COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC 2021 INTEGRATED	**)**	**CASE NO.**
RESOURCE PLAN OF DUKE	**)**	**2021-00245**
ENERGY KENTUCKY, INC.	**)**	

SIERRA CLUB'S PREHEARING COMMENTS ON DUKE ENERGY KENTUCKY'S 2021 INTEGRATED RESOURCE PLAN

Sierra Club hereby submits its prehearing comments on the 2021 Integrated Resource Plan ("2021 IRP") of Duke Energy Kentucky (hereinafter "Duke" except as otherwise stated). These comments are subject to supplementation by future comments after the public hearing in this matter, as contemplated by the Commission's September 9, 2021, Order in this case. At the outset, Sierra Club wishes to thank Duke's counsel and other staff for their efforts, candor, and collegiality in responding to Sierra Club's discovery requests. Further, Sierra Club appreciates all the work that went into the 2021 IRP and is grateful for Duke's receptiveness to input on its planning going forward.

Sierra Club's comments at this juncture concern Duke's plans for its East Bend 2 coal-fired unit. The 2021 IRP moves the unit's tentatively predicted retirement year from 2041 to 2035.[1] Notably, 2027 is the optimal retirement year in Duke's Base Case, the Reference with a Carbon Regulation Scenario, which "is a description of those expectations considered [by Duke to be] most likely to unfold over the 15-year planning period with no major disruptions to the business environment."[2] In other words, in the set of circumstances that Duke currently believes

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[1] *E.g.*, 2021 IRP at 4, 65.

[2] *Id.* at 12, 42; Duke Response to Sierra-DR-02-002(a), (b) (Dec. 17, 2021).

is more likely to manifest than any other set, Duke would retire the East Bend 2 coal unit in 2027 (and perhaps even earlier, depending on gas prices[3]). At first blush, that position may seem at odds with Duke's response to the Attorney General's question, "Q: Based on all facts and circumstances known today, and recognizing the rapidly changing regulatory environment, provide the year for East Bend's retirement which [Duke] believes to be most likely," to which Duke responded "A: At the time of this IRP analysis, the Company believes that the most likely retirement year for East Bend 2 is 2035, as indicated in the preferred portfolio . . . ."[4] By way of reconciliation, Duke suggests that its Base Case scenario, although more likely than any other given single set of assumptions, is not necessarily more likely than not to manifest (*i.e.*, it has only plurality, not majority, likelihood); and that the combined probabilities of other sets, in conjunction with Duke's analysis of risk and optionality, render 2035 the most appropriate retirement year to project at present.[5] Sierra Club appreciates Duke's explanations and will likely follow up on this at the hearing.

Next, in support of the conclusion that retiring East Bend 2 earlier than 2035 would be economical (while preserving reliability and satisfying capacity obligations), Sierra Club submits the Technical Comments attached hereto as Exhibit A. The Technical Comments suggest that

[3] 2021 IRP at 42 ("When evaluated in a low gas environment, the retirement of East Bend 2 is accelerated even further to 2025 and largely replaced by a combined cycle resource.").

[4] Duke Response to AG-DR-01-001(j) (Oct. 22, 2021).

[5] Duke Response to Sierra-DR-02-002(c); *see also* 2021 IRP at 42-43 ("The takeaway from these three scenarios is that, should carbon regulation come to fruition of a similar magnitude to what is assumed in this IRP, economic retirement of East Bend 2 follows within a few years. Given the swiftness with which carbon regulation can impact the Duke Energy Kentucky portfolio in a significant way, preserving the option to react is paramount."); *id.* at 65 ("Retirement of East Bend 2 was accelerated to 2035, compared to the 2041 retirement date in the most recent rate case. This approach better positions the portfolio to respond to risk drivers identified in the scenarios that called for the retirement of East Bend 2 in the mid-2020s. This will also make the transition once East Bend 2 retires less impactful to customers by preparing for that possibility.").

