COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR (1) AN ADJUSTMENT OF ELECTRIC RATES; (2) APPROVAL OF NEW TARIFFS; (3) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND (4) ALL OTHER REQUIRED APPROVALS AND RELIEF	)	**Case No. 2022-00372**

DIRECT TESTIMONY OF

SARAH SHENSTONE-HARRIS

ON BEHALF OF SIERRA CLUB

PUBLIC VERSION

MARCH 10, 2023

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR (1) AN ADJUSTMENT OF ELECTRIC RATES; (2) APPROVAL OF NEW TARIFFS; (3) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND (4) ALL OTHER REQUIRED APPROVALS AND RELIEF	))))))))	**Case No. 2022-00372**

AFFIDAVIT OF SARAH SHENSTONE-HARRIS
IN SUPPORT OF DIRECT TESTIMONY ON BEHALF OF SIERRA CLUB

Commonwealth of)
Massachusetts)

Affiant Sarah Shenstone-Harris, being first duly sworn, states the following: The prepared Direct Testimony and associated exhibits filed herewith on Friday, March 10, 2023, constitute the direct testimony of Affiant in the above-captioned case. Affiant states that she would give the answers set forth in her Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of her knowledge, her statements made are true and correct.

____
Sarah Shenstone-Harris

SUBSCRIBED, ACKNOWLEDGED, AND SWORN to before me by Sarah Shenstone-Harris on this 8th day of March, 2023.

____
Notary Public

Notary ID No.: __________________

My Commission expires:

JENNIFER MARUSIAK
Notary Public, Commonwealth of Massachusetts
MY COMMISSION EXPIRES MAY 4, 2029

TABLE OF CONTENTS

LIST OF EXHIBITS

SSH-1: Resume of Sarah Shenstone-Harris

SSH-2: Public Company Responses to Data Requests

SSH-3: Confidential Company Responses to Data Requests

SSH-4: Supporting Materials

LIST OF FIGURES

LIST OF TABLES

1. INTRODUCTION AND SUMMARY

Q Please state your name and occupation.

A My name is Sarah Shenstone-Harris. I am a Senior Associate at Synapse Energy Economics, Inc. ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q Please summarize your work experience and educational background.

A I provide research, analysis, and consulting services on various electricity-sector issues, including integrated resource planning and clean energy project evaluation. Prior to joining Synapse, I worked at Reading Municipal Light Department, one of Massachusetts's largest municipally owned utilities, as an Integrated Resource Analyst. I helped manage Reading Light's energy portfolio and secured reliable and cost-competitive long-term power contracts. I led the rate increase process and the design of new rate structures, such as a residential electric vehicle ("EV") time-of-use rate. I was also involved in the administration and development of numerous energy efficiency and electrification programs, including incentive programs for air-source heat pumps and EV chargers, among others.

I received a Master of Science in Environmental Sustainability from the University of Ottawa's Institute for the Environment, as well as a Bachelor of Science in Biology from Queen's University in Kingston, Ontario, Canada.

A copy of my current resume is attached as Exhibit SSH-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Have you testified previously before the Kentucky Public Service Commission ("Commission")?

A No.

Q What is the purpose of your testimony in this proceeding?

A I review Duke Energy Kentucky's ("Company" or "DEK") proposal to update East Bend Generating Station's ("East Bend") depreciation schedule. I evaluate East Bend's recent historical economic performance and its likely economic performance going forward. I provide recommendations for East Bend's retirement date and for DEK to evaluate the use of depreciation financing to minimize risks and costs for ratepayers. Additionally, I review the Company's proposed rate increases and evaluate their potential impact on EV adoption.

Q How is your testimony structured?

A In Section 2, I summarize my findings and recommendations for the Commission.

In Section 3, I describe East Bend and discuss DEK's selection of East Bend's 2035 retirement date. I recommend DEK retire the plant by 2030, at the latest.

In Section 4, I review East Bend's historical and future economic performance based on the Company's own data. I evaluate the assumptions DEK relied on in its own assessment of East Bend's future performance. I outline costs DEK can avoid if it retires East Bend and replaces it with alternatives. I also summarize the risks DEK is subjecting ratepayers to by continuing to operate a generation fleet that is so heavily reliant on coal.

In Section 5, I discuss ratepayer-backed securitization and other tools available to DEK to mitigate potential rate shock impacts associated with the early retirement of East Bend.

In Section 6, I review the proposed changes to the Residential Time-of-Use Critical Peak Pricing Rate ("Rate RS-TOU-CPP"), the Time-of-Day Rate for Service at Distribution Voltage ("Rate DT"), and the Load Management Rider ("Rider LM"). I evaluate the impact of these rates on customer bills and demonstrate that these proposed changes undermine DEK's stated intent of increasing EV adoption and directing charging load to periods of low demand.

Q What documents did you rely on for your analysis, findings, and observations?

A My analysis relies primarily on the workpapers, exhibits, and discovery responses of Duke Energy witnesses in this proceeding. I also rely on public information from other Kentucky Public Service Commission proceedings and other publicly available documents.

2. FINDINGS AND RECOMMENDATIONS

Q Please summarize your findings.

A My primary findings are:

1. Between 2018 and 2021, East Bend incurred costs in excess of its market energy revenue and capacity value. These excess costs have been passed on to DEK ratepayers.

2. DEK has not demonstrated the prudence of continuing to invest in and operate East Bend through to its current retirement date. My analysis shows that East Bend is not expected to be economic going forward, under reasonable assumptions about the future, and that ratepayers would likely be better off retiring the plant by 2030.

3. DEK and its ratepayers can avoid capital expenditures and operations and maintenance ("O&M") costs and mitigate the risks associated with relying heavily on coal by retiring East Bend earlier than 2035.

4. The Company's projections of the future costs required to operate and maintain East Bend are unrealistically low and lack transparency.

5. The analysis that Duke used to support its ongoing operation of East Bend is at minimum two years old, and it relies on outdated assumptions that pre-date the federal Inflation Reduction Act ("IRA") and current market conditions.

6. There are alternative financing mechanisms available to DEK that would enable the Company to recover the value of East Bend, while avoiding rate shocks to customers that could result from an early retirement.

7. The proposed changes to Rider LM and Rate DT will result in EV customers paying more than their fair share of costs for off-peak charging and will reduce incentives to shift load to off-peak hours, resulting in less efficient use of the grid.

Q Please summarize your recommendations.

A Based on my findings, I recommend the following:

1. Duke Energy should commit to retiring East Bend by 2030 to reduce costs and avoid risks for DEK ratepayers.

2. Before any other future rate cases, fuel dockets, or other regulatory proceedings involving any of DEK's generating assets, the Commission should require DEK to conduct more appropriate and accurate electricity system modeling and forecasting of East Bend's economic and operational performance.

3. The Commission should require DEK to provide more clear and consistent accounting of historical and projected future costs associated with operating East Bend including variable O&M, fixed O&M, and sustaining capital expenditures.

4. The Commission should order the Company, as part of its next Integrated Resource Plan ("IRP"), to evaluate the economics of retiring the plant early (2030 or 2035) and using securitization to finance the remaining balance. This would minimize the rate shock to customers while still allowing DEK to recover the capital it invested in the plant.

5. To encourage transportation electrification and maximize benefits for all customers, the Commission should require the Company to maintain the use of time-varying volumetric rates for the recovery of distribution costs

for Rate DT, rather than shifting these costs to a non-coincident demand charge. The Commission should also reject the changes to Rider LM, and only apply demand charges to on-peak hours.

3. Duke Energy Kentucky plans to retire East Bend in 2035 and seeks to align its depreciation schedule to this retirement date

i. DEK plans on retiring East Bend in 2035 and seeks to align its depreciation schedule to this new date

Q What is Duke Energy requesting in this docket relating to East Bend?

A Duke Energy is requesting approval to align East Bend's depreciation schedule with its planned retirement date of 2035.[1]

Q What is the application test-year?

A The application test-year is the future 12-month period from July 1, 2023, to June 30, 2024.[2]

Q Please provide an overview of Duke Energy's East Bend Generating Station.

A East Bend Generating Station is a 600 MW (net summer rating) coal-fired generator located along the Ohio River, in Boone County, KY.[3] Duke Energy

[1] Direct testimony of Amy B. Spiller, pg. 28-29.
[2] *Ibid*.
[3] Direct testimony of William Luke, pg. 3.

Kentucky is the sole owner of the plant.[4] The plant was commissioned in 1981[5] and is currently 42 years old.

Q What is the undepreciated balance of East Bend as of 2022?

A East Bend still has an undepreciated balance of roughly $570 million.[6]

Q What was Duke Energy's assumed retirement plan for East Bend in the last rate case?

A In the Company's last rate case, East Bend was assumed to have a retirement date of 2041.

Q Why does DEK say it is seeking to accelerate the retirement of East Bend from 2041 to 2035?

A DEK cites mounting costs, increasing adoption of renewables, and market changes that reduce the coal plant's dispatchability as factors driving the acceleration of the retirement date of East Bend.[7]

---

[4] Kentucky Public Service Commission, PSC Order, Case No. 2014-00201, *available at* https://psc.ky.gov/pscscf/2014%20cases/2014-00201/20141204_psc_order.pdf.

[5] Direct testimony of Duke Energy witness William Luke, pg. 3.

[6] DEK response to Kroger request 1-5 Attachment.

[7] Direct Testimony of Scott Park, pg. 8-9.

ii. ***<u>DEK modeling supports a retirement date for East Bend of no later than 2035, if not earlier</u>***

Q What is the most recent analysis conducted by DEK to support its proposed retirement plan and depreciation schedule for East Bend?

A The Company's 2021 IRP is the most recent analysis and modeling DEK has done to support the proposed 2035 retirement date for East Bend.[8]

Q Provide an overview of the modeling conducted for the 2021 IRP.

A In its most recent IRP, DEK modeled scenarios both with and without a carbon price. The Company tested low, base, and high gas price sensitivities for scenarios both with and without a carbon price. DEK selected a Carbon Regulation scenario for its base case.[9] These scenarios informed selection of the 2021 IRP Portfolio, which plans for an East Bend retirement in 2035.

Q Why is DEK assuming a future with carbon regulation in its IRP baseline scenario? Is it because the Company believes that carbon regulation is likely?

A DEK states that a future with carbon regulation is likely over the 15-year planning period with no major disruptions to the business environment.[10] For the sake of modeling, the Company assumes a $5 per ton price on carbon starting in 2025 and increasing by $5 per ton each year thereafter.[11] This is analogous to a mass CO_2 cap or a cap-and-trade program.[12]

[8] DEK response to Sierra Club request 1-7.
[9] Duke Energy Kentucky. 2021 Integrated Resource Plan, pg. 12.
[10] *Ibid*.
[11] Duke Energy Kentucky. 2021 Integrated Resource Plan, pg. 30.
[12] *Ibid*.

No one can say for certain whether there will be a price on carbon, a cap-and-trade program, or a mass CO_2 cap at any point in the next 15 years. But based on current trends, most experts in the industry agree that there will be greater regulation for coal-fired power plants in general over this timeframe. A carbon price can serve as a proxy for any type of regulation which will increase the cost to operate a coal-fired power plant and continue to make renewables and clean energy resources less costly economic alternatives.

Relative to other energy resource types, coal-fired power plants have numerous environmental compliance costs and regulatory risks. These include (1) carbon emissions, (2) air emissions (e.g., particulate matter), (3) water emissions (e.g., wastewater), (4) by-products and waste (e.g., coal ash), and (5) plant inputs (e.g., coal mining). The risk of future regulation touching on at least one, or even more than one, of these inputs and outputs is almost inevitable. Increased regulation of fossil fuels, whether that be carbon or otherwise, is highly probable.

Q What does DEK find regarding East Bend's retirement in its most recent IRP analysis?

