOPR risk and makes Duke Energy Kentucky able to freely transition to RPM without risk of MOPR restrictions for its generation.

Q. PLEASE EXPLAIN THE PJM CAPACITY PERFORMANCE CONCEPT.

A. In a stated effort to improve the reliability of generating resources in the PJM footprint, PJM redesigned its capacity markets with its "Capacity Performance" construct. In doing so, PJM redefined its capacity products and implemented new performance-based penalties. Capacity resources must be capable of sustained, predictable operation that allows the resource to be available to provide energy and reserves during performance assessment hours throughout the delivery year. Capacity resources are subject to non-performance charges assessed during emergency conditions throughout the entire delivery year. Capacity resources must be available to the RTO during periods of high load demand or system emergency or face substantial performance penalties. With Capacity Performance, PJM adopted a no-excuses policy to improve reliability through a new penalty structure.

In this new construct, PJM transitioned all capacity in the footprint to Capacity Performance. In other words, all capacity purchased on behalf of the load through RPM or eligible for inclusion in FRR capacity plans must meet the Capacity Performance criteria.

Q. HOW WOULD YOU CLASSIFY THE CURRENT DUKE ENERGY KENTUCKY RESOURCES IN TERMS OF COMPLIANCE WITH THE CAPACITY PERFORMANCE CONSTRUCT?

A. East Bend 2 meets the minimum requirements of a Capacity Performance resource in that it is a coal fired facility with a significant reserve of fuel stored on-site. The Woodsdale Combustion Turbine facility successfully meets the Capacity Performance requirements with the completion of the construction of its new dual fuel system in 2019. Even so, the Company continues to evaluate Capacity Performance compliance opportunities for its portfolio to increase their value and mitigate non-performance risks.

Q. PLEASE EXPLAIN PJM CAPACITY PERFORMANCE AS IT RELATES TO FRR.

A. Being in FRR means participants have an additional Capacity Performance option available than those under RPM in that they can elect for a physical capacity performance penalty option instead of a financial charge. This optionality is not available to RPM participants. In lower capacity price environments as has generally been the case, the FRR physical penalty option tends to be a lower cost alternative than the financial option, thus this is one benefit to remaining an FRR entity.

During times of *lower* PJM capacity market prices, the equivalent financial cost of a physical capacity performance penalty is less than the financial capacity performance penalty. Conversely, during times of *higher* PJM capacity market prices, the equivalent financial cost of a physical capacity performance penalty is roughly equal to the financial capacity performance penalty. Thus, with past relatively low-capacity price levels, the physical capacity performance penalty option has been a lower cost alternative than that available under participation as an RPM member. However, as stated earlier and as evident by the recently cleared 2025/2026 BRA, the Company believes capacity clearing prices will increase in the future and thus, the benefit to the FRR from the physical option will decrease over time.

Q. WERE THERE ANY ADDITIONAL CHANGES TO THE WAY PJM CHARGES CAPACITY PERFORMANCE PENALTIES TO RPM PARTICIPANTS THAT MAKE IT MORE ADVANTAGEOUS TO LEAVE FRR AND BECOME AN RPM PARTICIPANT?

A. Yes. PJM recently changed the “stop loss” amount for capacity performance charges. Previously, the most an entity could pay in Capacity Performance charges, or the “stop loss,” was tied to the CONE price for that LDA. However, under the new “stop loss,” the maximum Capacity Performance amount that can be charged is related to the BRA clearing price. Thus, if the BRA clears at a low price, the stop loss is 1.5 multiplied by the BRA price which is a lower amount than previously calculated. Unless the BRA clears at CONE, the maximum that can be charged for PJM Capacity Performance is less. This is one additional reason the Company is pursuing a change to RPM capacity market participation.

Q. HOW DID THE PJM'S RECENT CHANGE TO THE ELCC METHODOLOGY IMPACT DUKE ENERGY KENTUCKY'S CAPACITY POSITION?

A. PJM transitioned to the Effective Load Carry Capability (ELCC) methodology for the 2025/2026 Delivery Year. Generators now receive a class level ELCC. Thus, each generator within a certain class receives the same initial capacity value. For the Company's resources, as previously mentioned, East Bend received an ELCC class value of .84 (84%), Woodsdale CT 1-6 received an ELCC class value of .79 (79%), and Demand Response received an ELCC class value of .76 (76%). Next, each specific resource is adjusted using a performance adjustment factor to account for that individual resource's performance. Since the Company's resources have performed, in general, equal to or above the class average in most cases, and since the PJM ELCC class levels for Coal and Gas Combustion Turbine Dual Fuel units are relatively high, the Company's capacity position was either unchanged or became slightly longer under the ELCC methodology. In addition to a generally lower capacity value, the amount of load obligation is reduced as well. Thus, under ELCC, both the amount of resource capacity decreased as well as the amount of demand.

Q. DID THE PJM CHANGE TO ELCC IMPACT THE DECISION TO MOVE TO RPM?

A. On average, the ELCC change did not materially impact the Company's net position, or the difference between its resources and load. There was little net change due to both values decreasing. In general, the Company remains in a slightly long position as has been the case since joining PJM in 2012. However, the change to ELCC reduced other entities capacity values for its generators by an amount more than the load decreased. Thus, it is believed that overall capacity market clearing prices will be higher as a result, as was evidenced by the 2025/2026 BRA clearing price for the Rest of RTO of $269.92/MW-Day. Since the value to Duke Energy Kentucky being in the RPM capacity construct generally increases as capacity prices increase (think the upper right and lower right corners of the Heat Map), the change to ELCC is an added reason to transition to RPM.

