KyPSC Case No. 2024-00285
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VERIFICATION

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

The undersigned, John D. Swez, Managing Director, Trading and Dispatch, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

John D. Swez, Affiant

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

NOTARY PUBLIC

My Commission Expires:

SHAMELL M WILSON
My Comm. Expires
NOTARY PUBLIC
July 06, 2026
MECKLENBURG COUNTY, NC

VERIFICATION

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, Lisa D. Steinkuhl, Director, Rates & Regulatory Planning, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of her knowledge, information and belief.

Lisa D Steinkuhl
Lisa D. Steinkuhl Affiant

Subscribed and sworn to before me by Lisa D. Steinkuhl on this 26th day of September, 2024.

Shelia Janette Rogers
NOTARY PUBLIC

SHELIA JANETTE ROGERS
Notary Public-State at Large
KENTUCKY - Notary ID # KYNP66137
My Commission Expires 01-31-2027

My Commission Expires: 1-31-2027

`VERIFICATION

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

The undersigned, Bryan Garnett, RTO Policy & Compliance Manager, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Bryan Garnett

Bryan Garnett, Affiant

Subscribed and sworn to before me by Bryan Garnett on this 28 day of August, 2024.

NOTARY PUBLIC

My Commission Expires:

SHAMELL M WILSON
My Comm. Expires
NOTARY PUBLIC
July 06, 2026
MECKLENBURG COUNTY, NC

VERIFICATION

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

The undersigned, Alan Mok, Financial Market Manager, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Alan Mok, Affiant

Subscribed and sworn to before me by Alan Mok on this 28 day of August, 2024.

NOTARY PUBLIC

My Commission Expires:

SHAMELL M WILSON
My Comm. Expires
NOTARY PUBLIC
July 06, 2026
MECKLENBURG COUNTY, NC

VERIFICATION

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, Yanthi Boutwell, General Manager Transmission Resource & Project Management, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of her knowledge, information and belief.

Yanthi Boutwell

Yanthi Boutwell, Affiant

Subscribed and sworn to before me by Yanthi Boutwell on this 18th day of October, 2024.

Shelia Janette Rogers

NOTARY PUBLIC

My Commission Expires: 1-31-2027

VERIFICATION

STATE OF NORTH CAROLINA)
8L) **SS:**
COUNTY OF ~~MECKLENBURG~~)
Lincoln

The undersigned, Matt Kalemba, Vice President Integrated Resource Planning, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Matt Kalemba Affiant

Subscribed and sworn to before me by Matt Kalemba on this 2 day of October 2024.

SHEILA LEMOINE
Notary Public, North Carolina
Lincoln County
My Commission Expires
July 21, 2029

Sheila Lemoine
NOTARY PUBLIC

My Commission Expires: July 21, 2029

VERIFICATION

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

The undersigned, Tim Duff, General Manager Customer Solutions Regulatory Enablement, being duly sworn deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information, and belief.

Tim Duff Affiant

Subscribed and sworn to before me by Tim Duff on this 30 day of September 2024.

NOTARY PUBLIC

Renee B Crawford
NOTARY PUBLIC
Mecklenburg County
North Carolina
My Commission Expires 06/13/2029

My Commission Expires: 06/13/2029

VERIFICATION

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

The undersigned, Michael Chen, Lead Short Term Power Trader, being duly sworn deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information, and belief.

Michael Chen, Affiant

Subscribed and sworn to before me by Michael Chen on this 18th day of October, 2024.

Alexis Barnett
NOTARY PUBLIC

My Commission Expires: July 7th, 2027

ALEXIS BARNETT
NOTARY PUBLIC
Mecklenburg County
North Carolina
My Commission Expires July 7, 2027

VERIFICATION

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

The undersigned, John Verderame, VP Fuels & Systems Optimization, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

John Verderame

John Verderame, Affiant

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

NOTARY PUBLIC

My Commission Expires:

SHAMELL M WILSON
My Comm. Expires
NOTARY PUBLIC
July 06, 2026
MECKLENBURG COUNTY, NC

VERIFICATION

STATE OF FLORIDA)
) **SS:**
COUNTY OF PINELLAS)

The undersigned, Drew Scatizzi, Manager Product and Services, being duly sworn deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information, and belief.

Drew Scatizzi, Affiant

Subscribed and sworn to before me by Drew Scatizzi on this 18 day of OCTOBER, 2024.

NOTARY PUBLIC

CRAIG J. PALMER
Notary Public, State Of Florida
Commission No. HH 408718
My Commission Expires: 6/8/2027

My Commission Expires: 8/6/27

VERIFICATION

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, Sarah Lawler, VP Rates & Regulatory Strategy, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of her knowledge, information and belief.

Sarah Lawler Affiant

Subscribed and sworn to before me by Sarah Lawler on this 1st day of October, 2024.

NOTARY PUBLIC

My Commission Expires: July 8, 2027

NOTARY PUBLIC STATE OF OHIO

EMILIE SUNDERMAN
Notary Public
State of Ohio
My Comm. Expires
July 8, 2027

VERIFICATION

SOUTH
STATE OF ~~NORTH~~ CAROLINA)

LANCASTER) SS:
COUNTY OF ~~MECKLENBURG~~)

The undersigned, Thomas Heath, Corporate Finance Director, being duly sworn deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information, and belief.

Thomas Heath

Thomas Heath, Affiant

Subscribed and sworn to before me by Thomas Heath on this 18th day of October, 2024.

Shelia Janette Rogers

NOTARY PUBLIC

My Commission Expires: 1-31-2027

AG-DR-01-001

REQUEST:

Regarding cost-benefit analyses:

a. Please provide all workpapers associated with the cost benefit analysis included in Mr. Swez's Attachment JDS-1 to his Direct Testimony. Please provide the workpapers electronically with all formulae intact and no pasted values.

b. For the analysis included in Attachment JDS-1, provide a step by step explanation of how the analysis was performed, describe what modeling analyses were conducted, and state what models were used. It seemed from Mr. Swez's description that 4 scenarios (modeling runs were performed). Please explain how all the data points were developed if in fact just 4 modeling runs were performed.

c. Explain why in the JDS-1 analysis, the Company assumed it was sufficient to only consider being short or long by 9%, i.e., why didn't the Company consider being short or long by an even greater amount? Please provide any workpapers, electronically with all formulae intact created in deciding on these assumptions.

d. Explain why in the JDS-1 analysis, the Company assumed it was sufficient to only consider clearing prices between 50 and 500, i.e., why didn't the Company consider lower or higher values? Please provide any workpapers, electronically with all formulae intact created in deciding on these assumptions.

e. Provide a copy of all cost-benefit studies or any other kind of analyses regarding switching from the FRR to the RPM construct that were performed by or on behalf of DEK or any other party, including PJM, within the last eight years and that were not included in the Company's filing in this proceeding. Provide the studies and/or analyses electronically with all formulae intact and no pasted values.

f. Provide a copy of all cost-benefit studies or any other kind of analyses regarding switching from the FRR to the RPM construct that measured the annual revenue requirement and/or the cumulative net present value of the annual revenue requirements over the forecast study period. Provide the studies and/or analyses electronically with all formulae intact and no pasted values. If no such studies or analyses have been performed, then explain why not.

RESPONSE:

a. There were no additional workpapers developed to create Attachment JDS-1.

b. There were no models utilized in creation of Attachment JDS-1. Each of the 874 different cells on the "Heat Map" spreadsheet represents one potential forecasted annual financial impact to Duke Energy Kentucky customers from the PJM capacity requirement.

   The data points on the "Heat Map" were developed by breaking up the resulting Duke Energy Kentucky position (either long or short) and the BRA clearing price (from low to high prices) into reasonably sized increments. For the position, an incremental of 1% in the position was utilized, or approximately 10 MW. For the BRA price, an increment of $50/MW-Day was utilized. Note that spreadsheet could have been created with larger or smaller blocks, but these were felt to reasonably show the resulting customer impact from FRR versus RPM participation.

c. With the Company's relatively stable generation fleet and customer demand, the 9% position, with approximately 100 MW difference between 0% and 9%, and 100 MW difference between 0% and -9%, or a 200 MW range in total, captures all of the range that the Company's position has resided over the past 12 years since entering PJM. However, the user can change the input cells, shaded yellow, on the "Inputs" sheet to change the analysis to a larger range. For example, if Cell B19 is changed to 500 MW and cell B21 changed to 1,700 MW, the user can now view a new "Heat Map" with a 1,200 MW range instead of the original 200 MW range.

d. The range of $50/MW-Day to $500/MW-Day in BRA capacity prices represent the practical range of BRA clearing prices. On the lower range, the PJM BRA capacity market has not cleared $0/MW-Day historically, with the lowest value for the DEOK zone being $34.13/MW-Day for the 2023/2024 auction. Note that the "Rest of RTO" BRA capacity price cleared lower at $28.92/MW-Day for the 2024/2025 BRA, but the DEOK zone "split out" and cleared at a higher value of $96.24/MW-Day. Finally, for the high range value selected of $500/MW-Day, the highest the PJM BRA auction price can clear is equal to the highest price on the PJM Variable Resource Requirement (VRR) curve, or equal to higher of the Cost of New Entry (CONE) or 1.75 times net CONE. In either case, $500/MW-Day is currently equal to approximately the highest price that can currently clear. This maximum amount can change as updated by PJM yearly, however.

e. Please refer to AG-DR-01-001(e) Attachment for a copy of the FRR vs. RPM Presentation 2-13-2023, which was produced in FAC Case No. 2023-00012. Note that the previous analysis did not contain the same cost-benefit analysis performed and included as Attachment JDS-1 in the current application, thus there were no excel spreadsheet or other materials to produce with formulae intact.

f. See response to part (e) above.

PERSON RESPONSIBLE: John Swez

DEK: FRR vs. RPM Capacity Construct Analysis

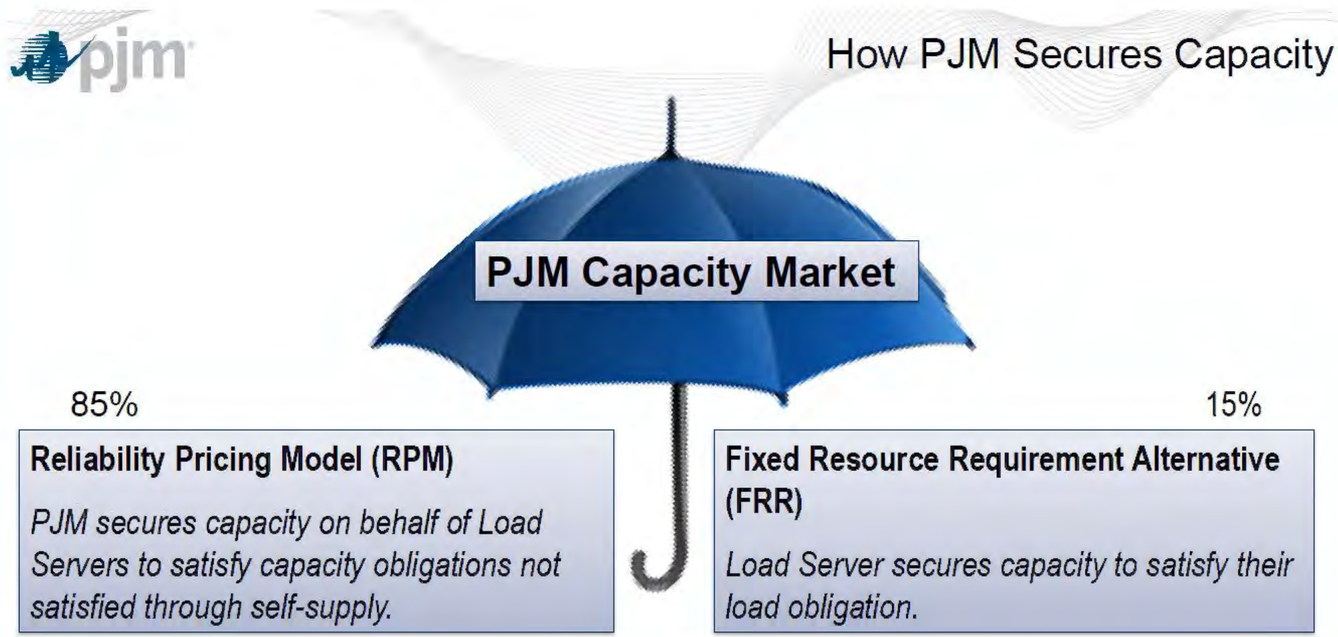
2/13/2023 Update

DUKE ENERGY

Executive Summary

- PJM offers two options for participation in its Capacity Market:
  - Fixed Resource Requirement (FRR) or Reliability Pricing Model (RPM)
  - 3 years ahead for 1 year in length
- FRR:
  - An opt-out option to RPM
  - Self-supplying capacity to fulfill capacity load obligation assigned by PJM
  - Receive no capacity auction revenue/charges from generation and load but have all capacity obligations and penalties equal to resources committed in RPM
- RPM:
  - PJM secures capacity on behalf of Load Serving Entities to satisfy capacity obligations not satisfied through self-supply
  - Generators submit competitive bids into a 3-year forward capacity auction
  - The quantity of capacity that PJM will procure in each capacity auction is a function of price

Capacity Markets



Executive Summary

- Since 2012 when entering PJM, DEK has been an FRR entity located in the DEOK zone in PJM.
- DEK has neither been materially long or short generation, no immediate plans to build generation, and has found sufficient liquidity in the bilateral market to make any necessary small portfolio adjustments. Remaining in FRR has been the logical decision.
- The decision to transition from FRR to RPM depends on how customers would ultimately benefit from such as change.
- The benefit of RPM lies in the ability to either monetize the market value of owned generation in excess of customer demand or to gain access to the market liquidity inherent in RPM in order to fill any shortfall in generation or additional customer demand.
  - E.g. If DEK units had a high EFOR one year or an additional 100 MW customer were to build in DEK, it would be difficult for DEK to meet its FRR plan

Executive Summary

- With potential DEK load growth and added flexibility in DEK generation supply transformation mean a move future move to RPM is in our customer's interest.
- However, the current recommendation is to remain in FRR and re-evaluate annually.
- Changing to the RPM construct costs ~$1.8M annually over the current FRR approach but avoids future potential costs of ~$16M to ~$32M for up to two years if DEK remains in FRR and decides to retire East Bend early or if has significant additional demand growth.

- Considerations in the FRR vs. RPM analysis includes:
  1. Minimum Offer Price Rule (MOPR) impact
  2. Change in reserve margin between RPM and FRR
  3. 3% FRR holdback for FRR sales into RPM
  4. FRR Commitment Insufficiency Penalty
  5. Liquidity Differences between FRR and RPM
  6. Physical vs. Financial Capacity Performance penalty
  7. Rate case timing and December 2022 events

Table of Benefits of RPM vs. FRR

	RPM	FRR
1. Min Offer Price Rule	Draw	Draw
2. Reserve Margin differential		✓
3. 3% hold back in Auctions for RPM	✓	
4. FRR Deficiency Penalty	✓	
5. Liquidity Differences	✓	
6. Physical/Financial CP Penalty		✓

Net expected cost to move to RPM ~$1.8M/year

Net expected expense to remain in FRR from early retirement of ~$16M to $32M for up to two years

Timeline & Next Steps

- 4.5 years PJM, regulatory, and approval process
- If we started today, switching possible for 2027/2028 (Year ends 5-31-2028)

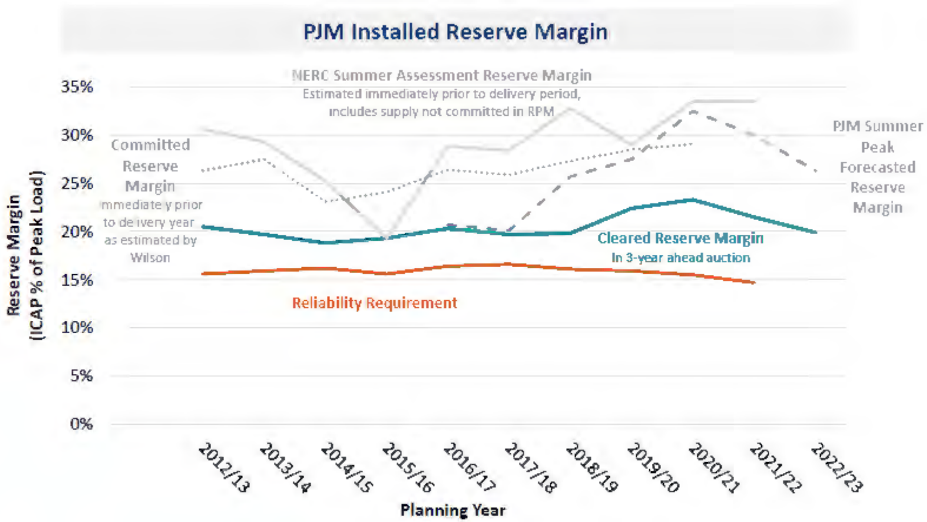
Appendix Material

1. Minimum Offer Price Rule (MOPR) Impact

- State subsidized Market sellers must certify that they don't meet two criteria to avoid focused MOPR:
  - Buyer side market power
    - Buyer-Side Market Power (BSMP) may occur when an LSE has a net short position and is offering generation at lower prices to reduce overall exposure to market.
      - Load is 1000 MW, Current Gen 600 MW, Seller offers 100 MW at 0 to artificially lower overall cost of load purchases
  - Conditioned State Support will occur if a state is giving a unit a subsidized based on how they offer into the capacity market.
- **For the 2025/2026 planning year, DEK certified that these two conditions did not occur for WDL and EB and PJM agreed with that determination.**
- This new MOPR rule virtually eliminates the MOPR risk & makes DEK indifferent between participating in FRR or RPM.

2. Change in Reserve Margin Between RPM and FRR

- FRR entities are required to purchase a fixed reserve margin for auctions (Roughly 15%).
- RPM entities purchase on a sloped demand curve which can cause additional purchases as the price of the auctions move lower.
- Concept of sloped demand is that at lower prices, loads will purchase more capacity to ensure greater reliability
- 2023/2024 BRA reserve margin was 19.8% vs. 14.8% for the FRR plan



3. 3% FRR holdback for FRR sales into RPM

- FRR entities are required to hold back 3% of their load if the have excess generation that they want to monetize in the auction
- DEK has roughly 30MW that they can't monetize in the RPM auction which wouldn't be the case as an RPM entity
- 30 MW at $100/MW-Day auction price is ~$1.1M / year

2 + 3. Net Expected Cash Flow Impact

Row Labels	Total FRR-RPM$
⊟ 29/30 Retirement $100 SPREAD	-$14,409,148
2026-2027	$1,836,863
2027-2028	$1,873,600
2028-2029	$1,911,072
2029-2030	-$16,068,570
2030-2031	-$16,727,791
2031-2032	$1,914,436
2032-2033	$2,632,771
2033-2034	$2,685,426
2034-2035	$2,739,135
2035-2036	$2,793,917
⊟ 29/30 Retirement $200 SPREAD	-$47,205,514
2026-2027	$1,836,863
2027-2028	$1,873,600
2028-2029	$1,911,072
2029-2030	-$32,137,151
2030-2031	-$33,455,582
2031-2032	$1,914,436
2032-2033	$2,632,771
2033-2034	$2,685,426
2034-2035	$2,739,135
2035-2036	$2,793,917

4. FRR Commitment Insufficiency Penalty

- FRR Commitment Insufficiency Penalty
  - Initial FRR plan - one month prior to BRA ("Rough Draft with Capacity Accreditation Volume Flexibility and a Steep Penalty")
    - Steep deficiency penalty of (Shortfall MW + 3% holdback) * (2 * Cost of New Entry $_{\$/MW\text{-}Year}$)
      - Example: If DEK is short 600 MW at initial FRR plan, could pay as much as **~$115+ million**
    - Very likely FERC referral as well
    - Will be removed from FRR status.

