COMMENTS OF CLEAN GRID ALLIANCE ON THE 2024 INTEGRATED RESOURCE PLAN OF DUKE ENERGY INDIANA

February 12, 2025

Introduction

Clean Grid Alliance ("CGA")[1] appreciates the opportunity to file comments with the Indiana Utility Regulatory Commission ("the IURC") in Docket No. 46155, the 2024 Integrated Resource Plan ("IRP") of Duke Energy Indiana ("the Company").[2] These comments address our concerns with the Company's Preferred Resource Portfolio ("the Preferred Plan") and with the overall approach to IRP taken by the Company.

The Company's IRP considered six unique candidate resource portfolios ("Candidate Plans"). Two of these potential strategies served as "extreme" bookends to three "blend" or "more balanced" strategies, while the sixth candidate plan explored aggressively retiring coal units.[3] Of the potential strategies, the mid-range scenario "Blend 2" emerged as the Company's Preferred Plan despite never being the top performer for any metric by which it was evaluated.[4] Consistent with its performance against the Company's priority metrics, CGA sees Blend 2 as only a mediocre strategy. Our overarching concerns with this portfolio regard first the slow pace

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[1] Clean Grid Alliance (CGA) is a 501(c)(3) nonprofit organization based in St. Paul, Minn., whose mission is to advance renewable energy in the Midwest. CGA has been an active stakeholder in the MISO process at the state and regional levels and a leading organization working on transforming state energy policy. CGA's membership includes industry representatives working in wind, solar and storage as well as environmental nonprofit organizations, public interest groups, clean energy advocates, farm groups, and businesses providing goods and services to the clean energy industry who come together to reduce carbon and deliver a clean energy future.

[2] *See* Indiana Utility Regulatory Commission ("IURC"). Docket No. 46155. *In the Matter of Duke Energy Indiana's 2024 Integrated Resource Plan* ("DEI 2024 IRP"). Filed November 1, 2024.

[3] DEI 2024 IRP, Chapter 4, "Candidate Resource Portfolios" (pp. 101-149). The "Retire Coal" and "Convert/Co-fire Coal" generation strategies are at the extreme ends of potential generation strategies; "Blend 1", "Blend 2", and "Blend 3" represent the middle of the range; and "Exit Coal Earlier" is a stakeholder-inspired strategy that more aggressively retires and replaces coal.

[4] DEI 2024 IRP, Chapter 5, "Preferred Resource Portfolio", Figure 5-5: 2024 IRP Scorecard (p. 158). Metrics incl. environmental sustainability, affordability, reliability, resiliency, cost risk, market exposure, and execution risk.

at which it transitions the Company to a carbon-free system, which also results in high exposure to wholesale market price volatility in the 2030s, and next, risks from potential and/or pending changes to resource accreditation, resource adequacy requirements, and capacity import capabilities (from MISO and/or the state of Indiana). In these comments, we address: (a) the total amount of renewable and storage capacity additions and the timing of those additions over the course of the planning period, (b) the minimal focus on integrating hybrid and co-located energy storage resources into the Company's system, and (c) recommended changes to the Company's Short-Term Action Plan. More broadly, we are finally concerned about deficiencies in the modeling inputs themselves (such as are related to cost projections for resource additions, technology availability, resource attributes, and load growth, among others) that impacted portfolio selection overall. Through our comments to the IURC we hope to elevate these issues and propose solutions that would improve the Company's strategy, starting with the Short-Term Action Plan.

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Comments

I. The scale of renewable and energy storage resource additions under the Preferred Plan is insufficient and the timing of most of these additions falls too late in the planning period.

Duke Energy Indiana proposes adding more than 13,400 MW of wind, solar, and storage capacity through the early 2040s, with the bulk of these resource additions coming online late in the planning period.[5] However, near-term renewable additions total only about 900 MW of solar and energy storage, including the 199 MW Speedway Solar project proposed in the 2021 IRP which will begin operating this year.[6] This capacity expansion will be offset in the short- and mid-terms when wind and solar Power Purchase Agreements ("PPAs") – totaling 125 MW of clean capacity – expire in 2028 and 2036, respectively, without being immediately replaced.

CGA is concerned with the strategy under the Preferred Plan to add more than 80% of the proposed clean energy so late in the planning period for two reasons. First, this plan requires substantial reliance on market purchases during the 2030s,[7] exposing Duke Energy Indiana to wholesale market price volatility and the risk of potential resource shortages during periods of grid stress impacting the greater MISO footprint. However, exposure to the market diminishes substantially in the 2040s once the Company adds the planned wind, solar, and storage,[8] which indicates that shifting their addition to the near-term (e.g., the 2030s) would have the same positive effect of reducing market-related risk.

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[5] This is the level of installed capacity ("ICAP") under the Company's Reference Scenario; the total ICAP varies across the three scenarios or "worldviews" by which the Preferred Plan was evaluated. *See* DEI 2024 IRP, "Appendix C: Quantitative Analysis, Results of Capacity Expansion Modeling", pp. 257-305, for ICAP under the Minimum Policy & Lagging Innovation and Aggressive Policy & Rapid Innovation Scenarios.

[6] DEI 2024 IRP, Chapter 6, "Short-Term Action Plan", p. 168.

[7] DEI 2024 IRP, "Executive Summary", Figure 10, "Energy Mix for Generation Strategies in Reference Scenario and 'No 111' Case", p. 12. Note the level of "Economic Purchases" in 2035.

[8] *Ibid.*

Secondly, this strategy delays most of the clean energy additions until after the federal Clean Electricity Investment Tax Credit ("ITC") and Clean Electricity Production Tax Credit for zero-emission energy could begin phasing out. According to the U.S. Treasury Department's final rules, the phase-out will be triggered by "the later of 2032 or when U.S. greenhouse gas emissions from electricity are 25% of 2022 emissions or lower."[9] Further, the Company's plan hinges on its assumption that the ITC and PTC "will not phase out during the 20-year IRP planning period" given that level of emissions reductions is not expected to be achieved until the 2040s.[10] However, analysts and industry experts fear the new U. S. president and the new Congress threaten the fate of clean energy incentives included in the Inflation Reduction Act and Bipartisan Infrastructure Law, including both the Clean Electricity ITC and PTC.[11] Even if the federal tax credits remain intact throughout the planning period as Duke Energy Indiana has gambled, each subsequent phase-out of the credits could substantially reduce their full value, which would significantly alter project economics.