Q. PLEASE EXPLAIN HOW THE RECENT 2025/2026 PJM BRA CLEARING PRICE OF $269.92/MW-DAY IMPACTS THE COMPANY'S DECISION.

A. Recently, on July 30, 2024, PJM released the results of the 2025/2026 BRA with the auction price for the "Rest of RTO" being $269.92/MW-Day. Since the DEOK Zone did not split out, the capacity price was the same price for the DEOK Zone. Although other PJM Zones have at times cleared at a higher capacity clearing price, the 2025/2026 clearing price represents the highest cost ever cleared for the DEOK Zone. These auction results further solidify the Company's position that PJM capacity prices are headed higher and that a move to RPM is in the best interest of DEK customers.

Q. WHAT WOULD HAVE BEEN THE APPROXIMATE FINANCIAL IMPACT HAD THE COMPANY BEEN IN THE RPM FOR THE 2025/2026 AUCTION?

A. Although the complete financial results cannot be calculated until after the 3rd incremental auction results are known, by looking at the heat map in Table 1, an approximate value amount can be calculated. If looking at the +5% row and interpolating between the $250/MW-Day and $300/MW-Day columns, an approximate savings to the customer of $1M for the year would have been realized from full participation in the 2025/2026 RPM as opposed to the FRR.

Q. PLEASE EXPLAIN HOW A POTENTIAL CHANGE TO A SEASONAL AUCTION STRUCTURE BY PJM COULD IMPACT THE COMPANY'S PARTICIPATION IN PJM.

A. There are no immediate plans for PJM to transition to a seasonal auction, but potential for this change does exists in the 2029/2030 timeframe. While currently the rules around any possible new seasonal auction construct have not been fully developed yet, previous discussion has indicated a Winter/Summer auction format. Regarding the possibility of a Winter auction, Duke Energy Kentucky has an advantage since the Woodsdale combustion turbine site is already dual fuel capable. Due to this dual fuel capability, the Company anticipates either a neutral or slightly positive impact if PJM were to transition to a seasonal auction format and Duke Energy Kentucky were an RPM capacity construct member.

Q. IS THE COMPANY AWARE OF NEW ADDITIONAL CUSTOMER LOAD BEING LOCATED IN THE DUKE ENERGY KENTUCKY SERVICE TERRITORY THAT WOULD INCREASE THE NEED FOR THIS TRANSITION?

A. Although the Company routinely engages in economic development conversations with potential new customer load, no recent significant additions have been announced for the Company's service territory. However, with the general increased trend of large-scale, energy intensive customers like data centers interested in locating in lower cost electricity priced jurisdictions like Kentucky, the flexibility to quickly serve provided by an RPM transition provides greater benefit for all customers. Moving to RPM eliminates the potential of an FRR deficiency penalty and saves the existing customers money as shown in the analysis.

V. PJM SETTLEMENTS

Q. WHAT ADDITIONAL PJM CREDITS AND CHARGES WILL BE RECEIVED FROM PJM IN THE EVENT THAT DUKE ENERGY KENTUCKY TRANSITIONS TO THE RPM CAPACITY CONSTRUCT?

A. By moving to RPM, Duke Energy Kentucky will continue receiving PJM Billing Line Items (BLI) 1600 and 2600 and will begin receiving additional PJM settlements charges and credits related to the capacity auction participation, specifically PJM BLI 1610, 1650, 1660, 1661, 1662, 1663, 1664, 1665, 1666, and PJM BLI 2605, 2620, 2625, 2630, 2640, 2650, 2660, 2661, 2662, 2663, 2664, 2665, and 2666. Note that historically the Company has received PJM BLI 2600 related to excess capacity sales, or the capacity sold into the PJM auctions after the Company's FRR plan and 3% holdback (in the case of the BRA and first and second incremental auctions) are satisfied. However, the amounts that the Company would receive in the future under PJM BLI 2600 would be much greater since all generation is offered and likely sold into the PJM auction, not just the small amount of excess as is the case today. Conversely, charges the Company would receive in PJM BLI 1600 would be much greater, since all customer load obligation would be purchased in the PJM auction. Please refer to Attachment JDS-2 for a detailed listing of PJM BLI's.

Q. PLEASE EXPLAIN PJM BLI'S 1600, 1610, 1650, 1660, 1661, 1662, 1663, 1664, 1665, 1666, AND PJM BLI'S 2600, 2605, 2620, 2625, 2630, 2640, 2650, 2660, 2661, 2662, 2663, 2664, 2665, AND 2666?

A. <u>1600 – RPM Auction</u>

Each bid cleared in an incremental auction pays the applicable LDA's resource clearing price. Resource make-whole payments for an incremental auction are also allocated as charges to Market Buyers based on the MW shares of cleared buy bids adjusted by cleared buy bid transactions for the incremental auction. Resource make-whole payments for the BRA and the portion of the resource make-whole payment for an incremental auction that would be based on PJM cleared buy bids are allocated as charges to LSEs in the applicable LDA via the Final Zonal Capacity Price.

1610 - Locational Reliability

Each LSE is charged for their daily unforced capacity obligation priced at the applicable zonal capacity price for the delivery year.

1650 - Auction Specific MW Capacity Transaction

Bilateral capacity transactions for multi-day durations are settled in the PJM capacity markets. Sellers are charged for the transaction MW times the transaction's pricing point for each day for which the transaction is in effect.

