February 13, 2025

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Re: Sierra Club's comments on Duke Energy Indiana's 2024 IRP

I. Introduction

The Sierra Club[1] appreciates Duke Energy Indiana's cooperation and responsiveness throughout the stakeholder process. We offer the following comments on the integrated resource plan (IRP) which address our main concerns with Duke's decisions on its fossil-fueled units. These key concerns include:

1. **The significant, near-term gas buildout included in the preferred plan is costly.** We find that Blend 1—which reduces the new build by converting Cayuga to gas rather than build new gas at that site—is a superior plan even by Duke's own metrics, including being more cost-effective in almost all scenarios.
2. **The delayed conversion of Edwardsport to a fully gas-powered plant in 2030 is costly.** We discuss how Duke's modeling shows that 2028 is more cost-effective and therefore should be a component of the preferred plan—regardless of the need for environmental compliance.
3. **Duke should not consider CCS at Edwardsport.** The variation on the preferred plan that includes CCS shows lower costs, but it relies on assumed high performance of the CCS technology and leads to higher fleetwide emissions.
4. **The projected performance of the coal fleet in Duke's modeling is overly optimistic relative to historical performance.** The modeling shows unrealistic

[1] These comments were prepared with assistance from Tyler Comings, Joshua Castigliego, and Jordan Burt at Applied Economics Clinic.

operations for many coal units due to unrealistic assumptions for operating efficiency and fuel costs.

5. **Clean resource replacement costs are overstated which leads the model to unfairly favor gas replacement when optimizing portfolios.** If more reasonable costs were used, then the Company would likely plan for additional clean resources in the short- to medium-term.

The sections below discuss these concerns in more detail. Ultimately, we find that Duke's own modeling, as well as our own analysis, shows that an earlier conversion of Edwardsport and conversion of Cayuga to gas are well-supported and should be incorporated in the final IRP's preferred plan.

II. Summary of Duke's preferred plan and modeling framework

In its 2024 IRP, Duke's preferred portfolio includes the following decisions for its coal units: (1) Edwardsport is converted to gas by 2030; (2) the Cayuga coal plant is fully retired by 2031; (3) Gibson units 1 and 2 are co-fired with 40 percent natural gas starting in 2032 and then retired by 2039; (4) Gibson units 3 and 4 are retired in 2032; and (5) Gibson unit 5 is retired in 2030.[2] In choosing this plan (also called "Blend 2"), the Company conducted capacity expansion and production cost modeling using the EnCompass model.[3] The capacity expansion stage allows for economic optimization of new resource builds to meet customer energy and peak demand needs over the planning period. Duke pre-set coal unit decisions in each portfolio; thus, the model selects new capacity to fulfill replacement capacity and/or new energy requirements that arise from changes to an existing resource and load growth. The portfolio determined by the capacity expansion modeling is then evaluated in production cost modeling that dispatches the expansion plan optimally to arrive at a system-wide cost, or present value revenue requirement ("PVRR") for comparison of costs between scenarios and sensitivities.

The reference case portfolios modeled by Duke are shown below in Table 1. The first six portfolios under the Company's reference case assume compliance with EPA's Clean Air Act Section 111(d) regulation. The last five portfolios are variations of the preferred portfolio that the Company tested, including converting Edwardsport to two years earlier (2028) or installing carbon capture and sequestration (CCS) at the plant—among others.

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[2] 2024 Duke Energy Indiana IRP, Executive Summary (DEI 2024 IRP), 2024, p. 15. Available at: https://www.duke-energy.com/-/media/pdfs/for-your-home/dei-irp/2024-plan-and-attachments/vol-i-complete-2024-dei-irp-plan.pdf?rev=93f4e009ddfc44b0baa3f94f3e195b4a. All retirement dates are for January 1st of the stated year.
[3] *Id*. at 56.

Table 1: Duke Coal Unit Decisions by Portfolio (Reference Case)[4]

Portfolio	Coal Retirement/Gas Conversion/2030 Co-firing							
	Edwardsport	Cayuga 1	Cayuga 2	Gibson 1	Gibson 2	Gibson 3	Gibson 4	Gibson 5
Blend 1	**2030**	**2030**	**2030**	2032	2032	2032	2032	2030
Blend 2	**2030**	2030	2031	**2039**	**2039**	2032	2032	2030
Blend 4	**2030**	2030	2031	**2039**	**2039**	**2030**	**2030**	2030
Convert Coal Units (CCU)	**2030**	**2030**	**2030**	**2039**	**2039**	**2030**	**2030**	2030
Retire Coal Units (RCU)	**2030**	2032	2032	2032	2032	2032	2032	2030
Stakeholder	**2030**	**2029**	**2029**	2032	2032	2030	2030	2030
No 111d	**2035**	2032	2032	2036	2036	2032	2032	2030
Blend 2 - No 111d	***2030***	*2030*	*2031*	***2039***	***2039***	*2032*	*2032*	*2030*
Blend 2 - Gibson 1&2 conversion	***2030***	*2030*	*2031*	***2032***	***2032***	*2032*	*2032*	*2030*
Blend 2 - Eport conversion in 2028	***2028***	*2030*	*2031*	***2039***	***2039***	*2032*	*2032*	*2030*
Blend 2 - Eport CCS	*none*	*2030*	*2031*	***2039***	***2039***	*2032*	*2032*	*2030*
Blend 2 - 2x1 NGCC	***2030***	*2032*	*2032*	***2039***	***2039***	*2032*	*2032*	*2030*

The selection and timing of alternatives considered at the coal units—converting, co-firing, or retiring—are largely driven by compliance with the 111(d) rule. There is limited optimization of coal unit options under a non-111(d) future. The Company only optimized one reference case portfolio without 111(d) compliance and tested one variation of its preferred plan without compliance being required—but the latter plan is composed of coal unit decisions made to comply with 111(d). The decisions for other coal units are also fixed for the one non-111(d) optimization. Regarding Edwardsport, the Company fixed the gas conversion for 2035 in its no-111(d) optimization—despite modeling 2030 in its other reference case portfolios with 111(d). Given this limited framework, it would be a mistake to assume that 2030 conversion of the plant would only make sense if 111(d) compliance were required. As we discuss further in these comments, early conversion of Edwardsport makes sense regardless of future compliance requirements.