Therefore, CGA argues that the Company should have planned to add more renewable capacity while the ITC and PTC (and the bonus credits or "adders") are still available in full.[12] Instead, the Company proposes investing in 2,876 MW of natural gas capacity by 2032—an

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[9] The U.S. Internal Revenue Service finalized the Clean Electricity tax credit rules on January 7, 2025. Information about each can be accessed at: https://www.irs.gov/credits-deductions/clean-electricity-production-credit and at https://www.irs.gov/credits-deductions/clean-electricity-investment-credit

[10] DEI 2024 IRP. "Appendix C: Quantitative Analysis", pp. 243-244.

[11] *See* Potomac Law Group. "Renewable Energy Tax Incentives: Opportunities and Risks in 2025". (January 22, 2025). Accessed at: https://www.potomaclaw.com/news-Renewable-Energy-Tax-Incentives-Opportunities-and-Risks-in-2025. *Also see* E&E News by Politico. "What Trump's Treasury pick means for clean energy tax credits". (November 25, 2024). Accessed at: https://www.eenews.net/articles/what-trumps-treasury-pick-means-for-clean-energy-tax-credits/. *Also see* Utility Dive. "Trump freezes IRA funding". (January 23, 2025). Accessed at: https://www.utilitydive.com/news/president-trump-inflation-reduction-act-executive-order-ev-mandate/738001/

[12] These include the ITC-applicable Low-Income Communities bonus credit and the ITC/PTC-applicable Energy Communities, Domestic Content, and Prevailing Wage bonus credits. *See* U.S. Environmental Protection Agency, "Summary of Inflation Reduction Act provisions related to renewable energy". (2025). Accessed at: https://www.epa.gov/green-power-markets/summary-inflation-reduction-act-provisions-related-renewable-energy

investment that is unsupported by an ITC or PTC—for a resource that is subject to fuel price volatility, regulatory and winter reliability risks, and fuel supply challenges.[13]

By contrast, renewable resources and energy storage are not subject to fuel price volatility or carbon regulations, and additionally provide geographically distributed economic benefits such as construction and permanent job opportunities,[14] local tax revenues,[15] and increases in assessed property value.[16] These resources also contribute to reliability and resource adequacy within the MISO region and support the state of Indiana's five pillars of energy policy (reliability, resilience, stability, affordability, and environmental sustainability).[17]

To be sure, siting and permitting renewable energy systems has become more challenging in Indiana, even while global supply chain challenges and regional interconnection issues extending project lead times persist. The Company noted how local zoning rules and moratoriums are limiting renewable development and stated that "regulatory or policy support" may be necessary in overcoming obstacles to siting these projects.[18] To this end, the Indiana legislature will consider policies for locating energy infrastructure during the 2025 legislative session, while Governor Braun has emphasized "Smart Renewable Development" in his 2025 policy agenda, which prioritizes "no-regrets renewable development opportunities through

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[13] *See* Section III of these comments, "Recommended improvements to the Short-Term Action Plan" for further discussion of reliability risk related to poor coordination between the gas and electric industries, among other things.
[14] *See* Clean Jobs Midwest. "Indiana Clean Energy & Vehicle Jobs Break Records". (2023). Accessed at: https://www.cleanjobsmidwest.com/state/indiana. In 2023, the Renewable Energy and Generation sector (e.g., solar, wind, geothermal, bioenergy/CHP, and low-impact hydroelectric provided 12,046 Indiana jobs.
[15] *See* Purdue Center for Regional Development ("PCRD"). "Economic and Fiscal Impacts of NextEra's Indiana Solar Investments". (February 22, 2023). Accessed at: https://pcrd.purdue.edu/economic-and-fiscal-impacts-of-nexteras-indiana-solar-investments/?_ga=2.45067556.1228532910.1736455274-209943707.1730488169. According to this study, the average solar project would contribute about $1 million in property taxes to host counties, notwithstanding tax abatements or other economic development arrangements between developers and counties.
[16] PCRD. "Capitol Comments: Solar Energy Projects and Property Taxes". (February 22, 2023). Accessed at: https://extension.purdue.edu/news/2023/02/solar-energy-projects-and-property-taxes.html
[17] *See* Indiana Office of Energy Development, "Indiana's Energy Policy: Electricity". Accessed at: https://www.in.gov/oed/indianas-energy-policy/electricity/
[18] DEI 2024 IRP, Chapter 6, "Short-Term Action Plan", p. 172.

expedited permitting for agrivoltaics and developments on marginal land, former mine land, and brownfields."[19]

In keeping with the theme of pursuing "no-regrets" development, Duke Energy Indiana should have explored whether permitting challenges could be temporarily circumvented if renewable resources were deployed at the site of existing power plants (including at any planned for retirement in this IRP). Additionally, given that Indiana currently benefits from a relatively high Capacity Import Limit ("CIL"),[20] the Company could have also considered flexible or short-term PPAs for out-of-state renewables; these would help cover any project delays (including those related to siting) with the Company's in-state renewable projects while simultaneously increasing its zero-carbon resource capacity and ability to nimbly meet growing demand.

CGA advocates for clean energy development and deployment across nine MISO states, including by engaging with IRP before other state utility commissions. Our geographic scope enables us to comment on this filing in comparison to other recent IRPs, such as that produced by Ameren Missouri ("Ameren") in 2023.

Although Ameren is a somewhat larger utility[21] than Duke Energy Indiana, Ameren's IRP provides a good counterpoint as the Missouri regulatory structure, IRP process, and state energy policy priorities, which are comparable to those of Indiana. It should be noted further that Ameren and Duke Energy Indiana anticipate retail sales to grow at similar rates (respectively

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[19] *See* Governor-Elect Mike Braun Transition Team. "Freedom and Opportunity for Every Hoosier: 2025 Policy Agenda". (December 2024). Pp. 37-38. Accessed at: https://www.brauntransition.com/wp-content/uploads/2024/12/Braun-Policy-Agenda12324.pdf

[20] *See* Section III of these comments, "Recommended improvements to the Short-Term Action Plan" for discussion of potential changes to the CIL and further related opportunities.