1660 – Demand Resource Interruptible Load for Reliability (ILR) Compliance Penalty

Sellers with zonal aggregate committed Demand Resources or nominated ILR that cannot demonstrate hourly real-time performance pay a penalty charge which is allocated to Demand Resource and ILR providers and, potentially, LSEs. This billing is performed on a three-month lag. For each non-compliant reduction event, under-compliance MW (on an unforced capacity basis) are charged at the lesser of one divided by the actual number of events during the year or 0.50 of the Weighted Annual Revenue Rate. The Weighted Annual Revenue Rate equals the average rate for all cleared Demand Resources, weighted by the MWs cleared at each price, multiplied by the number of days in the delivery year. The total Compliance Penalty Charge for the delivery year is capped at the annual revenue received for such resources.

1661 - Capacity Resource Deficiency

Capacity resources that are unable or unavailable to deliver unforced capacity, and do not obtain replacement unforced capacity to satisfy their cleared sell offer pay this charge which is allocated to eligible LSEs. Each capacity resource's deficiency MW for each day it is deficient pays the daily deficiency rate.

1662 - Generation Resource Rating Test Failure

Generation capacity resources that fail a capacity test pay this charge which is allocated to eligible LSEs. This billing is performed in the June billing cycle after the conclusion of the delivery year. Each capacity resource's installed capacity minus its highest rating in the relevant testing period (on an unforced capacity basis) pays a daily deficiency rate which is the weighted average capacity resource clearing price plus the higher of: 1) 0.2 times the weighted average capacity resource clearing price or 2) $20/MW-day.

1663 - Qualifying Transmission Upgrade Compliance Penalty

Cleared qualifying transmission upgrades delayed in coming into service for the applicable delivery year pay a daily penalty charge which is allocated to eligible LSEs. Capacity market sellers with import capability cleared in a base residual auction based on a qualifying transmission upgrade are charged each day that the upgrade is not in service during the applicable delivery year and the seller does not obtain replacement capacity resources. The import capability MW are charged at the higher of the following rates: 1) two times the locational price adder of the applicable LDA; or 2) the Net CONE less the clearing price in the applicable LDA.

1664 – Peak Season Maintenance Compliance Penalty

Each generation capacity resource must have available unforced capacity during the peak season to satisfy its cleared MW. This billing is performed in the

June billing cycle after the conclusion of the delivery year, and only applies to the month of June. Each generation capacity resource's cleared MW for each day of the peak season that is out-of-service on a maintenance outage not authorized by PJM pays the daily deficiency rate times (1-EFORd).

1665 – Peak-Hour Period Availability

To ensure capacity resource availability during critical peak hours, incentives are provided to resources that exceed expected availability and penalties are assessed to those who fall short. This billing is performed in the August billing cycle after the conclusion of the delivery year, and only applies to the month of August. Net peak period capacity shortfall MW are charged at the weighted average resource clearing price for the applicable LDA (except for FRR capacity that are charged at the LDA's Net CONE).

1666 - Load Management Test Failure

Sellers with committed Demand Resources that fail performance tests pay a penalty charge which is allocated to eligible LSEs. This billing is performed in the August monthly bill issued in September after the conclusion of the delivery year. Net capability testing shortfall MW are charged daily at the weighted annual revenue rate for the applicable zone plus the greater of 0.2 times that weighted annual revenue rate or $20/MW-day.

2600 - RPM Auction

Each sell offer for generation, demand, or qualified transmission upgrade resource MW cleared in an RPM Auction is paid the applicable resource's clearing price in the applicable auction. Resource make-whole payments are also provided to sell offers that clear less than the minimum amount specified. Sell offers are adjusted by approved unit-specific transactions for cleared capacity.

2605 - RPM Seasonal Capacity Performance Auction

Each sell offer for generation, demand, or qualified transmission upgrade resource MW cleared in an RPM Auction is paid the applicable resource's clearing price in the applicable auction. Resource make-whole payments are also provided to sell offers that clear less than the minimum amount specified. Sell offers are adjusted by approved unit-specific transactions for cleared capacity.

2620 – Interruptible Load for Reliability

Each ILR resource is credited for their certified zonal MW priced at the applicable zonal ILR price.

2625 - LSE Price Responsive Demand

An annual capacity resource provided by a PRD Provider that represents customers that will reduce load based on price.

2630 - Capacity Transfer Rights

To recognize the value of import capability to constrained LDAs, Capacity Transfer Rights (CTRs) are allocated to LSEs in those LDAs to offset their higher load charges. CTRs equal to the unforced capacity imported into the LDA (less any incremental CTRs) are allocated to LSEs in that LDA based on daily unforced capacity obligations. These MW allocations are priced at the difference between the LDA's clearing price and the unconstrained price.

2640 - Incremental Capacity Transfer Rights (CTRs)

Incremental CTRs are provided to fund for transmission upgrades (not including qualifying transmission upgrades cleared in the BRA) that increase import capability into a constrained LDA. Incremental CTRs for Incremental-Rights Eligible Required Transmission Enhancements are determined and allocated as defined in Schedule 12A of the Tariff. Incremental CTR MW are priced at the sum of: 1) locational price adder of the sink LDA minus that of the Source LDA from the BRA; and 2) locational price adder of the sink LDA minus that of the source LDA from the Second Incremental Auction multiplied by the increase in unforced capacity imported into the sink LDA in the Second Incremental Auction compared to the Base Residual Auction, divided by the base unforced capacity imported into the sink LDA. Incremental CTR credits determined for an Incremental-Rights Eligible Required Transmission Enhancement are allocated to the responsible customers that are assigned cost responsibility for the transmission enhancements in accordance with the cost allocations in the appendix to Schedule 12. Responsible customers include Network Customers, Transmission Customers with an agreement for Firm Point-to-Point Service, or Merchant Transmission Facility Owners. Network Customers serving load in a responsible zone receive credits in proportion to their network service peak load share in that zone.

2650 - Auction Specific MW Capacity Transaction

Bilateral capacity transactions for multi-day durations are settled in the PJM capacity markets. Buyers are credited for the transaction MW times the transaction’s pricing point for each day for which the transaction is in effect.