In addition to the reference case, the Company also modeled two alternative scenarios that depart from the reference case future: (1) the Aggressive Policy and Rapid Innovation (APRI) scenario assumes a carbon tax, high fuel prices, extension of Inflation Reduction Act (IRA) tax credits for clean resources, and low clean resource costs (among others); and (2) the Minimum Policy and Lagging Innovation (MPLI) scenario assumes no carbon tax, repeal of the IRA, repeal of 111(d) and low fuel prices (among others).[5] The Company also conducted several sensitivities by optimizing portfolios under individual changes to conditions including: low load, high load, and high capital costs for new gas units.[6] Importantly, these alternative scenario and sensitivity portfolios keep the coal unit decisions from the corresponding reference case portfolio fixed; they only allow the model to choose a different suite of replacement resources given the

[4] *Id*. at 251. The events in this charge are modeled to occur on the first day of the year.
[5] DEI 2024 IRP at 252.
[6] DEI 2024 IRP at 257. Seasonal accreditation was also modeled as a sensitivity but only for the Retire Coal and Convert Coal portfolios.

alternative conditions. In addition, the Company also tested the sensitivity of holding the reference case portfolios completely fixed but operating under low and high fuel prices.[7]

III. Duke's Blend 1 portfolio is a more cost-effective and lower-risk plan than Blend 2, its preferred plan

After a review of Duke's modeling, we find that Blend 1 is the superior portfolio to Blend 2 and we encourage the Company to adopt it for several reasons: (1) Blend 1 reduces new gas plant investments by relying on coal-to-gas conversion at Cayuga; (2) Blend 1 is a cheaper plan in almost every run conducted by Duke; and (3) Blend 1 is a less risky and more reliable plan by Duke's own analysis.

A. Blend 1 reduces new gas investments by converting Cayuga

One key difference between Blend 1 and Blend 2 (Duke's preferred plan) is that Blend 1 converts Cayuga to gas and builds a new natural gas combined cycle (NGCC) in 2032, whereas Blend 2 *replaces* Cayuga with an NGCC in 2030. Figures 1 and 2 below show the comparison of new capacity additions between Blend 2 and Blend 1, respectively.

[7] *Id*.

Figure 1: Duke's Preferred Plan (Blend 2) Additions (MW)[8]

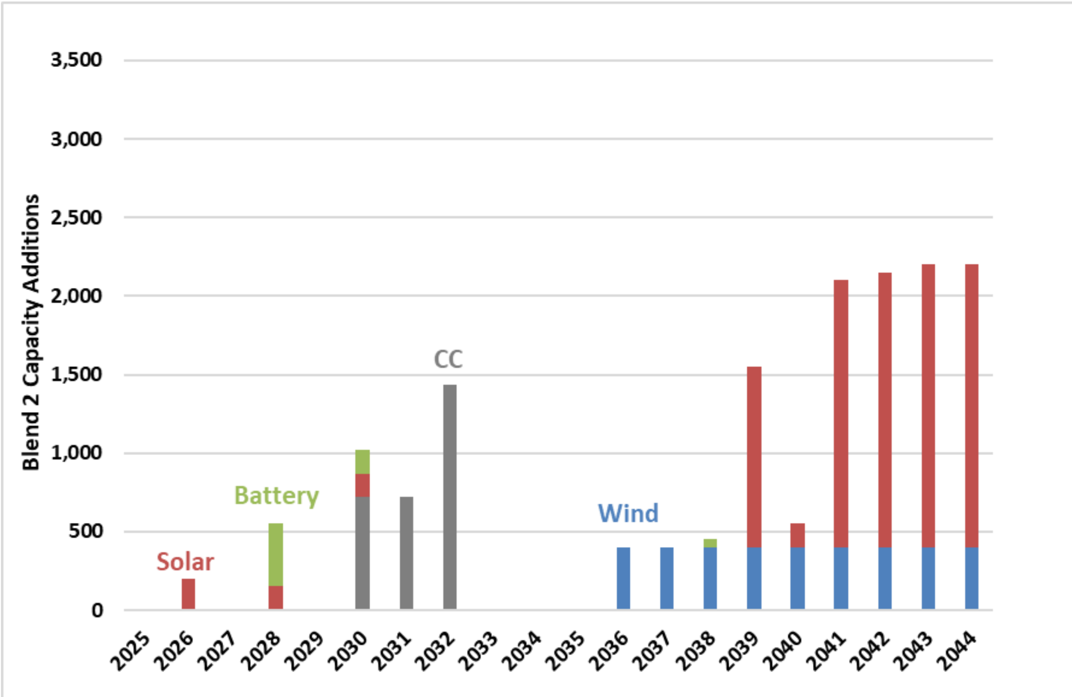
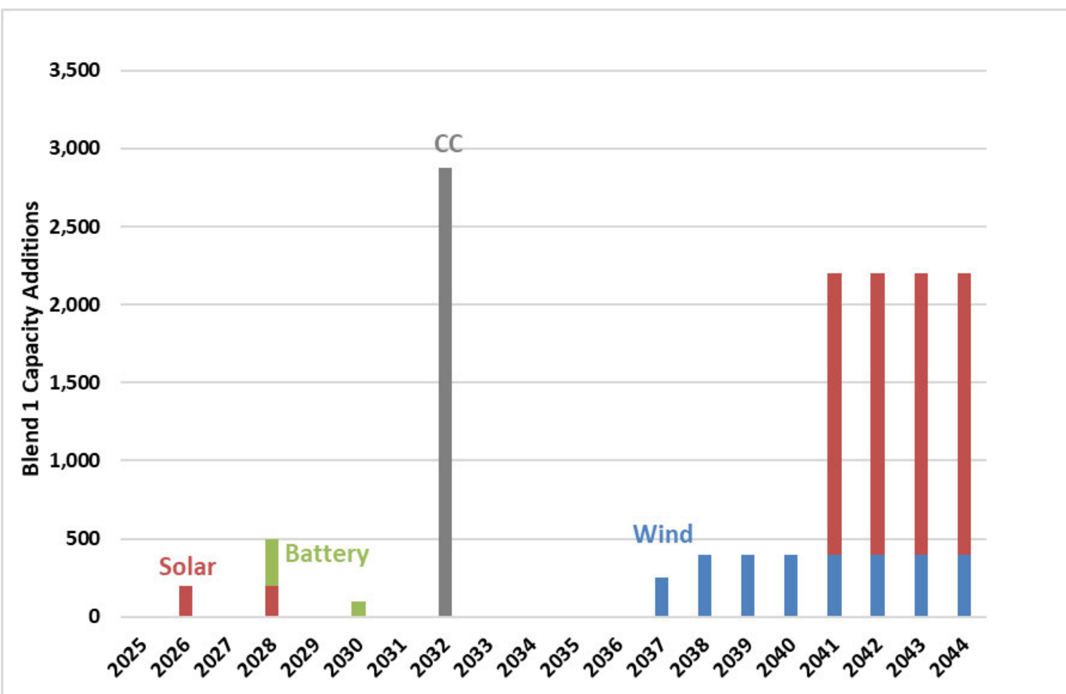