[21] *See* Ameren Missouri, "Ameren Missouri Facts". (April 2024). Ameren serves about 1.2 million customers with 10,000 MW of generating capacity; compare to the roughly 900,000 customers and 6,900 MW generating capacity of DEI. Accessed at: https://www.ameren.com/-/media/missouri-site/files/aboutus/amerenmissourifactsheet.ashx. *Also see* DEI 2024 IRP, Chapter 1, "Executive Summary", p. 4.

0.9% and 1.2% annually) and both plan to add 300 MW or more in "economic development" projects over the next five years.[22] Finally, as does Duke Energy Indiana, Ameren plans to retire or replace several thermal generating units by 2032.[23] And yet, Ameren's IRP includes near-term plans to add proportionally more clean energy: up to 2,800 MW of wind and solar by 2030 and 800 MW of energy storage by 2035.[24]

Even accounting for the difference in size between the two utilities, the amount of clean energy additions proposed by Duke Energy Indiana to meet customer demand in the near-term is far less than that proposed by Ameren. To be comparable, Duke Energy Indiana would need to add closer to 600 MW of storage capacity (rather than just 400 MW) by 2035 and 2,300 MW of wind or solar (rather than just 500 MW) by 2030.

Another comparison within Duke Energy Indiana's own home state perhaps merits more consideration: the 2024 IRP of Northern Indiana Public Service Company ("NIPSCO"). Despite being half the size of Duke Energy Indiana,[25] NIPSCO ambitiously seeks to bring 1,741 MW of wind, solar, and both hybrid and standalone storage online *this year alone*, and to add enough clean energy resources in future years to meet its internal 2040 net-zero goal.[26] NIPSCO has planned for these additions even as the utility – which serves an area of Indiana that is highly

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[22] *See* the Ameren Missouri 2023 IRP and the DEI 2024 IRP for information about retail sales growth and economic development projects; however, note that Ameren Missouri recently stated that signed agreements for economic development projects now total 350 MW, exceeding the 2023 IRP projection of 220 MW projects (reported by S&P Capital IQ, "Ameren continues to see load growth, with 10-year investment pipeline of $55B" on November 7, 2024).

[23] *See* Missouri Public Service Commission, Case No. EA-2024-0020. *In the Matter of Union Electric Company d/b/a Ameren Missouri 2023 Utility Resource Filing Pursuant to 20 CSR 4240-Chapter 22* ("Ameren Missouri 2023 IRP"). Filed September 26, 2023. Ameren will retire 2,639 MW of coal- and- gas-fired generating units by 2032.

[24] Ameren Missouri 2023 IRP.

[25] *See* IURC. 2024-2025 Winter Reliability Forum. (November 22, 2024). *See* NIPSCO presentation, slide 2, "NIPSCO Profile". NIPSCO serves 483,000 customers with 3,365 MW generating capacity; compare to the roughly 900,000 customers and 6,900 MW generating capacity of DEI. Accessed at: https://www.in.gov/iurc/files/8.-NIPSCO-WRF-2024.pdf

[26] *See* IURC. Docket No. 46172. *In the Matter of Northern Indiana Public Service Company's 2024 Integrated Resource Plan* ("NIPSCO 2024 IRP"). Filed December 9, 2024. See "Section 1: IRP Summary", pp. 1-4.

desirable for data center development – expects to add *at least* 600 MW of new large-load demand over the next several years,[27] and to retire more than 1,100 MW in baseload capacity. Ultimately, NIPSCO's plan is far more responsive to the opportunities and challenges of the evolving electricity industry than is Duke Energy Indiana's.

II. Energy storage systems in the Preferred Plan are underutilized.

The Company's Preferred Plan proposes the procurement of 400 MW of energy storage resources that "could be standalone, paired with solar, or a combination of the two."[28] However, the Preferred Plan does not indicate what portion of the planned storage could be standalone or paired with solar (i.e., "hybrid"), nor does it include other potential siting arrangements that would have maximized the value of energy storage resources. In fact, the Company's treatment of energy storage in modeling was deeply flawed and leads CGA to conclude that Duke Energy Indiana did not thoroughly consider the addition of this resource to its system. For example, the Company did not allow long-duration energy storage ("LDES") resources (i.e., 10-hr duration or 100-hr duration systems) to be selected at all in the Reference case despite evidence that these resources are likely to become widely deployed before then.[29] Additionally, the Company did not consider hybrid storage configurations for any generating resource but solar, although wind pairs particularly well with LDES and storage generally can be paired with thermal units.[30] And while solar-plus-storage systems were considered, the Company did not model the potential for storage resources to be developed at specific solar sites (such as at Speedway Solar) but only allowed its

[27] NIPSCO 2024 IRP, "Section 3: Energy and Demand Forecast", pp. 79-80.
[28] DEI 2024 IRP, "Table 6-1: Short-Term Action Plan Summary".
[29] DEI 2024 IRP, Chapter 3, "Key Assumptions", pp. 89-90.
[30] Renewable-thermal hybrids (e.g., solar paired with gas) are another type of integrated system the Company could have considered. This type of hybrid is of particular use when thermal resources face operating limits, such as the capacity factor thresholds required under the U.S. Environmental Protection Agency's greenhouse gas regulations.

model to optimize for storage paired *generically* with solar or grid charging. The Company even acknowledged this was a limited approach due to the lack of site specificity.[31] Yet the 199 MW Speedway Solar project is currently under development and expected to come online this year. Duke Energy Indiana could have studied different siting arrangements at that site that would have led to installed energy storage capacity on a shortened timeframe and/or that could have "firmed up" the solar resource (e.g., surplus and/or co-located storage).

Beyond standalone storage, there are three siting strategies falling under the umbrella of "co-location" and a unit replacement strategy that Duke Energy Indiana could have utilized (at least in theory) at other existing or planned sites of generation, including at both renewable and thermal facilities. Yet these strategies were never fully considered by the Company despite their well-recognized contributions to the broader system (e.g., load balancing, capacity firming, backup power supply, and economic dispatch):

Co-located storage opportunity. A co-located energy storage project shares interconnection with another generating facility of any type (i.e., renewable or thermal) but participates in the market separately from the other on-site generator. As noted above, the Company should have evaluated co-located storage under this framework for the Speedway Solar project and at any of its existing generating units.