East Bend 2 could be economically retired and replaced by a clean energy portfolio (including renewable generation and battery storage) as early as 2022-2024, depending on DSM assumptions. Further, the analysis further indicates that retiring East Bend 2 and replacing it with a clean energy portfolio in 2027 (*i.e.*, the year in which Duke tentatively plans on replacing the coal-fired unit with a combination of gas and solar generation under the current Base Case scenario[6]) could save customers between $61 million and $239 million through 2035 (*i.e.*, the retirement year currently selected by the 2021 IRP overall) relative to the cost of keeping the unit coal-fired. Sierra Club of course understands that a future docket will be the time and place for Duke to present, defend, and request approval of a specific replacement proposal versus alternatives, and that the prudence of Duke's tentative plan to replace East Bend 2's coal unit with at least some gas generation is not yet ripe for decision. Sierra Club nonetheless offers the attached Technical Comments at this time for the going-forward benefit of Duke, the Commission, stakeholders, and the public. In a word, Duke should retire East Bend 2 sooner rather than later, and gas should not be a presumptive favorite in the replacement mix.

At the upcoming hearing, Sierra Club will likely have questions about carbon emissions reduction goals, and how they do or do not factor into Duke's planning, in addition to the topics above and potentially other issues as well. Sierra Club thanks Duke, the Commission, Staff, and the other parties for their consideration, and looks forward to continued dialogue.

Dated: January 10, 2022

Respectfully submitted,

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Of counsel
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[6] 2021 IRP at 42.

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CERTIFICATE OF SERVICE

This is to certify that the foregoing copy of SIERRA CLUB'S PREHEARING COMMENTS ON DUKE ENERGY KENTUCKY'S 2021 INTEGRATED RESOURCE PLAN in this action is being electronically transmitted to the Commission on January 10, 2022; and that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding.

JOE F. CHILDERS

EXHIBIT A
Sierra Club Technical Comments in PSC Case No. 2021-00245

Analysis of Public Information Suggests That a Clean Energy Portfolio Can Cost Effectively Replace East Bend 2 Coal Unit by 2022-2024

I. Overview

Sierra Club analysts find, based on an analysis of publicly available information, that **a clean energy portfolio (CEP) could satisfy the same energy and capacity needs as Duke Energy Kentucky's East Bend 2 power plant, at a cheaper cost than continuing to maintain and operate the coal-fired unit, as early as 2022**, depending on the nature and assumptions of the clean replacement portfolio. Moreover, **retiring and replacing East Bend 2 with clean energy after 2027—i.e., the year that Duke's IRP contemplates replacing East Bend 2 with a combination of gas and solar under certain scenarios—could save customers between $61 million and $239 million through 2035—i.e., the unit's currently projected retirement year—relative to the cost of keeping the unit coal-fired.** These findings are based on relatively conservative assumptions about the technology, economics, and electricity grid needs. Interceding developments, such as more stringent regulations or faster technological advancements, could further improve the economic advantage of replacement with clean energy.

The CEP that Sierra Club assesses in this analysis consists of wind, solar, storage, energy efficiency, and/or demand response technologies. While Duke should increase its current demand-side management (DSM) portfolio in its replacement clean energy portfolio, even if the utility does not do so, the CEP *without* any DSM is still less costly than continuing to operate East Bend 2 as a coal-fired plant by the year 2023. Moreover, replacing East Bend 2 with a CEP without DSM in 2027 could save customers roughly $134 million through 2035.

Meanwhile, a narrower clean portfolio that looks exclusively to solar generation coupled with battery storage renders a breakeven retirement year of 2024, and could save customers roughly $61 million between 2027 and 2035.

This analysis suggests that, from a cost-savings perspective alone, Duke should revisit its tentative plans not to retire East Bend 2 until 2035. Further, when the time comes to retire and replace (to the extent that may be necessary) East Bend 2, Duke should robustly assess clean energy options; gas-fired generation should not be a presumptively preferred replacement option.

