REBUTTAL TESTIMONY OF KELLEY A. KARN
VICE PRESIDENT, REGULATORY AFFAIRS & POLICY
DUKE ENERGY INDIANA, LLC
CAUSE NO. 46193
BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kelley A. Karn, and my business address is 1000 East Main Street, Plainfield, Indiana 46168.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Vice President, Regulatory Affairs & Policy for Duke Energy Indiana, LLC ("Petitioner," "Duke Energy Indiana," or "Company"), a wholly owned subsidiary of Duke Energy Indiana Holdco, LLC and an affiliate of Duke Energy Corporation ("Duke Energy").

Q. ARE YOU THE SAME KELLEY A. KARN THAT PRESENTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to certain positions advocated by the Indiana Office of the Utility Consumer Counselor ("OUCC"), Citizens Action Coalition of Indiana, Inc. and Vote Solar (collectively "CAC"), and Duke Industrial Group ("Industrial Group" or "IG"). Specifically, my testimony will explain the benefits of adding natural gas combined cycle ("CC") generation to our system, address issues raised by the parties regarding environmental compliance, the potential for future environmental rule changes and how the Company's proposal to construct two CC natural gas-fired units, at approximately 738 megawatts (winter rating) each, at the existing Cayuga Generating Station ("Cayuga CC Project" or "CC Project") is directionally in line with more recent governmental announcements regarding the importance of dispatchable generation and of adding generation to the grid. I will reiterate how the Cayuga CC Project is well situated to withstand future environmental compliance rule changes. I will also respond to the parties' arguments regarding the viability of continuing to operate the Cayuga coal units. My rebuttal testimony also addresses issues raised by the parties regarding the Company's Request for Proposal ("RFP") process, the transmission interconnection for the Cayuga CC Project, and the Company's investment in energy efficiency, demand response and distributed energy renewable generation ("DERS"). Finally, I will update the Commission on HEA 1007 and its continued applicability to this proceeding.

II. THE CAYUGA CC PROJECT WILL BRING MANY BENEFITS TO DUKE ENERGY INDIANA'S SYSTEM

Q. WOULD YOU PLEASE EXPAND ON THE BENEFITS OF THE CC PROJECT AND ADDING NATURAL GAS TO DUKE ENERGY INDIANA'S SYSTEM NOT CONSIDERED BY THE PARTIES' POSITIONS IN THIS PROCEEDING?

A. The Cayuga CC Project provides many benefits in the following categories:

environmental sustainability, reliability, and cost. First, we know the current coal units are challenged to comply with current and new environmental regulations, such as river water temperature permit limits found in the Clean Water Act Section 316(a) and (b), mercury air toxic standards ("MATS"), effluent limitation guidelines ("ELG") requirements, and the new Clean Air Act greenhouse gas standards ("GHG Rules" or "Rule 111"). As I will explain in more detail below, some of these regulations may be repealed and/or modified, but not all of them are expected to go away immediately, as suggested by the OUCC, and there are still remaining risks. In contrast, the Cayuga CC Project is best suited to meet current environmental standards and a variety of future standards. For the benefit of customers, the Company is investing in the most efficient natural gas plant on the market today, meaning it has the lowest emissions achievable, positioning it well to meet even stricter environmental requirements if they occur in the future. As noted in our case in chief testimony, even if the very strict GHG Rules were implemented, our 2024 integrated resource plan ("IRP") analysis demonstrated that the Cayuga CC Project is still an economic choice for customers. Today, we believe the GHG Rules will likely be repealed or replaced prior to the required implementation timeline. Of course, the Company anticipated that potential in the 2024 IRP and ran scenarios and strategy variations reflecting that assumption. We demonstrated that a No 111 portfolio that still retired and replaced the Cayuga coal units with natural gas CC would be lower cost by about $700 million and would be much less reliant on market purchases as it would allow the Cayuga CCs to run with unrestricted capacity factors. So, the recent policy changes that the OUCC and IG are so concerned with actually provide additional benefit to customers from the Cayuga CC Project.