Hybrid storage opportunity. This type of project constitutes one or more new storage systems co-located with one or more new generating resources, that utilizes a shared point of interconnection ("POI") for all co-located units, and that participates in the MISO market as a single resource. Hybrid storage was evaluated by the Company for units paired with solar alone.

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[31] DEI 2024 IRP, "Appendix C, Quantitative Analysis", pp. 216-217

CGA views the Company's analysis of this resource as incomplete because only solar-plus-storage projects were evaluated, yet storage units can be paired with other types of generators, including wind resources or thermal units such as Duke Energy Indiana proposes to add to its system. Hybrid storage projects bring the added benefit of improved resource accreditation of the paired system, which will matter a great deal once MISO's new Direct Loss of Load ("DLOL") framework is implemented in the 2028/2029 Planning Year.[32]

Replacement storage opportunity. This type of project is defined by MISO as one that replaces "one or more generating units and/or storage devices at an Existing Generating Facility with one or more new generating units or storage devices at the same electrical Point of Interconnection."[33] The Company plans to retire or modify seven thermal generating units by 2032 (five units at Gibson Station and two units at Cayuga Station) and could have evaluated a role for replacement storage at any of these sites. Particularly at the two Gibson units that will be modified to co-fire with gas, Duke Energy Indiana should have considered whether energy storage could be added to the planned gas capacity or whether storage units could serve in lieu of any portion of the proposed gas. MISO requires notice of the generating facility replacement at least one year from the date at which the existing generator will cease operations, meaning the Company would have plenty of time to initiate replacement storage given the units are not planned for retirement until 2030 (at the earliest).[34]

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[32] *See* Federal Energy Regulatory Commission (*"*FERC"). Docket Nos. ER24-1638-000 and ER24-1638-001. *Order accepting proposed tariff revisions*. Issued October 25, 2024. *Also see* "Section III: Recommended improvements to the Short-Term Action Plan" of these comments for more discussion of capacity accreditation according to DLOL.
[33] *See* MISO. "FERC Electric Tariff: Attachment X, Appendix 6". Effective April 2, 2024. "Generating Facility Replacement" definition.
[34] *See* MISO. "FERC Electric Tariff: Attachment X, Generator Interconnection Procedures". Effective March 31, 2024. *Also see* DEI 2024 IRP, Ch.5, for the schedule of proposed unit retirements under the Preferred Plan.

Surplus storage opportunity. A surplus energy storage project utilizes MISO's Surplus Interconnection Service, which derives from unused Interconnection Service but which does not increase the total amount of Interconnection Service at the POI.[35] This option would be available at the Company's existing generating facilities, but again, was apparently not considered despite the opportunity for surplus storage to increase total generating *capability* — without impacting the terms of Interconnection Service — at the particular POI.

Developing co-located energy storage is also becoming a more common and cost-effective practice. Consumers Energy in Michigan recently called standalone storage "the baseline to which other storage projects can be compared" and "ideal … if replacement and surplus opportunities do not exist".[36] In other words, standalone storage might be the starting point but not necessarily the goal. Furthermore, co-locating storage is not novel to Duke Energy Corporation. Notably, Duke Energy North Carolina recently announced it would build more than 200 MW of energy storage at the site of its retiring Allen Steam Station, utilizing federal funds to cover nearly 40% of the cost.[37] Returning to the comparison of Duke Energy Indiana to another Indiana utility, NIPSCO issued requests for support for energy storage projects at "existing NIPSCO renewable sites" as part of a Request for Proposals ("RFP") informing development of its latest IRP.[38]

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[35] MISO. "FERC Electric Tariff: Attachment X, Appendix 6", "Surplus Interconnection Service" and "Interconnection Service" definitions.
[36] *See* Michigan Public Service Commission. Case No. U-21816. *In the matter of Consumers Energy Company's application for the regulatory reviews, revisions, determinations, and/or approvals necessary to fully comply with Public Act 295 of 2008, as amended by Public Act 235 of 2023.* Filed November 15, 2024. Direct Testimony of Mr. Thomas P. Clark. P.9.
[37] *See* Utility Dive. "North Carolina Oks Duke Energy plan to add 3.6 GW gas-fired capacity, 7 GW renewables." (November 5, 2024). Accessed at: https://www.utilitydive.com/news/north-carolina-commission-accepts-duke-energys-carbon-plan/732010/. *Also see* Canary Media. "Duke Energy to knock down coal plant and build its biggest battery yet". (December 3, 2024). Accessed at: https://www.canarymedia.com/articles/batteries/duke-energy-to-knock-down-coal-plant-and-build-its-biggest-battery-yet
[38] NIPSCO 2024 IRP, "Section 4: Supply-Side Resources", pp. 124-125.

Following these examples, Duke Energy Indiana should pursue co-located storage projects for the benefits these would contribute to the system and ratepayers alike. For example, the several federal financing opportunities for hybrid and/or co-located energy storage include the bonus "adders" to the ITC and PTC for projects located in energy communities as well as the Energy Infrastructure Reinvestment Program offered through the Loan Programs Office of DOE.[39] Perhaps an even more compelling reason for Duke Energy Indiana to develop storage at the site of former or existing power plants would be the opportunity to circumvent public opposition to storage projects by siting them on existing brownfields and using existing interconnection infrastructure.

III. CGA proposes several recommendations to improve the Short-Term Action Plan.

The Preferred Resource Portfolio includes a proposed Short-Term Action Plan ("Short-Term Plan") which details the Company's priority next steps over the next three years (e.g., through 2027).[40] CGA would like to submit to the IURC and the Company the following recommended improvements to the Short-Term Plan that would at least begin to address the deficiencies detailed above. Broadly, Duke Energy Indiana should increase the amount of renewable and energy storage capacity, add energy storage capacity to existing and planned generating units, expeditiously deploy emerging LDES technologies to derisk future IRP investment decisions and

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[39] *For information about the ITC, PTC, and tax credit adders, see* Internal Revenue Service, "Clean Electricity Investment Tax Credit", at: https://www.irs.gov/credits-deductions/clean-electricity-investment-credit, and "Clean Electricity Production Credit", at: https://www.irs.gov/credits-deductions/clean-electricity-production-credit#:~:text=The%20Clean%20Electricity%20Production%20Credit%20phase%2Dout%20starts%20for%20the,sold%20to%20an%20unrelated%20person. *For information about the DOE program, see* U.S. Department of Energy, "Energy Infrastructure Reinvestment". (2024). This program funds projects that "retool, repower, repurpose, or replace energy infrastructure that has ceased operations or enable operating energy infrastructure to avoid, reduce, utilize or sequester air pollutants or greenhouse gas emissions." Accessed at: https://www.energy.gov/lpo/energy-infrastructure-reinvestment

[40] DEI 2024 IRP, Ch. 6, pp. 164-175. Note "Table 6-1: Short-Term Action Plan Summary" on p. 168.

strengthen grid reliability, and mitigate risk related to the Capacity Import Limit ("CIL") as part of its Short-Term Plan. We discuss in detail the necessary steps to accomplish those goals below.