A In DEK's IRP base case modeling (which assumes carbon regulation with base gas prices), the Company finds that East Bend will be economically retired in 2027.[13] DEK also modeled a future without carbon regulation; in that scenario East Bend continues to operate economically until the end of its useful life.

While the 2021 IRP portfolio set East Bend's anticipated retirement date at 2035, the 2021 IRP modeling does not suggest 2035 as a specific retirement date for East Bend—in fact, it recommends an earlier date. IRP analysis suggests 2027 is the most economic retirement date for East Bend, according to its base case

[13] Duke Energy Kentucky. 2021 Integrated Resource Plan, pg. 42-46.

modeling.[14] DEK's proposal for a 2035 retirement date appears to be based on the Company's assessment that the plant is generally becoming more uneconomic to operate.[15]

Q What has changed since DEK completed its most recent IRP analysis?

A There have been many changes in the market since DEK completed its 2021 IRP. First, Congress passed the federal IRA in August 2022, which provides tax benefits for wind, solar, and battery storage, as well as other provisions that support the adoption of clean energy sources. The IRA will put downward pressure on the price of renewable energy and increase renewable energy's penetration on the grid. As a result, East Bend and other aging fossil fuel plants will have a harder time competing in the energy market, which will impact their economics.

Second, there has been more gas price volatility and higher regional coal prices as a result of global energy market changes that stemmed from the war in Ukraine. This has not only impacted the fuel costs for fossil fuel plants; it has also driven up energy prices across the region. This type of fuel volatility is inherent to systems that rely heavily on gas and coal plants.

Third, the country has experienced inflation and supply chain challenges. This has driven up prices across numerous industries, including the energy industry. This both impacts the cost of new resources and increases the cost to operate and maintain existing resources like East Bend, especially if additional environmental capital costs are required.

[14] Duke Energy Kentucky. 2021 Integrated Resource Plan, pg. 42.
[15] *See*, *e.g.*, Direct testimony of Scott Park, pg. 10.

The Company has not yet performed any detailed analysis of the impact of any of these forces on its long-term resource plan.[16]

Q Do these market changes mean that DEK should retire East Bend earlier than 2035?

A Yes. The changing market dynamics seen within the last two years will have a material impact on East Bend's economics.[17] In fact, Company Witness Park states in his direct testimony that, in light of market changes, "the retirement of East Bend is more likely to be sooner than 2035 rather than later."[18]

Unfortunately, DEK has not updated its modeling to incorporate these market shifts already underway.[19] As I will show in my analyses, DEK assumptions and analysis are no longer up to date, and they paint an inaccurate picture of the future. Updated DEK modeling would likely support a retirement date earlier than 2035. In light of recent federal policy changes, as well as shifting market dynamics, my analysis shows that DEK should commit to retiring East Bend by 2030.

Q Why do you propose retiring East Bend by at least 2030?

A The Company has presented no evidence that keeping the plant online beyond 2030 is the lowest cost option. Based on all data provided by DEK, retiring East Bend by 2030 and replacing it with alternatives likely provides the lowest cost and lowest risk option for ratepayers. This date will allow DEK sufficient time to

---

[16] DEK response to Sierra Club request 1-23.
[17] Direct testimony of William Luke, pg. 12.
[18] Direct testimony of Scott Park, pg. 10.
[19] DEK response to Sierra Club request 1-7.

build or procure replacement resources while also reducing how long East Bend operates beyond when it is providing economic benefits to ratepayers.

Q Early retirement can cause rate shocks to customers. Are there options to mitigate rate impacts as a result of early retirement?

A I recognize the concern that if the depreciation schedule is advanced to 2030 or earlier, customer rates could increase. Likewise, if East Bend is converted to a regulatory asset, customers in the future could be asked to continue to pay depreciation expenses, while also paying for replacement energy. But there are ways to minimize these barriers and cost impacts to ratepayers, such as ratepayer-backed securitization or regulatory assets without a return on equity allowed. I explore the options of securitization in greater detail in Section 6 below, and I recommend the Commission order the Company to evaluate the economics of using the tool to minimize ratepayer impacts of early retirement of East Bend.

Additionally, retiring East Bend early will protect ratepayers against numerous other rate increases, from ongoing O&M and sustaining capital costs (which can be expected to increase as the plant ages) to volatile fuel costs, as well as replacement energy during forced outages. I discuss these avoided risks and costs in more detail in Section 4(iii) below.

4. DEK HAS NOT DEMONSTRATED THE PRUDENCE OF CONTINUING TO INVEST IN AND OPERATE EAST BEND THROUGH TO ITS CURRENT RETIREMENT DATE OF 2035

i. DEK's East Bend costs have exceeded its revenue and value in recent years

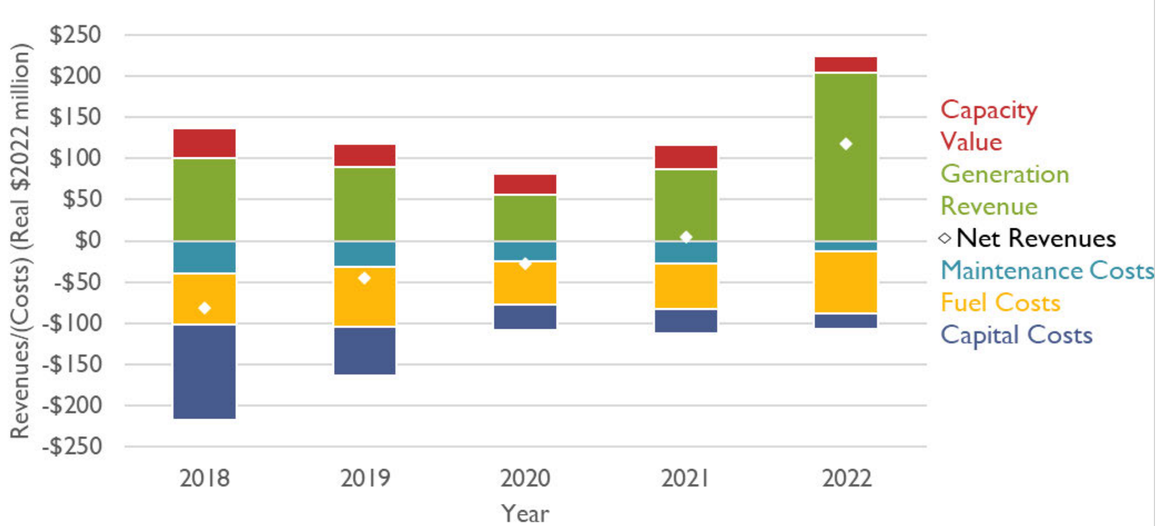
Q Describe East Bend's historical utilization rate.

A Between 2018 and 2021, East Bend's utilization rate ranged from 43 percent to 60 percent[20] (as seen in Figure 3, below).

Q Describe East Bend's financial performance in recent historical years.

A Based on the Company's own data, I find that East Bend incurred costs in excess of its market energy and capacity value each year from 2018 to 2020, and broke even in 2021 (Figure 1). These costs have been passed on to DEK ratepayers.

Figure 1. East Bend historical costs and revenues



Source: see description in text.

[20] Calculated using East Bend's net summer capacity and generation data from U.S. Energy Information Administration Form 923.

The exception was the outlier year of 2022 where, as can be seen above in Figure 1, East Bend's generation revenues were particularly high. Although average generation was roughly the same as previous years, locational marginal prices ("LMP") were unusually high for much of 2022 (Figure 2). This was due to a variety of global factors, most notably the war in Ukraine, which increased gas and energy market prices. These high LMP prices were responsible for uniquely high generation revenue in that year and should be viewed as an anomaly.

Figure 2. PJM hourly day-ahead (DA) and real-time (RT) locational marginal prices (LMP) for the East Bend node, and East Bend generation

Source: Hourly DA and RT prices from PJM, available at https://www.pjm.com/markets-and-operations/energy, and East Bend generation from U.S. Energy Information Administration ("EIA") Form 923.

Q Describe your methodology for evaluating the historical economic performance of East Bend.

A I relied on data DEK provided in discovery. I summed annual historical East Bend fuel costs,[21] maintenance costs,[22] and capital expenditures[23] to determine total historical costs for each year. I estimated East Bend's historical capacity value based on its unforced capacity (UCAP)[24] and the capacity value in PJM's Base Residual Auction (BRA)[25] for each planning year. We relied on BRA as a proxy for the capacity value of East Bend, even though DEK is a fixed resource requirement (FRR) entity and does not actually participate in the PJM BRA. I summed this capacity value with East Bend's annual energy revenues[26] to find the total historical value per year. I netted the annual costs and values to find East Bend's historical net value (or cost) for each year.[27]

[21] DEK response to Sierra Club request 1-9 Confidential Attachment 2 for 2018-2021. 2022 data from U.S. Energy Information Administration Form 923.

[22] DEK response to Kroger request 1-2(a) Attachment.

[23] DEK response to Kroger request 1-3(a) Attachment.

[24] DEK response to Sierra Club request 1-9 Confidential Attachment 1.

[25] Final zonal capacity prices (DEOK zone), PJM Base Residual Auction Results for 2016-2017 Planning Year through 2022–2023 Planning Year.

[26] DEK response to Sierra Club request 1-14(b) Attachment.

[27] An alternative method for calculating capacity value is using PJM's Net Cost of New Entry (CONE). The CONE values are calculated based on the cost to build a new natural gas-fired combustion turbine facility in PJM's territory. Given that East Bend's PJM zone, DOEK, has not been constrained in recent years, capacity can generally be procured for less than the cost of building an entirely new peaking plant. For this reason, auction prices were used to value historical capacity instead of CONE.

ii. My analysis shows that East Bend is not expected to be economic going forward, under reasonable assumptions about the future

Q Describe your methodology for forecasting the economic performance of East Bend.

A I evaluated East Bend's going-forward economics using DEK data provided in discovery as well as publicly available documents. Similar to my methodology for evaluating East Bend's historical economic performance, I summed DEK's own annual projected fuel costs,[28] O&M costs,[29] and capital expenditures[30] for East Bend to determine total projected costs per year. I estimated East Bend's capacity value based on its projected firm capacity[31] and both the BRA clearing prices and Net Cost of New Entry (CONE). I summed this capacity value with DEK's annual projected energy revenues[32] for East Bend to find the total value per year. I netted the annual costs and values to find East Bend's projected net value (or cost) for each year. I calculated the economic performance under both the scenario with carbon regulation and the scenario without carbon regulation, assuming base gas prices in both cases. To determine net present value (NPV), I used DEK's weighted average cost of capital[33] as a discount rate.

My analysis is not intended to calculate East Bend's full revenue requirements. Instead, it looks at East Bend spending relative to what it is earning, on a forward-going basis, and it identifies the costs that can be avoided for ratepayers if DEK retires East Bend ahead of 2035.

[28] DEK response to Sierra Club request 2-2 Confidential Attachments 2 and 5.
[29] *Ibid*.
[30] *Ibid*.
[31] DEK response to Sierra Club request 2-2 Revised Confidential Attachments 2 and 5.
[32] DEK confidential response to Sierra Club request 2-1 Confidential attachment.
[33] DEK response to Commission Staff request 1-56, Attachment_BLS-2.

Q What factors are driving your conclusion that East Bend is not likely to provide economic value to ratepayers going forward?

A As I will explain in more detail below, East Bend is not projected to be economic on a forward going basis, when using reasonable assumptions for several key variables: (1) fixed costs, (2) East Bend's utilization, (3) LMPs and market dynamics, and (4) capacity price. Using more realistic assumptions, I find that East Bend is expected to incur costs in excess of its value of between $261 million and $154 million over the period 2023-2034.

Q How is your analysis presented below?