5. Liquidity Difference Between FRR & RPM

- FRR Entities cannot access the PJM RPM auction to purchase capacity for shortfalls to fulfill the FRR plan
  - Shortfalls caused by changes in supply (could be a retirement or unexpected change in units EFOR) or demand (increase in customer demand)
- FRR participants need to purchase unit specific bilateral contracts to meet their load obligations
  - Contract negotiations can be messy especially given the potential of a Capacity Performance risk

6. Physical vs. Financial Capacity Performance Penalty

- DEK utilized the physical CP option for the 2022/2023 capacity planning year (during the time period of the CP events during December 23-24, 2022)
- Penalty assessed when a capacity resource fails to meet its committed capacity obligation during a Capacity Performance event.
- Capacity Performance Penalty = ~ $3000 per deficient MW per performance event hour for RPM entities.
  - Financial penalty rate = Yearly CONE/ 30.
- FRR entities has a physical penalty option not available to RPM
- If physical penalty is elected, it will be required to carry an additional 0.01667 MW/ per deficient MW per performance event hour to the next year FRR self supply plan
  - Physical penalty rate = 0.5/ 30
- In lower capacity price environments, FRR physical penalty seems to be cheaper than the financial option in low capacity price environment

Settlements, Recovery, & Timing

- Settlement Charges/Credits:
  - Potential additional settlement charges and credits would be received on the PJM Settlement Statement
  - DEK would need the ability to credit revenue and charge customers for costs
- Recovery:
  - DEK would need to submit testimony to commission
  - Expected that Commission would need ~1 year due to staffing issues
- Timing:
  - Earliest potential would be the 27/28 auction in May 2024

AG-DR-01-002

REQUEST:

Confirm or deny the following regarding the Company's analysis reflected in Exhibit JDS-1, and provide detailed explanations:

(i) That the Company's analysis quantifies only the effect on the Company's net capacity costs and revenues from switching to the RPM construct.

(ii) That the Company's analysis does not reflect the effects of retiring owned capacity and/or adding owned capacity and/or making changes in the amount of capacity and/or pricing of capacity pursuant to bilateral agreements in response to forecasts of capacity costs resulting from the BRAs and IAs and/or any financial hedges against the forecasts of those capacity costs.

RESPONSE:

(i) Confirmed. Note that there is no impact to the PJM Energy and Ancillary Services market due to the decision to either participate as an FRR or RPM capacity entity.

(ii) Deny - The impacts of adding additional generation, or retiring generation, can be seen on the "Heat Map" of Attachment JDS-1, although the range of the Duke Energy Kentucky Portfolio (long or short position) may need to be changed to a larger value than the current 200 MW range to see the impact from a unit additional or retirement of greater than 200 MW.

The pricing of any additional bilateral agreements is not included in any analysis in this case, but the resulting change to the Company's position as a result of any additional bilateral agreements can be seen as a change to the Company's position on the Y-Axis of the Heat Map.

PERSON RESPONSIBLE: John Swez

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-003

REQUEST:

Confirm or deny the following and provide explanations:

a. That DEK's immediate parent entity is Duke Energy, Ohio ("DEO").

b. That DEK and DEO share the same transmission system, and that transmission-related costs are allocated between the two companies.

c. That DEO participates in PJM solely as a transmission owner.

d. That DEO: (i) does not own any of its own generation resources; (ii) owns its own distribution system located entirely within Ohio; and (iii) procures power for its customers' use from other sources, including the PJM market.

e. That in the most recent PJM auction, no new generation resources were identified within the DEOK zone. If so confirmed, does DEK believe that in the next PJM auction, prices for the DEOK zone will increase? Provide all forecasts and other support for your response.

RESPONSE:

a. Confirm - Duke Energy Kentucky is a wholly owned subsidiary of Duke Energy Ohio.

b. Under the PJM Open Access Transmission Tariff (OATT), the Duke Energy Ohio and Duke Energy Kentucky transmission systems are treated as one zone and the users of the zone are charged for the use of the system. The rate users of the system are charged is based on the PJM OATT. Therefore, the costs of the Duke Energy Ohio and Duke Energy Kentucky transmission system are charged to the users of the system which are Duke Energy Kentucky retail customers, Duke Energy Ohio retail customers, and other transmission customers.

c. Duke Energy Ohio does not own and operate any generation assets to serve its load. Duke Energy Ohio participates in PJM as an electric distribution company. Its unswitched load is currently served through a competitive retail auction process. Duke Energy Ohio is a 9% shareholder of OVEC corporation, which participates in the PJM Energy and Ancillary as well as PJM Capacity Markets. OVEC is not used to serve Duke Energy Ohio's load.

d.

    i. See part (c).

    ii. Confirm

    iii. Confirm

e. Deny. A comparison of the resources between the 2025-2026 and 2024-2025 PJM auctions delivery year (DY) is included as AG-DR-01-003(e) Attachment. Under the "difference" column, the difference in Installed Capacity (ICAP) between the two DY is shown. There was 76.2 MW additional ICAP in the DEOK zone in the 2025-2026 PJM DY from the 2024-2025 DY. The majority of this was the addition of 43.8 MW of ICAP for the Nestlewood Solar for the 2025-2026 PJM DY.

    The Company believes that absent changes to the PJM capacity market, PJM capacity prices are more likely than not, to increase in the future. Please see the Direct Testimony of Mr. Swez on page 16, lines 2-4.

PERSON RESPONSIBLE: Legal – a.
Lisa Steinkuhl – b.
John Swez – b., c., d., e.
Bryan Garnett – e.

Data Description:
PJM existing Capacity Resources for 2025/2026 and 2024/2025
ICAP MW is the Summer Installed Capacity (ICAP) rating of the unit

This posting **includes**:
- Existing Generation Resources located within the PJM footprint that qualify as Capacity Resources

This posting does **not include**:
- Planned Generation Resources (uprates or new units)
- Demand Resources (Planned or Existing)
- Energy Efficiency Resources (Planned or Existing)
- Qualifying Transmission Upgrades (Planned or Existing)
- Capacity rating changes not yet represented in Capacity Exchange system
- External Generation Resources
- Capacity rating changes from Publicly Announced Generation Retirements that have not yet submitted a Cap Mod

2025/2026					2024/2025				
RESOURCENAME	**ICAP (MW)**	**ZONENAME**	**LDANAME**	**CLASSTYPE**	**RESOURCENAME**	**ICAP (MW)**	**ZONENAME**	**LDANAME**	Difference (MW)
BROWN COUNTY LF	4.3	DEOK	DEOK	Landfill Intermittent	BROWN COUNTY LF	3	DEOK	DEOK	1.3
DICKS CREEK 1	69	DEOK	DEOK	Gas Combustion Turbine	DICKS CREEK 1	69	DEOK	DEOK	0
DICKS CREEK 3	12.9	DEOK	DEOK	Gas Combustion Turbine	DICKS CREEK 3	12.9	DEOK	DEOK	0
DICKS CREEK 4	15	DEOK	DEOK	Gas Combustion Turbine	DICKS CREEK 4	15	DEOK	DEOK	0
DICKS CREEK 5	15	DEOK	DEOK	Gas Combustion Turbine	DICKS CREEK 5	15	DEOK	DEOK	0
EAST BEND 2	600	DEOK	DEOK	Coal	EAST BEND 2	600	DEOK	DEOK	0
HILLCREST SOLAR	120	DEOK	DEOK	Solar Tracking	HILLCREST SOLAR	112.3	DEOK	DEOK	7.7
MELDAHL 1	34.2	DEOK	DEOK	Hydro Intermittent	MELDAHL 1	22.2	DEOK	DEOK	12
MELDAHL 2	34.7	DEOK	DEOK	Hydro Intermittent	MELDAHL 2	22.2	DEOK	DEOK	12.5
MELDAHL 3	34.4	DEOK	DEOK	Hydro Intermittent	MELDAHL 3	22.2	DEOK	DEOK	12.2
MIAMI FORT 7	510	DEOK	DEOK	Coal	MIAMI FORT 7	510	DEOK	DEOK	0
MIAMI FORT 8	510	DEOK	DEOK	Coal	MIAMI FORT 8	510	DEOK	DEOK	0
MIAMI FORT GT3	12.7	DEOK	DEOK	Other	MIAMI FORT GT3	12.7	DEOK	DEOK	0
MIAMI FORT GT4	12.3	DEOK	DEOK	Other	MIAMI FORT GT4	12.3	DEOK	DEOK	0
MIAMI FORT GT5	13	DEOK	DEOK	Other	MIAMI FORT GT5	13	DEOK	DEOK	0
MIAMI FORT GT6	14	DEOK	DEOK	Other	MIAMI FORT GT6	14	DEOK	DEOK	0
MIDDLETOWN CC	463.7	DEOK	DEOK	Gas Combined Cycle	MIDDLETOWN CC	468	DEOK	DEOK	-4.3
MIDDLETOWN COKE	38	DEOK	DEOK	Coal	MIDDLETOWN COKE	47	DEOK	DEOK	-9
NESTLEWOOD SOLAR	43.8	DEOK	DEOK	Solar Tracking	NESTLEWOOD SOLAR	N/A	N/A	N/A	43.8
WOODSDALE GT1	77	DEOK	DEOK	Gas Combustion Turbine Dual	WOODSDALE GT1	77	DEOK	DEOK	0
WOODSDALE GT2	77	DEOK	DEOK	Gas Combustion Turbine Dual	WOODSDALE GT2	77	DEOK	DEOK	0
WOODSDALE GT3	77	DEOK	DEOK	Gas Combustion Turbine Dual	WOODSDALE GT3	77	DEOK	DEOK	0
WOODSDALE GT4	77	DEOK	DEOK	Gas Combustion Turbine Dual	WOODSDALE GT4	77	DEOK	DEOK	0
WOODSDALE GT5	77	DEOK	DEOK	Gas Combustion Turbine Dual	WOODSDALE GT5	77	DEOK	DEOK	0
WOODSDALE GT6	77	DEOK	DEOK	Gas Combustion Turbine Dual	WOODSDALE GT6	77	DEOK	DEOK	0
								Total	**76.2**

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

CONFIDENTIAL AG-DR-01-004
(As to Attachment only)

REQUEST:

Regarding bilateral sales or off-system sales.

a. Explain whether DEK provides power to DEO through bilateral sales or off-system sales. Include in your response a description of the accounting entries DEK makes to record power sales to DEO.

b. For the last eight years, provide a list by year and by category of bilateral sales or off-system sales that DEK made to DEO, and for each include the sales type, the maximum capacity, the energy, and the cost.

c. For the last eight years, provide a list by year and by category of bilateral sales or off-system sales that DEK made to MISO, and for each include the sales type, the maximum capacity, the energy, and the cost.

d. For the last eight years, provide a list by year and by category of bilateral sales or off-system sales that DEK made to any party other than DEO or MISO, and for each include the sales type, the maximum capacity, the energy, and the cost.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment only)

Objection. This request is overbroad and unduly burdensome to the extent it seeks information over the last eight years. Without waiving said objection, and to the extent discoverable, the Company states as follows:

a. In responding to this question, it was assumed that "provides power" was asking for sales of energy, not capacity. Since becoming a member of PJM in 2012, and prior to that while a member of MISO, Duke Energy Kentucky has not purchased nor sold any energy from or to Duke Energy Ohio. Additionally, after acquiring its own generation in 2006, Duke Energy Ohio has either used its own generation or purchased from an RTO to serve its customers energy needs (MISO-prior to 2012) and has either used its own generation or purchased from PJM to serve its customers energy needs (since 2012) exclusively.

b. There were no bilateral sales or off-system sales of energy nor capacity that Duke Energy Kentucky made to Duke Energy Ohio during the last five years.

c. There were no bilateral sales or off-system sales of energy nor capacity that Duke Energy Kentucky made to MISO during the last five years.

d. For the purposes of answering this response, only capacity sales during the past 5 PJM delivery years were included; 2025/2026, 2024/2025, 2023/2024, 2022/2023, and 2021/2022. Please see AG-DR-01-004 Confidential Attachment for sales of capacity that Duke Energy Kentucky made to any party other than Duke Energy Ohio and MISO in the past 5 PJM capacity delivery years.

    Additionally, Duke Energy Kentucky made off-system energy sales to only PJM during this period. Please refer to quarterly PSM tariff filings on the Kentucky Public Service Commission website at KY Public Service Commission for non-native PJM energy sales during this time.

PERSON RESPONSIBLE: As to objection, Legal
As to response, John Swez
Alan Mok

CONFIDENTIAL PROPRIETARY TRADE SECRET

AG-DR-01-004
CONFIDENTIAL ATTACHMENT

FILED UNDER SEAL

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-005

REQUEST:

Does Duke Energy Kentucky agree that one result of Duke Energy Kentucky's change to become an RPM participant is that there could be increased prices within the DEOK zone, which could result in the region becoming less economically competitive? Whether Duke Energy Kentucky agrees or disagrees please provide a detailed explanation.

RESPONSE:

Objection. This request is vague, ambiguous and calls for speculation and guesswork. Without waiving said objection and to the extent discoverable, prices could increase or decrease due to any number of factors in PJM wholly unrelated to the Company transitioning from FRR to RPM. The decision for Duke Energy Kentucky to move from an FRR participant to an RPM participant will likely have a nonconsequential impact on cleared PJM capacity. It should be noted that if Duke Energy Kentucky moves to RPM, both the generation and load move to the RPM, not only the Duke Energy Kentucky generation fleet or only the load. Thus, since Duke Energy Kentucky is relatively small and also has a fairly balanced amount of generation and customer demand, a change in resulting capacity price is not expected from the Duke Energy Kentucky supply/demand balance. In addition, due to the PJM requirement that FRR entities withhold 3% of its capacity before selling excess into the BRA, under RPM, Duke Energy Kentucky would be able to offer slightly (approximately 30 MW) more capacity into the BRA than under the FRR. Thus, the 3% holdback could have the impact of slightly reducing capacity prices in the BRA, not increasing prices. However, again, any impact is likely nonconsequential. Further, depending on the capacity clearing price, there can either be slightly more or less required reserve margin between Duke Energy Kentucky's FRR and RPM participation, with again, either change relatively small in the context of the larger system. Finally, the current rules at PJM assume that Duke Energy Kentucky's portfolio is equal to the minimum internal requirement for that zone. Thus, in the 2025/2026 auction, the minimum internal requirement was only 4%, but Duke Energy Kentucky had 100% of its FRR Obligation served by DEOK resources. This difference would tend to lower the reserve requirement in the DEOK zone, putting slightly downward pressure on capacity price levels.

Overall, the Company believes that Duke Energy Kentucky's move from an FRR participant to an RPM participant will likely have minimal, if any, impact on cleared PJM capacity prices.

PERSON RESPONSIBLE: As to objection, Legal
As to response, John Swez
Bryan Garnett

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

PUBLIC AG-DR-01-006

REQUEST:

Identify the approximate date when DEK believes it will have to procure a new capacity resource, and the reason(s) why the Company believes such new capacity will be necessary. If DEK's answer would be different depending on whether DEK is an FRR or an RPM participant, please provide an answer for each case.

RESPONSE:

<u>CONFIDENTIAL PROPRIETARY TRADE SECRET</u>

<u>IRP Perspective:</u>

From a long-term integrated resource planning perspective, the Company plans to PJM's reserve margin requirements. In the 2024 IRP, the Company has adequate capacity to meet reserve margin requirements until 12/31/2038 when East Bend is retired. At that point, new capacity resources would be required. This answer does not change whether Duke Energy Kentucky is an FRR or an RPM participant.

<u>FRR Plan Perspective:</u>

The initial Duke Energy Kentucky FRR plan for 2025/2026 consisted of East Bend, Woodsdale 1-6, and Demand Response in amounts as specified below. The preliminary load obligation is [redacted] MW, and [redacted] MW is the calculated 3% threshold that Duke Energy Kentucky must carry in the FRR plan in order to make capacity sales. Duke Energy Kentucky has set aside [redacted] MW for the load obligation and 3% threshold. In addition, Duke Energy Ken[redacted]y has MW excess capacity.

See below for details of the Duke Energy Kentucky FRR plan:

2025/2026 Initial
FRR Plan

Resource	Nameplate ICAP (MW)	Class Level ELCC	Performance Adj Factor	Accredited UCAP Factor	Nameplate UCAP (MW)	FRR Committed (MW) - Load Obligation	FRR Committed (MW) - Add'l 3% Holdback	RPM Committed (MW)	Capacity Position (MW)
East Bend	600	0.84	0.99	0.83160	499	422	24	0	53
Woodsdale 1	77	0.79	0.94	0.74260	57.2	57.2	0	0	0
Woodsdale 2	77	0.79	1.07	0.84530	65.1	65.1	0	0	0
Woodsdale 3	77	0.79	1.01	0.79790	61.4	61.4	0	0	0
Woodsdale 4	77	0.79	1.05	0.82950	63.9	63.9	0	0	0
Woodsdale 5	77	0.79	1.06	0.83740	64.5	64.5	0	0	0
Woodsdale 6	77	0.79	1.06	0.83740	64.5	64.5	0	0	0
Demand Response	2.6	0.76	1.00	0.76000	2	2	0	0	0
Total	1064.6				877.6	800.6	24	0	53

DEK UCAP	877.6
DEK Capacity Load Obligation	800.6
DEK 3% Holdback	24
DEK RPM Sales	0
DEK Total Excess Capacity	53

Additionally, PJM accepted the Duke Energy Kentucky FRR plan for 2025/2206 on 6-19-2024. Duke Energy Kentucky has not submitted an initial FRR plan to PJM for the 2026/2027 delivery year. Since the data that is used to create this plan is not finalized to date, any preliminary information may change, but at this time the Company expects the 2026/2027 FRR Plan to have a slight excess capacity position similar to the FRR plan for 2025/2026, and thus no additional capacity is expected at this time.

PERSON RESPONSIBLE: Matthew Kalemba – IRP Perspective
Alan Mok – FRR Plan Perspective

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

CONFIDENTIAL AG-DR-01-007
(As to Attachment only)

REQUEST:

Identify all transmission projects planned for the DEOK transmission system and the DEOK zone over the next 5 years. Explain also whether the projects you identify in your response are included within the "Submission of Supplemental Projects for Inclusion in the Local Plan," also referred to as the "DEOK Local Plan 2024" filed with PJM.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment only)

Please see AG-DR-01-007 Confidential Attachment.

PERSON RESPONSIBLE: Yanthi Boutwell

CONFIDENTIAL PROPRIETARY TRADE SECRET

AG-DR-01-007
CONFIDENTIAL ATTACHMENT

FILED UNDER SEAL

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-008

REQUEST:

Would Duke Energy Kentucky be willing to hold all neighboring transmission owners harmless from cost increases arising from the proposed transaction? If not, explain fully why not. If so, explain how this could be accomplished.

RESPONSE:

The Company does not foresee any cost increases to neighboring transmission owners from Duke Energy Kentucky's change from the FRR to RPM capacity construct. Please see the response to AG-DR-01-002 and AG-DR-01-005.

In addition, the decision of Duke Energy Kentucky to pursue a move to the RPM arrangement was made because the Company believes that such a move financially benefits the Duke Energy Kentucky customer and reduces the Duke Energy Kentucky customer risk from participation as an FRR entity, with the reduction in costs from such a move shown in the Attachment JDS-1. The Company believes that there is no impact to other Kentucky utility customers not in PJM and has a nonconsequential impact to other Kentucky utility customers located in the PJM market, especially during the BRA, where most financial transactions occur, since currently Duke Energy Kentucky is required to withhold approximately 30 MW before selling excess capacity from its FRR plan into the BRA. Thus, under RPM, the Company will have approximately 30 MW additional offered into the BRA; if any change were to occur from this additional capacity offer, the effect would be to lower the price of capacity and reducing customer costs, not increasing costs.

Finally, due to the difference in reserve margin required between FRR and RPM members, at extremely high-capacity prices, RPM entities hold a lower reserve margin than under FRR, thus reducing customer costs. Please refer to Table 2 from the direct testimony of Mr. Swez in this proceeding. Additionally, please refer to the response to AG-DR-01-005.

PERSON RESPONSIBLE: John Swez
Bryan Garnett

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-009

REQUEST:

Do DEK customers subsidize DEO customers? If so, please explain.

RESPONSE:

No.

PERSON RESPONSIBLE: Lisa Steinkuhl

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-010

REQUEST:

Explain the following:

a. How the dispatch/operation/operating life expectation of the East Bend generation plant ("East Bend") would change in the event the Company becomes an RPM participant as opposed to an FRR participant.

b. How the dispatch/operation/operating life expectation of East Bend would change in the event the Company's application for a CPCN in Case No. 2024-00152 is approved, and its application in the instant case is also approved. For purposes of these questions, this scenario shall be referenced as "Scenario 1."

c. How the dispatch/operation/operating life expectation of East Bend would change in the event the Company's application for a CPCN in Case No. 2024-00152 is approved, but its application in the instant case is denied. For purposes of these questions, this scenario shall be referenced as "Scenario 2."

d. Provide any projections DEK (or any entity on its behalf) may have conducted regarding additional revenues to be shared with ratepayers in Rider PSM, under both Scenario 1 and Scenario 2.

e. Provide any modeling studies/workpapers developed to derive the projections referenced in part d above. Provide the analyses electronically with all formulae intact and no pasted values.