2660 – Demand Resource and ILR Compliance Penalty

Sellers with zonal aggregate committed Demand Resources or nominated ILR that cannot demonstrate hourly real-time performance pay a penalty charge which is allocated to Demand Resource and ILR providers and, potentially, LSEs. This billing is performed on a three-month lag. Revenues from events in each month are allocated to Demand Resources that reduced in excess of their commitment. Any resource credit by event is capped at their excess MW times 1/5th of their Annual Revenue Rate. Revenues above that cap are allocated to LSEs based on their average daily unforced capacity obligations during the month of the event.

2661 - Capacity Resource Deficiency

Capacity resources that are unable or unavailable to deliver unforced capacity, and do not obtain replacement unforced capacity to satisfy their cleared sell offer pay this charge which is allocated to eligible LSEs. Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.

2662 - Generation Resource Rating Test Failure

Generation capacity resources that fail a capacity test pay this charge which is allocated to eligible LSEs. This billing is performed in the June billing cycle after the conclusion of the delivery year, and only applies to the month of June. Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.

2663 - Qualifying Transmission Upgrade Compliance Penalty

Cleared qualifying transmission upgrades delayed in coming into service for the applicable delivery year pay a daily penalty charge which is allocated to eligible LSEs. Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.

2664 – Peak Season Maintenance Compliance Penalty

Each generation capacity resource must have available unforced capacity during the peak season to satisfy its cleared MW. This billing is performed in the June billing cycle after the conclusion of the delivery year, and only applies to the month of June. Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.

2665 – Peak-Hour Period Availability

To ensure capacity resource availability during critical peak hours, incentives are provided to resources that exceed expected availability and penalties are assessed to those who fall short. This billing is performed in the August billing cycle after the conclusion of the delivery year, and only applies to the month of August. Total revenues for the delivery year for each LDA are allocated to resources with peak period excesses based on their excess MW. Since these allocations are capped, any remaining credits are allocated to LSEs that paid a Locational Reliability charge based on their daily unforced capacity obligations.

2666 - Load Management Test Failure

Sellers with committed Demand Resources that fail performance tests pay a penalty charge which is allocated to eligible LSEs. This billing is performed in the August monthly bill issued in September after the conclusion of the delivery year. Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.

Q. PLEASE EXPLAIN HOW DUKE ENERGY KENTUCKY PROPOSES TO RECOVER THE COSTS AND TO PROVIDE CUSTOMERS WITH THE VALUE OF THE BENEFITS OF RPM PARTICIPATION.

A. As further explained by Company Witness Ms. Lisa Steinkuhl, the Company is proposing to modify its Rider PSM to recover the BLIs I previously described so to net the entirety of RPM capacity market participation. Presently, Rider PSM allows the Company to share the benefits/costs of any net sales (costs and credits) related to the Company's generating units including off-system energy, ASM sales/costs, capacity purchases/sales, and net proceeds from the sale of renewable energy credits with the customer through a 90/10 sharing mechanism where customers receive 90 percent of the net benefits/costs. As Ms. Steinkuhl explains, the Company is proposing to modify that sharing with respect to capacity participation only such that customer will receive 100 percent of any net benefit or net cost of RPM participation. This would include all net capacity sales and capacity purchases from PJM and bilateral markets to meet PJM FERC-approved reliability requirements. As capacity prices move higher, with the Company's net long capacity position, and the ability to monetize that capacity in RPM auctions, customers should receive a net benefit of RPM participation. The remaining items included in Rider PSM will continue to be shared with customers based on a 90/10 sharing mechanism where customers receive 90 percent of the net benefits/costs as is currently the practice.

Q. WHY IS IT REASONABLE TO CHANGE THE RIDER PSM SHARING FOR CAPACITY RELATED TRANSACTIONS TO A 100 PERCENT CUSTOMER-FOCUSED ALLOCATION?

A. The size of the Company's generation portfolio and the capacity necessary to reliably serve is determined by customer demand. Customers pay for these assets, whether "steel in the ground" generators owned and operated by the Company or through long-term bilateral purchases. Because moving to RPM provides a new opportunity to fully monetize the existing length of Company's existing portfolio (and future generating assets) as compared to current demand, assuming these assets will clear the auctions, the Company believes net credits will accrue to customers. Because customers are paying for these assets in base rates, the assets are serving customers, the Company believes that all the costs and benefits of satisfying that demand should be borne by customers.

The Company also believes that it continues to make sense for the Company to share in the energy market risks and revenues, which are more volatile, and the Company has managerial responsibility in terms of the daily dispatch and operation. This small amount of profit sharing, while the vast majority accrues to customers, does maintain some "skin in the game" for the Company to attempt to maximize their value and keep managing these assets in an efficient, reasonable, and beneficial manner.

Q. IS THE COMPANY REQUESTING CHANGES TO PJM BLIs RELATED TO PJM CAPACITY PERFORMCE?

A. No. It is possible today for the Company to receive PJM BLI 1667 (Capacity Performance Non-Performance charge) and PJM BLI 2667 (Capacity Performance Bonus Performances payment) from PJM. The Commission previously approved a modification to the Rider PSM in Case No. 2017-00321 to allow the company to include both capacity performance charges and bonus payments as part of that sharing mechanism with a 90/10 sharing mechanism where customers receive 90 percent of the net benefits/costs related to capacity performance.[27] The Company is not requesting any change in the treatment of the PJM BLIs related to PJM Capacity Performance.