A I first discuss DEK's base case modeling, which assumes a carbon price. I review the projected capacity factor for East Bend under this scenario, and I present analysis on the plant's forward-going economics using DEK-provided data. I show this analysis using both BRA and CONE prices for capacity. I then provide a critique of DEK's assumptions of fixed costs and present analysis with more realistic fixed cost assumptions.

Second, I discuss DEK's modeling assuming no carbon price. I discuss DEK's very unrealistic assumptions about East Bend's capacity factor for this scenario. I also discuss DEK's outdated assumptions for LMPs and the energy market generally. I then present analysis on East Bend's forward-going economics with more realistic fixed cost assumptions. Next, I present analysis on East Bend with both more realistic fixed cost assumptions and much more realistic utilization assumptions.

I then provide a summary of my analysis and conclusions and offer some additional context on my methodology and DEK data.

Q What does the Company project East Bend's utilization to be in the future?

A DEK projects utilization of East Bend will [redacted] onwards (Figure 3). These modeling results assume that a carbon price or other environmental restrictions are implemented in 2025 which increase the cost to operate fossil power plants.

Figure 3. Confidential historical and projected capacity factors for East Bend

[redacted]

Source: Historical values from U.S. Energy Information Administration Form 923. Projections from DEK response to Sierra Club 2-2 Confidential Attachments 2 and 5.

Q Why do you rely on DEK's scenario with a carbon price?

A As carbon regulations are implemented, coal plant costs will increase. East Bend will not be able to compete with low-cost renewable energy alternatives in the PJM market and will therefore be committed and dispatched less and less. This trend of decreasing utilization and increasing costs at aging coal plants does not depend on a carbon tax—as DEK witnesses acknowledge in their testimonies, the industry is already moving in this direction.

Q What do your findings show about the future financial performance of East Bend, assuming a future with carbon regulation?

A As shown in Figure 4, I find that East Bend is projected to incur net losses of $123 million (on a NPV basis) from 2023 to 2034, or an average of $14 million per year (2022$) at East Bend. These results are based on valuing capacity based on PJM auction capacity prices.

Figure 4. Confidential projected net revenues for East Bend, assuming carbon regulation and PJM BRA capacity values

[redacted]

Source: see description in text.

Q What do the results look like for East Bend's financial performance, assuming a future with carbon regulation but with a higher (but unlikely and overly conservative) capacity price?

A I conducted a sensitivity analysis using a higher capacity price represented by the PJM's Net CONE.[34] The CONE values are calculated based on the cost to build a new natural gas-fired combustion turbine in PJM's territory.[35] In my opinion, this is a very unlikely estimate because unless a region's capacity is highly constrained (i.e., all existing capacity is cleared, and a new facility is required as the marginal resource) then capacity can generally be procured for less than the cost of building an entirely new peaking plant. Furthermore, CONE is the value for the plant's first year of operation; it would be highly unlikely that one would need to build a new plant each year. Therefore, applying CONE to each year is very conservative. It is also unlikely that bilateral capacity sales wouldn't be available to cover at least some of the replacement capacity.

I find that East Bend is projected to incur net positive revenue when using CONE to estimate capacity prices. I applied CONE starting in 2024, when DEK's PJM zone, DEOK, was somewhat constrained in the capacity auction.[36] As I discussed, this is likely an unrealistically high capacity value, especially when applied to all

---

[34] Net CONE is defined as "the total annual net revenue (net of variable operating costs) that a new generation resource would need to recover its capital investment and fixed costs, given reasonable expectations about future recovery over its economic life." PJM CONE 2026/2027 Report, The Brattle Group, Apr. 2022, *available at:* https://www.pjm.com/-/media/library/reports-notices/special-reports/2022/20220422-brattle-final-cone-report.ashx.

[35] *Ibid*.

[36] PJM 2024/2025 Base Residual Auction Report, Feb. 28, 2023, *available at* https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-base-residual-auction-report.ashx.

years. In this case, I find that East Bend is projected to incur a net revenue of $159 million (on a NPV basis) from 2023 to 2034.

Q **For DEK's carbon regulation scenario, do you have concerns with the Company's fixed costs forecast?**

A Yes. From 2023 to 2034, DEK is forecasting that East Bend will incur fixed costs at an average of [redacted] per year (Figure 5). With the exception of 2024, DEK assumes little variability between years. Fixed costs include maintenance capital (also known as sustaining capital costs) and fixed O&M.[37]

Figure 5. East Bend historical capital expenditures and confidential projected fixed O&M and maintenance capital (combined)

[redacted]

Source: Historical capital expenditures from DEK response to Kroger 1-3(a). Projections from DEK response to Sierra Club request 2-2 Confidential Attachments 2 and 5. DEK combines fixed O&M and maintenance capital projections.

---

[37] DEK data for fixed O&M and maintenance capital were combined. DEK response to Sierra Club 2-3.

But projected fixed spending is (1) substantially below industry averages, (2) unreasonably low based on historical spending, and (3) identical between scenarios with and without carbon regulation.

East Bend's average historical spending[38] is on par with coal plants of similar size and age. Yet when looking at East Bend's projected fixed costs, spending is well below the industry average (Table 1). DEK has not explained why its projected fixed costs are so much lower than plants of similar size and age. This discrepancy, particularly in light of the historical similarity, indicates that the Company is likely significantly underestimating future costs for East Bend in its modeling.

Table 1. EIA (Sargent & Lundy) industry averages and confidential East Bend projected CapEx and fixed O&M costs (combined)

	CapEx and Fixed Operations & Maintenance (Combined) $2022 $/kW-year			
East Bend Future Scenario	Sargent & Lundy annual estimates	Historical **CapEx** avg 2018–2022	Projected average 2023–2027	Projected average 2023–2034
Carbon regulation & no carbon regulation	$71	$77	[redacted]	[redacted]

Source: DEK response to Sierra Club request 1-18 confidential attachment, and U.S. EIA, Generating Unit Annual Capital and Life Extension Costs Analysis (December 2019), available at https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf. Sargent & Lundy CapEx and fixed O&M estimates are combined. Sargent & Lundy CapEx were specific to coal plants between 40 and 50 years old with flue gas desulfurization.

Furthermore, when considering future environmental regulation, capital upgrades are a near certainty. This applies especially to the carbon regulation modeling scenario, but DEK should also have considered it to a lesser degree in the non-regulation scenario. Plants such as East Bend with flue gas desulfurization (FGD) are particularly cost-intensive for capital maintenance. Chemicals and reagents

[38] Historical capital expenditures (DEK response to Kroger request 1-3(a)).

corrode equipment such as pumps, valves, etc., and need replacement more frequently compared to plants without FGD.[39]

By under-projecting future spending in its modeling, DEK is making the plant look more economic on a forward-going basis than both its own historical data and industry standard data would suggest.

Q What does your analysis show when fixed-spending assumptions are more realistic?

A As I previously stated, DEK's forecasts for East Bend's fixed costs are significantly below both historical spending and industry averages. I increased the fixed costs (for 2023–2034) from DEK's projection of [redacted][40] to DEK's own historical 5-year average of $51 million, which is also in line with industry averages.[41] As can be seen in Figure 6, when fixed costs projections are more realistic, East Bend becomes even less economic to operate. My analysis estimates it will incur net losses of $261 million (on a NPV basis) over its current lifetime, or an average of $32 million per year (2022$). These estimates assume PJM's BRA auction price as a capacity value. Even when I apply high conservative CONE values to estimate the capacity value (still correcting for fixed costs), East Bend breaks even.

[39] U.S. EIA, Generating Unit Annual Capital and Life Extension Costs Analysis (Dec. 2019), *available at* https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf. Sargent & Lundy CapEx and fixed O&M estimates are combined. Sargent & Lundy CapEx were specific to coal plants between 40 and 50 years old with flue gas desulfurization.

[40] Annual average.

[41] U.S. EIA, Generating Unit Annual Capital and Life Extension Costs Analysis (Dec. 2019), *available at* https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf.

Figure 6. Confidential projected net revenues for East Bend, with corrected fixed costs, assuming carbon regulation and BRA capacity values

[redacted]

Source: see description in text.

Q DEK separately models its system without any carbon regulations. What do your findings show about the future financial performance of East Bend in that scenario?

A Using DEK's values (i.e., no corrections) from its no carbon regulation scenario modeling, East Bend nets positive revenues from 2023 to 2034. Assuming PJM BRA capacity prices, East Bend has a lifetime NPV revenue (2023 to 2034) of $91 million. East Bend is projected to net higher positive revenues when assuming a CONE value for capacity. However, as I discuss below, DEK's assumptions for this scenario are flawed and are highly unlikely to be realized.

Q What are the Company's projected utilization rates for East Bend in a future without carbon regulation?

A In the Company's modeling without carbon regulation, DEK projects East Bend's capacity factor will increase from [redacted] (Figure 3). But as even DEK itself admits, the scenario with a carbon price represents a far more realistic future. To reiterate, it is highly unlikely that utilization for an aging coal plant such as East Bend will increase significantly and sustain itself at the levels DEK modeled, especially given the likelihood of increasing environmental regulations, fuel price volatility, and falling renewable costs. The results without a carbon scenario likely overstate capacity factor, expected revenue forecasts, and forward-going costs. As a result, the scenario without a carbon price does not reflect a reasonably likely future for East Bend.

In the next two responses, I will discuss why capacity factors should fall as a result of (1) East Bend's increasing age and (2) renewable energy adoption. In the subsequent response, I will critique East Bend's associated LMP assumptions.

Q Why is East Bend's utilization expected to fall as a result of its increasing age?

A DEK is projecting capacity factors of [redacted] This is unusually high for a coal power plant, and especially high for a plant over the age of 40. Average annual capacity factors for coal generators in the United States have been between 53 percent and 61 percent since 2012,[42] and as discussed above, East Bend's average capacity factors over the past five years have been between 43 and 60 percent. These levels are all much lower than what

[42] U.S. Energy Information Administration (EIA). Electric Power Monthly, Table 6.07.A. Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels, *available at* https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a.

DEK is projecting. I am not aware of any comparable coal plants projecting such high utilization rates going forward. Even if East Bend is well maintained, it is unreasonable to assume that East Bend is immune from the forced outages and breakdowns that accompany an aging generator.

Q How will market dynamics affect East Bend's utilization rates?

A Since wind and solar have a dispatch price of zero, they displace the marginally priced resources, which are typically expensive and aging fossil plants. This puts downward pressure on LMPs; PJM forecasts that average LMPs could fall by as much as 26 percent in the future as a result of renewable energy adoption.[43] Not only do lower LMPs mean that East Bend and other fossil fuel generators will be less cost-competitive and be dispatched less, but East Bend's energy revenues will also fall and thus become even more uneconomic. This dynamic will continue regardless of whether or not there is a carbon price. Company Witnesses, including Ms. Lawler,[44] Mr. Luke,[45] Mr. Scott,[46] and Mr. Swez,[47] all commented in their direct testimonies that East Bend's capacity factors will decline in the future rather than grow and stay elevated.

For example, DEK placed East Bend on reserve shutdown status for 57 days during the beginning of the COVID-19 pandemic in 2020 as a result of low LMPs during that period.[48] Costs were projected to exceed energy and ancillary

[43] PJM Planning Division. Grid of the Future: PJM's Regional Planning Perspective, pg. 9 (May 10, 2022).
[44] Direct Testimony of Sarah E. Lawler, pg. 13.
[45] Direct Testimony of William Luke, pg. 12.
[46] Direct Testimony of Scott Park, pg. 8.
[47] Direct Testimony of John D. Swez, pg. 10.
[48] Direct Testimony of John D. Swez, pg. 9.