Figure 2: Blend 1 Additions (MW)[9]



[8] Duke IRP Public Meeting #5, Slide 59
[9] Duke IRP Public Meeting #5, Slide 57

We are concerned that the Company will use the selection of the Blend 2 plan in this IRP as justification for a future Certificate of Public Convenience and Necessity (CPCN) filing for a new NGCC in 2030. Such a filing would be ill-advised given the evidence from Duke's modeling that overwhelmingly shows that reducing new NGCC investments in part by converting Cayuga rather than retiring it is favorable—as we show below. In the last section of these comments, we discuss how the Company's assumed clean resource costs unfairly handicapped them from being selected in the model's optimization. A conversion of Cayuga to gas provides more time for the additional clean replacement options in the late 2020's or early 2030's than is projected in either Blend 1 or Blend 2.

B. Duke's Blend 1 produces more savings for Duke customers

The Company's choice of Blend 2 is puzzling given that its own modeling demonstrates that Blend 1 is cheaper and reduces customers' bills more than Blend 2 in almost every modeling run. In its portfolio scorecard, the Company established two metrics to measure affordability: (1) present value of revenue requirements (PVRR) to estimate the total customer cost over the planning period, and (2) customer bill impacts measured using compound annual growth rates (CAGR) to estimate near-term impacts to customers.[10] Table 2 below shows the PVRR of reference case portfolios which show that Blend 1 is $100 million cheaper than Blend 2.

Table 2: Customer Costs for Portfolios in the Reference Case (PVRR $mil)[11]

Portfolio	Duke PVRR	Rank (lowest =1)
Blend 1	$24,173	3
Blend 2	$24,273	4
Blend 4	$24,515	6
Retire Coal	$23,563	2
Convert Coal	$25,010	7
Stakeholder	$24,289	5
No 111(d)	$23,196	1

Blend 1 has a lower cost in seven of the eight iterations modeled by the Company—including the reference and "minimum policy" cases and in all sensitivities modeled—as shown below in Table 3. This savings is most pronounced under the minimum policy scenario and high load sensitivity where Blend 1 saves roughly half of a billion compared to Blend 2.

[10] DEI 2024 IRP, Table 4-2 at 130.
[11] Sierra Club calculation

Table 3: Savings with Blend 1 Across Scenarios and Sensitivities—compared to Blend 2 (PVRR $mil)[12]

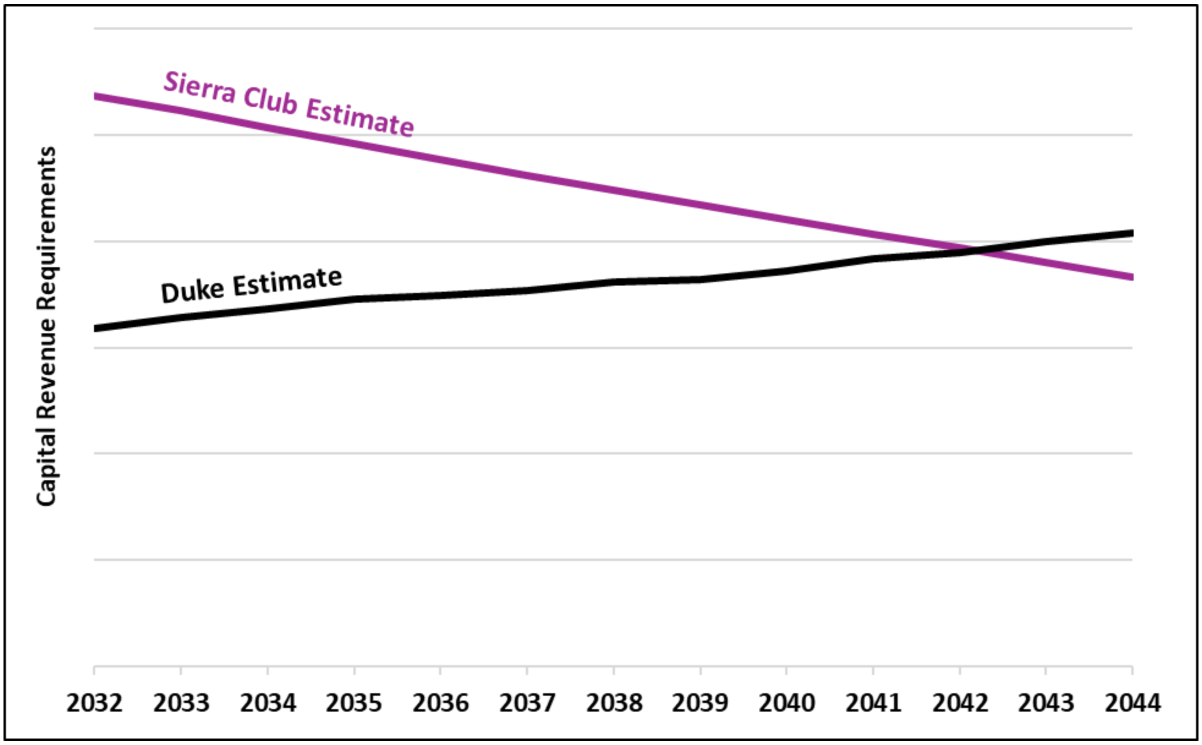
Portfolio	Duke estimate
Reference	$100
Low Fuel	$193
High Fuel	$16
Low Load	$245
High Load	$495
High CC CT	$187
APRI	-$303
MPLI	$558

The customer savings from Blend 1 shown above are understated given how the Company chose to calculate the revenue requirements. The capital costs of building a Company-owned resource that is allowed in rate base would be recovered from customers through annual depreciation and allowed rate of return on the undepreciated balance. The EnCompass model calculates these costs separately and collectively as "revenue requirement" in its "Company Capital" report. But the Company's PVRR calculation does not take the revenue requirements calculated by the model. Instead, the Company takes the "carrying cost" of new resource builds rather than the more realistic rate base method for capital costs used by EnCompass. As a result, the Company is essentially modeling all new resources as levelized costs or power purchase agreements (PPAs), whereas much of the new builds would be rate-based assets.