VI. TIMING

Q. PLEASE EXPLAIN THE CURRENT PJM COMPRESSED CAPACITY MARKETS SCHEDULE.

A. PJM is currently under a compressed schedule, with the 2025/2026 auction recently completed in late July 2024. The 2026/2027 auction is scheduled to occur in December 2024, the 2027/2028 auction in June 2025, the 2028/2029 auction in December 2025, and finally the 2029/2030 auction is scheduled for May 2026, putting PJM back on the regular tariff schedule.

[27] *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, (Ky.P.S.C. Order) (April 13, 2018).

Q. HOW MUCH TIME IS TYPICALLY NEEDED FOR A CHANGE TO THE FRR CAPACITY CONSTRUCT?

A. Since PJM capacity auctions are normally on a 3-year forward basis, when PJM is on their normal schedule, a move from FRR to RPM would occur at least 3 years before the delivery year. Additionally, since notification to PJM of a change in Duke Energy Kentucky's capacity construct status is required to occur approximately 60 days prior to the PJM BRA, this further increases the time frame required by this amount. Finally, since commission approval is required for such a move, the time for the regulatory process to occur would need to be added to this schedule. Thus, the total time needed to transition from FRR to RPM, as measured from the time that an application is initially submitted to the commission until the start of the PJM Delivery Year, is approximately 4 ½ years, depending on when the filing is made in relationship to the position within the PJM Delivery Year. However, because of PJM's compressed schedule, a unique opportunity exists for Duke Energy Kentucky to make this move now, faster than it otherwise could, to reduce the time needed by approximately 18 months.

Q. WHY IS THE COMPANY REQUESTING TO MAKE THE MOVE TO RPM NOW AND REQUESTING AN ORDER BY APRIL 1, 2025?

A. By making this change now during the time PJM is on a compressed auction schedule, if the Company receives an order by April 1, 2025, or earlier, it would be possible to notify PJM with the 60-day requirement met for the 2027/2028 BRA. Thus, Duke Energy Kentucky could transition to RPM by June 1, 2027, eighteen months earlier than it otherwise could.

VII. CONCLUSION

Q. PLEASE SUMMARIZE WHY YOU BELIEVE THAT A CHANGE TO RPM IS NECESSARY AND IN CUSTOMER'S BEST INTEREST.

A. Since first entering PJM, the FRR arrangement was the logical decision and has benefited customers. However, with the potential for customer load growth, especially those loads that can be added quicker than generation supply, PJM capacity market structural changes, projected increases in PJM market clearing prices, and changes to the PJM supply/demand balance, the Company has determined through analysis that a move to a full RPM auction participant is now in the customer's best interest.

Q. WERE ATTACHMENTS JDS-1 AND JDS-2 PREPARED BY YOU AND UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, John Swez, Managing Director Trading & Dispatch, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing direct testimony and that it is true and correct to the best of his knowledge, information and belief.

John Swez Affiant

Subscribed and sworn to before me by John Swez on this 28 day of August 2024.

Mary B Vicknair
NOTARY PUBLIC

My Commission Expires:

MARY B VICKNAIR
Notary Public, North Carolina
Davie County
My Commission Expires
September 21, 2027

DEK FRR vs. RPM Capacity Impact Analysis

All inputs are shown in Yellow

Inputs:		
Low BRA Clearing Price	50	$/MW-Day
Mid BRA Clearing Price	225	$/MW-Day
	300	$/MW-Day
High BRA Clearing Price	525	$/MW-Day
Low BRA Price RPM Reserve Margin	22.5%	
Mid BRA Price RPM Reserve Margin	19.5%	
High BRA Price RPM Reserve Margin	18%	
Max Price RPM Reserve Margin	17%	
Generation Capacity	1300	MW
FRR Reserve Margin	17.8%	
3rd Incremental Auction Clearing Price	50%	As Percentage of BRA
NET CONE	300	$/MW-Day
Long Scenario DEK Load	1000	MW (Must be less than 1,100 MW)
Flat Scenario DEK Load	1100	MW
Short Scenario DEK Load	1200	MW (Must be greater than 1,100 MW)

<u>LONG defined as percentage of Load plus Reserve Margin Before Holdback</u>

Generation	1300	MW
Load + Reserve Margin	1178	MW
Length before holdback	122	MW
Percentage difference	10.4%	

<u>FLAT defined as percentage of Load plus Reserve Margin Before Holdback</u>

Generation	1300	MW
Load + Reserve Margin	1296	MW
Length before holdback	4	MW
Percentage difference	0.3%	

<u>SHORT defined as percentage of Load plus Reserve Margin Before Holdback</u>

Generation	1300	MW
Load + Reserve Margin	1414	MW
Length before holdback	-114	MW
Percentage difference	-8.0%	