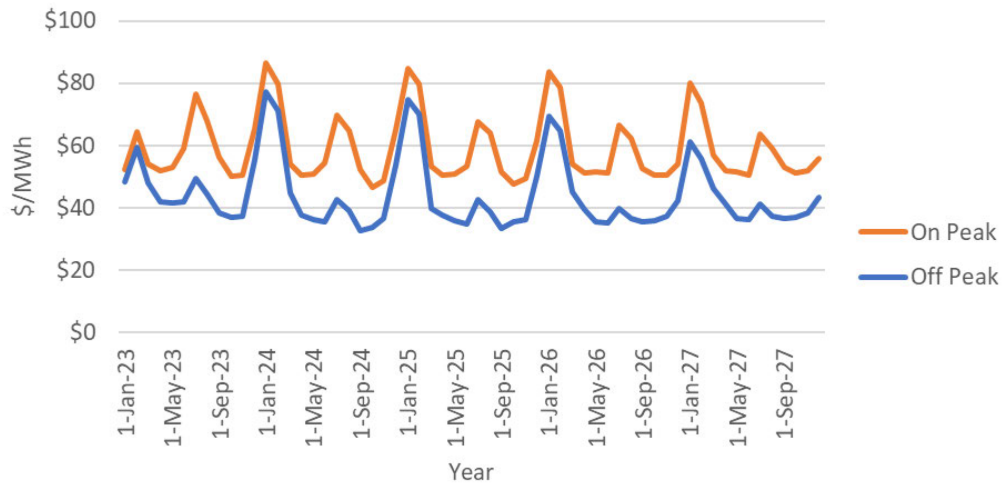
revenues, and East Bend became too uneconomic to run.[49] Company witness Mr. Swez notes the likelihood of more reserve shutdown instances in both the short term and longer term due to variable costs exceeding energy market revenues,[50] which in turn reduces the capacity factor and energy revenues for East Bend.

Q What are DEK assumptions about future LMPs?

A DEK is projecting that on an annual basis, LMPs will remain flat at least until 2027, aside from seasonal variations (Figure 7).[51] According to DEK's forecast of generation and energy revenues for the no carbon scenario, DEK is assuming that LMPs will [redacted][52] This is out of sync with Company witness testimony.[53] Although DEK understands that LMPs should fall, the Company has not updated its modeling and forecasts to include this critical assumption.

[49] *Ibid*.
[50] Direct Testimony of John D. Swez, pg. 10.
[51] DEK response to Sierra Club request 1-14(a).
[52] DEK response to Sierra Club request 2-2 Confidential Attachment 5.
[53] Direct testimony of Scott Park, pg. 9.

Figure 7. DEK forecast of locational marginal prices from 2023 to 2027



Source: DEK response to Sierra Club request 1-14(a).

In the scenario with carbon regulation, DEK assumes that LMPs will increase as a result of carbon regulation driving up the cost to operate existing fossil units.[54] Unfortunately, this means that there is no modeled scenario in which LMPs decline. Understanding the impact of declining LMPs as a result of greater renewable energy adoption will provide a better understanding of East Bend's future operational and economic performance.

Q What do your findings show about the future financial performance of East Bend, assuming no carbon regulation but with more appropriate fixed costs and capacity factor assumptions?

A As described above, I am concerned that DEK's fixed-spending assumptions are unrealistically low and do not account for the aging of the East Bend plant. Although the modeling scenario in question has no carbon regulation, East Bend's

[54] Calculation using data from DEK response to Sierra Club request 2-2 Confidential Attachment 5.

fixed costs are still not expected to decline going forward; they should at a minimum be on par with historical spending.

Likewise, DEK's forecasted generation revenue is inconsistent with the current reality of the energy market. Even without carbon regulation, East Bend generation revenue will likely decline as LMPs fall and East Bend fails to compete with the low-cost renewables on the grid.

First, I corrected East Bend's fixed spending to be more in line with historical spending and the industry standard for similar plants.[55] With this change, East Bend incurs net losses of $47 million (NPV) from 2023–2034.

Second, I corrected capacity factors to be on par with those of typical coal plants,[56] and I changed the variable O&M, fuel costs, and energy revenues proportionally. When correcting for both fixed costs and capacity factors,[57] East Bend incurs net revenue losses of $154 million (NPV) over the course of its life, or $17 million per year ($2022) (assuming PJM BRA capacity values). For the reasons described above, I believe this is a more realistic modeling scenario for future net revenues for East Bend (assuming no carbon price).

Q What do you conclude regarding the economic performance of East Bend and its future retirement?

A As summarized in Table 2 below, my analysis shows that, under most likely future scenarios, East Bend will be uneconomic to operate going forward.

---

[55] *See* description above for the analysis without carbon regulation.

[56] Five-year average for coal plants, from EIA Table 6.07.A. Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels, *available at* https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a.

[57] Corrected capacity factor starting in 2025 to be 10-year average for coal plants. Assume 1-percent decline starting in 2027. Coal plant average from EIA Table 6.07.A. Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels, *available at* https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a.

Specifically, assuming DEK's forward-going spending to maintain its coal plant is in line with its historical spending, and/or there are increased carbon regulations, I find that East Bend is expected to incur costs in excess of its value of between \$261 million and \$154 million. Only under unrealistically conservative scenarios, specifically with a high capacity value or no environmental regulations, is the plant expected to perform economically.

Table 2: Summary of NPV projected net revenues for East Bend, 2023–2034 (\$million) for various scenarios

Modeling Scenario	Capacity Price	Corrections	NPV (2023–2034)	Annual Average (\$2022)
Base with CO_2	PJM BRA	--	(\$123)	(\$14)
Base with CO_2	Net CONE	--	\$159	\$20
Base with CO_2	PJM BRA	Fixed cost (historical avg)	(\$261)	(\$32)
Base without CO_2	PJM BRA	--	\$91	\$15
Base without CO_2	PJM BRA	Fixed cost (historical avg)	(\$47)	(\$3)
Base without CO_2	PJM BRA	Fixed cost (historical avg) + capacity factor (10-yr industry avg)	(\$154)	(\$17)

Source: See individual results discussed above.

Q What do you find regarding DEK's analysis in this case?

A Overall, I find that the forecasts and analysis DEK relied on in this rate case lack accuracy and reasonableness, and they fail to capture the market changes already underway. While forecasting comes with uncertainty, it is irresponsible for the Company to assume that our future is business-as-usual, that fixed spending will decline as compared to historical spending, or that the capacity factor will increase so significantly in a manner inconsistent with other coal plants. My findings demonstrate how important it is for DEK to perform, and for the Commission to have access to, robust analyses to evaluate the cost of continuing to operate East Bend, to avoid locking in ratepayer costs for fuel, O&M, and fixed capital costs for the long-term. Based on my findings, I recommend that DEK commit to an earlier retirement date for East Bend and take the plant offline no later than 2030.

Q Explain why you added the full cost of each expenditure in the year it was incurred instead of annualizing the costs over the remaining life of the plant?

A I expensed the full cost of each capital expenditure in the year it was incurred because this approach is more robust against early retirements. In years where DEK undertakes large projects, capital expenditures will likely exceed the resources' total revenues and value; but the reverse is also true. And over a multi-year timeframe, if the plant is operating economically, the total costs incurred and total energy revenues earned plus capacity value should at the very least net out. If they do not, meaning that the plant's total fixed and variable costs consistently sum to more than its total energy market revenues plus capacity value, then continuing to invest in the plant is not in ratepayers' interest on a forward-going basis.

In contrast, the Company typically annualizes capital expenditures (based on the utility's cost of capital) and spreads the costs out over the remaining economic life of the plant. This approach is reasonable with projects where there is a reasonable degree of certainty that the plant will operate through its planned retirement date. But it is dangerous with aging resources such as coal plants that we know are likely to retire early. A project might look economic when spread out over 12 years with 12 years of energy market revenues and capacity value to balance it out. But if it has to be recovered over only five or eight years instead (with only five to eight years of revenue and value as well), it suddenly becomes clear how expensive and uneconomic it was to invest in the plant.

Q Is there any deviation from industry practice in terms of DEK data quality?

A Yes. DEK provided incorrect data on its East Bend costs and revenue forecasts, and the Company only corrected the data eight days before the testimony filing date. Revised data was sent two days before the testimony filing date. Furthermore, the Company's responses to questions were at times unclear and obtuse, adding more confusion than clarity.

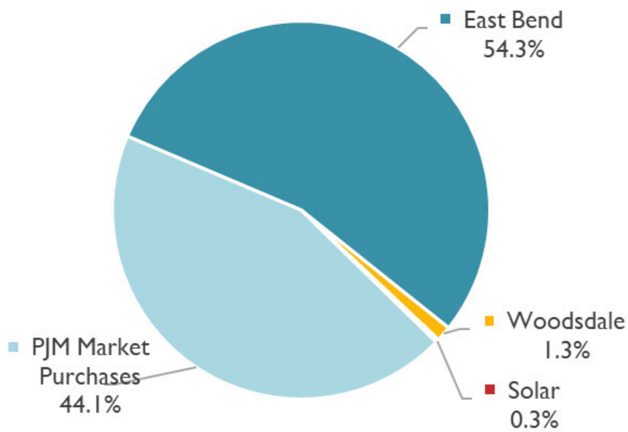
Based on my own experience and the experience of my colleagues, this is not in line with industry standard practice of providing accurate and high-quality data through discovery.

iii. There are mounting risks and costs associated with relying heavily on coal-fired generation; these can be avoided with an early East Bend retirement

Q What is Duke Energy Kentucky's current generation mix and what is its projected energy portfolio?

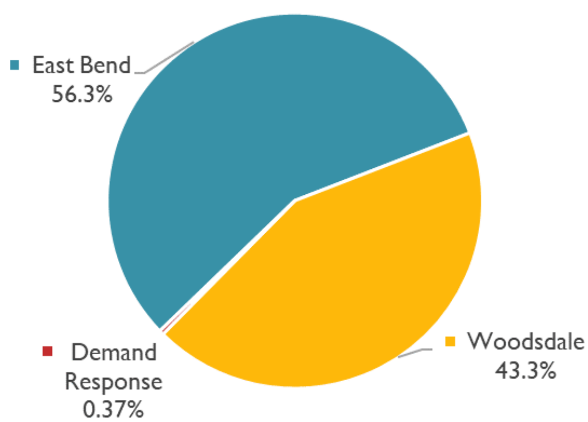
A East Bend provided over half of the Company's energy generation (Figure 8) and capacity mix (Figure 9) in 2020.

Figure 8. Duke Energy Kentucky's generation mix in 2020



Source: Figure 4.2 of DEK's 2021 IRP.

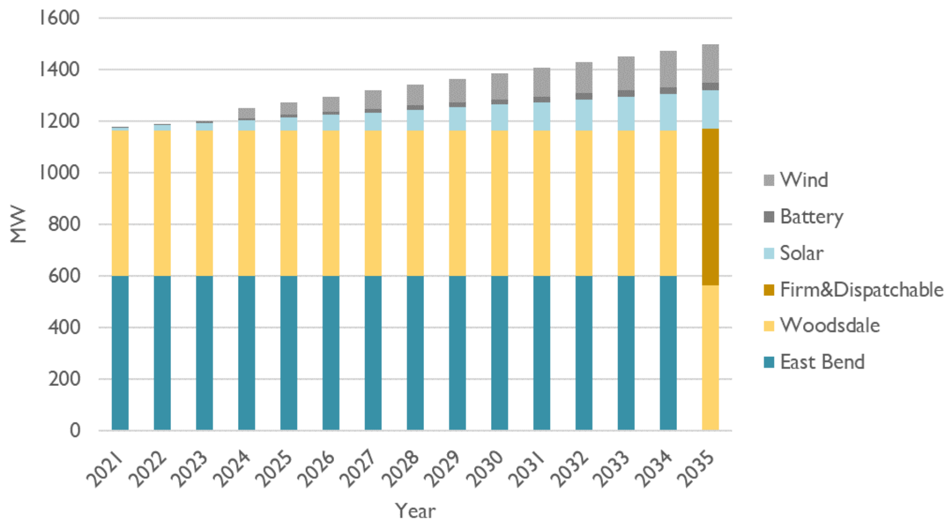
Figure 9. Duke Energy Kentucky's capacity mix (UCAP)



Source: Figure 4.2 of DEK's 2021 IRP.