My direct testimony also speaks to the many reliability benefits of adding dispatchable natural gas to the Duke Energy Indiana system. The Cayuga CCs will provide 471 MW of additional 24x7 energy and capacity. It is expected to dispatch economically with an estimated 87% capacity factor, estimated in our IRP, if unrestrained by the GHG Rules. The accredited capacity for the natural gas combined cycle is higher than that of the existing coal units, even if you don't include the additive 471 MW. It will be easier to manage planned outages with the two 1x1 configuration and the risk of forced outages is less. The plant will provide valuable contingency, supplemental, spinning, and regulating reserves, and much faster ramp capability than existing coal or gas-converted units. Further, the proposed split voltage transmission interconnection minimizes the potential for grid issues or required network upgrades.

Finally, the Cayuga CC Project is a good investment for customers from an affordability perspective. The ability to reuse existing assets and facilities that our customers have already paid for such as the existing transmission switchyard, the MISO replacement generator interconnection, the air permit, the river water intake and discharge and existing land at the Cayuga Station, provides cost savings to customers. As Company witness Mr. McClay has explained, this project provides the lowest costs opportunity to connect to the very close interstate pipeline and to obtain the firm natural gas transportation needed for ongoing reliability. Further, as Company witness Mr. Smith has explained, the Company took many proactive steps to position this project for success, at its own risk, including early deposits and queue positions for gas and steam turbines and transformers, and early engagement with a competitively bid EPC contractor. The Company also entered into the MISO generator interconnection queue process early. All of that activity results in cost savings in comparison to waiting until final certificate of public convenience and necessity ("CPCN") approval when costs would increase, and queues would be more full. Finally, the IRP modeling demonstrates that in virtually every portfolio and sensitivity run, natural gas combined cycle was the cost-effective choice to replace the aging Cayuga coal units.

In sum, considering all the benefits it provides customers, the Cayuga CC Project is the right project at the right location at the right time.

Q. WHAT POSITION DO THE OUCC AND INTERVENORS TAKE WITH RESPECT TO THE COMPANY'S IRP PROCESS AS IT RELATES TO THE CC PROJECT?

A. The OUCC, CAC, and to some extent IG, would have the Company go back to the drawing board and redo its entire IRP, even though this CPCN was filed a mere three months after we submitted the 2024 IRP. As the Indiana Utility Regulatory

Commission ("Commission") is aware, the IRP process is about a year-long process where stakeholders are included with multiple public meetings and feedback sessions. Have there been changes in policy outlook and other assumptions since we filed the 2024 IRP? Of course. That will be the case with any plan that is a year in the making. That's why we perform a robust analysis in the IRP that includes various scenarios, sensitivities and even stochastic analyses.

I have been engaged in our IRP process for many years and I know firsthand the major policy, regulation and load changes that necessitated the Company to go back and relook at its plans for Cayuga prior to filing for a CPCN between the 2021 and 2024 IRPs. This was a time of broad and rapid changes impacting IRP modeling, including MISO's seasonal accreditation changes (and later the move to direct loss of load accreditation) and increasing load growth. We also needed to update our analysis to reflect results from our 2021 RFP. So, while that re-analysis was important to a final decision on the right path for Cayuga, the time has come to stop analyzing and start executing on the best plan available.[1] The 2024 IRP submittal was made just three months prior to this CPCN filing; it remains current, robust, relevant and sufficient evidence to base this decision upon.

[1] Notably, the parties disagree regarding the Company's IRP analysis and timeline. While the OUCC (Armstrong, p. 4 and Hanks, p. 10) and IG (Fitzhenry, pp. 10-11; 16-18) call for further analysis with updated assumptions in support for delaying the retirement of Cayuga and the CC Project, the CAC recognizes that Duke Energy Indiana has been further analyzing its plan for Cayuga Station almost continuously since the 2021 IRP. In fact, CAC criticizes the Company for not acting faster to retire and replace the Cayuga coal units as called for in its 2021 IRP. CAC, rather, seeks something other than the CC Project as the replacement for the current units' retirement.