II. Analysis

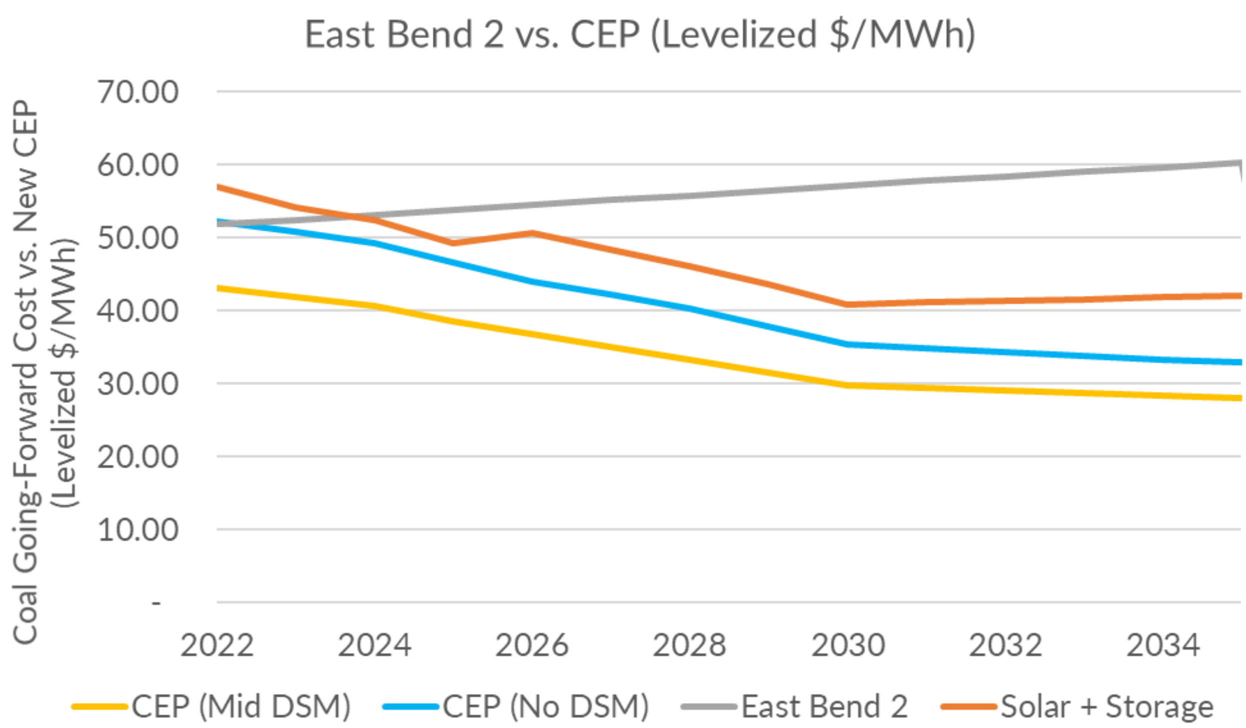
In our methodology, the CEP is constructed to match the energy, peak capacity, and ramping characteristics of the East Bend 2 coal unit, using an optimization model that selects the least-cost set of resources that meet these performance characteristics. The CEP model also accounts for region-specific capacity factors for renewable energy, and resulting portfolios have equivalent or better capacity contribution as East Bend 2, using PJM's values for capacity contributions of renewable energy and storage resources.[1] The technologies included in the CEP model are various forms of energy efficiency and demand response measures within residential, commercial, and industrial customer sets, as well as wind, utility scale solar PV, and battery storage. Once a CEP is selected by the model to match the coal plant's performance, we compare the cost of both building and operating that CEP, to the going-forward costs of operating the existing coal plant. When the CEP cost becomes cheaper, the coal plant is 'stranded' by the CEP. In an economist's terms, this is when the *total* cost of a new solution becomes cheaper than the *marginal* cost of an existing solution.[2] At this point, the sunk costs of the coal plant are the same in both the CEP case and the coal plant case; but going forward, building and operating the CEP would result in cost savings for customers.

The results of the CEP model are shown below in Figure 1 (cost comparison with coal plant) and Table 1 (technology mix of the clean energy portfolio). **The levelized cost of energy (LCOE) of the CEP would be lower than the cost of continuing coal operations by the year 2022, under the DSM scenario; by 2023, under the no-DSM scenario; and by 2024, under more limited solar-plus-storage scenario. Assuming replacement of East Bend 2 in 2027, these replacement options would save customers $239 million, $134 million, or $61 million, respectively, through the currently projected the lifetime of East Bend 2.** These savings are calculated as the net present value of the coal plant costs that would be avoided by retirement, less the annualized clean energy portfolio costs, between 2027 and 2035. More details on our methodology and data sources are discussed in the Sources and Methodology section below.