RESPONSE:

a. There is no impact to the life expectancy of East Bend from Duke Energy Kentucky's participation as either a FRR or RPM capacity construct participant.

b. If the Company's limestone CPCN application is approved, there would be no change in the retirement date of East Bend as presented in the 2024 Duke Energy Kentucky IRP. In addition, if the variable cost of a generating unit is lowered, as in the case of the Company's limestone CPCN application, the unit is more likely to be committed and dispatched in the PJM Energy and Ancillary Services Market. However, there is no change to East Bend's dispatch nor commitment in the PJM Energy and Ancillary Services Market as a result of being either an FRR or RPM capacity construct participant. Although the PJM capacity construct ensures that adequate capacity exists for future energy market's needs, the PJM energy and capacity markets are different, distinct markets. Thus, neither the Company nor PJM commits nor dispatches a unit differently depending on if the owning utility is under either the FRR or RPM capacity construct. The PJM energy and capacity markets are unrelated in this regard.

c. See response to part (b).

d. Please refer to the Limestone CPCN application testimony of Mr. Verderame for the PJM Energy Market benefits from completion of the limestone project. However, since the only difference between Scenario 1 and Scenario 2 is the approval (Scenario 1) or denial (Scenario 2) of the Company's application to move to the RPM capacity construct, the difference in the Scenario 1 and 2 annual impacts to the Duke Energy customer is projected in the Heat Map from Attachment JDS-1.

Thus, the benefit to the customer under Scenario 1 and at the four corners of the Heat Map with the assumptions stated are:

- an annual savings of $4.229M if PJM Capacity Prices are $50/MW Day and Duke Energy Kentucky has a short 9% position.
- an annual savings of $4.039M if PJM Capacity Prices are $500/MW-Day and Duke Energy Kentucky has a long 9% position.
- an annual savings of $5.659M if PJM Capacity Prices are $500/MW-Day and Duke Energy Kentucky has a short 9% position.
- an annual cost of $584K if PJM Capacity Prices are $50/MW-Day and Duke Energy Kentucky has a long 9% position.

Note that the annual savings or benefit could be anywhere within the different scenarios on this Heat Map.

e. Please refer to Heat Map from Attachment JDS-1 for this analysis.

PERSON RESPONSIBLE: John Swez
Matt Kalemba

AG-DR-01-011

REQUEST:

Explain the impact of a potential Commission approval of the application in the instant case on the potential for increased off-system sales.

a. Explain the impact of a potential Commission approval of the application in the instant case on any additional off-system sales / purchases to / from each of LG&E-KU, EKPC and Kentucky Power Co.

b. Provide a list of the interconnections between DEK and the other utilities identified in subpart a, above.

c. Explain the impact of a potential Commission approval of the application in the instant case on any additional off-system sales / purchases to / from Duke Energy, Indiana ("DEI"), and Duke Energy, Ohio ("DEO").

RESPONSE:

For the purpose of answering this response, "off-system sales" are assumed to be the result of energy market transactions resulting when Duke Energy Kentucky has more generation than customer demand.

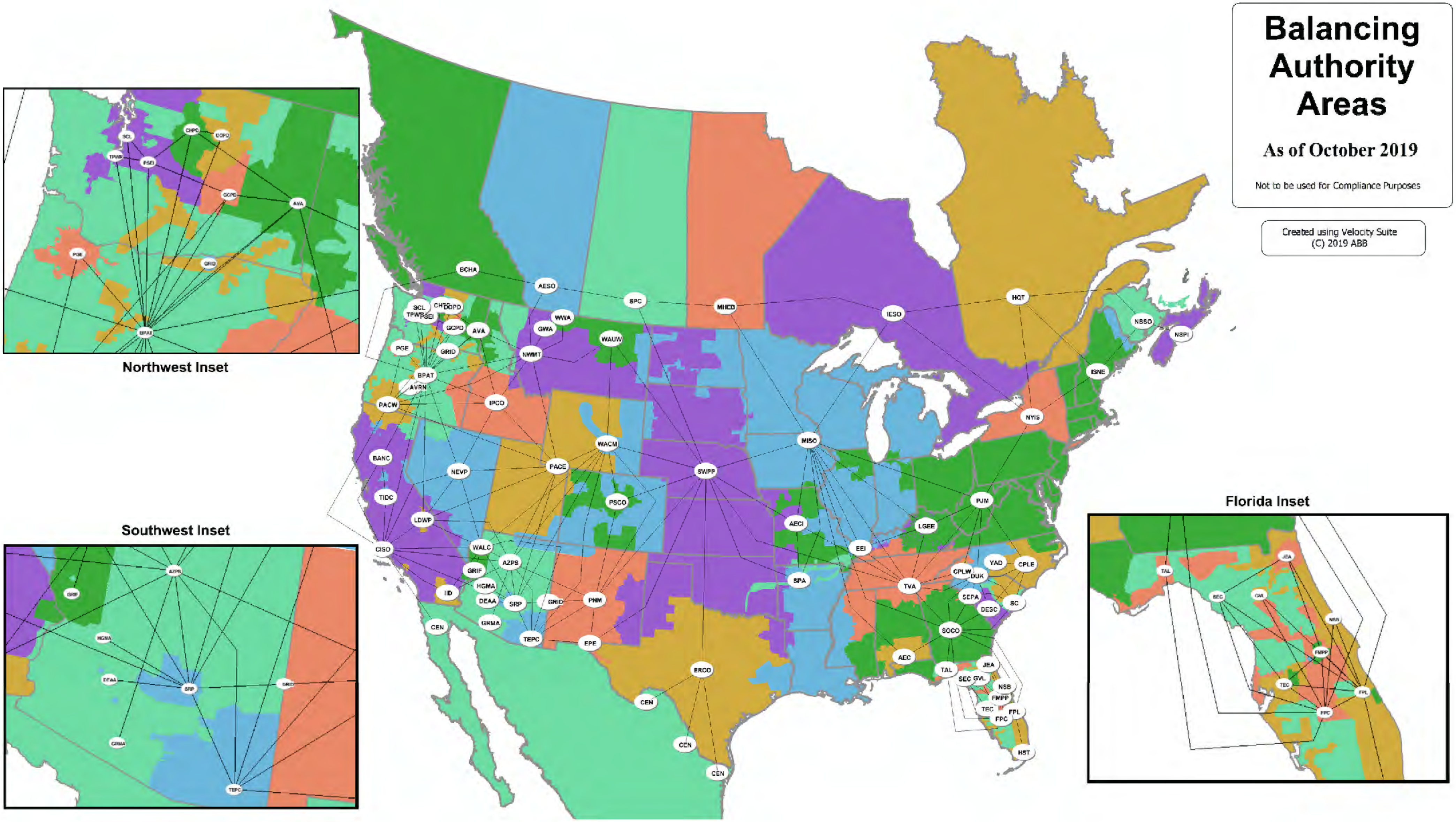
a. There is no impact. Duke Energy Kentucky does not make any off-system energy sales / energy purchases to / from LG&E-KU, EKPC and Kentucky Power Co. Additionally, since there is no change to the commitment and dispatch of any Duke Energy Kentucky generating units in the event that Duke Energy Kentucky were to become a PJM RPM capacity construct member, there is no change to any off-system energy sales to PJM. Finally, please see the response to AG-DR-01-010.

b. For the purpose of this response, interconnections are assumed to mean the connection of balancing authority areas. Please refer to AG-DR-01-011(b) Attachment 1, the most recent NERC "bubble chart" showing the different balancing authority areas of North America. DEK, EKPC, and Kentucky Power Co., as members of PJM, are included in the "PJM bubble." LG&E-KU is represented by the "LGEE bubble."

   Additionally, please refer to AG-DR-01-011(b) Attachment 2, which is From EIA-860 form, Annual Electric Power Industry Report, Form EIA-860 detailed data with previous form data (EIA-860A/860B) - U.S. Energy Information Administration (EIA), which was additionally utilized in this response.

c. There is no impact. Duke Energy Kentucky does not make any off-system energy sales / energy purchases to / from Duke Energy Indiana or Duke Energy Ohio.

PERSON RESPONSIBLE: John Swez


Balancing Authority Areas
As of October 2019
Not to be used for Compliance Purposes
Created using Velocity Suite
(C) 2019 ABB
Northwest Inset
Southwest Inset
Florida Inset
BCHA
AESO
SPC
MHEB
IESO
HQT
NBSO
NSPI
ISNE
NYIS
WWA
GWA
WAUW
NWMT
AVA
GCPD
DOPD
CHPD
SCL
TPWR
PSEI
PGE
GRID
BPAT
AVRN
PACW
IPCO
WACM
PACE
NEVP
BANC
TIDC
LDWP
CISO
PSCO
SWPP
MISO
AECI
LGEE
PJM
EEI
WALC
AZPS
GRIF
HGMA
DEAA
IID
SRP
GRMA
TEPC
PNM
EPE
CEN
ERCO
SPA
TVA
CPLW
DUK
YAD
CPLE
SEPA
DESC
SC
SOCO
AEC
TAL
JEA
SEC
GVL
NSB
FMPP
TEC
FPL
FPC
HST

From EIA-860 form, Annual Electric Power Industry Report, Form EIA-860 detailed data with previous form data (EIA-860A/860B) - U.S. Energy Information Administration (EIA)

Utility ID	Utility Name	Plant Code	Plant Name	Street Address	City	State	Zip	County	NERC Region	Balancing Authority Code	Balancing Authority Name
11249	Louisville Gas & Electric Co	1363	Cane Run	5252 Cane Run Road	Louisville	KY	40216	Jefferson	SERC	**LGEE**	Louisville Gas and Electric Company and Kentucky Utilities Company
11249	Louisville Gas & Electric Co	1364	Mill Creek (KY)	14660 Dixie Highway	Louisville	KY	40272	Jefferson	SERC	**LGEE**	Louisville Gas and Electric Company and Kentucky Utilities Company
11249	Louisville Gas & Electric Co	1365	Ohio Falls	811 North 27th Street	Shippingport Island	KY	40212	Jefferson	SERC	**LGEE**	Louisville Gas and Electric Company and Kentucky Utilities Company
11249	Louisville Gas & Electric Co	1366	Paddys Run	4512 Bells Lane	Louisville	KY	40211	Jefferson	SERC	**LGEE**	Louisville Gas and Electric Company and Kentucky Utilities Company
11249	Louisville Gas & Electric Co	1367	Waterside GT	233 West Washinigton Stree	Louisville	KY	40202	Jefferson	SERC		
11249	Louisville Gas & Electric Co	1368	Zorn	3001 Upper River Road	Louisville	KY	40207	Jefferson	SERC	**LGEE**	Louisville Gas and Electric Company and Kentucky Utilities Company
11249	Louisville Gas & Electric Co	6071	Trimble County	487 Corn Creek Road	Bedford	KY	40006	Trimble	SERC	**LGEE**	Louisville Gas and Electric Company and Kentucky Utilities Company
11249	Louisville Gas & Electric Co	7894	Unknown			KY			SERC		
5580	East Kentucky Power Coop, Inc	54	J K Smith	12145 Irvine Road	Winchester	KY	40391	Clark	SERC	**PJM**	PJM Interconnection, LLC
5580	East Kentucky Power Coop, Inc	1384	Cooper	670 Cooper Power Plant Rd.	Somerset	KY	42501	Pulaski	SERC	**PJM**	PJM Interconnection, LLC
5580	East Kentucky Power Coop, Inc	1385	Dale	1925 Ford Road	Winchester	KY	40391	Clark	SERC	**PJM**	PJM Interconnection, LLC
5580	East Kentucky Power Coop, Inc	6041	H L Spurlock	Route 8 P.O. Box 398	Maysville	KY	41056	Mason	SERC	**PJM**	PJM Interconnection, LLC
5580	East Kentucky Power Coop, Inc	55164	Bluegrass Generating Station	3095 Commerce Pkwy	LaGrange	KY	40031	Oldham	SERC	**LGEE**	Louisville Gas and Electric Company and Kentucky Utilities Company
5580	East Kentucky Power Coop, Inc	56277	Bavarian LFGTE	12760 McCoy Fork Road	Walton	KY	41094	Boone	SERC	**PJM**	PJM Interconnection, LLC
5580	East Kentucky Power Coop, Inc	56278	Green Valley LFGTE	517 Addington Drive	Ashland	KY	41102	Greenup	SERC	**PJM**	PJM Interconnection, LLC
5580	East Kentucky Power Coop, Inc	56279	Laurel Ridge LFGTE	3608 East Highway 552	Lily	KY	40740	Laurel	SERC	**PJM**	PJM Interconnection, LLC
5580	East Kentucky Power Coop, Inc	56280	Hardin County LFGTE	1598 Audubon Trace	Elizabethtown	KY	42701	Hardin	SERC	**PJM**	PJM Interconnection, LLC
5580	East Kentucky Power Coop, Inc	56327	Pendleton County LFGTE	1452 Bryan Griffen Road	Butler	KY	41006	Pendleton	SERC	**PJM**	PJM Interconnection, LLC
5580	East Kentucky Power Coop, Inc	56977	Mason County LFGTE	7055 Clarkson-Sherman Road	Maysville	KY	41056	Mason	SERC	**PJM**	PJM Interconnection, LLC
5580	East Kentucky Power Coop, Inc	60137	Glasgow LFGTE	405 Glenn Garry Road	Glasgow	KY	42141	Barren	SERC	**PJM**	PJM Interconnection, LLC
5580	East Kentucky Power Coop, Inc	60863	Cooperative Solar One	4775 Lexington Road	Winchester	KY	40391	Clark	SERC	**PJM**	PJM Interconnection, LLC
22053	Kentucky Power Co	1353	Big Sandy	23000 Hwy 23	Louisa	KY	41230	Lawrence	RFC	**PJM**	PJM Interconnection, LLC
22053	Kentucky Power Co	3948	Mitchell (WV)	W.Va. State Route 2	Captina	WV	26041	Marshall	RFC	**PJM**	PJM Interconnection, LLC
10171	Kentucky Utilities Co	1354	Dix Dam	815 Dix Dam Rd	Harrodsburg	KY	40330	Mercer	SERC	**LGEE**	Louisville Gas and Electric Company and Kentucky Utilities Company
10171	Kentucky Utilities Co	1355	E W Brown	815 Dix Dam Rd	Harrodsburg	KY	40330	Mercer	SERC	**LGEE**	Louisville Gas and Electric Company and Kentucky Utilities Company
10171	Kentucky Utilities Co	1356	Ghent	9485 US Hwy 42 East	Ghent	KY	41045	Carroll	SERC	**LGEE**	Louisville Gas and Electric Company and Kentucky Utilities Company
10171	Kentucky Utilities Co	1357	Green River	811 Power Plant Drive	Central City	KY	42330	Muhlenberg	SERC	**LGEE**	Louisville Gas and Electric Company and Kentucky Utilities Company
10171	Kentucky Utilities Co	1358	Haefling	1555 Baumann Dr.	Lexington	KY	40511	Fayette	SERC	**LGEE**	Louisville Gas and Electric Company and Kentucky Utilities Company
10171	Kentucky Utilities Co	1360	Pineville	Ely Rd.	Four Mile	KY	40939	Bell	SERC		
10171	Kentucky Utilities Co	1361	Tyrone	6800 Tyrone Pike	Versailles	KY	40383	Woodford	SERC	**LGEE**	Louisville Gas and Electric Company and Kentucky Utilities Company
10171	Kentucky Utilities Co	65406	LGE-KU Solar Share Facility Simpsonville	662 Conner Station Rd	Simpsonville	KY	40067	Shelby	SERC	**LGEE**	Louisville Gas and Electric Company and Kentucky Utilities Company

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-012

REQUEST:

Explain the potential cost impact on neighboring utilities of the proposed change from FRR status to RPM status. Include in your response how much load of each of the neighboring utilities is served on DEK's transmission system. In other words, how much of the LG&E-KU load is served over the DEK transmission system, how much EKPC load is served over the DEK transmission system, etc.

RESPONSE:

Energy Market/IRP:

The resources that are serving customer load are determined by and in the energy market, both for utilities that are part of an RTO and those that are not part of an RTO. The decisions that determine how customer load is served pertain to generating unit commitment and dispatch decisions, the availability and cost of generating units, the amount of customer demand, energy transactions, and transmission system configuration and availability, among other factors. These factors are energy market related and unrelated to the Company's decision to request a move from the FRR to the RPM capacity construct. In addition, please refer to the Company's response to AG-DR-01-010, part (a), which explains that the Company resource mix isn't impacted from a change to RPM.

Transmission:

The DEOK Transmission system is assessed annually to satisfy NERC TPL-001 and local system performance requirements. Powerflows on the networked DEOK transmission system change in real time due to evolving system conditions (ambient temperature, loading, generator availability, etc.) and contingencies (system outages) occurring in both the DEOK system and in neighboring transmission systems.

PERSON RESPONSIBLE: John Swez – Energy Market/IRP
Matt Kalemba – Energy Market/IRP
Yanthi Boutwell – Transmission

AG-DR-01-013

REQUEST:

Explain the impact of a potential Commission approval of the application in the instant case on any additional off-system sales / purchases from any other MISO and/or PJM market participants.

RESPONSE:

A move from the FRR to RPM capacity construct for Duke Energy Kentucky has no impact to off-system sales / purchases from MISO, PJM, or any other market participant since these are determined in the Energy Markets, not the Capacity Markets. Please see the response to AG-DR-01-012.

PERSON RESPONSIBLE: John Swez

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-014

REQUEST:

Explain how a potential Commission approval of the application in the instant case would benefit or harm the following companies:

a. DEO

b. DEI

c. EKPC

RESPONSE:

Energy Market: There is no impact to any of these entities in the energy market. See responses to AG-DR-01-012 and AG-DR-01-013.

Capacity Market:

- Since Duke Energy Indiana is in MISO and doesn't participate in the PJM BRA, no impact to Duke Energy Indiana is possible from the Company's move to the RPM capacity construct.
- Due to the Company's relatively small size, the fact that Duke Energy Kentucky currently already offers its excess capacity into the PJM capacity markets, and since Duke Energy Kentucky has an approximate balance between supply and demand, any impact to Duke Energy Ohio and/or EKPC is expected to be very minor. For Duke Energy Ohio and EKPC, since both are in PJM, Duke Energy Kentucky's change from FRR to RPM could have a non-consequential impact on BRA clearing prices. This change is dependent upon the impact of the approximately 30 MW

additional capacity Duke Energy Kentucky is able to offer in the BRA due to the removal of the FRR 3% holdback and the change in the required reserve margin between Duke Energy Kentucky's FRR and RPM participation. Further, depending on the capacity clearing price, there can be a change in the required reserve margin between Duke Energy Kentucky's FRR and RPM participation. Duke Energy Kentucky has no way to forecast the changes in capacity clearing prices from its change from FRR to RPM participation. Additionally, please see the response to AG-DR-01-005.

PERSON RESPONSIBLE: John Swez
Bryan Garnett

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-015

REQUEST:

In the event the Commission approves the application in the instant case, provide a discussion regarding potential impacts on the Company's demand response programs

RESPONSE:

If the Commission approves the Company's application to move Duke Energy Kentucky from FRR to RPM it should only increase the Company's ability to utilize its demand response programs since under RPM, the demand response programs that are only available in the Summer season (associated with Air Conditioner Load) could potentially have the ability to "match-up" with other programs in the RPM, whereas in the FRR, the Summer only demand response programs are effectively not used in the FRR plan. Additionally, to the extent it was cost effective to participate in any PJM capacity auctions with the Company's demand response programs, any capacity auctions revenues could be used to offset program expenses.

PERSON RESPONSIBLE: Tim Duff

AG-DR-01-016

REQUEST:

In the event the Commission approves the application in the instant case, explain the potential impacts on DEK's participation in PJM's: (i) ancillary services market; and (ii) energy markets (both day ahead and real-time). Include in your response the potential for any changes in the amount of revenues from ancillary market participation.

RESPONSE:

There is no impact on neither the PJM ancillary services market nor energy market (both Day-Ahead and Real-Time Markets). Please see the responses to AG-DR-01-010 through AG-DR-01-013.

PERSON RESPONSIBLE: John Swez

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-017

REQUEST:

Explain whether DEK engages in any market transactions (energy, capacity, or ancillary services) with TVA. If so, discuss the potential impact of a Commission approval of the application in the instant case on any type or sort of transactions with TVA.

RESPONSE:

Duke Energy Kentucky does not engage in any energy nor ancillary services transactions with TVA. All of Duke Energy Kentucky energy transactions are through the PJM Energy and Ancillary Services Market.

Although Duke Energy Kentucky has not had a capacity transaction with TVA to date, Duke Energy Kentucky could buy or sell capacity from or to TVA, subject to the availability of firm transmission service. Finally, Duke Energy Kentucky's decision to pursue a move to RPM does not mean that Duke Energy Kentucky is more or less likely to have a capacity transaction with TVA.