Company witness Mr. Gagnon discusses in detail in his direct and rebuttal testimonies how the Company accounted for the potential for the very policy changes we have seen and how the Cayuga CC Project remains the best plan regardless. As he explains, the Company took into account uncertainty through the study of various scenarios, strategy variations and even stochastic analyses as part of its 2024 IRP. Some of that predicted uncertainty is coming to bear and more remains. Yet, there will never be a time with no uncertainty, and that cannot be an excuse to do nothing. Rerunning the IRP analysis is simply not needed to make an informed decision today, and delaying the decision would be the wrong decision for our customers and the reliability of our system given the many benefits of the Cayuga CC Project to Duke Energy Indiana's system and customers.

Q. WHAT RISKS ARE ASSOCIATED WITH DELAYING THE DECISION AND NOT GOING FORWARD WITH THE CAYUGA CC PROJECT NOW?

A. Rather than recognize the urgency and necessity of modernizing the Company's fleet, the OUCC and Intervenor positions would delay the addition of any dispatchable, reliable and affordable generation for years, while we study, analyze and re-evaluate our options. The Company, and most importantly our customers who rely on us to keep the power on, do not have the luxury of endless analyses as the OUCC advocates, not taking a position as the Industrial Group has, or hoping that a distributed energy resource market develops in time to meet our customers' needs as the CAC postures. (Latham, p. 3, 12-13; Fitzhenry, p. 7; and Inskeep, pp. 34, 49-52.)

Additionally, there are risks with the wait and see approach, including the delay by two to three years of additive dispatchable generation, increased costs of that generation, the risk of continued load growth in the interim period, and the risk of further MISO accreditation changes making the Company's position even shorter. First, there is a need today for additive generation, not only on the Duke Energy Indiana system to reliably serve our customers, but also MISO-wide. Recent results from the MISO Planning Resource Auction for planning year 2025-2026 bear this out, with tight conditions demonstrated for summer 2025, resulting in the high auction clearing price of $666 per MW-day. When looking specifically at Duke Energy Indiana's customers' needs, the Company made several bi-lateral capacity purchases totaling 470 MW for the summer 2025 and cleared the auction with an additional purchase needed of 133 MW (or 2% of the Company's overall requirement) in order to satisfy the new MISO reliability-based demand curve reserve requirements. This demonstrates a *current* need for the additive capacity the Cayuga CC Project will provide. Importantly, of all the plans the Company analyzed, this was the only plan that could add incremental dispatchable energy generation as early as 2030.[2]

[2] I would note that the Company is also pursuing renewable and battery storage options coming out of its 2024 RFP process, which may be able to be in-service prior to 2030, but which do not provide the amount of 24x7 dispatchable energy and capacity needed.

Key risks of the OUCC and Intervenors' wait and reevaluate approach are that additive generation will take even longer to secure and the ultimate project selected will cost more. Imagine the Company re-starting its IRP analysis this October when the Commission issues its order in this proceeding: Assuming a similar timeline to the 2024 IRP, the process would not be complete until October 2026. Given that the Company has already identified a need for additive generation, the process will likely result in a CPCN to build new generation, which would add another ten months (assuming two months to prepare the filing). Just the regulatory process would add almost two years. That assumes the Company would have to take preliminary actions, such as entering the MISO queue and applying for environmental permits, as well as reserving long lead time equipment and beginning negotiations with an EPC vendor while the IRP and CPCN were proceeding, as we did this time around. If the Company waited on those activities until the results of the updated IRP, you would need to add at least another year to the process. All of this would delay the potential for any new dispatchable generation by two to three years, moving it to the 2032 / 2033 timeframe at the earliest.

Furthermore, as we have seen in the past, costs of the proposed generation project or projects would also increase in that two- to three-year period. IG witness Fitzhenry concedes (pp. 10): "The demand for natural gas combined cycle plants is near an all-time high." As Company witness Mr. Smith has testified (and shown in the cost estimate he supports) the equipment price of gas turbines increased by 16% percent just in the 10 months between when we ordered the first and second gas turbine.[3] We also know the cost of interconnecting to the MISO grid will only go up if we delay, as we would lose our position in the 2023 queue and have to start over with several years' worth of MW additions ahead of any new proposed project, resulting in a more congested grid and likely higher network upgrade costs.