Duke's approach understates the impact of new resources on rates in the near- and medium-term. To demonstrate this, below we show the two different approaches to calculating capital costs of the 1,200 MW NGCC being installed in 2032 for Duke's preferred plan. Our estimate is that the rate-based approach that is more aligned with how the capital costs of the new gas plant would be charged to customers. Duke's estimate is akin to a PPA where costs are recovered evenly but with annual escalation to account for inflation. Over the course of the plant's life—which runs past the analysis period—the PVRR of the two approaches should be identical. But the timing of the rate recovery matters to customers and should be realistically represented in the IRP, especially for major investment decisions.

[12] *Id.*

Figure 3: Capital Revenue Requirements ($mil) for Blend 2's NGCC in 2032[13]



With this in mind, we recalculated the portfolio's PVRRs by using the revenue requirements directly reported in EnCompass which treat new resources as rate-based.[14] We then calculated the net present value of these annual costs using the Company's weighted average cost of capital (WACC) as the discount rate.

[13] Both estimates exclude operating and fuel costs which are treated as annual expenses in both Duke's and Sierra Club's PVRR calculations. The chart only shows the recovery of the capital costs of installing the NGCC.
[14] The Company also excluded ongoing capital and fixed O&M costs for its *existing* units from the EnCompass model. These costs are also included in our revenue requirement calculation.

Table 4: Customer Costs for Portfolios in the Reference Case (PVRR $mil)[15]

Portfolio	Duke PVRR	Rank (lowest =1)	Sierra Club PVRR	Rank (lowest =1)
Blend 1	$24,173	3	$25,865	3
Blend 2	$24,273	4	$26,384	7
Blend 4	$24,515	6	$26,301	6
Retire Coal	$23,563	2	$25,845	2
Convert Coal	$25,010	7	$26,280	5
Stakeholder	$24,289	5	$25,939	4
No 111(d)	$23,196	1	$24,450	1

Our correction to the revenue requirement calculation increases the savings for Blend 2 across all of the modeling runs—as shown in Table 5.

Table 5: Savings with Blend 1 Across Scenarios—compared to Blend 2 (PVRR $mil)[16]

Portfolio	Duke estimate	Sierra Club estimate
Reference	$100	$519
Low Fuel	$193	$612
High Fuel	$16	$435
Low Load	$245	$365
High Load	$495	$773
High CC CT	$187	$410
APRI	-$303	-$139
MPLI	$558	$1,018

The Company may take issue with our correction to the revenue requirements; but the general point remains the same regardless of how they are calculated: Blend 1 is clearly the lower-cost option compared to Blend 2.

C. Blend 1 reduces other risks compared to Blend 2, including reliability

The results above show that Blend 1 reduces costs under almost all scenarios and sensitivities, which means that the plan also reduces risk because it fares better under alternate futures. In addition, Blend 1 reduces market risk, reliability risk, and execution risk. The Company

[15] Sierra Club calculation
[16] Sierra Club calculation

measured the performance of its portfolios for several other indicators, including: (1) energy market exposure, (2) expected unserved energy (EUE), and (3) execution risk:

- Energy market exposure captures the risk associated with a portfolio's reliance on purchases from the MISO energy market to serve customer needs. Blend 1 showed less reliance on energy market purchases than Blend 2 and therefore is less exposed to market price risk.[17]

- Duke also simulated extreme winter weather conditions by modeling the coldest 5 percent of hours to measure the expected unserved energy (EUE) to determine "resiliency."[18] On this measure, Blend 1 performed the best of all portfolios; thus, it provided the most reliability during harshly cold hours.[19]

- Execution risk measures each portfolio's scale and pace of new resource additions in the near-term.[20] Blend 1 has the lowest execution risk than all other portfolios in 2030 with cumulative resource additions accounting for 13 percent of current system capacity (Blend 2's resource additions accounted for 23 percent) and a slightly lower risk than Blend 2 in 2035 with 50 percent compared to 51 percent.[21]

The Company should not select Blend 2 as its preferred plan. Blend 1 clearly provides more savings for customers, reduces key risks, and allows time for Duke to seek cleaner replacement resources in subsequent IRPs rather than cement a massive gas decision now.

IV. Any preferred plan needs to convert Edwardsport to gas as soon as possible

Blend 1 is superior to Blend 2; but both plans assume that the Edwardsport plant should be converted to gas in 2030—as do all of Duke's reference case portfolios that comply with 111(d). But Edwardsport is too costly to justify operating with coal under any regulatory scenario. Indeed, when the Company tested a variation of Blend 2 with 2028 gas conversion, it was cheaper than 2030 conversion.[22] This finding is not surprising given the results from Duke's 2021 IRP that showed that the plant should have been converted even sooner. The Company should therefore incorporate the 2028 gas conversion of the plant as part of any preferred plan. Duke also ran a variation of Blend 2 with CCS on Edwardsport that showed savings with that project. But we discuss why that result is highly dubious and should not be used to justify pursuit of CCS at the plant. Edwardsport has already cost customers substantially with its initial cost

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[17] DEI 2024 IRP, Table 4-2. at 130.
[18] DEI 2024 IRP at 136.
[19] DEI 2024 IRP, Table 4-2. at 130.
[20] DEI 2024 IRP at 138.
[21] DEI 2024 IRP, Table 4-2. at 130.
[22] DEI 2024 IRP at 155.

overruns and continuing exorbitantly high fixed costs to operate each year. Customers should be spared yet another massive investment that prolongs coal operations at a plant that has proven to be a never-ending drain on customers' bottom line. Instead, Duke needs to convert the plant to gas as soon as possible.