DEK FRR vs. RPM Capacity Impact Analysis

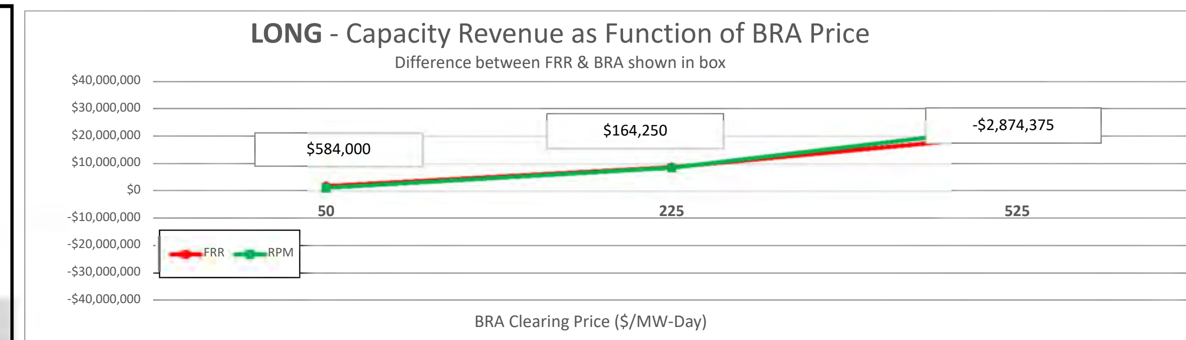
BRA Clearing Price

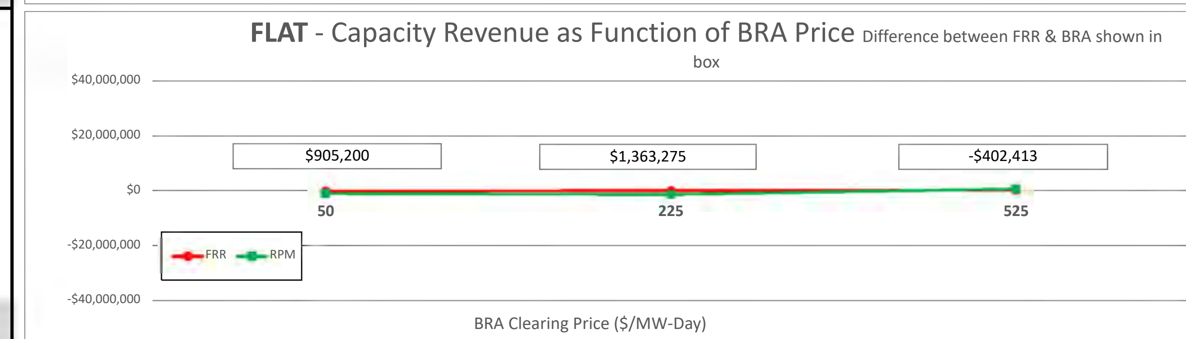
Scenario #1 - 10% **LONG** DEK Portfolio	50 FRR	50 RPM	225 FRR	225 RPM	525 FRR	525 RPM
BRA Clearing Price	50 $/MW-Day	50 $/MW-Day	225	225 $/MW-Day	525 $/MW-Day	525 $/MW-Day
Generation Capacity	1300 MW	1300 MW	1300 MW	1300 MW	1300 MW	1300 MW
Load	1000 MW	1000 MW	1000 MW	1000 MW	1000 MW	1000 MW
Reserve Margin	18%	23%	18%	20%	18%	18%
Load + Reserve Margin	1178 MW	1225 MW	1178 MW	1195 MW	1178 MW	1178 MW
Position before Holdback	122 MW	75 MW	122 MW	105 MW	122 MW	122 MW
FRR 3% Holdback Amount	30 MW		30 MW		30 MW	
Final BRA Position	92 MW	75 MW	92 MW	105 MW	92 MW	122 MW
BRA Capacity Revenue	$1,679,000	$1,368,750	$7,555,500	$8,623,125	$17,629,500	$23,378,250
3rd Incremental Auction Clearing Price	$25 $/MW-Day	$25 $/MW-Day	$113 $/MW-Day	$113 $/MW-Day	$263 $/MW-Day	$263 $/MW-Day
3rd Incremental Auction Revenue	$273,750		$1,231,875		$2,874,375	
FRR Penalty (1.75 x CONE)	$0		$0		$0	
Total Capacity Revenue	**$1,952,750**	**$1,368,750**	**$8,787,375**	**$8,623,125**	**$20,503,875**	**$23,378,250**
Difference	**FRR Better by**	**$584,000 per year**	**FRR Better by**	**$164,250 per year**	**FRR Worse by**	**-$2,874,375 per year**

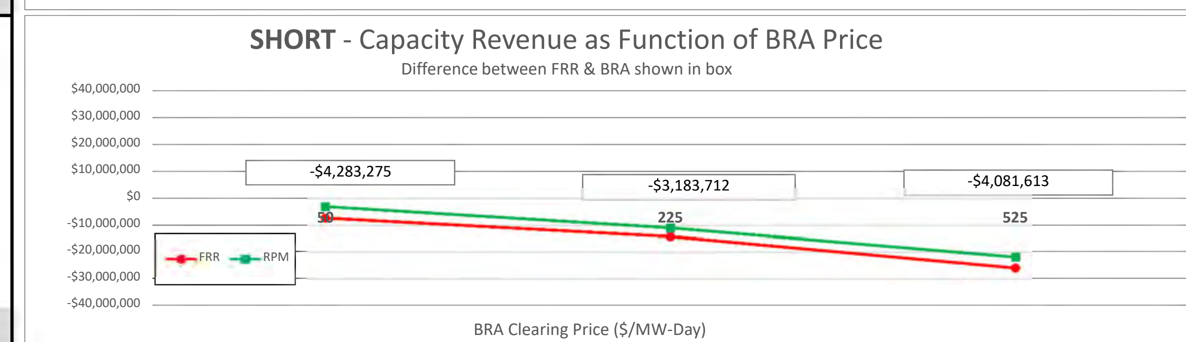
Scenario #2 - **FLAT** DEK Portfolio	50 FRR	50 RPM	225 FRR	225 RPM	525 FRR	525 RPM
BRA Clearing Price	50	50 $/MW-Day	225	225 $/MW-Day	525 $/MW-Day	525 $/MW-Day
Generation Capacity	1300 MW	1300 MW	1300 MW	1300 MW	1300 MW	1300 MW
Load	1100 MW	1100 MW	1100 MW	1100 MW	1100 MW	1100 MW
Reserve Margin	18%	23%	18%	20%	18%	18%
Load + Reserve Margin	1296 MW	1348 MW	1296 MW	1315 MW	1296 MW	1296 MW
Position before Holdback	4 MW	-48 MW	4 MW	-15 MW	4 MW	4 MW
FRR 3% Holdback Amount	33 MW		33 MW		33 MW	
Final BRA Position	0 MW	-48 MW	0 MW	-15 MW	0 MW	4 MW
BRA Capacity Revenue	$0	-$866,875	$0	-$1,190,813	$0	$804,825
3rd Incremental Auction Clearing Price	$25 $/MW-Day	$25 $/MW-Day	$113 $/MW-Day	$113 $/MW-Day	$263 $/MW-Day	$263 $/MW-Day
3rd Incremental Auction Revenue	$38,325		$172,463		$402,413	
FRR Penalty (1.75 x CONE)	$0		$0		$0	
Total Capacity Revenue	**$38,325**	**-$866,875**	**$172,463**	**-$1,190,813**	**$402,413**	**$804,825**
Difference	**FRR Better by**	**$905,200 per year**	**FRR Better by**	**$1,363,275 per year**	**FRR Worse by**	**-$402,413 per year**