[1] We estimate the capacity contribution of CEPs to range from 572 MW (with DSM) to 981 MW (Solar + Storage), compared with an estimated 553 MW for East Bend 2 (600 MW operating capacity with an assumed 7.8% forced outage factor). See Table 1, *infra*. We recognize that Duke "intends to retain its status as a fixed resource requirement (FRR) entity." IRP at 7. Assuming Duke does maintain FRR status, Duke's methodology for evaluating the contribution of resources to its capacity obligation should align with that used by PJM for resources participating in the region's capacity auctions. Nevertheless, the present analysis still tends to demonstrate that retirement of East Bend 2, and replacement with a CEP, substantially earlier than 2035 is cost effective.

[2] In this case, the long-run marginal cost of continuing to operate the plant inclusive of fixed operating and going-forward capital costs, not the short-run marginal cost of dispatching the plant.

Figure 1: Cost comparison of building and operating a new clean energy portfolio vs. cost of operation of coal-fired East Bend 2



Importantly, a portion of the CEP can be supplied by demand-side technologies that are cheaper than building large new power plants and thus save customers more money.

In 2019, the American Council for an Energy Efficient Economy (ACEEE) gave utilities in Kentucky a 1 out of 20 score (the lowest possible score) on their energy efficiency scorecard.[3] In their 2020 scorecard, ACEEE found that on average utilities will achieve energy efficiency savings equivalent to 1% of their annual sales.[4] According to EIA-861 filings, for 2020, Duke Energy Kentucky reported average annual incremental savings from energy efficiency of 7,149 megawatt-hours ("MWh") in the residential sector and 10,464 MWh in the commercial sector.[5] The utility's total sales in 2020 was 1.5 million MWh in the residential sector and 1.6 million MWh in the commercial sector, leading to incremental energy efficiency achievement of 0.5% and 0.6% of sales in these sectors, respectively. This is a low level of achievement; it means that the utility is leaving significant cost-effective energy efficiency potential unmet. Duke Energy

[3] ACEEE State and Local Policy Database, Kentucky (navigate to the "Utilities" tab), available at: https://database.aceee.org/state/kentucky.

[4] 2020 Utility Energy Efficiency Scorecard (Feb. 2020), Grace Relf *et al.*, ACEEE, at p.26 table 8, available at: https://www.aceee.org/sites/default/files/pdfs/u2004%20rev_0.pdf (compilation of data in table).

[5] See below for EIA and other sources as well as methodology.

Kentucky's own integrated resource plan (IRP) does not signal a ramp-up in energy efficiency investment. Rather, the IRP includes energy efficiency plans that would add at most 13,900 MWh of incremental energy efficiency per year, less than 0.4% of 2020 sales, with incremental energy savings from efficiency declining over time.[6]

While Duke should include increased demand-side management (DSM) in its replacement clean energy portfolio, even if it does not, the CEP without any DSM is still lower cost than continuing coal operations by the year 2023, and would save customers $134 million between 2027 and 2035, as explained above.

Table 1: Technology breakdown for clean energy portfolio to replace East Bend 2

	Solar (MW)	**Wind (MW)**	**Storage (MW)**	**Energy Efficiency (MW)**	**Demand Response (MW)**	**Capacity Contribution (MW) (2024/25 PJM ELCC Values)**
CEP (No DSM)	847	758	369	0	0	729
CEP (DSM)	582	633	231	208	72	572
Solar + Storage	1362	0	600	0	0	982

Notes: Capacities refer to alternating current (AC) capacity, rather than direct current rating of solar modules. Efficiency capacity refers to non-coincident peak load savings, rather than on-peak savings. Capacity contribution calculated based on PJM estimated effective load carrying capability values for solar, wind and energy storage for 2024/25, see: https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-class-ratings-for-2024-2025.ashx. Solar uses fixed-tilt value, storage uses 4-hour value, demand response based on full value, and capacity contribution of efficiency excluded.

[6] IRP at p. 41

III. Sources and Methodology

Sources

The data sources for this analysis are from public sources, as provided by S&P Global Market Intelligence, including data reported by Duke Energy Kentucky, Inc., to the Energy Information Administration (EIA) and Federal Energy Regulatory Commission (FERC) on fuel costs and operations and maintenance expenses.