PERSON RESPONSIBLE: John Swez
Alan Mok

AG-DR-01-018

REQUEST:

Please discuss the following:

a. Whether a potential Commission approval of the application in the instant case could enhance or degrade the potential for bilateral sales, whether inside PJM or elsewhere.

b. When DEK sells power to DEO, is this considered a bilateral sale? If it is not currently considered a bilateral sale, would it be considered one if the Commission approves the application in the instant docket?

RESPONSE:

a. Bilateral sales, whether inside PJM or elsewhere, are unaffected by Duke Energy Kentucky participating in the RPM as opposed to FRR capacity construct. Please refer to the responses to AG-DR-01-010 through AG-DR-01-014.

b. Duke Energy Kentucky does not sell power to Duke Energy Ohio. Please see response to AG-DR-01-014, part (a).

PERSON RESPONSIBLE: John Swez

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-019

REQUEST:

Reference DEK Tariff Sheet No. 2, 77th Revised Sheet No. 82, "Rider PSM Profit Sharing Mechanism," pages 1-3. Provide a complete word description of the current PJM Billing Line Items ["BLIs"] identified therein. Also, provide a complete description of all proposed changes to the tariff, and identify which BLIs would no longer be applicable in the event the Commission approves the application.

RESPONSE:

Please see below for descriptions of the current PJM BLIs identified in the PSM Tariff. All the current PJM BLIs listed below will be applicable if the Commission approves this application.

<u>OSS – Off-System Power Sales</u>

1. 1210: Day-Ahead Transmission Congestion
2. 2210: Transmission Congestion
3. 1215: Balancing Transmission Congestion
4. 1218: Planning Period Congestion Uplift
5. 2217: Planning Period Excess Congestion
6. 2218: Planning Period Congestion Uplift
7. 1230: Inadvertent Interchange
8. 1250: Meter Error Correction
9. 1260: Emergency Energy
10. 2260: Emergency Energy
11. 1370: Day-Ahead Operating Reserve
12. 2370: Day-Ahead Operating Reserve
13. 1375: Balancing Operating Reserve
14. 2375: Balancing Operating Reserve
15. 1400: Load Reconciliation for Spot Market Energy
16. 1410: Load Reconciliation for Transmission Congestion
17. 1420: Load Reconciliation for Transmission Losses
18. 1430: Load Reconciliation for Inadvertent Interchange

19. 1478: Load Reconciliation for Balancing Operating Reserve
20. 1340: Regulation and Frequency Response Service
21. 2340: Regulation and Frequency Response Service
22. 1460: Load Reconciliation for Regulation and Frequency Response Service
23. 1350: Energy Imbalance Service
24. 2350: Energy Imbalance Service
25. 1360: Synchronized Reserve
26. 2360: Balancing Synchronized Reserve
27. 1470: Load Reconciliation for Synchronized Reserve
28. 1377: Synchronous Condensing
29. 2377: Synchronous Condensing
30. 1480: Load Reconciliation for Synchronous Condensing
31. 1378: Reactive Services
32. 2378: Reactive Services
33. 1490: Load Reconciliation for Reactive Services
34. 1500: Financial Transmission Rights Auction
35. 2420: Load Reconciliation for Transmission Losses
36. 2220: Transmission Losses
37. 1200: Day-Ahead Spot Market Energy
38. 1205: Balancing Spot Market Energy
39. 1220: Day-Ahead Transmission Losses
40. 1225: Balancing Transmission Losses
41. 2500: Financial Transmission Rights Auction
42. 2510: Auction Revenue Rights
43. 1930: Generation Deactivation
44. 2211: Day-Ahead Transmission Congestion
45. 2215: Balancing Transmission Congestion
46. 2415: Balancing Transmission Congestion Load Reconciliation
47. 2930: Generation Deactivation

<u>NF – Non-Fuel Related PJM Charges and Credits Not Recovered Via Other Mechanisms</u>

1. 1240: Day-Ahead Economic Load Response
2. 2240: Day-Ahead Economic Load Response
3. 1241: Real-Time Economic Load Response
4. 2241: Real-Time Economic Load Response
5. 1242: Day-Ahead Load Response Charge Allocation
6. 1243: Real-Time Load Response Charge Allocation
7. 1245: Emergency Load Response
8. 2245: Emergency Load Response
9. 1330: Reactive Supply and Voltage Control from Generation and Other Sources Service
10. 2330: Reactive Supply and Voltage Control from Generation and Other Sources Service
11. 1362: Non-Synchronized Reserve
12. 2362: Balancing Non-Synchronized Reserve
13. 1472: Load Reconciliation for Non-Synchronized Reserve

14. 1365: Day-Ahead Scheduling Reserve
15. 2365: Day-Ahead Scheduling Reserve
16. 1475: Load Reconciliation for Day-Ahead Scheduling Reserve
17. 1371: Day-Ahead Operating Reserve for Load Response
18. 2371: Day-Ahead Operating Reserve for Load Response
19. 1376: Balancing Operating Reserve for Load Response
20. 2376: Balancing Operating Reserve for Load Response
21. 1380: Black Start Service
22. 2380: Black Start Service

<u>CAP – Capacity Charges and Credits</u>
1. 1600: RPM Auction Purchases
2. 2600: RPM Auction Sales
3. 1667: Non-Performance Capacity Assessments
4. 2667: Bonus Performance Capacity Credits

Please see Ms. Steinkuhl's testimony and Attachment LDS-1 for a complete description of all the proposed changes to the tariff. As stated in the testimony, Duke Energy Kentucky will continue receiving PJM BLIs 1600 and 2600 along with PJM BLIs 1667 and 2667. The Company is proposing a change in the sharing percentage of capacity transactions (revenues and costs) separately from the other Rider PSM components. The proposed tariff includes the formula below:

Rider PSM Factor = (((OSS + NF + CP+REC) x 0.90) + CAP + R) / S

The definitions in the proposed formula remain the same except for CAP, and there is a new component of the equation, CP. Please see below for proposed definitions of CAP and CP and descriptions of the PJM BLIs included for recovery.

<u>CP = Capacity performance credits and capacity performance assessments</u> identified in the following PJM Interconnection LLC Billing Line Items 1667 and 2667
1. 1667: Non-Performance Capacity Assessments
2. 2667: Bonus Performance Capacity Credits

<u>CAP = Net proceeds from capacity sales and capacity purchases</u> to meet PJM's FERC-approved reliability requirements from participation in the PJM Interconnection LLC auction-based Reliability Pricing Model (RPM) and bilateral markets. Includes PJM Billing Line Items charged/credited to the Company identified in the following Billing Line

Items 1600, 1610, 1650, 1660, 1661, 1662, 1663, 1664, 1665, 1666, 2600, 2605, 2620, 2625, 2630, 2640, 2650, 2660, 2661, 2662, 2663, 2664, 2665, and 2666.

1. 1600: RPM Auction Purchases
2. 1610: Locational Reliability
3. 1650: Auction Specific MW Capacity Transaction
4. 1660: Demand Resource Interruptible Load for Reliability (ILR) Compliance Penalty
5. 1661: Capacity Resource Deficiency
6. 1662: Generation Resource Rating Test Failure
7. 1663: Qualifying Transmission Upgrade Compliance Penalty
8. 1664: Peak Season Maintenance Compliance Penalty
9. 1665: Peak-Hour Period Availability
10. 1666: Load Management Test Failure
11. 2600: RPM Auction Sales
12. 2605: RPM Seasonal Capacity Performance Auction
13. 2620: Interruptible Load for Reliability
14. 2625: LSE Price Responsive Demand (PRD)
15. 2630: Capacity Transfer Rights (CTRs)
16. 2640: Incremental Capacity Transfer Rights (CTRs)
17. 2650: Auction Specific MW Capacity Transaction
18. 2660: Demand Resource and ILR Compliance Penalty
19. 2661: Capacity Resource Deficiency
20. 2662: Generation Resource Rating Test Failure
21. 2663: Qualifying Transmission Upgrade Compliance Penalty
22. 2664: Peak Season Maintenance Compliance Penalty
23. 2665: Peak-Hour Period Availability
24. 2666: Load Management Test Failure

For a detailed explanation of PJM BLI's included in the proposed changes, please see pages 37 through 45 of the direct testimony of Mr. Swez in this proceeding.

PERSON RESPONSIBLE: John Swez
Lisa Steinkuhl

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-020

REQUEST:

Please respond to the following:

a. Confirm that in the event the Commission should approve the application in the instant case, DEK would not incur any PJM penalties. Provide all support relied on for your response.

b. Explain also whether RPM participants are at greater risk or more susceptible to any PJM penalties than FRR entities. Provide all support for your response.

c. Discuss the situation in which if DEK were to acquire resources outside of the DEOK zone, either by a purchase or a PPA, it would be exposed to potential PJM penalties if PJM were to increase the minimum capacity construct Minimum Internal Generation Requirement. Provide all support for your response.

d. Discuss the situation in which if DEK were to acquire resources outside of the DEOK zone, it would be exposed to zonal pricing risk. Provide all support for your response.

e. Did DEK perform any analysis to determine whether FRR or RPM participation poses a greater risk for customers? If so, provide the analysis with all formulae intact and no pasted values. If not: (i) explain why not; and (ii) please provide DEK's view as to which could cause greater harm to customers, and explain in detail. Provide all support for your response.

RESPONSE:

a. There are no PJM penalties that will be applied to Duke Energy Kentucky moving from FRR to RPM. The only requirement is that Duke Energy Kentucky notifies PJM in the appropriate time to allow PJM to include Duke Energy Kentucky's portfolio in the auction parameters. For a discussion of capacity performance penalties, please see the response to AG-DR-01-024.

b. As indicated, there are no PJM penalties that will be applied in the transition to RPM. For a measure of the risk that exists between FRR and RPM, see Attachment JDS-1 for a "Heat map" of the different financial risks.

c. Under the assumption that Duke Energy Kentucky was still in FRR, Duke Energy Kentucky would have risk in that external purchases could not be used to satisfy the Duke Energy Kentucky load obligation if there is a change in the minimum internal generation requirement. This would lead to the Duke Energy Kentucky customer "paying twice" for capacity, once for the resource outside of the DEOK Zone and once for any bilaterial purchase needed to meet the Company's FRR plan and if not available within the DEOK zone, payment of the FRR Shortfall Penalty.

d. Under the assumption that Duke Energy Kentucky is now in the RPM, if Duke Energy Kentucky purchased external resources to meet their load as opposed to purchasing in the auction, Duke Energy Kentucky would be subject to the risk that the Duke Energy Kentucky zone cleared higher or lower than the zone where the capacity was purchased. Thus, this could result in a financial gain or loss, depending on the relationship of the Zone clearing price where the resource is located and the DEOK Zone.

e. Please see Attachment JDS-1.

PERSON RESPONSIBLE: Bryan Garnett
John Swez

AG-DR-01-021

REQUEST:

Reference the application, paragraph 9. Discuss whether in the event of large load growth in DEI and/or DEO, the potential for either bilateral or off-system sales from DEK would be enhanced.

RESPONSE:

- Since this question asks about bilateral or off-system sales, it was assumed that it was asking with regard to the Energy Markets only, not Capacity Markets.
- Duke Energy Kentucky does not engage in bilateral sales, so bilateral sells are not impacted.
- All of Duke Energy Kentucky's off-system sales are made to PJM.
- Since Duke Energy Ohio is in PJM, large load growth in Duke Energy Ohio (without any additional generation) could indirectly lead to additional Duke Energy Kentucky off-system sales to PJM. Absent additional generation added to the grid, generally additional load causes incrementally more resources inside PJM to be committed and/or dispatched to serve that load. Since incremental cost curves are monotonically increasing, this could indirectly lead to additional Duke Energy Kentucky off-system sales to PJM if a Duke Energy Kentucky unit is the incremental unit to increase output to serve this additional load. However, there are too many variables to know exactly how large load growth in Duke Energy Ohio would impact off-system sales in Duke Energy Kentucky.

Please refer to the direct testimony of Mr. Swez in this case for how additional customer load in the DEOK Zone impacts capacity decisions for Duke Energy Kentucky, specifically its decision to pursue the PJM RPM capacity construct.

- Given that Duke Energy Indiana is in MISO and Duke Energy Kentucky is in PJM, there are too many variables to know how large load growth in Duke Energy Indiana would impact off-system sales in Duke Energy Kentucky. However, since MISO and PJM are interconnected, higher loads and higher power prices in MISO, to the extent that transmission is available and entities are willing to buy from one RTO and sell to the other RTO, could indirectly cause higher energy prices in PJM, causing a slight increase in Duke Energy Kentucky off-system sales, all else being equal.

PERSON RESPONSIBLE: John Swez

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-022

REQUEST:

Reference the application, paragraph 9.

a. Provide a discussion regarding historical zonal separation within the DEOK zone, and its impacts and ramifications going forward, both in the event the Commission should approve the application in the instant case, and in the event it should deny the application.

b. Explain whether the risk of zone separation for DEK would be reduced by switching to RPM status. Provide all support for your response.

RESPONSE:

a. As shown in Table 4 of the Direct testimony of Mr. Swez, the DEOK Zone has cleared at a higher price than the RTO in 3 of the past 6 PJM BRA. As shown, when the DEOK zone clears at a different price, the price is higher than the rest of RTO, not lower.

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	[1] 269.92	269.92

There are multiple reasons why the PJM auction clearing prices can be different between capacity zones. Specifically related to DEOK, the reasons include the DEOK Capacity Emergency Transfer Objective (CETO), DEOK Capacity Emergency Transfer Limit (CETL), DEOK Reliability Requirement, the amount of generation within the DEOK zone, the offer prices of generating resources within DEOK in the BRA or Incremental Auction (IA), and the Cost of New Entry (CONE) price.

On the other hand, one 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. If a FRR plan required a purchase of additional capacity, such capacity may also need to meet those zone limitations, depending on that year's PJM minimum internal resource requirement. With recent and announced merchant generation, bilateral capacity within the DEOK zone is likely to become scarce. This PJM minimum internal resource requirement risk does not exist as an RPM participant. Instead, in RPM, the issue manifests itself in that the DEOK zone "splits out" at higher prices than the rest of the RTO clearing price. If Duke Energy Kentucky meets its FRR plan with internal resources and has no length to sell into the PJM auctions, or has no need to buy bilateral capacity, then there is no impact to Duke Energy Kentucky. If the DEOK Zone splits out higher, Duke Energy Kentucky can sell its length at a higher price.

Note that when under RPM and the DEOK Zone "splits out," both the load buys and the generation sells at this higher price. The financial impact to Duke Energy Kentucky of being in the FRR and selling capacity at a higher price (if long) or having to procure bilateral capacity at a premium within the DEOK zone (if short) is included in the "Heat Map". Additionally, financial impact to Duke Energy Kentucky of having either a long or short position in the RPM and experiencing a high-capacity price from the DEOK zone "splitting out", again are all calculated and contained in the "Heat Map" results, contained in the Direct Testimony of Mr. Swez's, Attachment JDS -1.

Since the question is pertaining to zonal separation, or situations when the DEOK zone "splits out" to a higher price than the rest of the RTO, the impact to Duke Energy Kentucky is seen by focusing on the "Heat Map" results on the far right side, both the upper right corner (Duke Energy Kentucky is long), lower right corner (Duke Energy Kentucky is short), and the far midpoint (Duke Energy Kentucky is flat) of the "Heat Map" shows:

<u>Upper right corner: DEOK Zone Splits Out & Long Capacity Position</u>:
This corner of the Heat Map shows the negative financial consequences to the Duke Energy Kentucky customers if the Company stays a FRR entity, is long, and the DEOK Zone "Splits out," creating a High Clearing Price.

- In this corner (scenario), staying in the FRR capacity construct produced a loss since the Company would have able to sell more of its excess length in the BRA had it been in the RPM.
- **In the upper right corner, the customer loses $4.039M annually from participation in the FRR.**

<u>Midpoint: DEOK Zone Splits Out & Flat Capacity Position</u>:
The midpoint of the upper right and lower right corners of the Heat Map shows the negative financial consequences to the Duke Energy Kentucky customers if the Company stays a FRR entity, is flat, and the DEOK Zone "Splits out," creating a High Clearing Price.

- At the midpoint (scenario), staying in the FRR capacity construct produced a loss since the Company would have able to sell more of its excess length in the BRA had it been in the RPM.
- **At the midpoint, the customer loses $1.810M annually from participation in the FRR.**

<u>Lower right corner: DEOK Zone Splits Out & Short-Capacity Position</u>:
This corner of the Heat Map shows the negative financial consequences to the Duke Energy Kentucky customers if the Company stays a FRR entity, is short, and the DEOK Zone "Splits out," creating a High Clearing Price.

- In this corner (scenario), staying in the FRR capacity construct produced a loss since the Company was forced to both purchase 75% of the short position via bilateral capacity at a premium, and 25% of the short position could not be purchased and that an FRR assessment (penalty) associated with failing to meet its FRR plan was charged to the Company.
- **In the lower right corner, the customer loses $5.659M annually from participation in the FRR.**

b. The risk to Duke Energy Kentucky of zonal separation is not changed dramatically from moving from FRR to RPM. The fact that all of Duke Energy Kentucky's assets are a part of the DEOK Zone helps reduce the reliability requirement in RPM as opposed to FRR. This is due to an assumption that PJM makes that Duke Energy Kentucky's assets in DEOK will match exactly the minimum internal generation number for the entire zone.

PERSON RESPONSIBLE: John Swez
Bryan Garnett

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

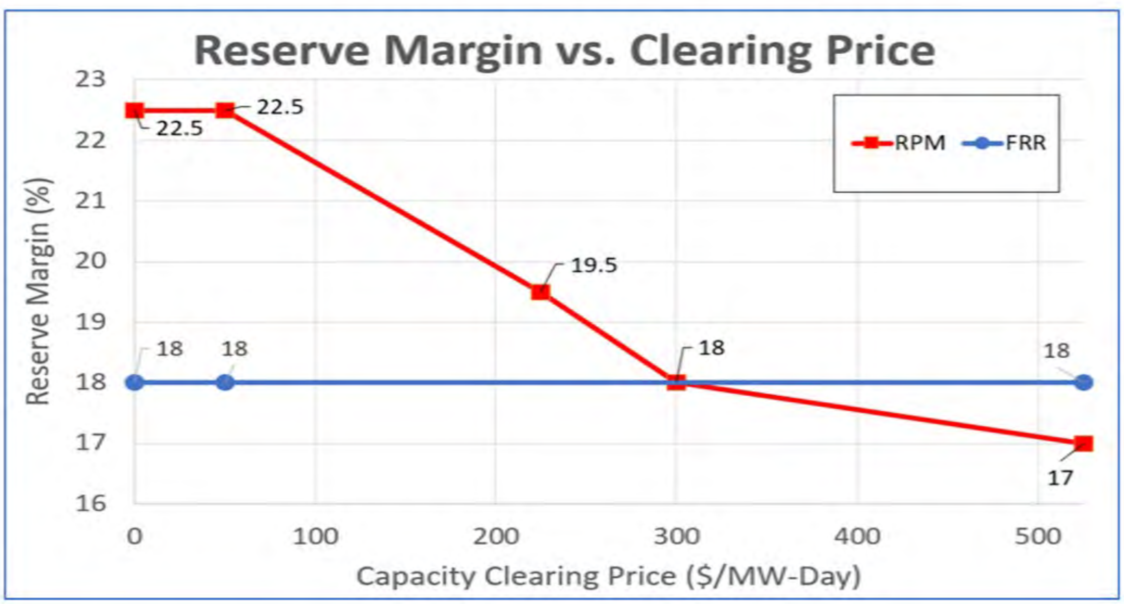
AG-DR-01-023

REQUEST:

Explain whether the potential transition to RPM status would impact the reserve margin that PJM requires from DEK. Provide all support for your response.

RESPONSE:

Yes, there is a difference in the reserve margin that PJM requires Duke Energy Kentucky to hold in its FRR Plan vs. the "cleared" reserve margin in the RPM. Please refer to Table 2: Graphical display of the FRR versus RPM reserve margin (ICAP basis), from Mr. Swez's direct testimony. While FRR reserve margin is constant, the "cleared" reserve margin, formed by a sloped demand curve, can vary for the RPM entities.



At low auction clearing prices, the RPM holds additional reserve margin than FRR. At the highest auction prices, the RPM holds less reserve margin than FRR. At the middle auction prices, the reserve margin is the same between FRR and RPM.

Note that the Company's analysis shown in the "Heat Map" includes the financial impact of this difference in reserve margin between RPM and FRR.