Going forward, DEK projects that East Bend will provide roughly 50 percent of generating capacity for its customers over the next decade (Figure 10).

Figure 10. Duke Energy Kentucky's generating capacity, 2021–2035



Source: Figure 7.1 of DEK's 2021 IRP.

DEK and its ratepayers are relying heavily on coal for their energy and capacity needs, which exposes them to avoidable costs and puts them in a risky position, as I will explain in greater detail throughout this section.

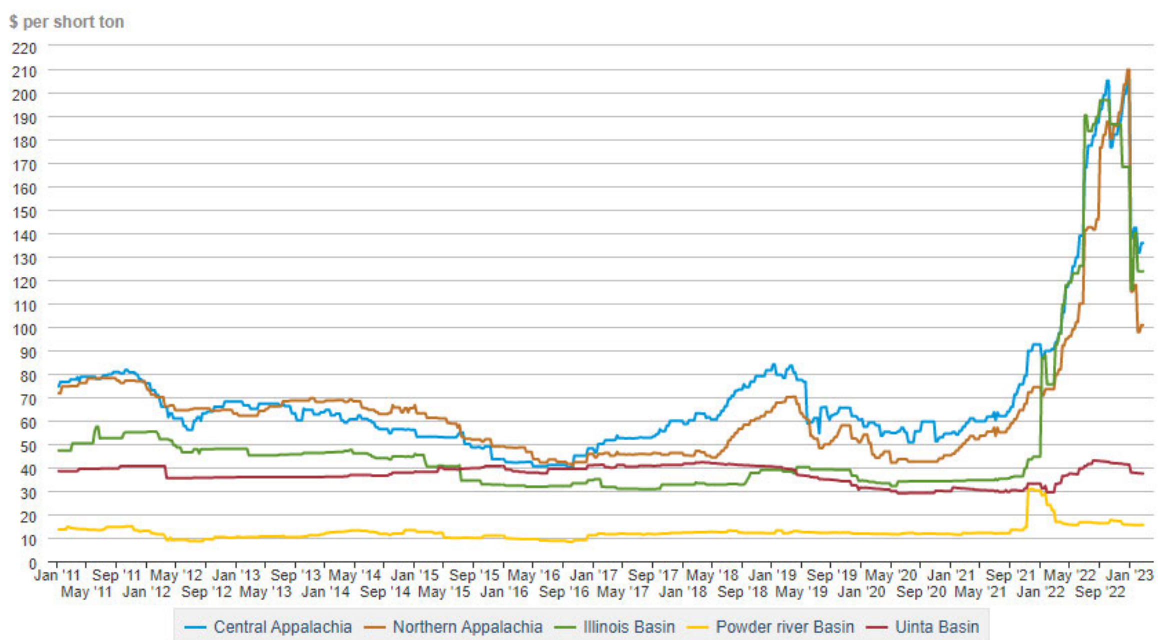
Q Are there avoidable costs and risks associated with continuing to rely on East Bend as a generating asset?

A Yes. There are numerous risks and costs for DEK ratepayers, who receive roughly half of their energy from a single, aging coal plant. Many of these can be mitigated with early retirement. They include (1) fuel price volatility, (2) future environmental compliance costs, (3) operational costs associated with running aging fossil fuel resources, (4) issues of coal supply and transportation, (5) reliability risks posed by extreme weather, and (6) forced outage risks associated with operating an aging plant. I will cover each of these six key risks—and the associated benefits of earlier retirement of East Bend—in the next six responses.

Q Please describe the avoided fuel costs associated with an earlier East Bend retirement.

A With such a significant portion of DEK energy coming from coal, ratepayers have high exposure to fuel price volatility. Coal, natural gas, and oil prices are determined in large part by global markets and are influenced by numerous factors including rail and pipeline access, natural gas reserves in Europe, volume of exports and imports, extreme weather, etc. As can be seen in Figure 11 below, prices for coal from the Appalachian regions and Illinois Basin experienced significant volatility in the last year. DEK purchases coal for East Bend from these regions.[58]

Figure 11. Historical coal prices by region, January 2011 to February 2023



Source: U.S. EIA average weekly coal commodity spot prices. Available at https://www.eia.gov/coal/markets/#tabs-prices-2.

[58] U.S. Energy Information Administration Form 923.

When fuel prices are high, ratepayers are on the hook to pay for high-cost electricity. In fact, over the last five years, fuel prices accounted for half of costs at East Bend, on an annual average basis.[59]

Not only do high and volatile fuel prices influence East Bend's generation costs, but high prices also drive up LMPs across the region, further driving up the cost of electricity for DEK and its ratepayers. If DEK retires East Bend early and adds more solar and wind resources to its portfolio, ratepayers will have a buffer from these impacts. If DEK continues to rely on East Bend, as well as the spot market, its ratepayers will bear the full burden of high and volatile fuel prices.

Q Please describe the risks and costs from environmental regulation that will be avoided with an earlier East Bend retirement.

A There are two additional categories of potential environmental compliance risk facing East Bend over the next decade: (1) ongoing implementation of the National Ambient Air Quality Standards ("NAAQS") for ozone, and (2) Clean Water Act Effluent Limitations Guidelines for coal-burning plants and Resource Conservation and Recovery Act regulations governing coal ash disposal.

First, as noted in DEK's IRP, ongoing implementation of the ozone NAAQS and the non-attainment status of the Cincinnati area may lead to additional reductions in nitrogen oxide emission allocations to East Bend, or the performance upgrade of selective catalytic reduction technology (SCR).[60] Although DEK did not provide any detailed information on projected costs associated with NAAQS

---

[59] See description in Section 4(i) on historical economic performance evaluation methodology.

[60] 2021 Integrated Resource Plan, Duke Energy Kentucky, pg. 141.

implementation via our discovery request,[61] costs could be substantial. As a result, the Company may be faced with the prospect of earlier retirement or a costly upgrade for East Bend in the early- to mid-2020s.[62]

Second, as the Company also acknowledges in its IRP, compliance with the U.S. Environmental Protection Agency's ("EPA") forthcoming updates to its Clean Water Act Effluent Limitation Guidelines and Coal Combustion Residuals rules may require additional capital and O&M investments at East Bend. Specifically, "more stringent discharge limitations (such as for bromides), may ultimately necessitate additional waste processing changes and/or equipment installations."[63] As with potential ozone compliance risk, DEK refused to provide detailed future cost estimates related to the implementation of the Clean Water Act or coal ash regulations,[64] but the Company projects that such costs may be required in the early 2030s.[65] On March 8, 2023, EPA proposed revisions to its Effluent Limitations Guidelines for coal-fired plants, which, if finalized, would require facilities like East Bend to eliminate FGD wastewater discharges by 2029; alternatively, for facilities that are in full compliance with EPA's existing rules, the source may commit to cease burning coal by 2032, in lieu of installing additional technology to comply with the updated standard.[66]

---

[61] DEK response to Sierra Club requests 1-16 and 1-19.

[62] 2021 Integrated Resource Plan, Duke Energy Kentucky, pg. 141.

[63] 2021 Integrated Resource Plan, Duke Energy Kentucky, pg. 142.

[64] DEK response to Sierra Club request 1-22.

[65] 2021 Integrated Resource Plan, Duke Energy Kentucky, pg. 142.

[66] U.S. Environmental Protection Agency, Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (prepublication version signed Mar. 7, 2023), *available at* https://www.epa.gov/system/files/documents/2023-03/Prepublication%20FRN_OW_Steam%20Electric%20ELG_NPRM_03_07_2023_1.pdf.

Q Please describe the avoided O&M and sustaining capital costs associated with an earlier East Bend retirement.

A Fixed O&M and sustaining capital costs make up a significant part of spending at East Bend; these are costs that are passed on entirely to ratepayers. Protecting ratepayers from unnecessary costs is especially important given East Bend's age. Total spending on sustaining capital expenses is likely to increase with the need for additional refurbishments of aging equipment, replacement of older parts, etc.

For wind and solar, O&M and sustaining capital costs are relatively low. As more renewable resources are added to DEK's portfolio after East Bend's retirement, its O&M spending should decline. This in turn will lower revenue requirements and reduce costs passed on to ratepayers.

Q Please describe the risks posed by coal supply and transportation issues that will be mitigated with an earlier East Bend retirement.

A Utilities around the country have experienced issues with their coal supplies over the last few years. For instance, the coal supplier for the San Juan Power Station in New Mexico was unable to supply the contracted amount of coal to that plant in 2022. As a result, the plant owners had to reduce how much they operated the plant.[67] Next door in Arizona, labor shortages in 2022 prevented Burlington Northern Santa Fe Railroad from delivering all the coal it was contracted to provide to Tucson Electric Power Company in 2022.[68] More generally in 2022, rail labor shortages—with employment down 20.4 percent since January 2019—inhibited the movement of coal throughout the country and contributed to soaring

[67] Direct Testimony of Devi Glick, pg. 32, Docket No. E-01933A-22-0107, Arizona Corporation Commission (Jan. 11, 2023).

[68] *Ibid*.

prices.[69] Similarly, the potential but avoided rail strike in fall of 2022 was a major threat to the coal industry. In fact, the coal industry is almost entirely dependent on railways, further exposing vulnerabilities of the coal supply chain.[70] DEK's heavy reliance on the East Bend coal plant exposes ratepayers to the risk of fuel supply constraints, as a result of these kinds of transportation or coal mine supply issues, which could result in paying high prices for replacement market energy—potentially for a lengthy period of time.

Q Please describe the risks posed by extreme weather that will be mitigated with an earlier East Bend retirement.

A Water is essential for cooling steam-fired generators, including coal plants. This can cause problems during droughts or other extreme weather events, and it is not just a hypothetical threat to coal-fired generators; Southwest Public Service Company in New Mexico accelerated the retirement date of the Tolk Generating Station twice in five years due to water shortages.[71] East Bend is located on the Ohio River, which experienced a drought in 2022.[72] Should the duration and/or

[69] Kuykendall, T., "Rail service 'meltdown' constraining US coal sector in hot market," S&P Global Market Intelligence, May 9, 2022, *available at* https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/rail-service-meltdown-constraining-us-coal-sector-in-hot-market-70189190#:~:text=During%20an%20April%20conference%20hosted,the%20second%20half%20of%202021.

[70] Bittle, J., "Railroad strike threatens power in coal-dependent states," Grist, September 14, 2022, *available at* https://grist.org/energy/railroad-strike-coal-power-shortage/.

[71] Direct Testimony of Devi Glick, pg. 36, Docket No. E-01933A-22-0107, Arizona Corporation Commission (Jan. 11, 2023).

[72] National Weather Service, "Low River Stages along the Lower Ohio and Mississippi Rivers," *available at* https://www.weather.gov/pah/LowRiverStages2022, and National Integrated Drought Information System. "Drought Conditions for Boone County," *available at* https://www.drought.gov/states/kentucky/county/boone.

frequency of Ohio River droughts intensify, they would likely threaten East Bend's ability to generate and potentially impact generation for months.

Water shortage issues can also occur with ice dams and blockages from cold weather events. During Winter Storm Elliot in December of 2022, ice on the Missouri River threatened 1000s of MWs of generation, as noted by Southwest Power Pool.[73]

Weather-related impacts to coal generators are happening in Kentucky too; all of TVA's coal plants in Kentucky had loss of availability during Storm Elliot.[74] When East Bend goes down during a storm, DEK and its ratepayers are forced to pay for replacement energy when prices are sky high; or worse, reliability suffers.