Scenario #3 - 10% **SHORT** DEK Portfolio	50 FRR	50 RPM	225 FRR	225 RPM	525 FRR	525 RPM
BRA Clearing Price	50	50 $/MW-Day	225	225 $/MW-Day	525 $/MW-Day	525 $/MW-Day
Generation Capacity	1300 MW	1300 MW	1300 MW	1300 MW	1300 MW	1300 MW
Load	1200 MW	1200 MW	1200 MW	1200 MW	1200 MW	1200 MW
Reserve Margin	18%	23%	18%	20%	18%	18%
Load + Reserve Margin	1414 MW	1470 MW	1414 MW	1434 MW	1414 MW	1414 MW
Position before Holdback	-114 MW	-170 MW	-114 MW	-134 MW	-114 MW	-114 MW
FRR 3% Holdback Amount	36 MW		36 MW		36 MW	
Final BRA Position	0 MW	-170 MW	0 MW	-134 MW	0 MW	-114 MW
BRA Capacity Revenue	$0	-$3,102,500	$0	-$11,004,750	$0	-$21,768,600
3rd Incremental Auction Clearing Price	$25 $/MW-Day	$25 $/MW-Day	$113 $/MW-Day	$113 $/MW-Day	$263 $/MW-Day	$263 $/MW-Day
3rd Incremental Auction Revenue	$0		$0		$0	
FRR Penalty (1.75 x CONE)	$7,385,775		$14,188,463		$25,850,213	
Total Capacity Revenue	**-$7,385,775**	**-$3,102,500**	**-$14,188,463**	**-$11,004,750**	**-$25,850,213**	**-$21,768,600**
Difference	**FRR Worse by**	**-$4,283,275 per year**	**FRR Worse by**	**-$3,183,712 per year**	**FRR Worse by**	**-$4,081,613 per year**

FRR Penalty assumes that 75% of the FRR Plan Shortfall is purchased at a premium of 1.25 x BRA Clearing Price and remaining 25% FRR Plan Shortfall is subject to penalty due to lack of available generation in DEOK zone







Annual Financial Impact of Duke Energy Kentucky Capacity Construct: Initial FRR Plan vs. RPM

FRR - RPM

BRA Clearing Price, $/MW-Day

DEK Portfolio Length
Long (Positive) or Short (Negative) Position
(Position = Length before Holdback or Short divided by Load Obligation)

Length	50	100	150	200	250	300	350	400	450	500
9%	$ 584,584	$ 855,998	$ 814,242	$ 459,316	$ (334,918)	$ (1,644,143)	$ (2,145,504)	$ (2,711,820)	$ (3,343,090)	$ (4,039,313)
8%	$ 591,008	$ 865,405	$ 823,190	$ 464,363	$ (338,598)	$ (1,662,210)	$ (2,169,081)	$ (2,741,620)	$ (3,379,827)	$ (4,083,701)
7%	$ 597,432	$ 874,811	$ 832,137	$ 469,411	$ (342,279)	$ (1,680,278)	$ (2,192,658)	$ (2,771,421)	$ (3,416,564)	$ (4,128,089)
6%	$ 603,856	$ 884,218	$ 841,085	$ 474,458	$ (345,959)	$ (1,698,345)	$ (2,216,235)	$ (2,801,221)	$ (3,453,301)	$ (4,172,477)
5%	$ 610,280	$ 893,624	$ 850,033	$ 479,506	$ (349,640)	$ (1,716,413)	$ (2,239,812)	$ (2,831,021)	$ (3,490,039)	$ (4,216,865)
4%	$ 616,704	$ 903,031	$ 858,981	$ 484,553	$ (353,320)	$ (1,734,480)	$ (2,263,389)	$ (2,860,821)	$ (3,526,776)	$ (4,261,253)
3%	$ 623,128	$ 912,437	$ 867,928	$ 489,601	$ (357,000)	$ (1,752,548)	$ (2,286,966)	$ (2,890,622)	$ (3,563,513)	$ (4,305,641)
2%	$ 649,846	$ 962,432	$ 937,758	$ 575,824	$ (259,211)	$ (1,648,851)	$ (2,168,485)	$ (2,758,070)	$ (3,417,604)	$ (4,147,089)
1%	$ 777,523	$ 1,214,345	$ 1,310,465	$ 1,065,883	$ 343,374	$ (939,401)	$ (1,343,291)	$ (1,817,846)	$ (2,363,065)	$ (2,978,948)
0%	$ 905,200	$ 1,466,257	$ 1,683,171	$ 1,555,943	$ 945,958	$ (229,950)	$ (518,097)	$ (877,622)	$ (1,308,525)	$ (1,810,806)
-1%	$ 543,387	$ 1,158,752	$ 1,426,534	$ 1,346,731	$ 779,344	$ (359,625)	$ (601,956)	$ (916,379)	$ (1,302,893)	$ (1,761,498)
-2%	$ (53,167)	$ 582,973	$ 868,087	$ 802,175	$ 243,852	$ (891,713)	$ (1,121,762)	$ (1,424,616)	$ (1,800,276)	$ (2,248,741)
-3%	$ (649,721)	$ 7,193	$ 309,640	$ 257,619	$ (291,640)	$ (1,423,801)	$ (1,641,568)	$ (1,932,854)	$ (2,297,659)	$ (2,735,983)
-4%	$ (1,246,274)	$ (568,587)	$ (248,807)	$ (286,937)	$ (827,133)	$ (1,955,889)	$ (2,161,374)	$ (2,441,092)	$ (2,795,042)	$ (3,223,226)
-5%	$ (1,842,828)	$ (1,144,366)	$ (807,255)	$ (831,493)	$ (1,362,625)	$ (2,487,977)	$ (2,681,180)	$ (2,949,329)	$ (3,292,425)	$ (3,710,468)
-6%	$ (2,439,382)	$ (1,720,146)	$ (1,365,702)	$ (1,376,049)	$ (1,898,117)	$ (3,020,065)	$ (3,200,986)	$ (3,457,567)	$ (3,789,809)	$ (4,197,711)
-7%	$ (3,035,935)	$ (2,295,926)	$ (1,924,149)	$ (1,920,605)	$ (2,433,609)	$ (3,552,153)	$ (3,720,791)	$ (3,965,805)	$ (4,287,192)	$ (4,684,953)
-8%	$ (3,632,489)	$ (2,871,705)	$ (2,482,596)	$ (2,465,160)	$ (2,969,102)	$ (4,084,241)	$ (4,240,597)	$ (4,474,042)	$ (4,784,575)	$ (5,172,196)
-9%	$ (4,229,043)	$ (3,447,485)	$ (3,041,043)	$ (3,009,716)	$ (3,504,594)	$ (4,616,328)	$ (4,760,403)	$ (4,982,280)	$ (5,281,958)	$ (5,659,439)