PERSON RESPONSIBLE: John Swez
Bryan Garnett

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-024

REQUEST:

Regarding the risk of potential capacity performance penalties:

a. Discuss any potential measures DEK might have to take to mitigate the risk of potential capacity performance penalties in the event the Commission approves the application in the instant docket. Provide all support for your response.

b. Discuss also whether the cost of such mitigation measures could outweigh the current or future costs DEK incurs to avoid FRR penalties. Provide all support for your response.

RESPONSE:

a. Even though 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, and the Woodsdale Combustion Turbine facility also successfully meets the Capacity Performance requirements with the completion of the construction of its new dual fuel system, the Company continues to evaluate Capacity Performance compliance opportunities for its portfolio to mitigate non-performance risks since the PJM Capacity non-compliance impacts are a risk with the Company's current FRR participation as well under RPM participation.

Currently, being in FRR means Duke Energy Kentucky has an additional Capacity Performance option available to 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. Thus, 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, 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.

Thus, due to higher expected capacity prices, Duke Energy Kentucky is considering pursuing insurance to manage this non-compliance risk.

b. Insurance may need to be purchased for two reasons, both (1) under RPM the physical option is not available, and (2) higher overall capacity prices make the physical option available under FRR have less value. Even if Duke Energy Kentucky were to say in FRR, it may pursue capacity performance insurance. Therefore, it is appropriate to assign all of the insurance premium against the savings from entering RPM, but it is appropriate to assign a portion of this insurance against the benefits shown in the "Heat Map".

At the time the response to this data request was being developed, the Company was still waiting on an insurance quote.

PERSON RESPONSIBLE: John Swez
Michael Chen

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-025

REQUEST:

Reference the Swez testimony at 11:12-13.

a. Explain the types of constraints that exist on the DEOK transmission system that pose an inability to import power. Describe also the types of improvements that would be necessary in order to allow the system to import more power.

b. Explain whether any constraints exist that may limit the ability of DEK to conduct bilateral sales and off-system sales.

RESPONSE:

a. <u>Transmission Response</u>:

Transmission lines have thermal operating limits, determined by individual line structure design, conductor type, etc., as well as ambient operating temperatures. In real time, if the load demand on a given transmission line exceeds its thermal limit, the conductor can deform/sag due to excessive heating. Improvements to increase line load ability typically involve a line rebuild, during which existing transmission conductor is replaced with larger, heavier-rated conductor (often on larger, taller structures).

<u>Capacity Market Response:</u>

Please refer to the PJM produced document AG-DR-01-025(a) Attachment, which is the PJM planning parameters for the 2025/2026 PJM BRA. Specifically, please refer to the "Planning Parameters" tab, row 94 and the "Key Transmission

Upgrades" tab. Note that no DEOK transmission upgrades are listed for the 2025/2026 PJM BRA Delivery Year.

b. In an RTO construct such as PJM, Locational Marginal Price (LMP) is used to modify unit output in response to both transmission congestion and losses. Thus, LMP contains both components of congestion (Marginal Congestion Component) and losses (Marginal Loss Component) that either make the LMP at a generator node either higher than the LMP's energy price (Marginal Energy Component), or lower than the LMP's energy price of LMP. Since a generators output is largely the result of the LMP at that node, and since generally off-system sales occur when the Company's generators have a higher collective output than customer demand, it is difficult to specify if any constraints exist in the PJM system that limit the ability of Duke Energy Kentucky to have additional off-system sales.

PERSON RESPONSIBLE: Yanti Boutwell – a. (Transmission)
John Swez – a. (Capacity Market), b.

2025-2026 RPM Base Residual Auction Planning Parameters **8/5/2024**

	RTO	Notes:
Installed Reserve Margin (IRM)	17.8%	endorsed at the March 20, 2024 MRC meeting https://www.pjm.com/-/media/committees-groups/committees/mrc/2024/20240320/20240320-item-05---irm-fpr-and-elcc-for-25-26-bra---presentation.ashx
Pool-Wide Accredited UCAP Factor	79.69%	endorsed at the March 20, 2024 MRC meeting.
Forecast Pool Requirement (FPR)	0.9387	endorsed at the March 20, 2024 MRC meeting.
Preliminary Forecast Peak Load	153,883.0	2024 Load Report with adjustments for load served outside PJM.

		Locational Deliverability Area														
	RTO	MAAC	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO	ATSI	ATSI-Cleveland	COMED	BGE	PL	DAYTON	DEOK	DOM
CETO	NA	-1,207.0	5,335.0	6,772.0	6,389.0	2,957.0	1,435.0	4,336.0	4,406.0	3,428.0	-3,270.0	4,620.0	-145.0	2,603.0	2,797.0	5,156.0
CETL	NA	3,222.0	8,717.0	8,467.0	8,501.0	4,282.0	2,030.0	6,572.0	10,846.0	4,713.0	5,254.0	6,031.0	4,681.0	3,931.0	5,387.0	5,164.0
Reliability Requirement	144,450.0	53,342.3	30,953.4	13,508.8	10,664.0	5,415.8	2,750.4	6,557.3	12,186.0	5,064.0	20,819.6	6,940.7	8,765.4	3,521.8	5,596.1	25,746.2
Total Peak Load of FRR Entities	11,597.3	0	0	0	0	0	0	0	0	0	0.0	0	0	0	831.9	0.0
Preliminary FRR Obligation	10,886.4	0	0	0	0	0	0	0	0	0	0.0	0	0	0	780.9	0.0
Reliability Requirement adjusted for FRR	**133,563.6**	**53,342.3**	**30,953.4**	**13,508.8**	**10,664.0**	**5,415.8**	**2,750.4**	**6,557.3**	**12,186.0**	**5,064.0**	**20,819.6**	**6,940.7**	**8,765.4**	**3,521.8**	**5,561.7**	**25,746.2**
Gross CONE, $/MW-Day (UCAP Price)	$451.61	$456.19	$461.66	$466.35	$461.66	$461.66	$461.66	$466.35	$444.26	$444.26	$447.33	$466.35	$438.47	$444.26	$444.26	$444.26
Net CONE, $/MW-Day (UCAP Price)	**$228.81**	**$250.98**	**$310.88**	**$134.57**	**$330.97**	**$330.97**	**$245.68**	**$223.80**	**$236.78**	**$236.78**	**$300.32**	**$45.34**	**$260.21**	**$191.38**	**$205.25**	**$152.69**
EE Addback (UCAP)	1,459.8	674.1	410.1	151.8	167.2	88.4	24.0	80.0	68.5	6.6	337.6	71.8	45.7	18.5	24.9	154.2
Variable Resource Requirement Curve:																
Point (a) UCAP Price, $/MW-Day	$451.61	$456.19	$466.32	$466.35	$496.46	$496.46	$461.66	$466.35	$444.26	$444.26	$450.48	$466.35	$438.47	$444.26	$444.26	$444.26
Point (b) UCAP Price, $/MW-Day	$171.61	$188.24	$233.16	$100.93	$248.23	$248.23	$184.26	$167.85	$177.59	$177.59	$225.24	$34.01	$195.16	$143.54	$153.94	$114.52
Point (c) UCAP Price, $/MW-Day	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Point (a) UCAP Level, MW	133,554.2	53,429.6	31,023.0	13,512.0	10,713.9	5,444.6	2,744.1	6,565.2	12,120.5	5,014.9	20,928.2	6,936.2	8,714.7	3,501.6	5,525.5	25,617.2
Point (b) UCAP Level, MW	137,160.4	54,869.9	31,858.8	13,876.7	11,001.8	5,590.9	2,818.4	6,742.2	12,449.5	5,151.6	21,490.3	7,123.6	8,951.3	3,596.6	5,675.6	26,312.3
Point (c) UCAP Level, MW	144,105.7	57,643.7	33,468.3	14,579.2	11,556.4	5,872.5	2,961.4	7,083.2	13,083.1	5,415.0	22,572.9	7,484.5	9,407.1	3,779.8	5,964.8	27,651.1
Nominated PRD Value, MW	224.0	224.0	14.0	210.0	0.0	0.0	0.0	75.0	0.0	0.0	0.0	135.0	0.0	0.0	0.0	0.0
VRR Curve adjusted for PRD:																
Point (a1) UCAP Price, $/MW-Day	$451.61	$456.19	$466.32	$466.35				$466.35				$466.35				
Point (b1) UCAP Price, $/MW-Day	$171.61	$188.24	$233.16	$100.93				$167.85				$34.01				
Point (prd1) UCAP Price, $/MW-Day	$0.01	$0.01	$0.01	$0.01				$0.01				$0.01				
Point (prd2) UCAP Price, $/MW-Day	$0.01	$0.01	$0.01	$0.01				$0.01				$0.01				
Point (c) UCAP Price, $/MW-Day	$0.00	$0.00	$0.00	$0.00				$0.00				$0.00				
Point (a1) UCAP Level, MW	133,343.9	53,219.3	31,009.9	13,314.9				6,494.8				6,809.5				
Point (b1) UCAP Level, MW	136,950.1	54,659.6	31,845.7	13,679.6				6,671.8				6,996.9				
Point (prd1) UCAP Level, MW	143,895.0	57,433.2	33,455.1	14,382.0				7,012.8				7,357.7				
Point (prd2) UCAP Level, MW	144,105.3	57,643.5	33,468.2	14,579.1				7,083.2				7,484.4				
Point (c) UCAP Level, MW	144,105.7	57,643.7	33,468.3	14,579.2				7,083.2				7,484.5				
Pre-Auction Credit Rate, $/MW	$41,757.83	$45,803.85	$56,735.60	$24,559.03	$60,402.03	$60,402.03	$44,836.60	$40,843.50	$43,212.35	$43,212.35	$54,808.40	$8,274.55	$47,488.33	$34,926.85	$37,458.13	$27,865.93
Post-Auction Credit Rate, $/MW	$19,704.16	$19,704.16	$35,942.57	$19,704.16	$44,632.00	$44,632.00	$19,704.16	$19,704.16	$19,704.16	$19,704.16	$31,375.11	$34,043.55	$19,704.16	$19,704.16	$19,704.16	$32,430.98
Participant-Funded ICTRs Awarded	NA	1557.0	40.0	NA	1070.0	639.0	72.0	NA	NA	NA	1376.0	65.7	NA	NA	155.0	NA
FRR Load Requirement (% Obligation):																
Minimum Internal Resource Requirement	NA	97.7%	79.4%	44.5%	NA	NA	34.3%	NA	NA	NA	88.0%	15.5%	NA	NA	4.4%	95.2%

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and FRR load.

LDA/Zone	CETO (Capacity Emergency Transfer Objective)	CETL (Capacity Emergency Transfer Limit)	CETL to CETO Ratio %	2023 Zonal W/N Coincident Peak Loads	Preliminary Zonal Peak Load Forecast	Base Zonal FRR Scaling Factor	FRR Portion of the Preliminary Peak Load Forecast	Preliminary Zonal Peak Load Forecast less FRR load	LDA/Zone
RTO	NA	NA	NA	**148,659.4**	**153,883.0**	NA	**11,597.3**	**142,285.8**	RTO
AE	2,025.0	>2,328.8	>115%	2,310.0	2,355.0	1.01948	0.0	2,355.0	AE
AEP	-2,203.0	*	*	21,723.0	23,296.0	1.00000	10,744.4	12,551.6	AEP
APS	1,606.0	>1,846.9	>115%	8,452.2	8,836.0	1.04541	0.0	8,836.0	APS
ATSI	4,406.0	**10,846.0**	246%	11,550.0	11,978.0	1.03706	0.0	11,978.0	ATSI
ATSI-CLEVELAND	3,428.0	**4,713.0**	137%	NA	4,012.6	NA	0.0	NA	ATSI-CLEVELAN
BGE	4,620.0	**6,031.0**	131%	6,200.0	6,259.0	1.00952	0.0	6,259.0	BGE
COMED	-3,270.0	**5,254.0**	*	18,720.0	18,839.0	1.00636	0.0	18,839.0	COMED
DAYTON	2,603.0	**3,931.0**	151%	3,140.0	3,135.0	0.99841	0.0	3,135.0	DAYTON
DEOK	2,797.0	**5,387.0**	193%	5,030.0	5,076.0	1.00915	831.9	4,244.1	DEOK
DLCO	1,873.0	>2,154.0	>115%	2,620.0	2,622.0	1.00076	0.0	2,622.0	DLCO
DOM	5,156.0	5,164.0	100%	21,200.0	23,021.0	1.08590	0.0	23,021.0	DOM
DPL	1,161.0	>1,335.2	>115%	3,660.0	3,673.0	1.00355	0.0	3,673.0	DPL
DPL SOUTH	1,435.0	**2,030.0**	141%	NA	2,236.9	NA	0.0	2,236.9	DPL SOUTH
EKPC	883.0	>1,015.5	>115%	1,950.0	2,362.0	1.21130	20.9	2,341.1	EKPC
JCPL	3,779.0	>4,345.9	>115%	5,730.0	5,719.0	0.99808	0.0	5,719.0	JCPL
METED	1,503.0	>1,728.5	>115%	2,900.0	2,958.0	1.02000	0.0	2,958.0	METED
OVEC	NA	NA	NA	60.0	60.0	1.00000	0.0	60.0	OVEC
PECO	2,900.0	>3,335.0	>115%	8,030.0	8,119.0	1.01108	0.0	8,119.0	PECO
PENLC	314.0	>361.1	*	2,730.0	2,745.0	1.00549	0.0	2,745.0	PENLC
PEPCO	4,336.0	**6,572.0**	152%	5,810.0	5,818.0	1.00138	0.0	5,818.0	PEPCO
PL (incl. UGI)	-145.0	**4,681.0**	*	7,034.2	7,040.0	1.00082	0.0	7,040.0	PL (incl. UGI)
PS	6,389.0	**8,501.0**	133%	9,420.0	9,584.0	1.01741	0.0	9,584.0	PS
PS NORTH	2,957.0	**4,282.0**	145%	NA	4,878.3	NA	0.0	4,878.3	PS NORTH
RECO	NA	NA	NA	390.0	388.0	0.99487	0.0	388.0	RECO
EMAAC	5,335.0	**8,717.0**	163%	NA	29,838.0	NA	0.0		EMAAC

SWMAAC	6,772.0	**8,467.0**	125%	NA	12,077.0	NA	0.0		SWMAAC
Western MAAC	-6,889.0	*	*	NA	12,743.0	NA	0.0		Western MAAC
MAAC	-1,207.0	*	*	NA	54,658.0	NA	0.0		MAAC
Western PJM	-2,334.0	*	*	NA	76,204.0	NA	11,597.3		Western PJM

*** LDA has adequate internal resources to meet the reliability criterion.**

Limiting conditions at the CETL for modeled LDAs:

LDA	Violation	Limiting Facility
MAAC	Thermal	Sporn - Kyger Creek 345 kV line in pre-contingency
EMAAC	Voltage	Voltage collapse for the loss of Keeney - Rock Springs 500 kV line
SWMAAC	Voltage	Voltage collapse for the loss of Brandon Shore unit 1
PS	Thermal	Brunswick - Meadow Road 230 kV ckt Z2331 for the loss of Metuchen -Pierson Ave - Meadow Rd- Deans 230 kV ckt s2219 Aldene - Stanley Terrance 230kV for the loss of WEST ORANGE - ORANGE HEIGHTS 230 kV Roseland - Williams PIPE 230 kV for the loss of Roseland - Cedar Grove 230 kV Kitattiny - Bush 230 kVline for the loss of Portland - Martins Creek 230 kV
PSNORTH	Thermal	Aldene - Stanley Terrance 230kV for the loss of WEST ORANGE - ORANGE HEIGHTS 230 kV Roseland - Williams PIPE 230 kV for the loss of Roseland - Cedar Grove 230 kV
DPLSOUTH	Thermal	Cool Spring - Milford 230 kV for the loss of the Indian River - Mildord 230 kV
PEPCO	Thermal	North West 326 - Conastone 230 kV line for the loss of Brighton - Conastone 500 kV line North West 326 - Conastone 230 kV line for the loss of North West 311 - Conastone 230 kV line
ATSI	Thermal	345 kV line Wylie Ridge - Toronto for the loss of two 345/138 kV transformers at Wylie Ridge
ATSI-CLEVELAND	Thermal	Austinburg - Sanborn 138 kV for the loss of Stacy - Leroy Center 138 kV Barberton - Alcoa 138 kV for the loss of Juniper - Star 345 kV
COMED	Thermal	Conastone - Peach Bottom 500 kV line pre contingency overload
BGE	Voltage	Voltage drop at various buses including PUMPHREY 115 kV bus for the loss of Brighton - Conastone 500 kV line
PL	Thermal	Wescosville 500/138 kV transformer pre-contingency
DAYTON	Thermal	Wylie Ridge - Toronto 345 kV for the loss of Wylie Ridge 345/138 kV transformer #1 and #2
DEOK	Thermal	Pierce 345/138 kV transformer for the loss of Pierce - Foster 345 kV line and Conastone - Peachbottom pre-contingency
DOM	Thermal	Goose Creek - Asburn 230 kV for the loss of Pleasant View - Ashburn - Beaumeade 230 kV Dickerson - Dickerson H 230 kV ckt 2 for the loss of Dickerson - Dickerson H 230 kV ckt 1

4/11/2024 - Added PRD to Planning Parameters.
4/11/2024 - Note: EE and FRR data is not currently final and will be added to the Planning Parameters after the appropriate submission deadlines.
6/5/2024 - Updated to include FRR values.
7/10/2024 - Updated to include EE addback values. EE Addback values are based on M&V plans submitted by EE Providers. Final values will be based on actual offers submitted and cleared in the auction.
8/5/24 - Final EE addback values and Post-Auction Credit Rates

RPM CONE and E&AS Values for 2025/2026 Base Residual Auction

ICAP to UCAP Conversion Factor:		
UCAP Price = ICAP Price / Pool-Wide Average Accredited UCAP Factor		
Reference Resource Accredited UCAP Factor	79.00%	Based on reference resource AUCAPF
CONE Area 1: AE, DPL, JCPL, PECO, PS, RECO		
CONE Area 2: BGE, PEPCO		
CONE Area 3: AEP, APS, ATSI, Dayton, DEOK, Dominion, Duquesne (DLCo), EKPC, OVEC		
CONE Area 4: MetEd, Penelec, PPL		
CONE Area 5: ComEd		

Zone/LDA	2024/2025 BRA CONE: Levelized Revenue Requirement, $/MW-Year	Escalation	2025/2026 BRA CONE: Levelized Revenue Requirement, $/MW-Year	Gross CONE, $/MW-Day, UCAP Price	Historic Net Energy Revenue Offset, $/MW-Year	Ancillary Services Offset, $/MW-Year per Tariff	Net E&AS Revenue Offset, $/MW-Year	Net CONE, $/MW-Day, ICAP Price	Net CONE, $/MW-Day, UCAP Price	LDA Modeled with VRR Curve
CONE Area 1	$123,118	1.081	$133,120	$461.66						
AE				$461.66	$36,136	$2,199	$38,335	$259.68	$328.71	
DPL				$461.66	$60,078	$2,199	$62,277	$194.09	$245.68	DPL SOUTH
JCPL				$461.66	$37,086	$2,199	$39,285	$257.08	$325.42	
PE				$461.66	$34,810	$2,199	$37,009	$263.32	$333.31	
PSEG				$461.66	$35,485	$2,199	$37,684	$261.47	$330.97	PS, PSEG NORTH
RECO				$461.66	$44,081	$2,199	$46,280	$237.92	$301.16	
EMAAC				$461.66				$245.60	$310.88	EMAAC
CONE Area 2	$123,920	1.085	$134,473	$466.35						
BGE				$466.35	$119,202	$2,199	$121,401	$35.82	$45.34	BGE
PEPCO				$466.35	$67,742	$2,199	$69,941	$176.80	$223.80	PEPCO
SWMAAC				$466.35				$106.31	$134.57	SWMAAC
CONE Area 4	$118,505	1.067	$126,433	$438.47						
METED				$438.47	$68,747	$2,199	$70,946	$152.02	$192.43	
PENELEC				$438.47	$74,118	$2,199	$76,317	$137.31	$173.80	
PPL				$438.47	$49,203	$2,199	$51,402	$205.57	$260.21	PPL
MAAC				$456.19				$198.27	$250.98	MAAC
CONE Area 3	$118,330	1.083	$128,102	$444.26						
AEP				$444.26	$74,246	$2,199	$76,445	$141.53	$179.15	
APS				$444.26	$86,470	$2,199	$88,669	$108.04	$136.75	
ATSI				$444.26	$57,627	$2,199	$59,826	$187.06	$236.78	ATSI, ATSI CLEVELAND
DAYTON				$444.26	$70,718	$2,199	$72,917	$151.19	$191.38	DAYTON
DEOK				$444.26	$66,721	$2,199	$68,920	$162.14	$205.25	DEOK
DLCO				$444.26	$68,386	$2,199	$70,585	$157.58	$199.47	
DOM				$444.26	$81,877	$2,199	$84,076	$120.62	$152.69	
EKPC				$444.26	$53,736	$2,199	$55,935	$197.72	$250.28	
OVEC				$444.26	$68,725	$2,199	$70,924	$156.65	$198.29	
CONE Area 5	$118,330	NA	$128,986	$447.33						
COMED				$447.33	$39,306	$2,199	$41,505	$237.25	$300.32	COMED
RTO	$120,440		$130,223	$451.61	$62,046	$2,199	$64,245	$180.76	$228.81	RTO