A. The plant should be converted to gas as soon as possible to save ratepayers from its exorbitant costs

This IRP provides further evidence that Edwardsport should be converted to natural gas as soon as possible. The company's preferred plan, Blend 2, converts Edwardsport in 2030; but the variation where the plant is converted in 2028 instead is $100 million cheaper, or, put differently, results in a 0.6 percent reduction compared to the preferred plan.[23] Our recalculation of the PVRR shows even higher savings with earlier conversion. The Company's last IRP in 2021 looked at continued coal operation, conversion to full gas, and retirement at the plant—ultimately concluding that full gas conversion in 2035 was part of its preferred plan.[24] But the modeling in that IRP found similar results: converting Edwardsport as soon as possible was cost-effective. When the Company allowed the model to choose the lowest-cost option for customers, the model chose conversion of Edwardsport in 2023 under all futures that were reported: the reference case without carbon regulation, reference case with carbon regulation, high gas prices, and low gas prices.[25] Despite that robust result, the Company opted to delay conversion in its 2021 preferred plan. Unfortunately, Duke is once again delaying conversion in the 2024 IRP despite the evidence that it should happen sooner.

The continued delay in ceasing coal at Edwardsport is costing ratepayers substantially. The plant was almost $1 billion over-budget during its construction and has continued to have exorbitant costs after starting operations in 2013.[26] The plant's fixed costs—including O&M and capital costs—are exorbitantly high, making it uneconomic to continue as-is. Since it began operations, the Company has spent nearly $500 million in additional capital costs at the plant.[27] This is essentially the cost of building another power plant on top of the site: for instance, the Commission approved $334 million for Centerpoint to build two new gas combustion turbines (CT) with a combined capacity of 460 MW.[28] Given the massive costs of maintain Edwardsport

[23] *Id*.
[24] 2021 Duke Energy Indiana IRP, Volume I, December 15, 2021 at 15-16, 43-44. Available at: https://www.duke-energy.com/-/media/pdfs/for-your-home/dei-irp-2021/public-duke-energy-indiana-2021-irp-volume-i.pdf?rev=2f3e42143e3e4875a8f7d38bebb9da51.
[25] 2021 Duke Energy Indiana IRP, Volume I, December 15, 2021 at 92-97. Available at: https://www.duke-energy.com/-/media/pdfs/for-your-home/dei-irp-2021/public-duke-energy-indiana-2021-irp-volume-i.pdf?rev=2f3e42143e3e4875a8f7d38bebb9da51.
[26] See: https://www.in.gov/oucc/electric/key-cases-by-utility/duke-energy-igcc-project/.
[27] IURC Cause No. 46038, Direct Testimony of Tyler Comings, Ex. TC-2, Company's response to IG 3.05.
[28] Final Order, Cause 45564, June 28, 2022 at 39.

as it currently operates, it is unsurprising that Duke's modeling in this IRP shows that earlier gas conversion of Edwardsport in 2028 is cheaper than converting the plant in 2030. Moreover, the earlier conversion also saves 3.8 million tons of carbon emissions in 2028 and 2029 (combined) on a portfolio basis.[29]

In the 2024 IRP, the Company only tested 2028 conversion in one variation of the preferred plan, whereas all other portfolios that comply with 111(d) assume 2030 conversion. Without 111(d), the Company assumed 2035 conversion; but the Company should have modeled the conversion of Edwardsport prior to 2035 under that scenario. The IRP's framework is misleading as it implies that it only makes sense to convert to gas sooner under 111(d). However, compliance with that rule is not the main obstacle for Edwardsport: the massive costs of operating the unit today are the problem. Thus, the Company should have modeled the earliest conversion possible in all scenarios.

B. Another massive capital investment at Edwardsport would be sorely misguided

The Company conducted another variation of its preferred plan that added carbon capture and sequestration (CCS) which showed savings when this equipment was added in 2032.[30] But these results should not be taken at face value given the risk that the level of removal will not be achieved. Carbon emissions removal through CCS may be eligible for tax credits through the Inflation Reduction Act Section 45Q; but the amount of credit dollars is directly dependent on the actual level of CO_2 removal from CCS, and the extent to which removed CO_2 is stored or piped off-site for other use. The plant is already substantially costly to own and operate for the Company and its ratepayers. Adding another massive capital cost to perpetuate coal operations that would be borne by ratepayers would be a mistake. The Company needs to cut its (substantial) losses and cease operating the plant on coal as soon as possible.

V. The Gibson and Cayuga units' performance in Duke's modeling is too optimistic

The frequency of operation—or capacity factors—at Gibson and Cayuga are well above the historical averages for the Company's coal units. For Gibson, this is likely driven by Duke assuming that the units are more efficient, despite recent past performance that contradicts those assumptions. Figure 4 shows historical average (2020-2023) for Gibson compared to the projected capacity factors from the IRP modeling and Figure 5 shows the same data for Cayuga. The units are modeled to operate at about double their typical performance.

[29] DEI 2024 IRP, CONFIDENTIAL Attachment C-1 - EnCompass Outputs., "DEIN 24 IRP 111 Blend 2 CAY 1x1s EDW 2028 PC."
[30] DEI 2024 IRP at 155.

Figure 4: Modeled Capacity Factors for Gibson Units under Blend 2[31]