As we would wait, there would also be a real potential for increased load growth from customer additions, electrification, onshoring manufacturing and data centers, further exacerbating our need for additive generation. Finally, for the last several years, MISO has proposed many reforms aimed at shoring up the reliability of the market. Waiting another two to three years to act, there would be a further risk that additional policy and tariff changes would result in lower accreditation or higher reserve margin requirements, again increasing the need for additive dispatchable generation.

Q. ARE THERE ENVIRONMENTAL REGULATION AND LITIGATION RISKS ASSOCIATED WITH NOT GOING FORWARD WITH THE CC PROJECT NOW?

A. Yes. I address this more thoroughly below, however, it is important to note that while President Trump has signaled an intent to reduce regulatory requirements on the energy industry and support coal-fired generation, it is not guaranteed that these

[3] *See* Company witness Smith Confidential Workpaper 3-JRS related to CTG 1 and Confidential Workpaper R1b-JRS related to CTG 2.

regulations will be repealed (they are certain to face lengthy legal challenges) and even if some regulations eventually are scaled back, all regulations certainly will not go away completely or immediately. Rather, as Ms. Armstong admitted (pp. 15-17), there is a long regulatory rulemaking process that must be followed and it will be replete with appeals and uncertainty for many years. We also know from prior experience that even if rules like the Clean Air Act Section 111 Final Rule are repealed, that does not mean the end of environmental risk related to GHG emissions. History shows us that citizen suits and nuisance claims can gain traction even in the absence of environmental regulation.

Further, while we are in an environment of reduced environmental regulation right now, that does not mean this will remain the status quo in the future. OUCC witness Armstrong herself acknowledges (p. 15) each time a new federal administration has issued regulations after a previous administration has relaxed or repealed regulations on fossil-fuel-fired electric generating units ("EGUs"), the new regulations have tended to be more stringent. CAC witness Inskeep (p. 19) makes similar statements.

The OUCC's recommendation to continue to operate 60 year old coal units into the 2040s and beyond faces many future environmental risks, and certainly more environmental risk than operating the most efficient, advanced class, natural gas plant, with lower overall emissions rates.

III. THE CC PROJECT WILL INCREASE RELIABILITY

Q. PLEASE EXPLAIN HOW THE CC PROJECT WILL CONTRIBUTE TO OVERALL SYSTEM RELIABILITY IN INDIANA AND HOW THE PROJECT WILL POSITION AND CONTRIBUTE TO DUKE ENERGY INDIANA HAVING A BALANCED PORTFOLIO THAT CAN RELIABLY SERVE ITS CUSTOMERS.

A. As I have testified, there is a need for additive dispatchable generation. Again, one of the noteworthy absences from the OUCC and Intervenor testimonies is any sense of urgency around adding incremental generation to the grid. NERC, MISO, and the State of Indiana, however, all recognize the urgency. In fact, NERC recently announced as part of the 2025 Summer Reliability Assessment[4] that record load growth and high temperatures are expected to strain the grid this summer.[5] Contrary to what Mr. Inskeep advocates (p. 21), NERC also highlighted that once again, the response by inverter-based resources ("IBRs") to system disturbances, which affect solar facilities, battery storage, and traditional generation, is a concern.[6] The NERC report includes the following important finding:

> MISO is expecting to have an existing certain capacity of 142,793 MW in the 2025 SRA, which is a slight reduction from the 143,866 MW submitted for the 2024 SRA. The retirement of 1,575 MW of natural gas and coal-fired generation since last summer, combined with a reduction in net firm capacity transfers due to some capacity

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[4] *See* the NERC 2025 Summer Reliability Assessment (May 2025) here: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf.
[5] *See* NERC May 14, 2025 announcement here: https://www.nerc.com/news/Headlines%20DL/05142025%20SRA%20Announcement%20Final.pdf.
[6] *Id.*

> outside the MISO market opting out of the MISO planning resource auction, is contributing to **less dispatchable generation in MISO**. With higher demand and less firm resources, MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output. **MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August. This shift is driven by the decline in dispatchable generation and the increasing share that solar and wind resources have in meeting demand. The risk of supply shortfalls increases in late summer as solar output diminishes earlier in the day, leaving variable wind and a more limited amount of dispatchable resources to meet demand**.[7]

(**emphasis added**).