CONE Area 5 based on asset life factor of CONE Area 3. 25/26: 1.0069; 27/28: 1.0376; 28/29: 1.0581; 29/30: 1.0818

New Key Transmission Upgrades included for 2025/2026 model		
Upgrade ID	**Description**	**Transmission Owner**
s2609.2	Install (1) 1440 MVA 500-230 kV transformer at Goose Creek Substation. Extend the existing 500kV ring bus at Goose Creek Substation to be set up for a future six-breaker ring arrangement. One breaker to be installed initially creating a five-breaker ring bus. Install a new 230kV ring bus at Goose Creek Substation to be set up for a future four-breaker ring arrangement. Three 230kV breakers to be installed initially. Cut and extend line #227 Belmont-Beaumeade into Goose Creek Substation.	Dominion
b3718.14	Construct a new 230 kV transmission line for ~3.5 miles along with substation upgrades at Wishing Star and Mars. New right-of-way will be needed and will share same structures with the 500 kV line. New conductor to have a minimum summer normal rating of 1573 MVA.	Dominion
b3718.13	Cut and loop 230 kV Line #2079 (Sterling Park-Dranesville) into Davis Drive substation and install two GIS 230 kV breakers.	Dominion
b3718.12	Upgrade 4-500 kV breakers (total) to 63 kA on either end of 500 kV Line #584 (Loudoun-Mosby)	Dominion
b3718.11	Upgrade 4-500 kV breakers (total) to 63kA on either end of 500 kV Line #502 (Loudoun-Mosby)	Dominion
b3718.10	Reconductor ~1.61 miles of 230 kV line #9349 (Sojourner-Mars) to achieve a summer rating of 1574 MVA.	Dominion
b3718.9	Reconductor ~3.98 miles of 230 kV line #2218 (Sojourner-Runway-Shellhorn) to achieve a summer rating of 1574 MVA.	Dominion
b3718.8	Reconductor ~0.84 miles of 230 kV line #2223 (Lockridge-Roundtable) to achieve a summer rating of 1574 MVA.	Dominion
b3718.7	Reconductor ~2.17 miles of 230 kV line #2188 (Lockridge-Greenway-Shellhorn) to achieve a summer rating of 1574 MVA.	Dominion
b3718.6	Reconductor ~0.64 miles of 230 kV line #2186 (Enterprise-Shellhorn) to achieve a summer rating of 1574 MVA.	Dominion
b3718.5	Reconductor ~1.52 miles of 230 kV line #2031 (Enterprise-Greenway-Roundtable) to achieve a summer rating of 1574 MVA.	Dominion
b3718.4	Reconductor ~0.62 miles of 230 kV line #2214 (Buttermilk-Roundtable) to achieve a summer rating of 1574 MVA.	Dominion
b3726	Install two new 500 kV breakers on the existing open SVC string to create a new bay position. Relocate & Reterminate facilities as necessary to move the 500 kV SVC into the new bay position and Install a 500 kV breaker on the 500/138 kV #3 transformer. Upgrade relaying at Black Oak substation.	APS

Key Transmission Upgrades included for 2024/2025 model but not included for 2025/2026 model		
Upgrade ID	**Description**	**Transmission Owner**
None		

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-026

REQUEST:

Explain for how long a period of time DEK would be required to remain an RPM participant, if its application is approved.

RESPONSE:

An FRR Entity may terminate its election of the FRR Alternative effective with the commencement of any Delivery Year following the minimum five Delivery Year commitment by providing written notice of such termination to PJM no later than two months prior to the Base Residual Auction for such Delivery Year. An FRR Entity that has terminated its election of the FRR Alternative shall not be eligible to re-elect the FRR Alternative for a period of five consecutive Delivery Years following the effective date of such termination.[1] Therefore, Duke Energy Kentucky would be required to remain as an RPM participant for a minimum of five Delivery Years following the termination of the FRR Alternative.

PERSON RESPONSIBLE: Alan Mok

[1] PJM RAA Schedule 8.1 C.2

AG-DR-01-027

REQUEST:

Reference the Swez testimony at 36:22 – 37:9.

a. Explain whether there could be some PJM billings in which PJM BLI 1600 could be greater than revenues received in PJM BLI 2600. If so: (i) explain whether the Company has conducted any analyses regarding the potential frequency of such occurrences; and (ii) explain whether a hedging product may be necessary to mitigate this risk exposure.

b. Reference further the Swez testimony at 45:22 through 46:4. If due to any unforeseen developments the costs of RPM participation should exceed benefits, explain whether DEK would consider altering the sharing mechanism so that ratepayers receive 100% of all benefits.

RESPONSE:

a. Since the Company uses the IRP planning process to maintain adequate resources to serve the Duke Energy Kentucky customer load, and since all of the Duke Energy Kentucky resources are located in the same DEOK Zone as is a majority of its customer demand, absent a sudden change such as the addition of a large load into the Duke Energy Kentucky service territory or a PJM change similar to the ELCC construct or a change in reserve margin, at higher capacity prices the Company does not anticipate a situation where the charges in BLI 1600 are greater than the revenues in BLI 2600. However, if the clearing were to clear at an extremely low price, such as nearer to zero, then the revenue received in BLI 2600 would likely be less than the charge in BLI 1600. This is due to the fact that the Company doesn't offer generators at a zero price, since there is a non-zero chance of a Capacity Performance charge. The Company employs the use of an "indifference curve" to offer the excess capacity into the BRA today. Thus, in the future under RPM, the Company would typically not offer its generators at a zero price in the BRA since this could be detrimental to customers. For example, suppose that the indifference curve calculates a breakeven price of $10/MW-Day, meaning that at this cleared capacity price, the cost of a capacity performance charge costs the customer *more* than the value received from selling capacity into the PJM auction and receiving the $10/MW-Day revenue. Thus, selling at a low price is detrimental to the customer since they could pay more in capacity performance charges than receive in capacity market revenue, and thus the Company would not employ this strategy in this case the charges received under BLI 1600 could be greater than the revenues received under BLI 2600.

i. Yes. This is precisely what the "Heat Map" represents since the Company's long or short position is shown on the Y-Axis. As this analysis showed, there were 190 different scenarios calculated. The 190 scenarios represent the different combinations of 10 different capacity clearing prices and 19 different Company positions (9 long positions, 9 short positions, and one flat position). Thus, 10 x 19 yields 190 scenarios. If each cell were to be examined, 136 out of 190 scenarios, or 72%, yield an annual savings for the customer from a change to RPM away from FRR.

ii. Since the Company is planning to procure resources as determined by the IRP process, these resources are already a hedge for customers against energy and capacity prices However, in the event that a large customer were to be added faster than a resource could be acquired or constructed, or do to a sudden change in PJM rules such as the recent change in ELCC or a change in reserve margin, or any other reason, the purchase of bilaterial capacity could be needed in the future.

b. This question is interpreted as meaning that ratepayers would receive 100% of all benefits of RPM participation but pay no costs of RPM participation. The Company would not consider altering the sharing mechanism so that the rate payer receives 100% of all benefits and 0% of the costs. If the Company is an RPM participant, the total capacity of the Company's generating resources is offered into PJM and the total capacity requirement is purchased from PJM. If the customer receives all the revenues (benefits) and none of the costs (charges), the customer has not paid for the capacity to fulfill its PJM capacity demand requirements. Therefore, the revenues must be offset by the costs incurred. This is analogous to participation in the PJM energy market, where the total energy generated by the generating resources are sold into PJM and the total load buy is purchased from PJM. If the total generation sold is more than the total load buy, these off-system sales are included in Rider PSM. If the total generation sold is less than the load buy, the difference is a purchase of energy included in Rider FAC.

PERSON RESPONSIBLE: Matthew Kalemba – a.
John Swez – a.
Alan Mok – a.
John Swez – b.
Lisa Steinkuhl – b.

AG-DR-01-028

REQUEST:

Regarding the staff who will monitor PJM RPM developments:

a. Explain whether the staff will be employed by DEK, or Duke Energy Business Services ("DEBS").

b. Explain whether the switch to RPM from FRR will require adding additional personnel, whether with DEK or DEBS.

RESPONSE:

a. There are four primary employees that monitor PJM RPM developments. Three of these employees work for the "Duke Energy Business Services, LLC" Company, and one works for the "Duke Energy Progress, LLC" Company.

b. No additional personnel are anticipated to be needed because of Duke Energy Kentucky's change from RPM to FRR.

PERSON RESPONSIBLE: John Swez

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-029

REQUEST:

Explain whether DEK would be able, if necessary, to meet its native load demand with its own resources, without participating in PJM on either the current FRR or the proposed RPM basis. If DEK has conducted any studies or analyses in this regard, please provide copies of all such items.

a. Does DEK believe the only way it can meet its native load would be through participating in PJM on an RPM basis?

RESPONSE:

If a member of PJM, an entity must participate as either a FRR or RPM capacity construct member. There is no third option.

Duke Energy Kentucky is largely a transmission dependent utility, utilizing the Duke Energy Ohio transmission system. Since the transmission owner makes the decision to participate in an RTO, Duke Energy Kentucky would need to first acquire its own transmission system or have an agreement with Duke Energy Ohio that allows Duke Energy Kentucky to operate outside of PJM. There are a host of additional items that would further need to be addressed, including potential additional metering, payment of transmission expansion costs to PJM, and other issues. Finally, assuming that Duke Energy Kentucky would address the above and any additional issues, due to Duke Energy Kentucky's small size and limited number of generating units, operation outside of another BAA is theoretically possible, but believed to be extremely cost prohibitive. As an example of the additional costs that would be charged to Duke Energy Kentucky customers, absent another agreement with another BAA to manage operating reserves, if the East Bend unit were to be off-line for any reason, including planned maintenance, the new BAA would be required to operate a Woodsdale CT for supply of operating reserves 24 hours a day, 7 days a week until East Bend were returned to service.

a. At the present time, the only practical method Duke Energy Kentucky has to meet its PJM Capacity Requirement is to participate in either the PJM RPM or FRR capacity construct.

PERSON RESPONSIBLE: John Swez

AG-DR-01-030

REQUEST:

Explain whether the increase in prices in PJM's recent Base Residual Auction influenced DEK's decision to file its application in this case, and if so, how. Provide all support for your response.

RESPONSE:

Yes. As stated in testimony, the Company believes that capacity prices, both in PJM, MISO, and other RTOs, as well as outside of RTO's will increase in the future. However, due to Duke Energy Kentucky's relatively stable supply stack, higher capacity prices are an opportunity for Duke Energy Kentucky customers to save move as shown on the right side of the "Heat Map." Please see the "Heat Map" in the Direct Testimony of Witness Swez, as well as discussion regarding the far-right side of the "Heat Map" discussed in the response to AG-DR-01-022.

PERSON RESPONSIBLE: John Swez

AG-DR-01-031

REQUEST:

Explain the basis upon which DEO participates in PJM. Include in your response whether there any plans to change this status. If so, explain why; if not, explain why not. Provide all support for your response.

RESPONSE:

Duke Energy Ohio does not own any generation that is used to serve its load. Duke Energy Ohio participates in PJM by procuring wholesale power through standard service offer (SSO) retail auctions under an electric security plan approved by the Public Utilities Commission of Ohio. Capacity for the SSO is procured through the RPM, and then the SSO auction winners/providers pay PJM for their capacity. This will not be affected by a change in Duke Energy Kentucky's participation status. This process is unlikely to change absent a change in Ohio law.

Duke Energy Ohio is a 9% shareholder in OVEC Corporation. In that ownership, Duke Energy Ohio's share of OVEC capacity is offered into the PJM capacity auctions. Energy offers for OVEC generators are offered to PJM by OVEC, of which Duke Energy Ohio receives 9% of the revenue and pays 9% of the costs associated with this sale. Finally, Duke Energy Ohio pays 9% of the fixed costs associated with OVEC.

PERSON RESPONSIBLE: Bryan Garnett

AG-DR-01-032

REQUEST:

Explain the basis upon which DEI participates in MISO, and whether there is any approximate equivalent to such status in PJM. Include in your response the degree to which DEI participates in MISO auctions. Provide all support for your response.

RESPONSE:

For Energy Markets, Duke Energy Indiana participates in a similar fashion to Duke Energy Kentucky, in that both offer their generation to each RTO in its respective Energy and Ancillary Services Markets.

For Capacity Markets, Duke Energy Indiana participates in the MISO Planning Resource Auction (PRA), the equivalent of the PJM RPM. Duke Energy Indiana does not participate in the MISO equivalent of PJM's FRR, called the Fixed Resource Adequacy Plan (FRAP).

PERSON RESPONSIBLE: John Swez

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-033

REQUEST:

Explain whether Duke (Carolinas) has plans to join PJM, and if so, whether its participation will be on an RPM or FRR basis.

RESPONSE:

Objection. This request is irrelevant, not likely to lead to the discovery of any relevant or admissible evidence. This request is further objectionable as far as it seeks information that is privileged. Without waiving said objection, and to the extent discoverable, no.

PERSON RESPONSIBLE: As to objection, Legal
As to response, John Verderame

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-034

REQUEST:

Has DEK evaluated how much it will pay annually in transmission costs to PJM based on its proposed RPM status? If so, provide the results of all such evaluations, and explain whether that sum represents an increase or decrease. If DEK has not conducted any such evaluations, explain why not.

RESPONSE:

The Company does not anticipate any change in transmission costs from PJM due to the move from the FRR to RPM capacity construct. PJM plans transmission upgrades under the Regional Transmission Expansion Planning (RTEPP) process if the CETL value is less than the CETO value. The CETO and CETL values for DEOK zone are not impacted by the move, thus there is no change in anticipated transmission costs.

PERSON RESPONSIBLE: Alan Mok

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-035

REQUEST:

Can DEK confirm that a portion of the PJM transmission charges it presently incurs based on its current status as an FRR participant includes a share of costs for public policy projects in some other states that have renewable energy portfolio mandates?[1] Explain whether the Company's proposed change to RPM status will, or could increase the amount of any such charges. Provide an estimate of the change in the charges DEK will be responsible to pay under the RPM status.

RESPONSE:

The Company does not anticipate any change in transmission charges from PJM from this proposed change since the load ratio share component of the transmission cost allocation would not change whether being in RPM or FRR.

PERSON RESPONSIBLE: Alan Mok

[1] *See, e.g.,* "Illinois Climate Bill Could Force $2B in Transmission Upgrades, PJM Says," by John Norris, *RTO Insider*, Aug. 14, 2022.

AG-DR-01-036

REQUEST:

In the event the Commission approves the application in the instant case, explain whether DEK intends to generate more or less power from its East Bend coal plant. Provide all support for your response.

RESPONSE:

The decision to participate in the PJM capacity markets as either a FRR or RPM entity has no impact on the actual generation from the East Bend coal plant. The operation of this unit, as the same is true for Woodsdale, is an independent decision that is made in the energy market. Additionally, please see the response to AG-DR-01-002, AG-DR-01-010 through AG-DR-01-013, and AG-DR-01-064.

PERSON RESPONSIBLE: John Swez

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

CONFIDENTIAL AG-DR-01-037
(As to Marked Attachments only)

REQUEST:

For each of the past 10 years, provide the following historical data:

a. Annual peak demand for the DEK system and DEOK zone, and the specific hours when peaks occurred.

b. Annual energy requirement for the DEK system.

c. Annual generation and costs by unit for each of DEK's generating units (costs broken down by fuel, fixed and variable O&M, emissions, etc.).

d. Annual fuel consumption, MBTUs, fuel units, and costs for each of DEK's generating units.

e. Annual DEK bilateral sales and purchases, by purchase and sales categories (MWs, MWhs and costs).

f. Annual DEK off-system sales and purchases by categories (MWs, MWhs and costs).

g. For each of the 10 years, provide DEK's calculation of its reserve margin target as required by PJM.

h. For each of the 10 years, provide DEK's load and resource balance table showing all capacity resources and how DEK satisfied its Reserve Margin requirement.

i. For each of the past 10 years, provide a copy of the FRR capacity plan that the Company submitted to PJM.

RESPONSE:

<u>CONFIDENTIAL PROPRITARY TRADE SECRET</u>
<u>(As to Marked Attachments only)</u>

Objection. This request seeks information that is overly broad and unduly burdensome in scope as seeking ten years or more of data, as well as of public record. Objecting further, this request seeks information that is not relevant to this proceeding nor is it likely to lead to the discovery of any relevant or admissible information. Without waiving said objection and to the extent discoverable, please see the following answers:

a. The annual peak load demand and hour for the Duke Energy Kentucky system can be found in the Duke Energy Kentucky FERC Form 1, page 401b, columns d and f. The annual peak load demand and hour for the DEOK zone can be found in the Duke Energy Ohio FERC Form 1, page 400, columns b and d.

b. See objection. Duke Energy Kentucky does not have an Annual Energy Requirement.

c. Please see AG-DR-01-037 Attachment 1.

d. Please see AG-DR-01-037 Attachment 1.

e. Please see AG-DR-01-037 Attachment 5.

f. Annual Duke Energy Kentucky off-system energy sales in kWh and dollars can be found in the following reviews of Duke Energy Kentucky's application of its Fuel Adjustment Clause (FAC) by the Commission for the 5-year period 2019-2023.

    1. The November and December 2023 sales in kWh and dollars have not been reviewed by the Commission; therefore, they are listed here.

        i. Nov 23: 18,721,060 kWh; $727,192

        ii. Dec 23: 22,291,050 kWh; $831,099

    2. Case No. 2024-00140, STAFF-DR-01-013 Attachment, May 23 – Oct 23

3. Case No. 2024-00148, STAFF-DR-01-013 Attachment, Nov 22 – Apr 23

4. Case No. 2023-00012, STAFF-DR-01-013 Attachment, Nov 20 – Oct 22

5. Case No. 2022-00267, STAFF-DR-01-013 Attachment, Nov 21 – Apr 22

6. Case No. 2022-00040, STAFF-DR-01-013 Attachment, May 21 – Oct 21

7. Case No. 2021-00296, STAFF-DR-01-013 Attachment, Nov 20 – Apr 21

8. Case No. 2021-00057, STAFF-DR-01-013 Attachment, Nov 18 – Oct 20

9. Case No. 2020-00249, STAFF-DR-01-013 Attachment, Nov 19 – Apr 20

10. Case No. 2020-00008, STAFF-DR-01-013 Attachment, May 19 – Oct 19

11. Case No. 2020-00230, STAFF-DR-01-013 Attachment, Nov 18 – Apr 19

Duke Energy Kentucky does not make off-system energy purchases; however, Duke Energy Kentucky does make power purchases from PJM to serve customer load. This purchased power can be found in the monthly Fuel Adjustment Clause (FAC) filings on the FAC Library (ky.gov) website. Purchased kWh can be found on Schedule 3, Section A, of the Duke Energy Kentucky FAC monthly filing. The purchased power costs can be found in Section B of Schedule 2 (Estimates), Schedule 4 (Initial True-Up), and Schedule 6 (Final True-Up) of the Duke Energy Kentucky FAC monthly filing.

See AG-DR-01-037 Attachment 5 for Annual Duke Energy Kentucky off-system capacity purchases and sales in dollars and MWs.

g. Please see AG-DR-01-037 Confidential Attachment 2.

h. Pease see AG-DR-01-037 Confidential Attachment 3.

i. Please see AG-DR-01-037 Confidential Attachment 4.