Q Please describe the forced outage risks associated with operating an aging plant that will be mitigated with an earlier East Bend retirement.

A The risk of forced outages is also a concern, especially given that East Bend is over 40 years old. As generators age, the likelihood and frequency of forced outages increases. For instance, CenterPoint's Culley Unit 3 in Indiana was shut down unexpectedly for nearly six months due to a turbine failure. Not only did this put reliability at risk, but it has also led to a rate hike for CenterPoint

[73] C.J. Brown, "December 2022 Winter Storm Elliott," pg. 7, Southwest Power Pool.

[74] Joint House & Senate Natural Resources & Energy Committee, Kentucky Legislature. February 2, 2023, Testimony of Arron Melda, Senior Vice President, Transmission and Power Supply, Tennessee Valley Authority, *available at* https://www.ket.org/legislature/archives/?nola=WGAOS+024020&stream=aHR0cHM6Ly81ODc4ZmQxZWQ1NDIyLnN0cmVhbWxvY2submV0L3dvcmRwcmVzcy9fZGVmaW5zdF8vbXA0OndnYW9zL3dnYW9zXzAyNDAyMC5tcDQvcGxheWxpc3QubTN1OA%3D%3D.

customers to cover the cost of replacement energy.[75] Similarly, as East Bend continues to age, total spending on replacement parts and maintenance will continue to grow, increasing costs to DEK and its ratepayers and increasing the likelihood of more forced outages.

More forced outages also impact capacity value. A higher forced outage rate results in a lower Unforced Capacity (UCAP). This means that, over time, East Bend will provide less and less capacity for the Company to use to satisfy its FRR Plan or to monetize in the PJM capacity auctions and through bilateral sales.[76] Recall that East Bend provides roughly half of DEK's capacity and will continue doing so for the next decade. Starting to build out resources that provide capacity now, ahead of prolonged forced outages and/or noticeable deteriorations in East Bend's UCAP, will serve customers in the long run.

*iv. **DEK should start building replacement resources for East Bend sooner rather than later***

Q What alternatives has Duke Energy considered for replacement resources?

A According to its IRP, DEK is considering natural gas-fired turbines (combustion turbine and combined-cycle), nuclear, solar photovoltaic, onshore wind, and battery storage.[77] Specifically, the Company is planning on replacing East Bend with a firm, dispatchable resource,[78] which the Company suggests will likely be

[75] Schneider, K., "CenterPoint Energy request 3-month rate hike for 2023 following coal plant failure," Indianapolis Star, Nov. 25, 2022, *available at* https://www.indystar.com/story/news/2022/11/25/centerpoint-files-for-rate-hike-following-coal-plant-malfunction/69670232007/.

[76] Direct Testimony of John D. Swez, pg. 15.

[77] Duke Energy Kentucky, 2021 Integrated Resource Plan, pg. 38.

[78] Direct Testimony of William Luke, pg. 14.

combined cycle natural gas or nuclear.[79] As part of DEK's long-term planning, DEK also plans on adding more renewables, which will make up 16 and 22 percent of generating capacity by 2030 and 2035, respectively.[80]

Q Are there risks with the resources DEK is considering?

A Yes. As I have discussed, there are numerous risks associated with reliance on thermal plants, such as fuel supply, volatile fuel prices, and extreme weather, among others. Though no resource is perfect, solar and wind, especially when paired with batteries, can mitigate many of these risks and costs that are passed onto ratepayers. Furthermore, adding diversity in terms of plant size, number, location and resource type also adds flexibility and reliability to DEK's portfolio.

Q Has DEK started to build replacement resources?

A No. Although the Company is continually evaluating replacement of East Bend,[81] I am not aware that DEK has started to build energy or capacity resources in preparation for East Bend's retirement.

Q Should DEK wait until closer to East Bend's retirement before starting to procure or build replacement resources?

A No, the Company should begin building resources as soon as possible.

My analysis shows the outlook for East Bend's economic performance is shaky at best. As Company witness Mr. Park has already stated, "the retirement of East

---

[79] Direct Testimony of Scott Park, pg. 9.
[80] Duke Energy Kentucky, Integrated Resource Plan, pg. 4.
[81] Direct Testimony of Scott Park, pg. 9.

Bend is more likely to be sooner than 2035 rather than later."[82] The clock is ticking: DEK may not have as much time as it currently expects.

Currently, there are numerous tax benefits available that DEK should act on now. The IRA increased the tax credits available for solar and wind and introduced new tax credits for batteries. However, many of these could expire within the next 10 years; acting now ensures that DEK and its customers can still benefit. For example, through the IRA, utility-scale wind and solar are now both eligible for a 30 percent investment tax credit (ITC), which increases to 40 percent if the facility is located in an energy community.[83] Stand-alone battery storage is also newly eligible for a 30 percent ITC. The IRA also increased production tax credits (PTC): it increased wind and solar PTCs to $26/MWh ($2022). However, the new ITC and PTC options could be phased out in 2032.[84] Another example is IRA funding that supports the retirement of aging coal plants and other assets. Through the U.S. Department of Energy's Loan Program Office, the IRA creates a $5 billion fund for low-cost loans that can be used similarly to ratepayer-backed bond securitization.[85] This program is scheduled for phase-out in 2026.[86]

[82] Direct testimony of Scott Park, pg. 10.

[83] Energy community includes census tracts where a coal-fired electric generating unit has been retired since 2009, statistical areas with 0.17% or greater fossil fuel employment since 2010, or 25% or greater local tax revenues related to fossil fuel extraction, processing, or transport.

[84] The later of 2032 or the first year that greenhouse gas emissions from U.S. electricity production are less than or equal to 25 percent of 2022 levels. Inflation Reduction Act, Pub. L. No. 117-169, § 13701 (Aug. 16, 2022), *available at:* https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

[85] Solomon, M., "Inflation Reduction Act Benefits: Billions In Just Transition Funding For Coal Communities," Forbes, Aug. 24, 2022, *available at* https://www.forbes.com/sites/energyinnovation/2022/08/24/inflation-reduction-act-benefits-billions-in-just-transition-funding-for-coal-communities/?sh=3100554e6ebd.

[86] Inflation Reduction Act, Pub. L. No. 117-169, § 1706 (Aug. 16, 2022), *available at:* https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

As I and Company witnesses have discussed, the electricity market is changing, and East Bend will be outcompeted over time by renewables. East Bend is also aging and exposed to risks that include extreme weather and fuel supply risks. East Bend may be placed on reserve shutdown more frequently, experience more forced outages and derates, or be forced to retire early. Preparing now to avoid expensive replacement energy purchases in the future will benefit ratepayers.

Furthermore, the build-out of new resources can take many years. There are numerous implementation barriers, including the PJM interconnection queue. Starting early improves DEK's preparedness for East Bend's retirement, whether in this decade or the next.

5. MECHANISMS TO MITIGATE THE RATE IMPACTS OF EARLY EAST BEND RETIREMENT

Q Describe the rate impacts that might occur with early retirement.

A If the depreciation schedule is advanced, the period shortens, and rates could increase. Another option would be to convert East Bend to a regulatory asset with the full rate of return allowed. Under this option, customers in the future will continue to pay for its depreciation while also paying for replacement energy. This can result in unequal intergenerational impacts. A third option, disallowance of the remaining depreciation value, though an immediate relief to ratepayers, can impact the Company's ability to pay off its debts. This would affect its credit score and potentially make future projects more expensive.[87]

However, DEK and the Commission have another option to consider to help minimize the costs and barriers associated with early retirement: a financial instrument known as ratepayer-backed bond securitization.

[87] Varadarajan, U., Posner, D., Fisher, J., "Harnessing Financial Tools to Transform the Electric Sector." Sierra Club (November 2018).

Q Please describe securitization in more detail.

A Ratepayer-backed bond securitization could be a win-win for both customers and the Company, in instances when costs are almost certain to be passed on to ratepayers. It would enable the Company to recover the full undepreciated amount of East Bend without increasing rates for customers.

Securitization is a refinancing mechanism; bonds are issued to raise funds to refinance the plant's undepreciated value. These bonds are paid back over time by customers through a dedicated surcharge on their bills. Although collected on utility bills, the payments go to the debt investors, rather than the utility. Importantly, the customer bond repayment surcharge is irrevocable and non-bypassable.[88] In other words, payment is guaranteed to the lender; there is zero risk that future ratepayers will not pay the bond in the future. This guarantee, or "securitization" of the repayment, means that the bond can be issued at a lower interest rate compared to typical utility interest rates.[89] Furthermore, many major credit rating agencies exclude securitization debt in their assessment of debt-to-equity ratio for utility credit scoring. This exclusion allows utilities to refinance the remaining net book value through 100-percent securitization, rather than the typical combination of debt-to-equity financing.[90] The lower interest rate, combined with 100-percent securitization financing, means that customers ultimately pay a lower overall cost compared to paying the utility directly. The

[88] "Securitization for Generation Asset Retirement: Study Group Work Products," 2020 North Carolina Energy Regulatory Process, Dec. 18, 2020, *available at* https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/Securitization-Products-Final.pdf.

[89] *Ibid*.

[90] *Ibid*.

utility also benefits by recovering of the remaining undepreciated value of the plant.

Q How is bond securitization implemented?

A Regulators create a special purpose entity, which issues the bond on behalf of ratepayers.[91] The entity also owns the future ratepayer charges (which are still collected on the utility bill) and repays the bond using those charges. This entity must be "bankruptcy remote" from the utility. In other words, should the utility encounter financial problems, the ratepayer charges dedicated to the bond would not be available to the utility or its creditors.[92] Once the obligations to the bondholders are met, the surcharge is removed from customer bills.

Q Please describe the potential benefits of securitization for utilities in more detail.

A Through securitization, the utility collects the full outstanding value of the plant; its return of capital is satisfied. Yet the return on capital, or the utility's earnings, is limited. However, the capital released through securitization can be re-invested in other capital projects, which has the potential to increase total utility earnings.[93] This is especially true if the utility invests in clean energy, which is typically more capital intensive to build than fossil plants (on a per-kWh-generated basis),[94] but has minimal fuel and operational costs. If the plant's remaining net

---

[91] Varadarajan, U., Posner, D., Fisher, J., "Harnessing Financial Tools to Transform the Electric Sector." Sierra Club (November 2018)

[92] *Ibid*.

[93] "Securitization for Generation Asset Retirement: Study Group Work Products."

[94] Varadarajan, U., Posner, D., Fisher, J., "Harnessing Financial Tools to Transform the Electric Sector." Sierra Club (November 2018)

book value is released through securitization, and re-invested in other capital projects, shareholders can see profits grow while still benefiting ratepayers.

Q Is there enabling legislation in Kentucky for securitization?

A No, not yet. Enabling legislation is required for securitization, to ensure that bond repayment is irrevocable and non-bypassable and to allow for the creation of the special purpose entity.[95] Legislation for this has been proposed in Kentucky.[96]

Q Has securitization been recommended before?

A Securitization was recommended in Cases No. 2020-00349 and No. 2020-00350, regarding the recovery of the net book value of Kentucky Utilities' and Louisville Gas and Electric Company's retired coal-fired and gas-fired generating units.

Q Has securitization been adopted in other jurisdictions?

A Yes. Securitization is not new. In fact, securitization of stranded assets—particularly, coal-related assets—is quickly becoming the industry norm. In the 1990s during utility restructuring, utilities selling generation assets could not always recoup their capital expenses when the book value of the plants turned out to be higher than their market value. As a result, states and Commissions allowed for bond securitization to compensate utilities for their stranded assets.[97] Since

[95] *Ibid*.

[96] An Act Related to Securitization of Public Utilities, S.B. 326 (Ky. introduced Mar. 3., 2022), *available at:* https://openstates.org/ky/bills/2022RS/SB326/.