Increasing renewable capacity and reducing new gas capacity. As discussed, CGA does not believe the amount of renewable or energy storage capacity proposed through the early 2030s is sufficient, especially compared to the amount of thermal generation the Company intends to bring online during that timeframe. Duke Energy Indiana can address this issue by (1) evaluating brownfield sites for their renewable project development potential, (2) issuing a renewable resource RFP (open to wind, solar, and both 4-hour and LDES storage hybrids) to replace the PPA for the 100 MW Benton County wind capacity which will expire in 2028, and (3) pursuing flexible or short-term renewable PPAs to cover the period between now and 2030, while the 300 MW of solar capacity the Company plans to procure by then is being developed.[41] This last item would, in effect, hasten the timing of that renewable capacity being added to the system and could offset the amount of proposed new gas capacity while meeting energy and capacity needs in the short-term. While on the topic of RFPs, we encourage the Company to ensure that future procurements for renewable resources allow the option for wind resources to participate, which will encourage diversity in resource bids and ultimately lead to lower costs. For example, RFPs in the Short-Term Plan and resulting procurements should be open to responses for wind.

CGA is concerned with the Company's proposal to increase gas capacity by 2,876 MW via new combined cycle units at the Cayuga and Gibson stations and to modify existing coal-fired units at the Gibson Station for co-firing with gas by 2032, because this pathway substantially increases the Company's reliance on gas as a fuel source compared to other

[41] DEI 2024 IRP, Ch. 6, p. 168.

resources.[42] Adding this amount of gas capacity on the timeline proposed will likely be untenable for the Company, given (1) current supply chain challenges extending project lead times by several years,[43] and (2) gas supply and pipeline capacity constraints,[44] compared to the level of demand for the product across MISO.[45] Furthermore, the poor performance of gas resources during Winter Storms Uri, Elliott, and Heather merits serious attention.[46]

To this end, the Gas Electric Harmonization Forum ("GEH Forum"), convened by the North American Energy Standards Board ("NAESB") in 2023, submitted nearly two dozen recommendations to FERC, the North American Electric Reliability Corporation ("NERC"), state regulators, and industry for improving coordination between the gas and electric sectors in the current era of "new gas usage patterns" that has exacerbated existing issues and introduced new system reliability risks, especially during extreme winter weather.[47]

The Gas-Electric Alignment for Reliability ("GEAR") working group was subsequently organized to address these reliability risks. While the GEAR working group has yet to issue

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[42] *Ibid.*

[43] CGA has been informed by industry experts that the time to bring a new gas plant online could increase by several years given these issues; anecdotally, the currently expected length of time is from 4-7 years.

[44] *See* North American Energy Standards Board ("NAESB"). "Gas Electric Harmonization ('GEH') Forum Report." (July 28, 2023). Note Recommendations 19 and 20 regarding gas supply and infrastructure adequacy. Accessed at: https://www.naesb.org/pdf4/geh_final_report_072823.pdf

[45] In the MISO region, 1.7 GW of gas-fired capacity has been announced or approved for 2025. *See* S&P Global. "Commodities 2025: US renewables growth to surge as fossil plant retirements tick up". (December 27, 2024). Accessed at: https://www.spglobal.com/commodity-insights/en/news-research/latest-news/natural-gas/122724-commodities-2025-us-renewables-growth-to-surge-as-fossil-plant-retirements-tick-up

[46] *See* FERC-NERC Regional Joint Entity Staff Enquiry. "December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations". (September 21, 2023). Accessed at: https://www.ferc.gov/news-events/news/presentation-ferc-nerc-regional-entity-joint-inquiry-winter-storm-elliott. Also note that Winter Storms Uri, Elliott, and Heather interrupted weekly U.S. natural gas production by more than 15 billion cubic feet per day, declines representing the largest interruptions to U.S. natural gas production in the past four years.
See U.S. Energy Information Administration. "Winter storms have disrupted U.S. natural gas production". (March 13, 2024). Accessed at: https://www.eia.gov/todayinenergy/detail.php?id=61563. More recently, severe cold weather reduced gas production in North Dakota by 370-450 million cubic feet/day. *See* KFYR-TV. "Extreme cold disrupts North Dakota oil and natural gas production". (January 2025). Accessed at: https://www.kfyrtv.com/video/2025/01/22/extreme-cold-disrupts-north-dakota-oil-natural-gas-production/?utm_medium=email

[47] NAESB. GEH Forum. "GEH Forum Report". (July 28, 2023). Accessed at: https://www.naesb.org/pdf4/geh_final_report_072823.pdf

recommendations, it already recognizes the urgent need to address the major challenges highlighted by the Chairs of the GEH Forum[48] as follows:

> *"The electric industry is more reliant than ever on the gas industry to fuel electricity generation. However, since the gas industry was largely designed and constructed to deliver gas for home heating and industrial processes, gas infrastructure and markets are misaligned from electric markets. The lack of coordination between these two systems poses serious reliability concerns, as demonstrated during winter storms where dependence on gas in both systems is high."*[49]

Shortly after the GEAR working group formed, MISO and other RTOs issued recommendations for improving gas-electric coordination.[50] The RTOs recommended work for various industry sectors, as well as state and federal regulators, noting the recommendations "are not set in stone, but can be flexibly adopted by particular regions to address each region's unique needs".[51] The Company, however, has proposed a massive investment in gas while recommendations to improve gas-electric operations pertinent to Indiana remain in limbo.