PERSON RESPONSIBLE: As to objection, Legal
As to response, John Swez
Alan Mok
Lisa Steinkuhl

Duke Energy Kentucky
2024 RPM - Case 2024-00285
AG 1.37

East Bend Unit 2	Fuel Costs ($)	Total Fuel Usage (MMBTu)	Net Actual Generation (MWh)
2019	$ 67,767,903	34,340,517	3,165,500
2020	$ 50,256,155	25,386,946	2,269,190
2021	$ 54,171,470	28,010,832	2,542,673
2022	$ 79,902,243	31,564,779	2,777,700
2023	$ 85,370,908	24,473,365	2,211,385

Woodsdale Unit 1	Fuel Costs ($)	Total Fuel Usage (MMBTu)	Net Actual Generation (MWh)
2019	$ 8,374,379	1,891,638	21,950
2020	$ 2,837,023	1,083,895	8,022
2021	$ 4,420,219	867,793	9,076
2022	$ 14,683,042	1,772,540	20,832
2023	$ 7,811,120	3,129,201	27,175

Woodsdale Unit 2	Fuel Costs ($)	Total Fuel Usage (MMBTu)	Net Actual Generation (MWh)
2019	See NOTE1 for Fuel Costs at Woodsdale	See NOTE$_1$ for Fuel Usage at Woodsdale	24,364
2020			9,110
2021			11,572
2022			20,288
2023			38,257

Woodsdale Unit 3	Fuel Costs ($)	Total Fuel Usage (MMBTu)	Net Actual Generation (MWh)
2019	See NOTE1 for Fuel Costs at Woodsdale	See NOTE$_1$ for Fuel Usage at Woodsdale	28,871
2020			8,643
2021			12,107
2022			214
2023			14,654

NOTE$_1$: Fuel Costs and Usage for Woodsdale are only availabe at a Station Level. The total site costs are included under Woodsdale Unit 1 data

Woodsdale Unit 4	Fuel Costs ($)	Total Fuel Usage (MMBTu)	Net Actual Generation (MWh)
2019	See NOTE1 for Fuel Costs at Woodsdale	See NOTE$_1$ for Fuel Usage at Woodsdale	22,723
2020			9,127
2021			11,492
2022			19,755
2023			35,908

Woodsdale Unit 5	Fuel Costs ($)	Total Fuel Usage (MMBTu)	Net Actual Generation (MWh)
2019	See NOTE1 for Fuel Costs at Woodsdale	See NOTE$_1$ for Fuel Usage at Woodsdale	21,972
2020			9,560
2021			6,402
2022			19,336
2023			39,188

Woodsdale Unit 6	Fuel Costs ($)	Total Fuel Usage (MMBTu)	Net Actual Generation (MWh)
2019	See NOTE1 for Fuel Costs at Woodsdale	See NOTE$_1$ for Fuel Usage at Woodsdale	18,345
2020			10,485
2021			7,140
2022			20,839
2023			37,221

NOTE$_1$: Fuel Costs and Usage for Woodsdale are only availabe at a Station Level. The total site costs are included under Woodsdale Unit 1 data

Station Name	2019	2020	2021	2022	2023
DEK Other	($13,039)	($88,286)	($311,722)	$240,828	($43,564)
East Bend Coal	$50,360,969	$47,008,576	$50,281,246	$46,528,830	$47,434,646
Regional Services & Other	$23,217	$40,403	$73,749	$149,611	$145,136
Woodsdale CT	$5,156,499	$4,288,591	$3,937,812	$3,746,420	$3,905,804
Total O&M	**$55,527,646**	**$51,249,284**	**$53,981,085**	**$50,665,688**	**$51,442,021**

	2019	2020	2021	2022	2023
DEK Annual Total Emission Allowance Expense/Cost	$3,280.19	$962.44	$666.54	$657.93	$401.81

Data from KyPSC ESM Case 2023-00374

CONFIDENTIAL PROPRIETARY TRADE SECRET

AG-DR-01-037
CONFIDENTIAL ATTACHMENTS 2-4

FILED UNDER SEAL

(e.)

DUKE ENERGY KENTUCKY - BILATERAL PURCHASES AND SALES

Line No.	Description	2019	2020	2021	2022	2023
1	Bilateral Sales Revenues	$ -	$ -	$ -	$ -	$ -
2	Bilateral Sales MWs	-	-	-	-	-
3	Bilateral Purchase Costs	$ -	$ -	$ -	$ -	$ 615,080
4	Bilateral Purchase MWs	-	-	-	-	70
5	Bilateral Sales Revenues	$ -	$ -	$ -	$ -	$ -
6	Bilateral Sales MWhs	-	-	-	-	-
7	Bilateral Purchase Costs	$ -	$ -	$ -	$ -	$ -
8	Bilateral Purchase MWhs	-	-	-	-	-

This purchase was a capacity bilateral purchase associated with replacement capacity for the 2022-2023 delivery year.

(f.)

DUKE ENERGY KENTUCKY - OFF-SYSTEM CAPACITY PURCHASES AND SALES

Line No.	Description	2019	2020	2021	2022	2023
1	Capacity Sales Revenues	$ -	$ -	$ -	$ 1,537,235	$ 1,300,148
2	Capacity Sales MWs	-	-	-	100	30
3	Capacity Purchase Costs	$ -	$ -	$ -	$ -	$ -
4	Capacity Purchase MWs	-	-	-	-	-

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

CONFIDENTIAL AG-DR-01-038
(As to Attachment only)

REQUEST:

For each of the next 10 years, provide a projection of the following data, under the assumption that DEK continues as an FRR participant:

a. Annual peak demand for the DEK system and DEOK zone, and the specific hours when peaks are expected to occur.

b. Annual energy requirement for the DEK system.

c. Annual generation and costs by unit for each of DEK's generating units (costs broken down by fuel, fixed and variable O&M, emissions, etc).

d. Annual fuel consumption, MBTUs, fuel units, and costs by each of DEK's generating units.

e. Annual DEK bilateral sales and purchases, by purchase and sales categories (for MWs, MWhs and costs).

f. Annual DEK off-system sales and purchases by categories (for MWs, MWhs and costs).

g. For each of the next 10 years, provide DEK's calculation of its projected required reserve margin target.

h. For each of the next 10 years, provide DEK's projected load and resource balance analysis (showing each owned resource and its seasonal MW capacity and each purchased resource and its seasonal MW capacity) and the resulting reserve margin requirement compared to PJM minimum requirements.

RESPONSE:

<u>CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment only)</u>

a. Please see System Output tab in AG-DR-01-038 Confidential Attachment.

b. Please see System Output tab in AG-DR-01-038 Confidential Attachment.

c. Please see Total Cost to Program Cost tabs in AG-DR-01-038 Confidential Attachment.

d. Please see Fuel Cost and Fuel Usage Tabs in AG-DR-01-038 Confidential Attachment. Fuel usage provided in GBtu (1000x MMBtu).

e. No bilateral sales and purchases modeled.

f. No capacity purchases or sales (MW), see System Output tab in AG-DR-01-038 Confidential Attachment for Purchases and Sales in GWh and total costs/revenues for each.

g. Please see System Outputs in AG-DR-01-038 Confidential Attachment for calculated reserve margin target.

h. Please see Firm Capacity Summer and Firm Capacity Winter tabs in AG-DR-01-038 Confidential Attachment.

PERSON RESPONSIBLE: Matthew Kalemba

CONFIDENTIAL PROPRIETARY TRADE SECRET

AG-DR-01-038
CONFIDENTIAL ATTACHMENT

FILED UNDER SEAL

AG-DR-01-039

REQUEST:

For each of the next 10 years, provide a projection of the following data, under the assumption that DEK becomes an RPM auction participant:

a. Annual peak demand for the DEK system and DEOK zone, and the specific hours when peaks are expected to occur.

b. Annual energy requirement for the DEK system.

c. Annual generation and costs by category for each of DEK's generating units (fuel, fixed and variable O&M, emissions, etc).

d. Annual fuel consumption, MBTUs, fuel units, and costs by each of DEK's generating units.

e. Annual DEK bilateral sales and purchases, by purchase and sales categories (for MWs, MWhs and costs).

f. Annual DEK off-system sales and purchases, by purchase and sales categories (for MWs, MWhs and costs).

g. For each of the next 10 years, provide DEK's calculation of its projected required reserve margin target.

h. For each of the next 10 years, provide DEK's projected load and resource balance analysis (showing each owned resource and its seasonal MW capacity and each purchased resource and its seasonal MW capacity) and the resulting reserve margin requirement compared to PJM minimum requirements.

i. For any future year that the Company has submitted copies of FRR capacity plans or has developed FRR capacity plans, but has not yet submitted those, please provide copies of those plans.

RESPONSE:

For the purpose of IRP modeling there will be modeling differences between FRR and RPM, please see AG-DR-01-038 and confidential attachments for responses.

PERSON RESPONSIBLE: Matthew Kalemba

AG-DR-01-040

REQUEST:

Please provide evidence of the sudden load growth at a rate faster than the Company can construct or acquire additional baseload generation. Provide the old and new load forecasts that show the sudden load growth and provide all assumptions supporting the new load forecast.

RESPONSE:

The Company has not had realized or actual load growth in its service territory at a rate faster than the Company could construct or acquire additional baseload generation. However, the Company is aware of large actual projects that have been announced in other Duke Energy service areas that, if these were to have had been in the Duke Energy Kentucky territory, would have likely been able to become additional demand before additional baseload generation could have been build.

PERSON RESPONSIBLE: John Swez
Matthew Kalemba

AG-DR-01-041

REQUEST:

Please provide a list of potential capacity retirements in the DEOK zone (type of capacity, name of units, date of potential retirements). Explain how the potential retirements of the Company's generating units in the DEOK zone impact the Company's proposal and the cost-benefit, including the increase or decrease in net capacity costs and the revenue requirement impacts on customers to transition from the FRR to RPM construct. Also, explain how the potential retirements of other companies' generating units in the DEOK zone impact the Company's proposal and the cost-benefit, including the increase or decrease in net capacity costs and the revenue requirement impacts on customers to transition from the FRR to RPM construct. Provide all support relied on for your responses.

RESPONSE:

The only expected change the Company is aware of in the DEOK zone in the near future is the announced retirement of the 1,020 MW Miami Fort generating station within the DEOK zone beginning in August 2027. However, 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. Generating unit retirements, either in the DEOK Zone or elsewhere in PJM, generally result in higher capacity prices. Additionally, retirements inside the DEOK Zone can lead to the DEOK Zone separating, causing higher capacity prices within this zone. Additionally, as discussed in the testimony or Mr. Swez, under the FRR construct, the Company may be required to replace a shortfall in its FRR plan with bilateral capacity from inside the DEOK Zone due to the PJM minimum internal requirement.

As shown in the "Heat Map" in the Direct testimony of Mr. Swez, under any position (either short, flat, or long), there is value from being in the FRR construct at low-capacity prices. Thus, for the cells showing a financial value greater than zero, that represents the annual value to the customer from remaining in the FRR. However, as you move to the right (higher capacity prices) under any row, the value from being in the FRR decreases and at some point, it costs the customer more to be in FRR and thus, customer has a financial savings under the RPM capacity construct.

PERSON RESPONSIBLE: John Swez

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-042

REQUEST:

Explain why DEK would want to transition to the RPM and rely on the PJM auction for capacity, at a time when the Company is aware of shrinking reserve margins in PJM and higher capacity prices, which would hurt the Company in purchasing from the market.

RESPONSE:

The Company is not "rely(ing) on the PJM auction for capacity." The Company will retain the resources it has historically used annually to suffice its PJM approved FRR plan. These resources provide a hedge against both capacity and energy costs to our customers. There is no substantive change in the Company's IRP plan under a change from FRR to RPM. Under RPM, the difference is that the Company's customers will be paid for generation that clears the auction, instead of that generation specifically being utilized in the Company's FRR plan. Additionally, the Company will purchase its required amount of capacity due to its customer demand from PJM under RPM as well. Note that today, the Company may sell extra capacity into the PJM BRA or Incremental Auctions; thus, it already participates in these auctions today, albeit on a lesser extent.

The RPM capacity construct saves the Duke Energy Kentucky customer over the FRR PJM capacity construct in a higher capacity price environment. With the potential for customer load growth, 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.

PERSON RESPONSIBLE: John Swez
Matthew Kalemba

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-043

REQUEST:

See paragraph 6 of the Application, which states the Company, ". . . . is limited in its ability to sell any excess capacity in those auctions." Please explain how the Company is permitted to sell excess capacity in the RPM auction, and how it is limited to do so.

RESPONSE:

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) is 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.

Additionally, the amount of excess capacity that the Company can sell into the BRA is also influenced by the amount of reserve margin, which can vary between the Company's participation under FRR than under RPM. 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.

PERSON RESPONSIBLE: John Swez

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-044

REQUEST:

See paragraph 13 of the Application: ". .the Company requests herein a modification to Rider PSM to include the PJM BLIs that the Company will begin being billed by PJM once it commences participation in the RPM BRA and IAs and any costs or revenues in bilateral markets to meet PJM's FERC-approved reliability requirements."

a. Explain the Company's justification for including those two items in Rider PSM.

b. Explain why the Company believes it appropriate to require customers to provide recovery of or receive credit for 100% of these net capacity costs, and not continue the sharing percentage that current is in place.

RESPONSE:

a. The Rider PSM has evolved and been modified by the Commission on multiple occasions. The Commission approved including all capacity market charges net of credits in Rider PSM in Case No. 2017-00321. Since the rider already includes capacity transactions it seemed logical to revise the rider to include new capacity transaction related to participation in the RPM BRA and IAs and bilateral markets to meet PJM's FERC-approved reliability requirements.

b. It is appropriate for customers to receive credit of 100% of the net capacity costs because the customer pays for these generating resources through base rates. It is appropriate for the customer to provide recovery of capacity costs needed in addition to the generating resources because absent moving to the RPM the

Company would have to either build additional generating resources or purchase capacity. As discussed in AG-DR-01-027, the total capacity of the Company's generating resources is offered into PJM and the total capacity requirement is purchased from PJM. Therefore, based on the discussion, the netting of the capacity revenues and capacity costs is appropriate, so the customer receives 100% the net benefit or 100% the net cost.

PERSON RESPONSIBLE: Lisa Steinkuhl
John Swez

AG-DR-01-045

REQUEST:

Refer to paragraph 19 of the Application.

a. Explain why the Company anticipates that transition to the RPM construct will provide greater flexibility to meet the reliability needs of customers, and to respond to unanticipated changes in customer demand.
b. Explain what the FRR minimal zonal capacity requirement is.
c. Explain what risks the Company will take on by transitioning to the RPM construct, and why the Company believes those risks would be less harmful to customers compared to the risks of the FRR discussed in Paragraph 19 of the Application.

RESPONSE:

a. Participation under RPM provides for one additional method of transacting, which is through the PJM capacity auctions, or specifically within the PJM Base Residual Auctions (BRA) and Incremental Auctions (IA). Thus, today the Company can utilize only Company resources and/or bilateral capacity purchases to meet its FRR plan. Under RPM participation, the Company can utilize Company resources, bilateral capacity purchases, or PJM auction purchases to serve its customer capacity requirements. This additional option allows for greater flexibility to meet the reliability needs of customers, including responding to unanticipated changes in customer demand.

b. The FRR minimal zonal capacity requirement for Duke Energy Kentucky is the minimum amount of local capacity resource in DEOK Zone (and EKPC zone for Longbranch load) in the FRR Capacity Plan. PJM expressed this requirement as a percentage of the Duke Energy Kentucky's load obligation in the DEOK (and EKPC) Zone. The requirement is updated by PJM for every BRA and Incremental Auction. The requirement for DEOK zone has varied from as high as 45% to as low as 4%. There is no internal resource requirement in EKPC zone because EKPC zone is not explicitly modeled as a separate LDA.

c. The only additional risk the Company would assume by transitioning to the RPM construct results from no longer being able to choose the physical option of the Capacity Performance Non-Performance Assessment available under FRR. This physical option of capacity performance compliance is available only to FRR participants, but not available to RPM participants. Please refer to the direct testimony of Mr. Swez starting on page 31, line 19 through page 32, line 15.

    For example, Duke Energy Kentucky, as an FRR entity in PJM, elected the physical option of the Capacity Performance Non-Performance Assessment for resources committed to the 2022/2023 Delivery Year's FRR Capacity Plan.

    For the Non-Performance Assessment under the FRR physical option, the Company received a total 1.2 MW assessment related to Winter Storm Elliott. Thus, the Company committed an additional 1.2 MW of capacity in the 2023/2024 Delivery Year FRR Plan instead of paying a capacity performance financial penalty.

Zonal separation could be a risk of RPM participation for other entities besides Duke Energy Kentucky, but it is not a risk since all Duke Energy Kentucky resources are in the same zone (DEOK Zone) as the Company load. Thus, if the DEOK Zone separates out at a higher price while DEK is under the PJM RPM capacity construct, the load pays more capacity cost, but the generation receives more capacity revenue. Thus, the two cash flows offset.

The risks the Company avoids by not being a member of FRR, as described in the direct testimony of Mr. Swez, are (1) Risk of zonal separation for the DEOK zone and a resulting inability to purchase bilaterial capacity from outside of the DEOK Zone, causing an FRR plan penalty, (2) Risk of large and sudden load growth at a rate faster than the Company can construct or acquire additional baseload generation and/or inability to purchase bilaterial capacity, causing an FRR plan penalty.

Finally, other risks could impact both FRR and RPM, such as PJM "stroke of pen risk" like the transition to the PJM Effective Load Carrying Capability (ELCC), but depending on the changes, tend to impact FRR and RPM approximately equally.

PERSON RESPONSIBLE: John Swez – a., c.
Alan Mok – b.

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-046

REQUEST:

See paragraph 20 of the Application. If the Company were to continue as an FRR participant, why does the Company necessarily believe it would have to accept a large energy intensive customer locating in its service territory if the Company did not have sufficient capacity to serve that customer?

RESPONSE:

Objection. Calls for legal opinion. Without waiving said objection, and to the extent discoverable, see KRS 278.018, 278.030, 278.280.

PERSON RESPONSIBLE: Legal

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

CONFIDENTIAL AG-DR-01-047
(As to Attachment (c) only)

REQUEST:

Refer to Witness Swez's direct testimony at p. 8:

a. Explain how the 9.3 MW of nameplate solar capacity was determined to be considered net firm summer capacity of 3.9 MW. Please show the calculations used to determine that capacity accreditation.

b. What is the net firm winter capacity value for that solar capacity and how would it be determined?

c. Provide a description of the Company's demand response program capacity and the capacity accreditation value (summer and winter net firm capacity).

d. Provide information about all potential bilateral capacity purchases Mr. Swez was referring to at line 11.

RESPONSE:

<u>CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment (c) only)</u>

a. Please refer to AG-DR-01-047 Attachment. The net firm summer capacity is calculated using an assumed 42% contribution factor. Please note that PJM does not use the net firm summer and winter capacity for behind the meter generation (BTMGs). PJM incorporates the capacity contribution of the BTMGs in Duke Energy Kentucky's load forecast.

b. Please refer to AG-DR-01-047 Attachment.

c. Please refer to AG-DR-01-047(c) Confidential Attachment.

d. In line 11 of the direct testimony of Mr. Swez, "potential bilateral capacity purchases are utilized to meet the capacity load obligation from the Company's customers under the FRR" means any additional bilateral capacity purchases made by the Company that may be needed to satisfy the Company's FRR plan.

PERSON RESPONSIBLE: Alan Mok – a., b.
Drew Scatizzi – c.
John Swez – d.

Solar Reosurce	Name Plate (MW)	Summer Contribution to Peak %	Summer Firm Capacity	Winter Contribution to Peak %	Winter Firm Capacity
Walton 1	2.0	42%	0.8	0	0
Walton 2	2.0	42%	0.9	0	0
Crittenden	2.7	42%	1.1	0	0
Aero	2.5	42%	1.1	0	0
Total	9.3		3.9		0

CONFIDENTIAL PROPRIETARY TRADE SECRET

AG-DR-01-047(c)
CONFIDENTIAL ATTACHMENT

FILED UNDER SEAL

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-048

REQUEST:

Refer to Witness Swez's direct testimony at p. 10:4, which mentions future zonal separation. Please provide background and explain this situation further.

RESPONSE:

Please see the response to AG-DR-01-022.

PERSON RESPONSIBLE: John Swez

CONFIDENTIAL AG-DR-01-049
(As to Attachment only)

REQUEST:

Refer to Witness Swez's direct testimony at p. 14:18, and provide evidence that DEK's typical long capacity position has been 9%. Show evidence of the long position, and what length of time that has been typical.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment only)

The typical long capacity position in the testimony refers to the average historical excess capacity. While the Company's capacity position fluctuates every year due to the change in generation capacity accreditation and load obligation, the average excess capacity is roughly 9% in the last five years. Please see AG-DR-01-049 Confidential Attachment.

PERSON RESPONSIBLE: Alan Mok

CONFIDENTIAL PROPRIETARY TRADE SECRET

AG-DR-01-049
CONFIDENTIAL ATTACHMENT

FILED UNDER SEAL

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-050

REQUEST:

Refer to Witness Swez's direct testimony at p. 15:18, which explains that if market capacity costs were high, and DEK has a long capacity position that would lead to negative financial consequences if DEK were to remain an FRR participant. Explain this result further, as it seems counter-intuitive. In other words, if DEK has excess capacity and market costs are high it seems DEK would make a profit selling the excess capacity in the capacity market. Is the explanation related to the holdback provision required for FRR participants?