- Coal and gas price forecasts: EIA Annual Energy Outlook 2020 Reference case: https://www.eia.gov/outlooks/aeo/
- Fuel Costs, variable and fixed operations and maintenance costs: FERC Form 1, as provided by S&P Global Market Intelligence.
- Going-forward capital expenditures: Estimated consistent with equation used in EIA Annual Energy Outlook https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf (p. 14), and Sargent and Lundy. “Generating Unit Annual Capital and Life Extension Costs Analysis”. https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf
- Coal unit capacity factors, monthly and annual: 2018-2020 averages, as reported to EIA Form 923.
- Clean Energy Portfolio model: Rocky Mountain Institute, “The Growing Market for Clean Energy Portfolios,” https://rmi.org/insight/clean-energy-portfolios-pipelines-and-plants/

Clean energy portfolio

For this analysis, we used the Rocky Mountain Institute’s (RMI) Clean Energy Portfolio’s model originated in its 2019 report “The Growing Market for Clean Energy Portfolios”, and updated in 2021, to identify a suite of clean energy technologies (wind, solar, storage, energy efficiency, and demand response) that could replace the services of the coal plant.

A clean energy portfolio, or CEP, is a portfolio of renewable energy, storage, and demand-side management (DSM) projects that meets the performance characteristics of a given fossil fuel fired power plant. We use the term DSM to collectively refer to energy efficiency projects (which lead to a reduction in load) and demand response projects (which lead to the shifting or temporary reduction of load). This CEP analysis evaluates a range of available clean energy resources’ contribution in each hour of the year, and identifies the portfolio that meets the performance characteristics of a given fossil fuel power plant at the lowest cost. In this study, the CEPs are constructed to match the energy, peak capacity, and ramping characteristics of the coal plant. Portfolios are optimized to satisfy these needs at the lowest cost possible.

The CEPs are conservatively designed to meet peak capacity needs in the top 50 hours of capacity need of the year in PJM, the grid region where Duke operates, however, as shown in Table 1 above, the resultant portfolios have capacity contributions similar to or exceeding that of East Bend 2, using PJM's capacity accreditation rules. The CEP also must meet the average monthly energy requirement of the coal plant's total generation in each month of the year, based on average monthly performance from 2018 to 2020. The CEP algorithm errs on the side of caution, in the sense that the optimization does not account for the availability of other grid resources (like existing plants or market purchases), even though those resources are typically included in system dispatch or capacity expansion models that utilities utilize in portfolio analysis. In other words, the CEP algorithm accounts for a complete energy and capacity replacement of the coal plant *without the benefit of any other existing grid resources*. We assume that energy efficiency and demand response could only account for up to 25 percent of the replacement energy and capacity of replacement portfolios, respectively.

RMI's model uses storage and renewable cost assumptions from NREL ATB Advanced scenario — a widely-used source of cost estimates for future resource cost projections.[7] In addition, the modeling includes the solar investment tax credit (based on current law, under which the credit steps down from 30 percent to 10 percent for projects that begin constructions between 2021 and 2024) , excludes the wind production tax credit, and excludes an investment tax credit for storage (even though many storage projects qualify for that tax credit by pairing with solar). Any excess energy that renewables produced beyond the coal plant was conservatively valued at $15/MWh.

In addition, this optimized CEP was compared with a more constrained solar plus storage replacement, which was calculated as the levelized cost of utility-scale solar, sized to meet annual energy requirements from East Bend Unit 2, plus battery energy storage sized to meet the full operating capacity of East Bend Unit 2 with four hours of duration. This evaluation is also based on NREL ATB Advanced Scenario cost assumptions, and incorporate the current investment tax credit schedule for utility-scale solar.

Both the CEP (with and without DSM) and the solar plus storage scenarios are then compared to the going-forward cost of continued operation of the coal plant, based on reported fuel, operations and maintenance costs and estimated going-forward capital costs.

Dated: January 10, 2022

<u>*/s/ Brendan Pierpont*</u>
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[7] National Renewable Energy Laboratory, Annual Technology Baseline. https://atb.nrel.gov/