[97] Varadarajan, U., Posner, D., Fisher, J., "Harnessing Financial Tools to Transform the Electric Sector." Sierra Club (November 2018)

then, it has been used widely as a tool to enable early retirements or finance pollution control upgrades.

For instance, securitization was used by Duke Energy Florida to finance $1.3 billion for the closed Crystal River nuclear plant. The bond interest rate of 2.72 percent was much lower than Duke Energy's cost of capital, avoiding $700 million in customer costs over 20 years.[98]

The New Mexico Public Regulation Commission approved the use of securitization to collect $361 million to recover costs associated with the closure of San Juan Generating Station.[99] Bond funds will be used to recover the net book value of the plant, pay for decommissioning, and provide $40 million for the economic development of the area, including assistance for laid off coal plant workers.[100]

In 2007, Allegheny Power, next door in West Virginia, used securitization bonds to finance $450 million in environmental controls, saving $130 million for ratepayers.[101]

---

[98] *Ibid*.

[99] Robinson-Avila, K. 2020, "PNM gets OK to abandon San Juan," Albuquerque Journal, *available at* https://www.abqjournal.com/1439120/prc-approves-san-juan-abandonment.html.

[100] *Ibid*.

[101] Saber Partners, LLC, "State of West Virginia, Public Service Commission," *available at* https://saberpartners.com/engagements/state-of-west-virginia-public-service-commission/.

Q Are there other options for securitization if enabling legislation is not passed in Kentucky?

A Yes. In the recently passed IRA, the U.S. Department of Energy's Loan Program Office provides $5 billion in funding to facilitate $250 billion in low-cost loans[102]. These government-backed loans act in the same way as ratepayer-backed bond securitization. Through this provision, the program requires reinvestment of the released capital. Specifically, utilities will need to "retool, repower, repurpose, or replace" retiring assets. Funding through this program expires in 2026.

Q What do you recommend for minimizing ratepayer impacts of an early East Bend retirement?

A The Commission should order the Company, as part of its IRP, to evaluate the economics of retiring the plant early (2030 or 2035) and using securitization to finance the remaining balance. This would minimize the rate shock to customers while still allowing DEK to recover the capital it invested in the plant.

6. PROPOSED CHANGES TO RATES WILL HINDER EV ADOPTION AND RESULT IN LESS EFFICIENT USE OF THE GRID

Q What principles should guide rate design?

A In his seminal work, *Principles of Public Utility Rates*, Professor James Bonbright described 10 guiding principles for rate design. These principles can be summarized as follows:

- Rates should be designed to yield revenues sufficient to recover utility costs.

[102] Inflation Reduction Act, Pub. L. No. 117-169, §§ 50141, 50144(Aug. 16, 2022), *available at:* https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

- Rates should be designed so that costs are fairly apportioned among different customers, and "undue discrimination" in rate relationships is avoided.
- Rates should provide efficient price signals and discourage wasteful usage.
- Rates should be relatively stable, predictable, simple, and easily understandable.

Q Do the Company's rate design proposals follow these principles?

A No. In particular, I have concerns regarding the efficiency and fairness of rates for customers who adopt EVs and who take service on the Company's proposed Rate R-TOU-CPP, Rate DT, or under Rider LM (for customers on Rate DS or Rate DP). My primary concerns are that the Company's rate design proposals:

1. Will result in EV customers paying more than their fair share of costs for off-peak charging;
2. Will reduce incentives to shift load to off-peak hours, resulting in less efficient use of the grid; and
3. Will hinder EV adoption by increasing the costs of charging EVs.

Q Do you agree with the Company's assertion that EV adoption will lead to benefits to all customers?

A Yes. The Company correctly argues that the incremental load from EVs will create a broader base of sales over which to spread utility costs, and that "savings to all customers are anticipated to result from increasing EV adoption due to incremental net revenue received by selling electricity to charge EVs in excess of any increases in costs of service related to the additional load."[103]

At the same time, the Company also notes that the growth in energy usage from EVs "must be actively managed to assure the greatest benefits for all customers,"

[103] Direct Testimony of Cormack Gordon, pg. 4.

primarily through smoothing charging load "to reduce the need for infrastructure growth at all levels."[104] Here I also agree with the Company that EV customers should be encouraged to charge in a manner that minimizes additional grid investments so that the benefits to all customers may be maximized.

Despite the Company's stated intent of simplifying EV adoption and setting the stage for future load management programs, I find that the Company's proposed rates are likely to undermine both goals, as I discuss below.

Q How does the Company propose to reduce the need for additional infrastructure due to EV charging load?

A The Company states that it will leverage its proposed Make Ready Credit (MRC) and Electric Vehicle Service Equipment (EVSE) tariffs to market managed charging options to customers. For residential customers, managed charging would be accomplished through the Company's proposed RS-TOU-CPP rate that encourages customers to avoid charging during on-peak hours, and particularly during critical peak hours when the electric system is most stressed.[105] The Company does not propose any new rates aimed at strengthening incentives for off-peak charging for commercial customers.

Q Will the Company's rate design proposals support the adoption of EVs and encourage customers to charge EVs during off-peak hours?

A No, for two reasons:

- First, the Company's proposed RS-TOU-CPP rate is unlikely to attract widespread enrollment in the rate, as it offers only a modest reduction in off-peak and super-off-peak ("discount") prices relative to the standard residential

[104] Direct Testimony of Cormack Gordon, pg. 6.
[105] Direct Testimony of Cormack Gordon, pg. 6.

flat rate. The rate is unlikely to achieve much success in shifting residential EV load to off-peak hours if few customers enroll.

- Second, several modifications to the Company's commercial rates would actually increase the cost of EV adoption through increasing demand charges, while reducing incentives for customers to charge during off-peak hours.

Q Please explain why the Company's proposed RS-TOU-CPP rate is unlikely to attract EV customers to enroll in the rate.

A The Company's proposed RS-TOU-CPP rate offers a very modest price discount relative to the standard residential rate (RS). Specifically, customers charging during the off-peak period would save less than a penny per kilowatt-hour, while customer charging during the discount period would save less than \$0.03/kWh, as shown in Table 3 below.

These rate differentials do not provide substantial savings to a typical residential EV customer using 300 kWh per month for EV charging. If an EV customer were to charge 100 percent during the off-peak hours, they would only save \$2.40 per month. If that customer were able to charge 100 percent during the discount hours, they would only save \$8.37 per month.

Table 3. Comparison of proposed Rate RS to proposed Rate RS-TOU-CPP, for EV owners charging during off-peak or discount periods

Rate	Rate Component	\$/kWh	Bill Cost (300 kWh/month)	Monthly Savings Relative to RS
RS	All kWh	\$0.1074	\$32.23	--
RS-TOU-CPP	Critical Peak	\$0.2486	--	--
RS-TOU-CPP	On-Peak	\$0.1491	--	--
RS-TOU-CPP	Off-Peak	\$0.0994	\$29.83	\$2.40
RS-TOU-CPP	Discount	\$0.0795	\$23.86	\$8.37

Source: Direct Testimony of Bruce Sailers, Attachment BLS-1, page 2 of 34.

Q Why do you argue that savings of between $2.40 and $8.37 per month will be insufficient to motivate many customers to enroll in the RS-TOU-CPP rate?

A A rate must provide meaningful financial incentives in order for customers to take the time and effort to enroll in the rate and shift their usage on a regular basis. This is particularly true for whole-home rates, where the customer also bears the risk that the rest of their household usage patterns could result in higher bills on the new rate.

In addition, I have reviewed EV tariffs and enrollment levels in multiple other jurisdictions and have observed that EV rates often suffer from low enrollment unless they offer the prospect of substantial savings for customers. For example, Duquesne Light Company in Pennsylvania has offered an EV time-of-use rate since June 2021. This rate provides approximately $9 in monthly savings for an EV customer who can charge during the super-off-peak period. Although Duquesne Light Company has proactively marketed the rate to customers, only 7 percent of EV drivers in its territory have enrolled in the rate.[106] In Maryland, Baltimore Gas & Electric's EV time-of-use rate offers approximately $10.50 in monthly savings for EV charging, but the utility successfully enrolled less than 5 percent of its EV customers on the rate between May 1, 2020 and June 30, 2022.[107]

---

[106] Personal communications with Emily Phan-Gruber and Lindsay Baxter of Duquesne Light Company on January 25, 2023. Duquesne Light Company offers customers a $50 incentive simply for registering their vehicle with the utility. Of approximately 7,300 EV customers, 1,644 have claimed the incentive. However, only 522 have enrolled in the EV-TOU rate.

[107] Baltimore Gas & Electric, Case No. 9478, BGE Semi-Annual Progress Report (Aug. 1, 2022), *available at* https://opendata.maryland.gov/Transportation/MDOT-MVA-Electric-and-Plug-in-Hybrid-Vehicle-Regis/qtcv-n3tc. The report lists 1,064 customers enrolled in the EV-TOU rate, while data provided by MDOT/ Maryland Motor Vehicle Administration reports 22,169 EV owners in counties served by BGE as of June 2022.

Q Do you recommend any changes to the R-TOU-CPP rate to encourage greater enrollment and load shifting?

A Yes. As shown in Attachment BLS-5, page 8, the on-peak to off-peak differentials in the R-TOU-CPP rate were developed by using generation LMP differentials as a guide. By only reflecting differentials in energy costs, the Company ignores the fact that off-peak EV charging imposes lower costs on the distribution grid than on-peak charging. By ignoring differences in costs on the distribution system, the proposed design of the R-TOU-CPP rate results in EV customers paying more than their fair share of distribution costs during the off-peak hours. To more accurately reflect cost causation and provide greater incentives for customers to enroll in the rate, I recommend that the Company strengthen the on-peak to off-peak differential. Reducing the cost of off-peak charging will also provide EV customers with greater fuel cost savings, which will support greater EV adoption.

Q What proposed modifications to commercial rates do you address in your testimony?

A My testimony addresses proposed modifications to commercial rates that would negatively impact transportation electrification in the Company's territory. Specifically, the Company proposes the following changes to its Time-of-Day Distribution Voltage Rate DT and Rider LM (for Rates DS and DP):

1. For Rate DT, a $6.23/kW non-coincident demand charge would be added to recover distribution demand costs. These costs would be removed from the other rate components.[108] When combined with the tariff's existing demand charges, the proposal would result in a demand charge of

[108] Direct Testimony Bruce Sailers, pg. 10.

$20.61/kW during winter on-peak hours, $21.43/kW during summer on-peak hours, and $7.60/kW during all off-peak hours.

2. For customers taking service on Rider LM (Load Management), billed demand would be measured as the greater of demand during on-peak hours or 50 percent of off-peak hours. Currently Rider LM only assesses a demand charge during on-peak hours.

Q What types of customers take service on Rate DT?

A Rate DT is applicable to customers with an average monthly demand of 500 kW or greater. Customers on this rate may include EV DC Fast-Charging (DCFC) customers or larger fleets customers, such as those with heavy-duty trucks.

Q What is your concern with the addition of a $6.23/kW non-coincident demand charge for Rate DT?

A I have two primary concerns.

1. Non-coincident demand charges poorly reflect cost causation and would result in customers paying too much for off-peak charging.

2. Non-coincident demand charges would substantially increase costs for public DCFC and fleet customers and create additional barriers to transportation electrification.

Q Why do non-coincident demand charges poorly reflect how costs are imposed on the system?

A Most of the distribution system is shared by multiple customers. It is the maximum simultaneous demand of all customers using a shared piece of equipment that drives the costs associated with shared equipment, not an individual customer’s maximum demand during any hour of the day. For example, if a customer’s peak demand occurs at 2 am, this demand likely has little impact on distribution capacity needs because overall demand is low during overnight hours.