A final concern with the Company's gas-fired generation expansion plan regards the U.S. Environmental Protection Agency's ("EPA") new carbon pollution standards; assuming these remain intact, the Company will ultimately have to either pursue carbon capture technology at the regulated units *or* curtail them so as not to exceed the capacity factor thresholds established under the rules.[52] Either approach calls the cost-effectiveness of this resource further into

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[48] NAESB. "GEH Forum Report." Foreword from the Chairs of the NAESB GEH Forum, p. 2.
[49] *See* National Association of Regulatory Utility Commissioners. GEAR. "Memorandum of the creation of the Gas-Electric Alignment for Reliability ('GEAR')." Accessed at: https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fpubs.naruc.org%2Fpub%2FED9675C9-B864-1AC7-A249-54E476425D44&wdOrigin=BROWSELINK
[50] MISO, ISO-New England, PJM, and SPP. "Strategies for Enhanced Gas-Electric Coordination: A Blueprint for National Progress." (February 21, 2024). Accessed at: https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2024/20240221-strategies-for-enhanced-gas-electric-coordination-paper.ashx
[51] *Ibid.*; see the introduction on p. 1.
[52] *See* U.S. EPA. "Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants." (Updated January 16, 2025). Accessed at: https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power. *Also see* DEI 2024 IRP, Ch. 3, "Key Assumptions", pp. 79-80; "Appendix F: Supply-Side Resources", pp. 411-412; and "Appendix J: Environmental Compliance", pp. 515-517.

question. CGA urges Duke Energy Indiana to re-evaluate and reduce its gas capacity expansion plan and instead pursue more renewables in the short-term and increase storage capacity in the manner described below.

Adding storage capacity to planned and existing generating units. Three of Duke Energy Indiana's Candidate Plans[53] include more energy storage capacity to "meet incremental capacity needs" and ultimately replace retiring thermal generation than the Preferred Plan does, a move the Company even justified under those Plans based on "the relatively short lead time to develop new battery projects" which "makes them an important source of capacity".[54] Duke Energy Indiana should apply this reasoning to the Preferred Plan and pursue more storage capacity than the 415 MW planned for the near term by (1) issuing RFPs for the 300 MW of clean energy resources included in the Short-Term Plan that allow for storage to be paired with renewable resources, including wind, rather than issuing the solar-only RFPs that are planned for release this year; (2) adding some version of on-site battery storage capacity (e.g., co-located, hybrid, or surplus) to all new thermal units, potentially offsetting a portion of the proposed 2,876 MW of new gas capacity; (3) initiating Generator Replacement Requests with MISO for the Gibson Station coal units planned for co-firing with gas, for the purpose of adding storage capacity that could either supplement or offset a portion of the planned gas capacity at those units; and (4) planning for standalone storage *only* after all co-located storage potential has been maximized.

The case for co-located storage merits further discussion here. For example, co-located storage can improve the generating economics of both renewable and thermal resources, at both the unit and fleet levels. Batteries capture and bank excess wind and solar production, storing

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[53] DEI 2024 IRP, "Appendix C", pp. 257-263. The three plans with more installed storage capacity are the Convert/Co-fire Coal, Blend 4, and Exit Coal Earlier strategies (based on the Reference Scenario ICAP).
[54] DEI 2024 IRP, Ch. 4, pp. 111.

that cheaper power until it is economically dispatched, as well as unlocking greater PTC potential from the paired units by maximizing the system's total production. Similarly, batteries can be charged with excess energy produced by thermal units when those are the most economic source of power, such as in the event of sporadic energy shortages, when thermal units can be reasonably used to maintain battery charge cost-effectively. Finally, storage co-located with thermal units can serve as critical "bridge" to gaps in gas-electric coordination noted above.[55]

The DLOL capacity accreditation framework, which will take effect across MISO at the end of the Short-Term Plan period, provides a final strong case for greater integration of battery energy storage into the Company's system. While MISO has yet to issue final values across all resource classes, the 2024 Regional Resource Assessment showed storage remaining competitive with thermal resources and even performing slightly better than gas – across all seasons – through 2030; even after 2030, when storage accreditation values are expected to begin decreasing due to increased renewable penetration, the resource maintains its competitiveness.[56]

Deploying LDES resources strategically. While on the topic of energy storage, we also encourage the Company to use the Short-Term Action Plan period to prepare for deployment of LDES resources, including alternatives to lithium-ion batteries, sooner than 2030 or 2032 (the respective dates for when 10-hour LDES and 100-hour LDES were selectable by the model). Duke Energy Indiana can do this by (1) issuing RFPs that specifically seek emerging LDES resources, either for individual procurements or within storage and renewable energy

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[55] Utility Dive. "Using energy storage to bridge gaps in gas-electric coordination". (February 10, 2025). Accessed at: https://www.utilitydive.com/news/gas-electric-coordination-energy-storage-acp-zalewski/739341/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202025-02-10%20Utility%20Dive%20Newsletter%20%5Bissue:70311%5D&utm_term=Utility%20Dive

[56] *See* MISO. "2024 Regional Resource Assessment Workshop". (December 18, 2024). Note the table on slide 19: "Change in resource class DLOL accreditation by Study Year". Accessed at: https://cdn.misoenergy.org/20241218%20RRA%20Workshop%20Presentation667199.pdf

procurements, to ensure the Company sends clear investment signals encouraging developers to propose a range of technology options; and (2) pursuing pilot or demonstration projects utilizing LDES resources, enabling the Company to gain firsthand experience with this new resource class and make progress towards greater integration of LDES into its system in the future. If Duke Energy Indiana delays learning about the benefits of LDES resources in the near term, the utility will struggle to incorporate and benefit from LDES in the 2030s.

Mitigating risks related to the CIL for MISO Local Resource ("LRZ") Zone 6. MISO's zonal Capacity Import Limits, used to determine Local Clearing Requirements and enforced in the MISO Capacity Auction, are influenced by seasonal generation and demand and by the location of new generation.[57] The state of Indiana, which lies within MISO LRZ-6, currently benefits from the highest CIL of any of MISO's nine (9) LRZs: the Winter 2024-2025 CIL is 8,526 MW and the Spring 2025 CIL is just over 8,000 MW.[58] As noted in Section I of these comments, the high CIL allows for novel solutions to in-state capacity expansion, particularly while the Company navigates the particularly challenging renewable energy siting environment currently at issue in Indiana.