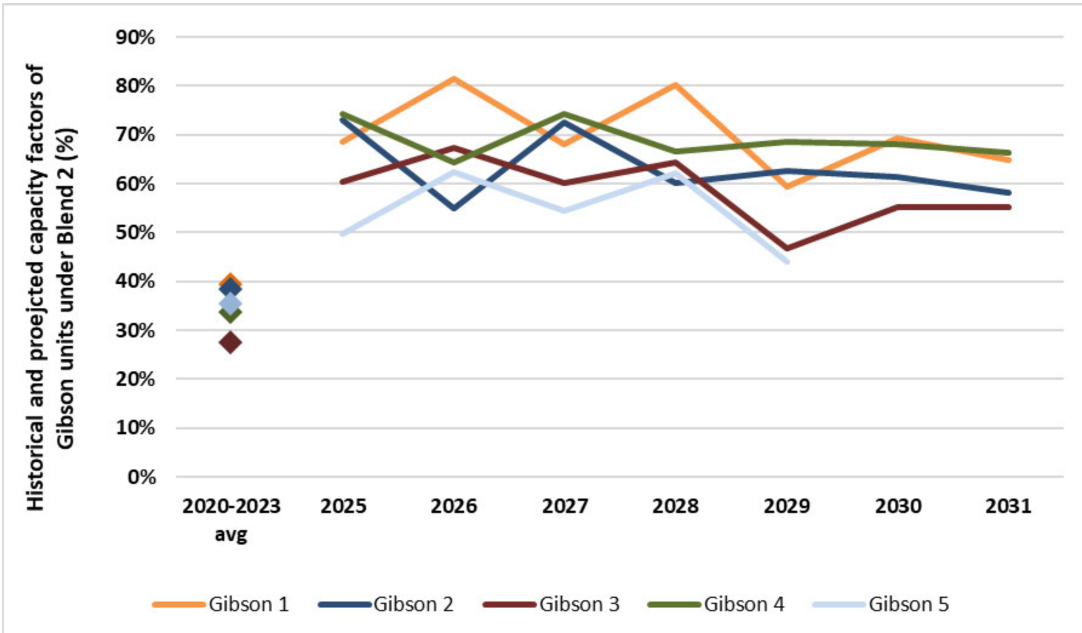
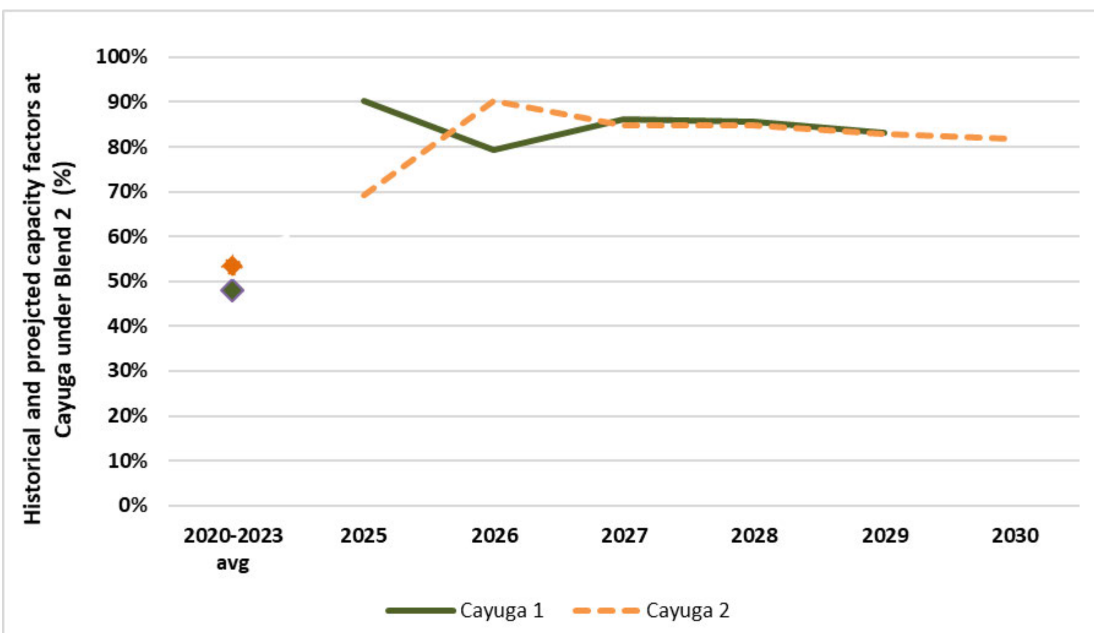


Figure 5: Modeled Capacity Factors for Cayuga Units under Blend 2[32]



[31] Sierra Club calculation
[32] Sierra Club calculation

These drastic increases in capacity factors are likely due to the Company's modeling assuming that the units are more economically attractive than they have been recently. Primarily, we are concerned that the heat rates of the Gibson units 1 through 4 are far understated in the Company's modeling, and therefore the units are appearing much more efficient than they are in reality. Shown below in Table 6, the Gibson units in the model are on average 9 percent more efficient than they have been in recent years. We are unaware of any technical reason that all of the Gibson units would improve their efficiency to this extent. Therefore, we recommend that the Company adjust the heat rates of the Gibson units to be more in line with past performance.

Table 6: Historical vs. Projected Heat Rates at the Gibson Units[33]

Unit	Actual 2020-2023 avg	Projected 2025-2031 avg	% change
Gibson 1	10,993	10,458	-5%
Gibson 2	11,509	10,363	-10%
Gibson 3	11,758	10,867	-8%
Gibson 4	11,247	9,782	-13%

Furthermore, the Company's modeling of fuel prices ($/MMBtu) are likely understated. We compared the fuel costs at Cayuga and Gibson units 1-4 and they appear much lower than the costs have been most recently.[34]

We encourage the Company to model more realistic fuel costs and heat rates for Cayuga and Gibson units 1-4 in the IRP.

VI. The Company only modeled sustained, high prices for clean replacement

The Company's capacity expansion modeling tested what new resources would be built given the decision options for retirement, co-firing or conversion of its coal units. This type of modeling is standard utility planning practice, but the cost assumptions for new resources are instrumental in conducting a fair assessment. Unfortunately, Duke has assumed that clean replacement options are expensive and will remain so through the 20-year modeling period. This unreasonable assumption biased the results in favor of gas options, instead of new clean energy resources such as wind, solar, and batteries. Blend 1 and Blend 2 include large build-outs of gas prior to 2033.