As discussed in my direct testimony, and largely ignored by the parties, MISO also continues to caution that retirement of dispatchable generation needs to be at least replaced with like kind dispatchable and accredited generation. In a post entitled: "Why the Urgency", MISO explained, "One challenge is the looming mismatch between the speed of new generation coming online and the retirement of existing generation. This mismatch must be addressed today if we want to ensure power flows 24/7/365 long after tomorrow."[8] As recently as this summer, MISO continues to warn of tight capacity conditions, noting that surplus generation above the target planning resource margin dropped by 43% compared to last summer, reinforcing "the need to increase capacity, as demand is expected to grow with new large load additions."[9] Again, the Cayuga CC Project best addresses the problems outlined by

[7] NERC 2025 Summer Reliability Assessment (May 2025) at 5.
[8] MISO's Reliability Imperative: Why the Urgency?
[9] MISO 2025 Summer Readiness Presentation, 1.-MISO-SRF-Presentation-2025.pdf.

NERC and MISO, providing additive, flexible, reliable, dispatchable resources to the grid with a sense of urgency.

Likewise, the Indiana General Assembly and the Indiana Governor have recognized the urgency of providing additional dispatchable generation to the grid. This past legislative session, House Concurrent Resolution No. 3, attached to my testimony as Attachment 9-A (KAK) was passed and states in pertinent part: "… *The ability to quickly develop and build additive energy infrastructure, including generation and transmission, is critical to the economic development and electric resource adequacy of Indiana and the Midwest.*" Further, a recent Governor Braun Executive Order 25-50 ("EO-25-50") recognizes that "… Indiana needs baseload, dispatchable energy to provide for existing energy needs and to serve growing demand" and directs state agencies in part to "encourage an additive energy strategy, rather than just replacing energy generation."[10] Company President Pinegar's testimony explains how the Cayuga CC Project is consistent with the Governor's recent executive orders, as it retires aging assets (which happen to be coal), but replaces it with additive dispatchable generation with a higher accreditation value.

It is practically unanimous by those that monitor and care about the reliability of the grid that the Cayuga CC Project is the type of generation utilities like Duke Energy Indiana need to be bringing to the system. The OUCC and the

[10] EO-25-50-.pdf

other parties cannot ignore the significant risks they are placing on Duke Energy Indiana customers and the grid with their various recommendations which ultimately would have the Commission deny the CC Project. Given this important and significant need to maintain system reliability, the OUCC's plan to continue to operate Cayuga as a coal fired generating plant or refuel (Latham, p. 12), or the CAC's plan to rely on IBRs or DERS (Inskeep, p. 21), are simply not viable options even under the changing federal and state regulatory landscape, which the Company thoroughly considered.

Q. CAC WITNESS INSKEEP CLAIMS (PP. 20-21) THE COMPANY'S RESOURCE PORTFOLIO IS EXTREMELY UNBALANCED AND SUGGESTS DERS ARE A BETTER SUBSTITUTE FOR THE CAYUGA CC PROJECT. HOW DO YOU RESPOND?

A. I disagree with Mr. Inskeep that DERS provide the required reliability and stability benefits that are needed on the grid today. NERC's latest Summer Reliability Assessment was just released in May 2025, and it emphasized the need for dispatchable generation, finding for the MISO region: "With higher demand and *less firm resources*, MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[11] MISO needs more firm resources like the CC Project to combat these potential risks. DERS are not firm resources and relying on them to replace coal units is a risky approach for Duke Energy

[11] NERC 2025 Summer Reliability Assessment, May 2025, at 5 (https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf).