Importantly, while the IURC has played, and can continue to play, an important role in maintaining a high CIL for LRZ-6, a continued high import limit is no guarantee. Therefore, the Company should take the following steps. First, Duke Energy Indiana should prepare for a lower CIL than what was established in PY 2024/2025, noting that the Winter 2025-2026 CIL is

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[57] *See* MISO. "2024-2025 PY Seasonal CIL/CEL Final Results". (October 17, 2023). Accessed at: https://cdn.misoenergy.org/20231017%20LOLEWG%20Item%2004%20PY%202024-25%20Final%20CIL-CEL%20Results630536.pdf
[58] *Ibid.*

already lower by about 600 MW (at 7,936 MW) than the current CIL.[59] Secondly, the Company should also push MISO to mitigate unnecessary and unreasonable (e.g., not justified by reliability) risk related to the CIL by adopting recommendation 2014-6 from its Independent Market Monitor ("IMM").[60] The Company can accomplish the first recommendation by rapidly boosting co-located energy storage capacity within its system, as already discussed in this section of our comments.

As to the second recommendation, the IMM encouraged MISO to redefine LRZs to be more meaningfully and usefully related to the transmission network. According to the IMM's recommendations, the redrawn boundaries would be based (ideally exclusively) on transmission constraints that are known or expected to affect energy transfers and thus the resulting day-ahead and real-time energy market clearing solutions, as well as other local reliability requirements (e.g., due to lower-voltage thermal transmission constraints or voltage support needs), as opposed to MISO's current method that precludes any LRZ from being smaller than an entire Local Balancing Area ("LBA").[61] As the boundaries are currently drawn, LRZs become an issue when capacity needs emerge within a load pocket *within an LBA*. Even presuming that MISO has accurately identified a Local Clearing Requirement ("LCR") and CIL for LRZ-6, the zone-wide LCR ignores where a capacity need or other (low-voltage or voltage-related) transmission need might emerge in real-time energy market operations.[62]

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[59] *Ibid. Also see* MISO. "Planning Year 2025-2026 Loss of Load Expectation Study Report". Table 4-3: Planning Year 2025–2026 Import Limits, p. 41. However, the Summer, Spring, and Fall seasons still benefit from the strongest CIL of any of the LRZs. Accessed at: https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report662942.pdf

[60] *See* IMM for the Midcontinent ISO. Prepared by Potomac Economics. "2023 State of the Market Report for the MISO Electricity Markets." (June 2024). Note item 2014-6 on p. 122. Accessed at: https://www.potomaceconomics.com/wp-content/uploads/2024/06/2023-MISO-SOM_Report_Body-Final.pdf

[61] *Ibid.* Also note that while LBAs are essentially transmission owner ("TO") zones, in some states LBAs include a greater geographic region than that within a single TOs service territory.

[62] Indeed, MISO has long had formal operations and cost allocation rules for unit commitments needed for voltage and other local reliability needs in the day-ahead and real-time markets.

In other words, the existing method problematically creates incentives simply for new capacity anywhere within Zone 6 or new (import-enhancing) transmission upgrades somewhere in or near Zone 6 (or even farther away depending on all the possible transmission network effects that could affect Zone 6 imports). However, the actual (and possibly urgent) need is confined to a smaller load pocket within the LRZ. The IMM's recommendation would instead help create more targeted incentives for investments that would improve energy market operations – and thus the affordability and reliability of the Company's service.

If MISO were to re-draw boundaries around load pockets and other known transmission constraints affecting the energy market in this way, the applicable Local Clearing Requirement ("LCR") would be large only for areas within Indiana where new investment is needed (and will be useful for improving energy market operations) and would be (nearly) zero in less constrained areas within the state. Despite agreeing with the premise of recommendation 2014-6, MISO deferred action.[63] CGA strongly encourages the Company – and the IURC – to entreat MISO to redefine LRZs so that LRZ import limits are more meaningful and the investment signals created by LCRs are more useful for maintaining reliable and affordable wholesale energy supply for the benefit of Duke Energy Indiana's ratepayers.

IV. The Company's approach to energy storage modeling under the IRP scenarios and to modeling resource costs under the Candidate Plans did not adhere to IRP best practices.

Energy storage modeling. The Company only analyzed a limited range of commercially available storage technologies within the resource class by singularly considering 4-hour lithium-

[63] *See* MISO, Markets Subcommittee. "MISO's Response to the Independent Market Monitor (IMM) 2023 State of the Market (SoM) Recommendations". (October 25, 2024). Accessed at: https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=524360

ion storage for all scenarios but the Aggressive Policy & Rapid Innovation worldview, for which long-duration, multi-day, and 4-hour storage options were allowed – although 10-hour LDES were only allowed after 2030 and 100-hour LDES were only allowed after 2032.[64] As a best practice, the model should have been allowed to select from this diversity of storage technologies in <u>all</u> scenarios or worldviews, while optimizing for least-cost resources under each. Given that Duke Energy Indiana recognizes the energy storage industry is seeing "continued declines in the installed cost of energy storage" and that many emerging energy storage technologies "passed the technology screening," the limitation placed on the model in both the Reference Scenario and Minimum Policy & Lagging Innovation worldviews is egregiously artificial.[65] Furthermore, many utility and industry studies have demonstrated the benefits provided by a diverse portfolio of energy storage technologies (e.g., a combination of short, long, and multi-day energy storage resources) such as lowered overall portfolio costs, reduced new resource needs, and strengthened grid reliability.[66] In short, a blend of these resources could help ensure the "balanced and orderly energy transition" the Company is planning for amidst the current era of load growth and generation fleet retirements.[67] Given the Company highlighted particular challenges associated with accurately modeling energy storage, Duke Energy Indiana should be sure to engage stakeholders in a broader discussion about emerging modeling best-practices that allow

[64] DEI 2024 IRP, Ch.3, "Table 3-28: Availability of Renewables & Storage Resources Across Worldviews" on p. 96 and "Appendix F: Supply Side Resources", pp. 412-413.
[65] DEI 2024 IRP, "Appendix F", pp. 412 and 417, respectively.
[66] *See* U.S. Department of Energy. "Pathways to Commercial Liftoff: Long Duration Energy Storage". (2023). This report discusses the benefits of inter-day and multi-day long-duration energy storage and discusses a range of technologies in these resource classes. Accessed at: https://liftoff.energy.gov/wp-content/uploads/2023/10/Pathways-to-Commercial-Liftoff-LDES-May-5_UPDATED-v10.pdf
[67] IURC Case No. 46155, Appendix F, p.410.