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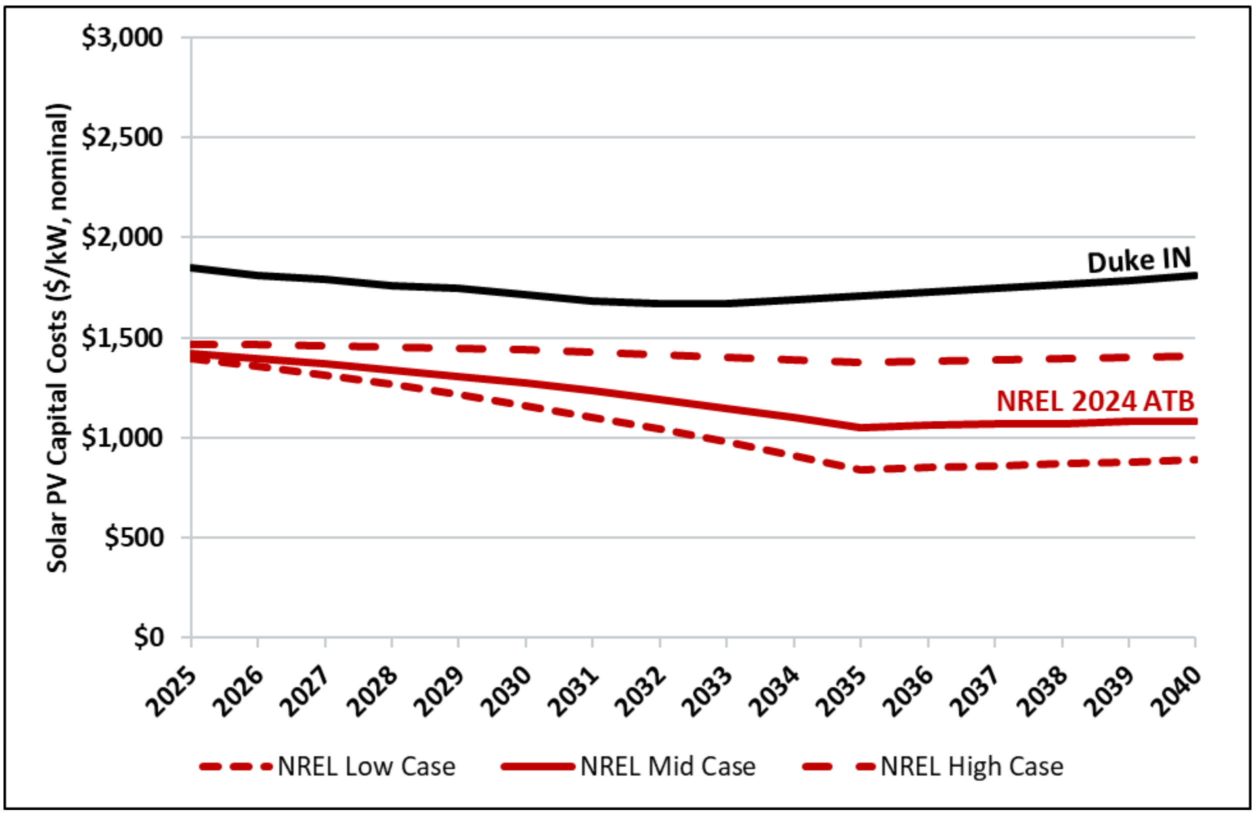
33 Sierra Club calculation

34 IURC Cause No. 46038, Direct Testimony of Tyler Comings, Company response to Sierra Club Data Request SC-DR-1-17.

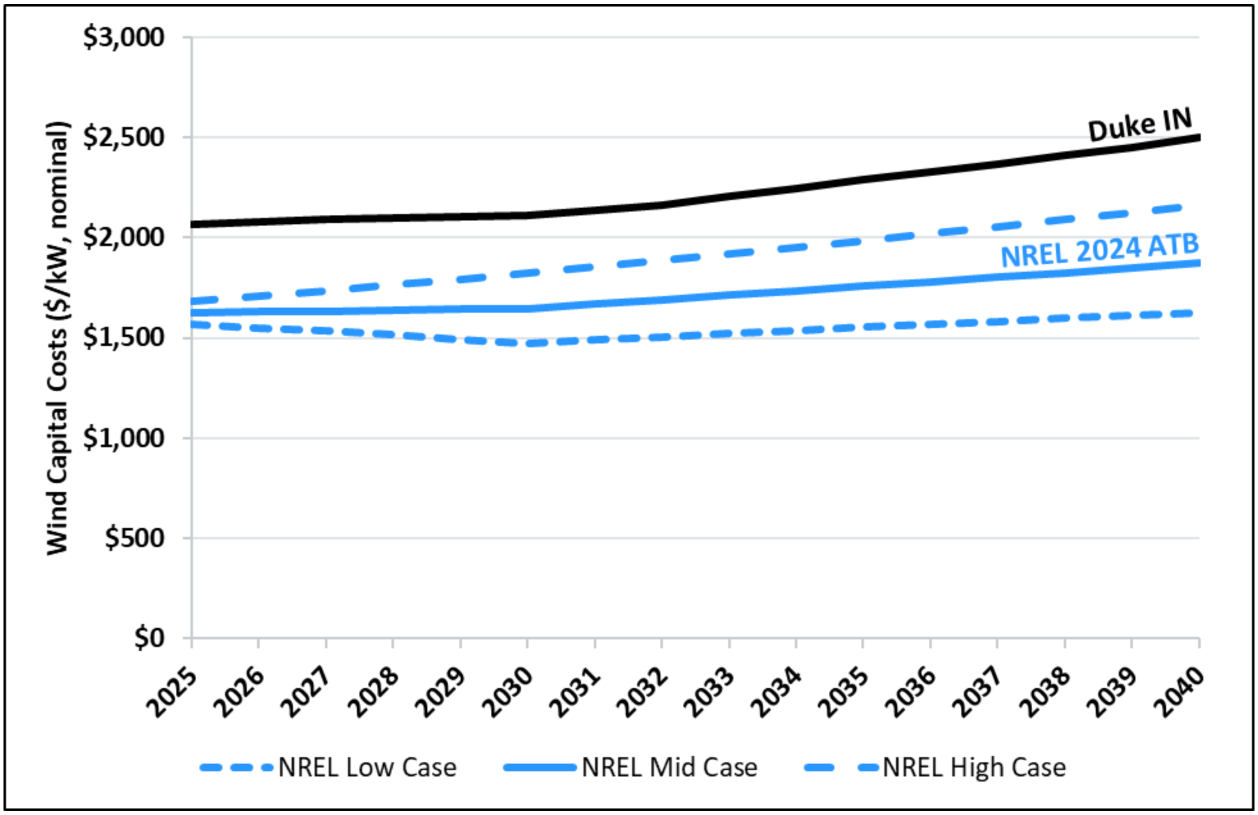
For new clean energy resources, Duke constructed long-term forecasts of capital costs using the U.S. Energy Information Administration's ("EIA") Annual Energy Outlook ("AEO") data in combination with data prepared by Guidehouse for solar, wind, and storage resources.[35] For solar resources, Duke's forecast sets the initial project cost at $1,850/kW and applies nominal escalation rates (i.e., annual percent changes).[36] For wind resources, Duke's forecast starts at $2,050/kW and for battery storage resources it starts at $2,300/kW.[37] We compared Duke's forecasts with more up-to-date cost projections from the National Renewable Energy Laboratory's ("NREL") 2024 Annual Technology Baseline ("ATB"), including NREL's sensitivities for low, mid, and high costs (i.e., NREL's Advanced, Moderate, and Conservative cases, respectively). Duke's assumed capital costs for solar and wind resources are substantially higher than those reported in NREL's 2024 ATB—as shown below in the figures below.