RESPONSE:

If Duke Energy Kentucky were to remain in the FRR capacity construct and were to be long, assuming that the Company continues to offer this excess capacity and it clears the PJM BRA and incremental auctions, Duke Energy Kentucky would receive additional revenue from these capacity transactions. The Companies analysis is not suggesting otherwise. However, what the analysis shows is that if Duke Energy Kentucky were to transition to RPM, remain long, and buy the required capacity to serve its customer demand, offer and sell its capacity into the PJM BRA and incremental auctions, Duke Energy Kentucky would receive a net additional revenue than that it would receive by remaining in FRR. Thus, the analysis doesn't say that Duke Energy Kentucky wouldn't have additional revenue under FRR with high-capacity prices and a long position, it says that Duke Energy Kentucky would have ***more*** net revenue under RPM with high-capacity prices and a long position.

For example, if one examines a 9% long position and $300/MW-Day capacity price on the “Heat Map” in Attachment JDS-1, a value of -$1,644,143 is shown. This means that Duke Energy Kentucky benefits by $1,644,143 additionally annually from RPM participation over FRR participation. The actual amount of additional revenue in this situation is $13,230,009 under RPM and $11,585,867 under FRR; thus, the difference of $1,644,143 shown in the “Heat Map.” Being in the FRR is beneficial to the customer, but being in the RPM is ***more*** beneficial to the customer.

PERSON RESPONSIBLE: John Swez

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-051

REQUEST:

Refer to Witness Swez's direct testimony at p. 18, and provide the Company's logic for the assumptions selected associated with replacement capacity costs discussed between lines 9 and 14. Similarly provide the same for the subsequent incremental auction assumptions discussed between lines 15 and 18.

RESPONSE:

Lines 9-14:

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

The assumptions made on lines 9-14 were based on the Company's experience from engaging in bilateral market capacity transactions. A reasonable expectation was made about the ability to procure bilateral capacity within the DEOK Zone in the future, after retirement of generating units inside of the DEOK Zone.

Lines 15-18:

Relationship between the BRA and subsequent incremental auctions:

- Incremental auction clearing price = 50% x BRA clearing price

The actual historical relationship between the PJM BRA and 3rd incremental auction over the past 6 auctions is 41%, shown below. The assumption of a 50% relationship between BRA and incremental auctions was adjusted upward from historical results; the Company believes that 3rd incremental prices will increase over time, similar to it view of BRA prices. Note that the "Heat Map" can be updated with the actual historical results by changing cell B21 on the Inputs tab to 41%. After this, the "Heat Map" will now use this historical relationship between BRA and Incremental auctions in the calculations. Since the values in the "Heat Map" become more negative after thus change, there is more value to move to RPM from this update, not less.

Delivery Year	BRA	3rd Incremental Auction	Percent 3rd IA is below BRA
2019/2020	$ 100.00	$ 28.35	28%
2020/2021	$ 130.00	$ 10.00	8%
2021/2022	$ 140.00	$ 20.55	15%
2022/2023	$ 71.69	$ 19.00	27%
2023/2024	$ 34.13	$ 37.53	110%
2024/2025	$ 96.24	$ 58.00	60%
			41%

PERSON RESPONSIBLE: John Swez

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-052

REQUEST:

Refer to Witness Swez's direct testimony at p. 18:7, which states that Table 2 shows a graphical representation of the reserve margin. Provide all workpapers, electronically with all formulae intact used to create that table.

RESPONSE:

There were no excel spreadsheet other workpapers with formulae intact that were used to create this table. Table 2 was constructed from information supplied by PJM. Please refer to the response to STAFF-DR-01-011 for a complete description of the PJM Variable Resource Requirement (VRR) curve.

PERSON RESPONSIBLE: John Swez
Bryan Garnett

AG-DR-01-053

REQUEST:

Refer to Witness Swez's direct testimony at p. 23:14. Provide the analysis that determined the current year's zonal requirement is 4.4%, and the previous yearly requirement was 29.3%.

RESPONSE:

The internal resource zonal requirement is to ensure that internal committed capacity plus imported capability can meet the LDA's reliability requirement. Based on PJM's planning parameters for the capacity, the internal resource zonal requirement can be viewed as (Reliability Requirement less CETL) divided by the zonal capacity obligation. The internal requirement for DY 2025/2026 decreases from 29.3% to 4.4% from the previous year due to:

1. Decrease in Reliability Requirement less CETL from 1661 MW to 209.1 MW
2. Decrease in DEOK zonal capacity obligation from 5682.2 MW to 4721.7 MW

The decrease is primarily due to the implementation of ELCC capacity accreditation in DY 2025/2026. Please refer to AG-DR-01-053 Attachment for the analysis.

PERSON RESPONSIBLE: Alan Mok

Attachment AG-DR-01-053: Internal Resource Requirement Calculation

	2024/2025 3rd IA	2025/2026 BRA
CETO (MW)	3120	2797
CETL (MW)	4999	5387
Reliability Requirement (RR) MW	6660	5596.1
Peak Load Forecast - DEOK (MW)	5087	5030
FPR	1.117	0.9387
RR - CETL	1661	209.1
Peak Load * FPR	5682.2	4721.7
Internal Requirement (%)	29.2%	4.4%

Based on PJM Planning Parameters for DY 2025/2026 BRA and 2024/2025 3rd IA

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-054

REQUEST:

Refer to Witness Swez's direct testimony at p. 25, specifically the flowchart in Table 3. Provide any spreadsheets that were constructed that used the flowchart shown in that Table. Provide this electronically, with all formulae intact and no pasted values.

RESPONSE:

The Table 3 flowchart from Witness Swez's direct testimony was created directly from discussion in a working meeting where multiple persons participated, and the output was drawn on a whiteboard. There was no spreadsheet or anything else used to create this table.

PERSON RESPONSIBLE: John Swez

AG-DR-01-055

REQUEST:

Given that the heat map analysis appears to be strictly based on analyses of capacity impacts, explain why the Company did not consider energy cost impacts. For example, if the Company had excess capacity such as 9%, that would allow the Company to sell the capacity bilaterally, and would allow the Company to sell more energy in the PJM energy market, which would provide customer benefits. Please explain why these types of impacts were not evaluated.

RESPONSE:

The energy benefit from off-system sales is not impacted from the Company's decision to participate in either the PJM FRR or RPM capacity construct. This energy benefit will occur in the same manner, independently from the capacity decision. Please see the responses to AG-DR-01-011 through AG-DR-01-013 and AG-DR-01-064.

PERSON RESPONSIBLE: John Swez

AG-DR-01-056

REQUEST:

Refer to Witness Swez's direct testimony at p. 32, which states: "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."

a. Please provide evidence/support for the statement the FRR physical penalty option tends to be a lower cost alternative than the financial option.

b. Provide evidence/support for the statement that in 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."

RESPONSE:

a. The Non-Performance Charge is calculated as the Performance Shortfall multiplied by the Non-Performance Charge Rate. Under the financial option, the Non-Performance Charge Rate is equal to the modeled LDA Net CONE ($/MW-Day in installed capacity terms) times the number of days in Delivery Year divided by 30 divided by intervals in an hour[1].

Under the physical option, the net Performance Shortfall for each interval is multiplied by a rate of 0.00139 MWs per Performance Assessment Interval. i.e., 0.5 MWs/30 PAHs/12 intervals per hour to establish the additional MW that such

[1] Refer to Section 8.4A of PJM Manual 18

FRR Entity must add to its FRR Capacity Plan for the following Delivery Year. The Company has to either self-supply the additional MW or purchase the additional capacity in the bilateral market (subject to the minimal local zonal requirement). Assuming a low-capacity auction price environment, the cost of the bilateral capacity transaction or the value of the self-supplied capacity is close to the auction clearing price.

For example, in referring to the response to AG-DR-01-045, During Winter Storm Elliott under the physical option, the Company had a 1.2 MW FRR impact to the 2023/2024 Delivery Year FRR Plan. In a low-capacity price environment, this 1.2 MW additional capacity replacement cost is very low. However, as capacity prices go higher, the cost of the physical option increases as the price of capacity increases.

As a result, the physical option tends to be a lower cost option than the financial option, which is based on the Net CONE, at lower clearing prices. As auction clearing prices increase to levels near the price of CONE, the cost of the physical option increases.

Finally, it should be noted that there are no capacity performance bonus payments available for resources committed in an FRR Plan.

b. Please refer to AG-DR-01-056 Attachment for an example of the impacts of choosing the Financial vs. Physical Capacity Performance Option for the 2025/2026 PJM Delivery year. This analysis shows that the Physical Option capacity performance cost impact will be approximately equal, or even more expensive, in future delivery years than the Financial Option.

Referring to AG-DR-01-056 Attachment, this analysis calculates the cost impact under both the financial and physical options for the loss of East Bend for 45 hours, or approximately two days, under a capacity performance event.

- Under the financial penalty option, the capacity performance penalty is $44,297,053.
- Under the physical penalty option available under FRR, there are two scenarios, a low replacement price scenario and a market replacement price scenario:
    - Under the physical penalty option <u>low</u>-replacement price scenario, the cost of the replacement capacity (or reduction in value of any excess capacity sold into the BRA) is a cost of $22,148,526. However, this assumption uses a low replacement capacity cost of $162.14/MW-Day, or the current value of Net CONE. Since the current bilaterial market *bid* price of capacity is substantially higher at $300/MW-Day, this cost is understated.
    - Under the physical penalty option <u>market</u>-replacement price scenario, the cost of the replacement capacity (or reduction in value of any excess capacity sold into the BRA) is a cost of $44,297,053. This assumption uses the approximate current bilaterial market price of capacity of $324.28/MW-Day. As mentioned previously, the current bid price for

capacity is $300/MW-Day, so the likely transaction price would be likely slightly above this price.

Since the Company expects a continued environment of higher capacity prices, capacity performance costs under either the physical or financial capacity performance options are currently approximately equal. If capacity prices go higher than the current market price levels, the physical option becomes the more expensive option.

PERSON RESPONSIBLE: Alan Mok
John Swez

<u>Financial vs Physical Penalty Option in DY 2025/2026</u>

For East Bend 600 MW Outage

Committed ICAP	600	
Accredited UCAP Factor	0.8316	
Committed UCAP	499.0	
DEOK LDA Net CONE $/MW-Day, ICAP	$ 162.14	source: (https://www.pjm.com/markets-and-operations/rpm.aspx)
DEOK Max Clearing Price	$ 444.26	Highest price point on DEOK LDA VRR Curve
Number of CP Hours	45	

Financial Option	
Financial Penalty Rate ($ per PA Hour)	$ 1,972.70
Total Financial Penalty ($ per PA Hour)	$ 984,378.96
Total Finacial Penalty	$ 44,297,053.35

Physical Option (Replacement Rate = Net CONE)	
Physical Penalty Rate (MW per PA Hour)	0.016666667
Total Penalty (MW per PA Hour)	8.3
Total Physical Penalty (MW)	374.3
Replacement Rate ($/MW-Day)	$ 162.14
Assume Net CONE Replacement Cost	$ 22,148,526.68

Physical Option (Replacement Rate = $324.28)	
Physical Penalty Rate (MW per PA Hour)	0.016666667
Total Penalty (MW per PA Hour)	8.3
Total Physical Penalty (MW)	374.3
Replacement Rate ($/MW-Day)	$ 324.28
Assume $324.28 Replacement Cost	$ 44,297,053.35

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-057

REQUEST:

Refer to Witness Steinkuhl's direct testimony at p. 7:16-21 wherein she states: ". . . the Company is requesting authorization to change the sharing percentage for these net capacity transactions (revenues and costs) separately from other Rider PSM components with customers to receive 100 percent of the net benefit or cost of participation in the PJM capacity auctions and capacity transactions in the bilateral markets to meet PJM's FERC-approved reliability requirements."

a. For each of the BLIs specified in the CAP term as shown in Attachment LDS-1 page 2 of 3, explain why the Company believes the allocations should be 100% to customers and 0% to the Company rather than 90% to customers and 10% to the Company or some other lesser allocation to customers and greater allocation to the Company.

b. For BLIs 1600 and 2600, explain why the Commission should modify the allocation to 100% to customers and 0% to the Company from the present 90% to customers and 10% to the Company.

RESPONSE:

a. All the BLIs specified in the CAP term should be allocated the same way as they are all related to meeting PJM's FERC-approved reliability requirement. Please see the response to AG-DR-01-044(b) for the Company's reasoning for allocating 100% to customers.

b. In Case No. 2017-00321, the Commission authorized a change in Rider PSM to streamline it administration and calculation which approved the sharing of BLIs 1600 and 2600 90% to customers and 10% to the Company. Please see the response to AG-DR-01-044(b) and AG-DR-01-057(a) for the Company's reasoning for changing the allocation of these PJM BLIs to 100% to customers.

PERSON RESPONSIBLE: Lisa Steinkuhl

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-058

REQUEST:

In the event the Company retires existing capacity, the cost of which is recovered through base rates and replaces the capacity in the BRA/IA, the cost of which will be recovered through the PSM rider, confirm this circumstance could result in excess recovery of costs that no longer will be incurred. Explain your response and provide all support relied on for your response. In addition, provide a proposal that would ensure there is no excess recovery in this circumstance.

RESPONSE:

Objection, this question is vague and ambiguous as it relates to the phrase "confirm this circumstance could result in excess recovery of costs that no longer will be incurred." Without waiving said objection, and to the extent discoverable, if any double recovery occurred, the Company could reconcile that through Rider PSM.

PERSON RESPONSIBLE: As to objection, Legal
As to response, Sarah E. Lawler

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-059

REQUEST:

In the event the Company retires existing capacity and replaces the capacity in the BRA/IA, confirm that such purchases would essentially self-effectuate the Company's decision and ensure the related recovery of the costs incurred through the PSM in lieu of seeking a CPCN for replacement capacity from the Commission. Provide a proposal that includes relevant safeguards to ensure the Commission retains oversight over the Company's decision to replace the capacity in the BRA/IA and recover the costs incurred through the PSM rather than through owned capacity or bilateral agreements to purchase the capacity and recover the costs through the base revenue requirement or through a PPA type of rider.

RESPONSE:

Objection. This request calls for speculation and guesswork. This request is further objectionable insofar as it seeks legal analysis and opinion. Without waiving said objection and to the extent discoverable, nothing in the Company's application in this proceeding impacts the Commission's authority or Kentucky energy policy as set forth in KRS 278.020 and KRS 278.264, respectively. Answering further, a change from participation from an FRR to RPM capacity construct member has no implication to the existing IRP planning process. The Company continues to believe owning resources is both an effective energy and capacity hedge for its customers.

PERSON RESPONSIBLE: As to objection, Legal
As to response, John Swez

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-060

REQUEST:

Confirm that net capacity purchases in the BRA/IA are subject to greater cost volatility compared to owned capacity or bilateral agreements to purchase the capacity. Explain how the Company plans to mitigate the risk of the greater cost volatility from net capacity purchases in the BRA/IA that will be reflected in the PSM rider charges to customers. In your explanation, address whether there is value in limiting the net capacity purchases in some manner to limit the cost volatility on customers.

RESPONSE:

Deny. The Company has a relatively balanced capacity portfolio. Thus, it has a naturally hedged position in place because its generation capacity gets paid the same capacity clearing price by PJM as the price its load pays to PJM in BRA/IA auctions. If generation capacity quantity matched that of load obligation, revenue received from PJM would completely offset load cost paid to PJM. In reality, the Company would either have a small, long capacity position or a small, short position. Such a residual position would be settled at the auction clearing price. In recent years, the Company had slightly more capacity from generation than load capacity obligation, or a slightly long capacity position.

Because FRR entities have restricted access to PJM capacity auctions, the Company's customers are subject to similar or greater volatility in the FRR as opposed to RPM. Risks of FRR participation are discussed in the direct testimony of Mr. Swez, particularly the FRR deficiency penalty. For example, if for some reason in a year East

Bend is limited to a capacity value of only 300 MW, the Company would be approximately 150 MW to 200 MW short for its FRR plan. Since an FRR entity is not permitted to purchase capacity in PJM auctions, the Company would be forced to go out and procure this much additional replacement capacity in the bilateral market to avoid FRR deficiency penalty. Per past experiences and observations over the years, sellers in bilateral market typically try to sell capacity at a price at least equal, and likely at a premium, to the expected price that PJM auction would clear. On the other hand, in RPM, the Company would have unrestricted access to PJM capacity auctions, in addition to bilateral markets. It has the option to decide how much capacity to procure as bilateral purchases and how much capacity any to buy in the PJM auction. With more available tools to use, participation RPM provides the Company with more effective ways to manage customers' risk.

Under the FRR or RPM, the Company will continue to actively manage its capacity position and would continue to engage in bilateral transactions that reduce customer volatility and risk.

As shown in the Company's analysis and testimony, transition to RPM reduces risk, introduces more methods to reduce volatility, and reduces customer costs.

PERSON RESPONSIBLE: John Swez
Jim McClay

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-061

REQUEST:

Refer to Witness Steinkuhl's direct testimony at p. 7:11-13 wherein she states: "The Company is also requesting authority to amend its Rider PSM to include any capacity transactions in bilateral markets to meet PJM's reliability requirements."

a. Provide a more detailed explanation of this request, including the circumstances pursuant to which the recovery for such capacity transactions would be excluded from the base revenue requirement and instead recovered through the PSM rider.

b. Confirm that this request results in a significant change in the form of recovery, shifting from recovery through the base revenue requirement, in which base rates are reset infrequently and at multiple year intervals compared to recovery through the PSM rider on a monthly basis, essentially ensuring nearly real-time recovery of capacity costs similar to the recovery of fuel and economy energy purchases through the FAC on a monthly basis. If confirmed, explain why the Company believes this significant change in the form of recovery is justified.

c. Confirm that capacity costs recovered through the base revenue requirement are allocated on production demand, unlike the costs recovered through the PSM rider, which are allocated on energy. If confirmed, explain why the Company believes this significant change in the allocation of capacity costs is justified.

RESPONSE:

Currently, bilateral capacity market purchases to meet the Company's three-year FRR requirement are recovered in Rider PSM, not base rates, as approved by the Commission in Case No. 2017-00321.

a. Denied. This request does not result in a change in recovery.

b. As stated in (a) above, capacity transactions in the bilateral market are currently included in Rider PSM so the costs are billed to customers based on kWh.

PERSON RESPONSIBLE: Lisa Steinkuhl

AG-DR-01-062

REQUEST:

In the event the Commission approves the application in the instant case, explain whether the change to RPM status will increase DEK's share of RTEP costs.

RESPONSE:

Since the RTEP costs depend on the load ratio share component of the transmission cost allocation in RTEP, the Company does not believe that there is any difference in RTEP costs from its decision from being either in the RPM or FRR PJM capacity construct.

PERSON RESPONSIBLE: Alan Mok

AG-DR-01-063

REQUEST:

Explain whether DEK would be required to pay all or any portion of uplift charges in the event the change to RPM status is approved.

RESPONSE:

There is no known recurring or one-time uplift costs or charges to Duke Energy Kentucky from the transition from the FRR to RPM capacity construct.

In addition, Duke Energy Kentucky already pays for its share of the PJM's monthly capacity market operating expenses under Billing Line Item 1305, "PJM Scheduling, System Control and Dispatch Service - Capacity Resource/Obligation Mgmt." A further review the 1000 series PJM Billing Line items (charges) contained in the direct testimony of Mr. Swez on pages 37, line 13 through page 40, line 19 show no additional administration charges related to operation of the PJM capacity market.

PERSON RESPONSIBLE: John Swez

AG-DR-01-064

REQUEST:

Explain whether the proposed change to RPM status will have any impact on DEK's fuel costs.

RESPONSE:

Since there is no impact to the commitment nor dispatch of any generating unit in the PJM Energy Market as a result of the Company's move from the FRR to RPM capacity construct, there is no change to the Company's fuel costs. Please see the responses to AG-DR-01-010 through AG-DR-01-014.

PERSON RESPONSIBLE: John Swez

Duke Energy Kentucky
Case No. 2024-00285
AG First Set of Data Requests
Date Received: October 7, 2024

AG-DR-01-065

REQUEST:

Explain whether the proposed change to RPM status is expected to have any impact on DEK's credit status.

RESPONSE:

The proposed change to RPM is not expected to have any impact (positive or negative) to Duke Energy Kentucky's credit ratings or outlook.

PERSON RESPONSIBLE: Thomas J. Heath, Jr.