Encompass to capture the full value of energy storage resources over realistic grid conditions as its next IRP is developed.[68]

Projected costs of wind, solar, and storage. The Company cited cost increases as a continuing constraint common to all supply-side technologies. While true, recent market analysis shows that both the levelized cost of energy ("LCOE") and capital costs for renewables dropped by more than 4% in the fourth quarter of 2024 and that continued decreases in the LCOE are expected through 2060.[69] In the short-term, analysts expect utility-scale solar to grow by a 6.6% compounded annual rate that should exert downward pressure on project costs through 2030.[70] Even accounting for wind and solar "firming" costs (e.g., the LCOE of the renewable resource plus additional costs required to achieve the resource adequacy requirements of the reliability region), both wind and solar are still competitive with natural gas.[71] Energy storage system costs have also declined dramatically, largely driven by technological advancements and decreasing costs of raw materials, including for the lithium carbonate widely used in lithium-ion batteries.[72]

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[68] Capacity expansion modeling for energy storage resources should attempt to capture accurate state of charge over a year and diverse weather conditions, and accurately represent the hourly generation profile, among other things.
[69] *See* Wood Mackenzie. "Wind and solar lead accelerating LCOE drop for renewable energy". (October 28, 2024). Accessed at: https://www.utilitydive.com/news/wind-solar-levelized-cost-electricity-drop/730533/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202024-10-31%20Utility%20Dive%20Renewable%20Energy%20%5Bissue:67386%5D&utm_term=Utility%20Dive:%20Renewable%20Energy
[70] *See* S&P Global, "Solar Market Monitor, H1 2024", "Executive Summary". (November 25, 2024). Accessed at: https://cleanpower.org/wp-content/uploads/gateway/2024/11/ACP_Solar-Market-Monitor-H1-2024_Public-Executive-Summary_v2.pdf
[71] *See* Lazard, "Levelized Cost of Energy Plus". (June 2024). See slide #15, "Levelized Cost of Energy Comparison—Cost of Firming Intermittency". For this cost comparison, Effective Load Carrying Capability (by RTO/ISO), capacity factors, and resource penetration are accounted for. Under this analysis, wind and solar are both competitive with peaking gas and wind is competitive with combined cycle gas. Accessed at: https://www.lazard.com/media/xemfey0k/lazards-lcoeplus-june-2024-_vf.pdf
[72] *See* Jefferies, USA: Power & Utilities, Equity Research. "Recent Industry Chats: Storage, Large Transmission, Insurance, PA, Gas LDCs". (January 17, 2025). Accessed at: https://javatar.bluematrix.com/pdf/wWuXBezO

Yet the overall cost-competitiveness of wind, solar, and storage is not reflected in the Company's IRP, in which only overnight capital costs by technology type are compared.[73] Duke Energy Indiana claims it did not evaluate the LCOE as this metric "has limitations" that can "create uneven results".[74] Frankly, modeling of any kind has limitations and cannot predict all potential outcomes—but the LCOE is a widely recognized economic measure that contributes to a more comprehensive picture of potential future costs over the lifetime of the system than an assessment of capital costs alone can provide. At the very least, the Company should have included a comparison of the LCOE by technology types selectable under each modeling scenario (i.e., the Reference Scenario, Minimum Policy & Lagging Innovation, and the Aggressive Policy & Rapid Innovation worldviews) in addition to the capital cost comparison.

More broadly, however, we are concerned with both the limited sources used by the Company to develop the unit technology costs and the lack of transparency for those cost inputs. Duke Energy Indiana relied on privately contracting with engineering and consulting firms and its own "internal data and expertise to inform generic resource costs and characteristics", presumably based on RFPs issued between 2022 and 2024.[75] The Company notes it "carefully considered" other reputable industry sources, including the EPRI TAGWeb database, the National Renewable Energy Lab's Annual Technology Baseline ("ATB"), the U.S. Energy Information Administration's Annual Energy Outlook, ("AEO"), and Lazard's latest LCOE.[76]

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[73] DEI 2024 IRP. "Appendix F". See "Table F-2: Generic Unit Overnight Technology Capital Costs for Projects in 2024 Dollars" on p. 421.
[74] DEI 2024 IRP, "Appendix F", p. 422.
[75] DEI 2024 IRP, "Appendix F", pp. 418-420, and "Appendix G: Competitive Procurement Process", pp. 423-436. On p. 436, DEI states that "bid information … informs the market costs for specific resource types to help confirm [IRP] modeling assumptions."
[76] DEI 2024 IRP, "Appendix F".

A better approach would have been for the Company to do more than "consider" these other resources and instead to compare the cost projections of its own modeling to those of the widely used, publicly available sources and to discuss potential reasons for any major differences. In fact, this process is considered a best practice in IRP, as it provides for the utility's own projected costs to be "sense-checked against cost estimates in the best-available public resources."[77]

To compare Duke Energy Indiana's approach to that of NIPSCO's for a final time: NIPSCO issued RFPs specific to its 2024 IRP to assist with modeling of clean energy additions, relying on recent project experience only for resources for which no proposals were offered (in this instance, wind resources), and basing assumptions for longer-term additions (e.g., beyond the RFPs) on both (a) RFP data and recent project experience with wind, and (b) the mid-range cost decline rate from NREL's ATB.[78] Had Duke Energy Indiana used these methods (e.g., cost comparisons using publicly available data and the issuance of RFPs specific to this IRP), the Commission, stakeholder participants, and other interested parties would have then been able to share the same understanding for the cost basis behind each portfolio. CGA suggests this analysis be performed in all future IRP filings.

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[77] *See* Synapse Energy Economics and Lawrence Berkeley National Laboratory. "Best Practices in IRP". (December 6, 2024). "Supply-side Inputs: Best practice 12" on p. 31.

[78] NIPSCO 2024 IRP, "Section 4: Supply-Side Resources". For more information about the use of RFP data specifically, note pp. 121-130.

Respectfully submitted,

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