Figure 6: Overnight capital costs for solar PV ($/kW nominal, unsubsidized)[38]



[35] DEI 2024 IRP at 418-419.
[36] *Id*. at 87
[37] *Id*. at 89, 92
[38] National Renewable Energy Laboratory (NREL). 2024. *2024 Annual Technology Baseline (ATB) Cost and Performance Data for Electricity Generation Technologies*, available at: https://atb nrel.gov/electricity/2024/data ; DEI 2024 IRP at 253.

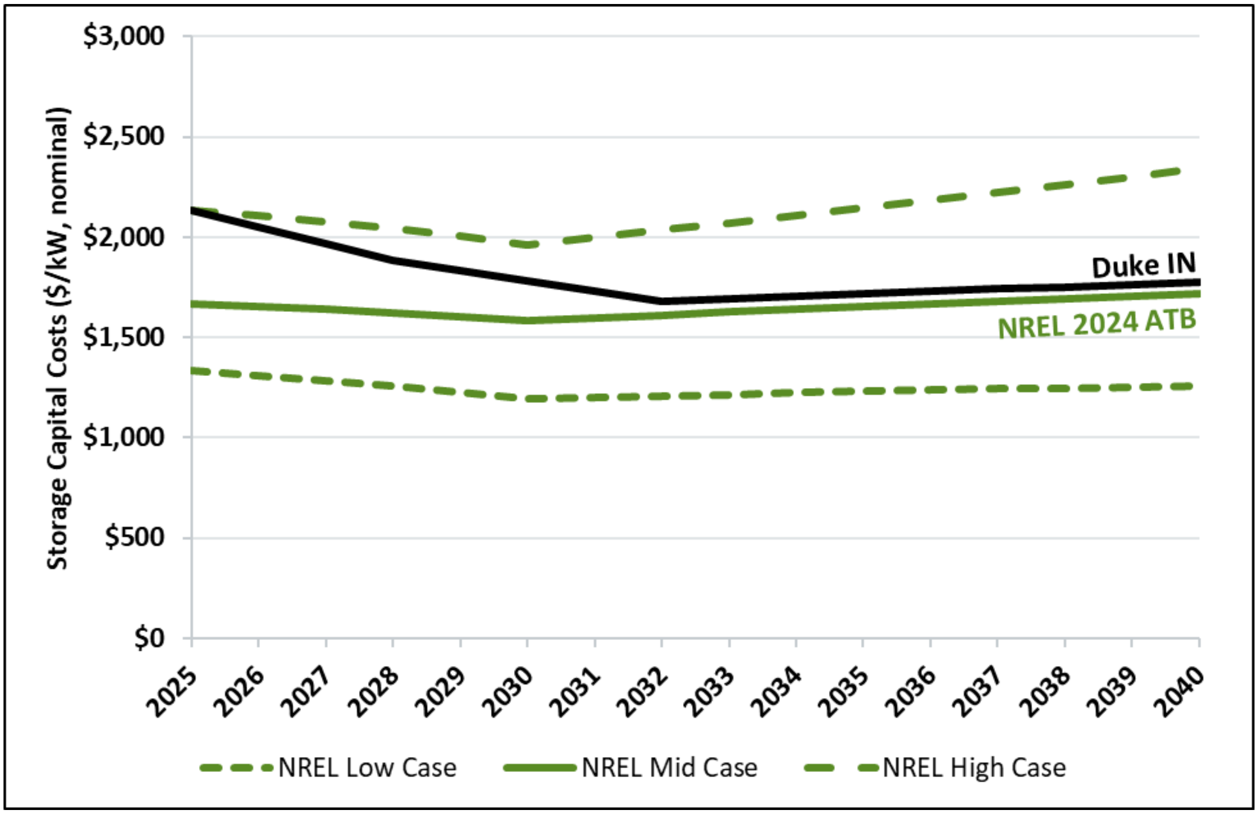
Figure 7: Overnight capital costs for wind ($/kW nominal, unsubsidized)[39]



The Company's forecast for battery storage is more in-line with NREL but only starting in 2032. In the meantime, it is assuming much higher costs for this resource, as shown below in Figure 8.

[39] *Id*.

Figure 8: Overnight capital costs for storage ($/kW nominal, unsubsidized)[40]



The Company modeled unreasonably high costs for clean energy resources. The Company's costs of solar are roughly 35 percent higher than the NREL's mid-price forecast in 2030; Duke's wind costs are roughly 29 percent higher as well. Sierra Club understands that there were temporary, short-term cost increases due in part to interconnection delays. But there are concerted efforts across the US to mitigate this obstacle—including in PJM. It is therefore widely assumed and forecasted that the high costs of clean replacement are temporary, therefore the Company should have at least modeled a scenario or sensitivity with lower capital costs for clean energy resources.

VII. Conclusion

Given the issues we have discussed above, we recommend the following changes:

1. Duke should amend its preferred plan to convert Edwardsport to natural gas in 2028 (or earlier, if feasible).
2. Duke should conduct updated modeling with more reasonable clean energy resource

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[40] *Id*. at 253

costs and less optimistic assumptions about the efficiency and fuel costs of the Gibson and Cayuga units. Updated capacity expansion runs should assume 2028 conversion of Edwardsport.

3. If Duke does not conduct the updated modeling specified above, its preferred plan should include the buildout from Blend 1 but with the conversion of Edwardsport in 2028.

Sincerely,

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