Indiana customers who rely on us to keep the lights on every day. Additionally, Mr. Inskeep's solution appears to be for the Company to rely upon the MISO market to have the type of projects like the CC Project available for our use. NERC and others have already indicated that the market may not be in the position to provide this support. Plus, he misses that if every utility took this approach, it is all but assured there would be no market to rely on. The Company must be a fair market participant.

I must also note, again, that the parties cannot seem to agree. In contrast to Mr. Inskeep's position, OUCC witness Latham testifies (p. 7) that both gas generation and coal generation are reliable sources and currently, coal and gas are more reliable than renewable energy, as neither are dependent on sunshine or wind to operate. He also testifies (p. 8) that both coal generation and gas generation provide resiliency. He then notes that the OUCC recognizes Duke Energy Indiana's IRP and updated analysis show additional replacement capacity for retiring generation is needed to preserve resiliency, as well as reliability and stability. Finally, he testifies (p. 9) that both coal-fired generation and gas-fired generation are stable resources for electric generation as defined in the statute.[12]

[12] IG witness Fitzhenry appears to disagree with CAC witness Inskeep too. He states on pp. 10-11 of his testimony that: "At this time, there are only a few types of generating resources that can provide intermediate or base-load generation and also have the ramping capability of advanced 1x1 CCs. As more variable energy resources are added to the grid, utilities are looking to add generating resources that can complement the unpredictable output of these generating resources. In addition, many industry analysts are projecting significant demand growth in the next decade to meet the energy requirements of new data centers."

Further, the Company supported that not only is this project good for the broader market, but it is needed for our own customers. While Mr. Inskeep would like the Commission to believe there are parallels with this proceeding and the decisions the Commission was faced with in Cause No. 45052, this is far from the case.

Q. PLEASE EXPLAIN FURTHER WHY IT IS INAPPROPRIATE TO ATTEMPT TO DRAW PARALLELS BETWEEN THIS PROCEEDING AND CAUSE NO. 45052.

A. Cause No. 45052 was filed February 20, 2018, decided April 24, 2019, and was based on a 2016 IRP. Duke Energy Indiana's IRP modeling, in contrast, was finalized in November 2024, just three months prior to filing this CPCN. There have been numerous policy and regulatory changes and MISO market and economic changes over the past seven years, including growing economic development, a tightening MISO capacity market, and more stringent environmental regulations. The need for resource adequacy and reliability has gained keen focus from organizations responsible for reliability like NERC and MISO. Furthermore, unlike the Commission's determination in Cause No. 45052 that the proposed natural gas combined cycle plant was too large for the utility's system and therefore their generation portfolio would lack diversity, the Company has shown the CC Project is right sized to meet our current and future customer needs and adds diversity to the Company's portfolio. The choice of two 1x1 units increases the flexibility of the system as well, making it easier to plan for outages and reducing risk of unplanned outages by limiting the impact to just 700 MW, as opposed to 1,400 MW. Circumstances today differ from 2019 and support the approval of the CC Project as a reasonable and necessary addition of energy and capacity for the Company's system and MISO wide.[13]

IV. IN A CHANGING FEDERAL AND STATE REGULATORY LANDSCAPE THE CC PROJECT SUPPORTS ENVIRONMENTAL SUSTAINABILITY

Q. DID THE COMPANY ACCOUNT FOR A CHANGING FEDERAL AND STATE REGULATORY LANDSCAPE IN ITS ANALYSIS?

A. Yes, extensively. Company witness Mr. Gagnon will be responding to the parties' concerns and recommendations regarding the IRP modeling, demonstrating that the Company foreshadowed and modeled the very changes in regulatory landscape that are occurring today. With respect to Ms. Armstrong's, Mr. Fitzhenry's, and Mr. Inskeep's testimonies suggesting that regulatory uncertainty calls into question the Cayuga CC Project, I think it is important to note that when the Company was developing the IRP, different regulatory environments were considered, including