Q Is it appropriate to use non-coincident demand as a cost allocator in a cost-of-service study?

A Yes, the diversified maximum non-coincident demand of a class of customers measures the maximum simultaneous demand of that class. This is a fairly reasonable approximation of the costs imposed by the class as a whole on the distribution system. However, this class non-coincident peak allocator is distinct from the sum of individual customers’ maximum demands, which can occur at any time.

To clarify, class non-coincident peak demand is a reasonable cost allocator for most distribution system costs in a cost-of-service study, but an individual customer’s non-coincident demand is generally *not* reasonable as an element in rate design. This is because a customer’s individual non-coincident peak demand may occur at an entirely different time than the class non-coincident peak demand.

Q Are there any costs that are appropriate for recovery through a non-coincident demand charge in rates?

A Non-coincident demand charges may be appropriate for the recovery of distribution equipment that is sized specifically to meet an individual customer’s maximum demand whenever that occurs (e.g., a transformer sized specifically to a customer’s individual demand). However, non-coincident demand charges are not appropriate for recovering costs associated with equipment that is shared by multiple customers, such as feeders and substations.

Q **Are there rate designs that are more cost-reflective than non-coincident demand charges?**

A Yes. There are two primary alternatives: time-limited demand charges and time-varying volumetric rates.

A time-limited demand charge that applies only during certain hours of the day reflects costs on the system more accurately, as it is assessed only during hours in which the system tends to be stressed. For example, if DEK's feeder and substations typically peak between the hours of 4 pm and 8 pm, a demand charge might be designed to only apply during these hours. This would more closely approximate a customer's contribution to distribution capacity costs than a non-coincident demand charge. Indeed, this is the type of demand charge that the Company currently uses.

An even better alternative is the use of time-varying volumetric charges. Whereas a demand charge only measures a customer's highest demand during the month, a time-varying rate also accounts for the duration of that demand. Accounting for the length of time that a customer uses shared equipment is important, as that impacts the ability of other customers to also use that equipment. Consider two customers using the same piece of distribution equipment:

- Customer A typically uses 300 kW but experiences occasional, brief bursts of demand to 600 kW.
- Customer B's demand is typically 600 kW but occasionally falls to 300 kW.

In this example, both customers would face a demand charge based on 600 kW of demand. However, the system may be able to accommodate many customers with demands similar to Customer A if the timing of the customers' peak demands are fairly staggered. That is, there is likely to be greater diversity of demand on the system for customers with load similar to Customer A. In contrast, the distribution system would likely not be able to accommodate as many customers with demands similar to Customer B, because the maximum demands of such customers would be more likely to overlap. In other words, because Customer B uses 600 kW of demand more regularly, there is less potential for load diversity to accommodate multiple customers.

By accounting for the volume of usage of a customer during hours when the system is stressed, a time-varying volumetric rate better reflects the fact that Customer B imposes demands of 600 kW on the distribution system far more than Customer A, thereby precluding other customers from using the same equipment. Unlike volumetric rates, a demand charge cannot account for this.

Finally, I note that non-coincident demand charges simply encourage customers to spread their charging evenly over the course of the day. This could have the perverse incentive of encouraging some charging to shift from off-peak to on-peak hours to flatten demand, despite the system facing capacity constraints only during on-peak hours.

Q Why do you claim that non-coincident demand charges would create additional barriers to transportation electrification?

A The addition of a demand charge to Rate DT would substantially increase costs for public DCFC and fleet customers. In particular, DCFC stations frequently experience low load factors, where the quantity of electricity consumed (kWh) is low but the demand (kW) is high. For low-load-factor DCFC customers, demand charges tend to dominate customers' electric bills and make it difficult to earn sufficient revenue to cover their costs.[109] Access to fast-charging infrastructure is

---

[109] *See, e.g.*, Fitzgerald, Garrett, and Chris Nelder. DCFC Rate Design Study, Rocky Mountain Institute, 2019, *available at* http://www.rmi.org/insight/DCFC-rate-

critical for reducing "range anxiety" and supporting transportation electrification. Range anxiety is of particular concern in rural parts of the state. It is also important to enable EV adoption among customers without access to at-home charging (such as those living in apartment buildings).

Likewise, medium- and heavy-duty EVs (such as buses and freight trucks) may require fast-charging capabilities to quickly recharge their large capacity batteries between routes. Again, these customers may have low load factors, particularly in the early days of fleet electrification. Because demand charges would disproportionately increase bills for low-load-factor customers, they may make electrification of fleets uneconomic and impede adoption of medium- and heavy-duty EVs. Lower adoption of medium- and heavy-duty vehicles also has equity implications, as lower-income customers are more likely to utilize public transit and live in communities that suffer from high levels of air pollution from vehicle operations.

Q What does your analysis show regarding the potential impacts on customers' bills from the Company's proposed additional demand charge for Rate DT?

The additional distribution demand charge proposed for Rate DT will disproportionately increase bills for owners of DCFC stations and large EV fleets, relative to the rest of the class, while also discouraging off-peak charging (Table 4). I estimated the bill impacts for hypothetical customers with public DCFC stations or EV fleets. For customers who charge the EVs during both on and off

---

designstudy; *and* Garrett Fitzgerald and Chris Nelder, EVgo Fleet and Tariff Analysis, Rocky Mountain Institute, Mar. 2017, *available at* www.rmi.org/wpcontent/uploads/2017/04/eLab_EVgo_Fleet_and_Tariff_Analysis_2017.pdf.

periods, their effective rate ($/kWh)[110] increased an additional 19 to 29 percent more than the class average rate increase.[111] In other words, owners of public DCFC stations or EV fleets are impacted disproportionately relative to the rest of the rate class.

More specifically, the effective cost of electricity for a DCFC station with a 5% load factor would increase from $0.44/kWh to $0.62/kWh. For customers who primarily charge off-peak and who were previously benefitting from low demand charges during that period, the effective rates would more than double due to the addition of the non-coincident demand charge. These customers could expect an effective rate increase of between 66 percent and 97 percent over the class average rate increase. The fact that customers who charge primarily off-peak would see the largest percentage rate increases is particularly alarming, given the Company's purported focus on minimizing costs associated with EV charging.

[110] The total effective rate is the total bill divided by the total kWh of a customer (in other words, it is a measure of all charges on a per kWh basis).
[111] Direct Testimony of Bruce L. Sailers, Attachment BLS-1, pg. 33.

Table 4. Comparison of current and proposed Rate DT (effective rate, \$/kWh), and percent change relative to class rate increase, for commercial customers with an EV fleet

Example Customer	Charging Periods (on peak vs off)	Effective Rate \$/kWh		% Change Relative to 12% Class Average Rate Increase
		Current	Proposed	
DC Fast Charger	On & off	\$0.44	\$0.62	29%
Tractor Trailer Fleet	On & off	\$0.13	\$0.17	19%
Tractor Trailer Fleet	Off only	\$0.05	\$0.09	66%
School Bus	Off only	\$0.05	\$0.11	97%

Source: Direct Testimony of Bruce L. Sailers, Attachment BLS-1, pg. 3. Analysis only includes base rates, including customer charge, but does not include any additional riders or taxes. Load curves for tractor trailer and school bus customers based on LBNL HEVI-Pro, modified to reflect lower load diversity of individual sites. (Lawrence Berkeley National Laboratory, "HEVI-Pro load profiles," provided to Synapse Energy Economics in August 2022). Assumes tractor trailers are 5-vehicle fleet, and school buses are 30-vehicle fleet. Load curves for DCFC from Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite, Alternative Fuels Data Center, US Department of Energy. Assumes 4-port DCFC charger, charged simultaneously for maximum demand. No non-EV load assumed.

Q What do you recommend regarding the Company's proposed modifications to Rate DT?

A I recommend that the Commission reject the Company's proposed modifications to Rate DT and require the Company to maintain the use of time-varying volumetric rates for the recovery of distribution costs, rather than shifting these costs into a non-coincident demand charge. The introduction of a non-coincident demand charge would poorly reflect cost causation, reduce incentives to charge during off-peak hours, and would undermine transportation electrification for DCFC customers and medium- and heavy-duty fleets.

Q What changes does the Company propose regarding Rider LM?

A The Company proposes to change the measurement of billed demand for Rider LM for Rates DS and DP (Distribution Secondary and Distribution Primary for customers with demand <500 kW). Currently Rider LM measures billed demand only during on-peak hours. The Company's proposal would change the definition of billed demand to be the greater of demand measured during on-peak hours or 50 percent of off-peak hours.

Q **Please explain your concerns regarding the application of the demand charge to off-peak hours for Rider LM.**

A My concerns hinge on the fact that including off-peak hours in the tariff would result in customers paying too much for charging during off-peak hours, resulting in lower adoption of EVs and inefficient use of the system.

As discussed above for Rate DT, the costs associated with shared distribution system equipment are driven by the maximum simultaneous demand of multiple customers, not individual customers. During off-peak hours, system demand is low, leaving substantial spare capacity to serve off-peak load. Further, the terms and conditions in the tariff state, "The Company shall not be required to increase the capacity of any service facilities in order to furnish off peak demands," which protects the Company from customers imposing excessive demand during off-peak hours without paying for any necessary upgrades to serve that demand. In sum, the Company's proposal would result in customers paying too much for off-peak EV charging. This in turn would raise the costs of fleet electrification for customers who charge during off-peak hours and it would slow transportation electrification in general.

In addition, the Company's proposal would result in less efficient use of the system. Specifically, a demand charge that applies during off-peak hours would reduce the incentive for customers to shift as much load to off-peak hours as possible. Instead, customers would face a perverse incentive to shift some charging from off-peak to on-peak hours to create a flatter load profile, despite the system facing capacity constraints only during on-peak hours.

Q What does your analysis show regarding the potential impacts on customers' bills from the Company's proposed changes to Rider LM?

A The proposed change to Rider LM impacts customers with EV fleets who primarily charge during off-peak hours. I calculated the impact of the proposed changes for two example customers with EV fleets. As can be seen in Table 5, on average, the proposed Rider LM results in a 50-percent increase in total effective rate (in $/kWh). The average 50-percent increase is substantially larger than the proposed class rate increase[112] of 15.9 percent and 13.1 percent for Rates DS and DP, respectively.

Table 5. Comparison of proposed Rider LM to current Rider LM (effective rate, $/kWh), for commercial customers with an EV fleet

Rate	Example Customer	Effective Rate $/kWh		% Change
		Current Rider LM	Proposed Rider LM	
DS	School Bus Fleet	$0.08	$0.12	59%
DP	School Bus Fleet	$0.07	$0.12	63%
DS	Medium-Duty Vehicle Fleet	$0.09	$0.12	37%
DP	Medium-Duty Vehicle Fleet	$0.08	$0.12	49%

Source: Direct Testimony of Bruce L. Sailers, Attachment BLS-1, pg. 3 (Rate DS), pg. 5 (Rate DP), pg. 22 (Rider LM). Analysis only includes base rates, including customer charge, for Rates DS and DP (with Rider LM), but does not include any additional riders or taxes. Load curves for tractor trailer and school bus customers based on LBNL HEVI-Pro, modified to reflect lower load diversity of individual sites (Lawrence Berkeley National Laboratory, "HEVI-Pro load profiles," provided to Synapse Energy Economics in August 2022). Assumes 10 vehicles per fleet, with 100% off-peak charging, and no additional monthly load.

Q What do you recommend regarding Rider LM?

A I recommend that the Commission reject the Company's proposed modification to Rider LM and require the Company to maintain the application of demand

[112] Direct Testimony of Bruce L. Sailers, Attachment BLS-1, pg. 33.

charges under Rider LM to on-peak hours only, as this would be more cost-reflective and better support transportation electrification.

Q **Does this conclude your testimony?**

A Yes.