Positive *value means FRR is a* ***better*** *financial outcome than RPM Capacity Construct annually for the amount shown.*
Negative *value means FRR is a* ***worse*** *financial outcome than RPM Capacity Construct annually for the amount shown.*

Bi-lateral capacity to fulfill FRR shortfall assumed purchased at a premium of 1.25 x Auction Clearing Price
(Capacity owners have general reluctance to sell bi-laterial capacity)

Percentage of FRR Shortfall Subject to FRR Penalty:

25.00	25%	25%

Percentage of 3rd Incremental Auction Clearing Price of Base Residual Auction Price:

50.00	50%	50%

2025/2026 FRR Positon Portfolio Length = 77 MW/800.6 MW = ~9%; Bi-lateral Market Trading $85/MW-Day @ $92/MW-Day as of 7-19-2024; 2025/2026 BRA ultimately cleared $269.92/MW-Day

DEK FRR vs. RPM Capacity Impact Analysis

BRA Clearing Price ($/MW-Day)

	50				225				525			
Scenario #1 - DEK is LONG 10%	FRR	RPM			FRR	RPM			FRR	RPM		
Total Capacity Revenue	$1,952,750	$1,368,750			$8,787,375	$8,623,125			$20,503,875	$23,378,250		
		FRR Better by	$584,000	per year		FRR Better by	$164,250	per year		FRR Worse by	-$2,874,375	per year
Scenario #2 - DEK is FLAT												
Total Capacity Revenue	$38,325	-$866,875			$172,463	-$1,190,813			$402,413	$804,825		
		FRR Better by	$905,200	per year		FRR Better by	$1,363,275	per year		FRR Worse by	-$402,413	per year
Scenario #3 - DEK is SHORT -8%												
Total Capacity Revenue	-$7,385,775	-$3,102,500			-$14,188,463	-$11,004,750			-$25,850,213	-$21,768,600		
		FRR Worse by	-$4,283,275	per year		FRR Worse by	-$3,183,712	per year		FRR Worse by	-$4,081,613	per year

FRR Penalty assumes that 75% of the FRR Plan Shortfall is purchased at a premium of 1.25 x BRA Clearing Price and remaining 25% FRR Plan Shortfall is subject to penalty due to lack of available generation in DEOK zone

RPM Capacity Market and Capacity Performance Billing Line Items (BLI)

ID #	CHARGES	ID #	CREDITS
1600	RPM Auction	2600	RPM Auction
		2605	RPM Seasonal Capacity Performance Auction
1610	Locational Reliability		
		2620	Interruptible Load for Reliability
		2625	LSE PRD
		2630	Capacity Transfer Rights
		2640	Incremental Capacity Transfer Rights
1650	Auction Specific MW Capacity Transaction	2650	Auction Specific MW Capacity Transaction
1660	Load Management Compliance Penalty	2660	Load Management Compliance Penalty
1661	Capacity Resource Deficiency	2661	Capacity Resource Deficiency
1662	Generation Resource Rating Test Failure	2662	Generation Resource Rating Test Failure
1663	Qualifying Transmission Upgrade Compliance Penalty	2663	Qualifying Transmission Upgrade Compliance Penalty
1664	Peak Season Maintenance Compliance Penalty	2664	Peak Season Maintenance Compliance Penalty
1665	Peak-Hour Period Availability	2665	Peak-Hour Period Availability
1666	Load Management Test Failure	2666	Load Management Test Failure
1667	Non-Performance	2667	Bonus Performance