[13] CAC witness Inskeep also incorrectly suggests this case is akin to the even older proceeding, Cause No. 44242 (pp. 71-72) when he advocates for risk mitigation measures. For many of the same reasons it's inappropriate to draw parallels to Cause No. 45052 it is inappropriate to liken Cause No. 44242 to this proceeding. First, Cause No. 44242 involved a Commission approved settlement agreement and is not precedential. Second, as evidenced by Company witness Mr. Gagnon and others, the Company's analysis was far from simplistic (which the Commission found IPL's analysis to be). IRP modeling has matured greatly since Cause No. 44242 which was decided in 2013 based on a 2011 IRP. Further, the Commission has a long history of rejecting hind-sight analysis. To the extent Mr. Inskeep is suggesting the Company be penalized for not predicting to perfection what an uncertain future holds, he is engaging in hindsight, and the Commission should reject that recommendation. Attempting to draw conclusions from comparing this proceeding to such different circumstances in these other proceedings is unreasonable.

the Minimum Policy & Lagging Innovation Scenario and the No 111 Strategy Variation, as detailed by Mr. Gagnon. Industrial Group witness Fitzhenry acknowledges this on page 19 of his testimony. Even under all these considerations, the modeling still supported natural gas combined cycle units in the same timeframe and amount as proposed by the Company. As I have testified, while I agree there is regulatory uncertainty, delaying the CC Project as the OUCC and Intervenor parties suggest ignores the numerous benefits of the CC Project and risks that potential delay could cause, as detailed in my testimony above.

Q. DID THE COMPANY THOROUGHLY ANALYZE AND IDENTIFY THE RIGHT TIME AND WAY TO REPLACE THE CAYUGA COAL UNITS AS THEY NEAR THE END OF THEIR LIFE?

A. Yes. In particular, I would like to reiterate, as both witness Pinegar and I have stated on direct and again in rebuttal, this is not about prematurely replacing coal units, as Ms. Armstrong states at p. 25 of her testimony. The existing units at the Cayuga Generating Station will be 60 plus years old in 2030 and have provided reliable baseload generation for many years. These aging units consistently have been slated for retirement in the 2027-2030 timeframe going back three IRPs to the Company's 2018 IRP. And, the Company's depreciation rates have been set to recover the costs of these coal units by those assumed retirement dates since 2020, minimizing the potential for stranded costs. These assets are simply facing the end of their useful life and now is the time for the Company to look towards a replacement. As indicated above, the CC Project is not just a replacement, but a modernization and an enhancement with the addition of 471 MW of dispatchable, reliable generation. It is also the only plan that is able to provide that dispatchable generation as soon as 2030. The OUCC's position that we should just continue to operate the coal plants and re-evaluate the replacement plan only causes delay and increased cost and risk. As such, the OUCC's proposal is simply not the best plan for customers.

Q. PLEASE EXPLAIN FURTHER WHY THE COMPANY'S PLAN IS THE MOST REASONABLE PATH FOR DUKE ENERGY INDIANA AS OPPOSED TO CONTINUING OPERATION OF THE COAL UNITS FOR ANOTHER 15 YEARS AS PROPOSED BY THE OUCC?

A. The Company's plan to construct the CC Project and retire the coal units is the most reasonable path forward for many reasons. First, as Company witness Mr. Luke explains in his rebuttal testimony, there is a significant additional cost associated with keeping the coal plants running to 2040 or longer. Mr. Luke addresses these costs and estimates it will cost hundreds of millions of dollars to keep the coal plants running. Making this type of investment into coal plants that will be 60 years old at the proposed transition date raises the specter of significant stranded costs. The Company believes it is much more prudent for our customers to invest in a new, state of the art natural gas plant with the most advanced and efficient technology than to spend hundreds of millions of dollars to keep the coal plants online.

Further, while Company witness Mr. Pinegar speaks to the overall affordability of the CC Project, I can definitively state that the affordability of these options was analyzed as part of the Company's IRP process and, as discussed in Mr. Gagnon's testimony, converting the plants to natural gas (as OUCC witness Hanks suggests at pp. 22-23) is not the most affordable option for our customers. Further, an analysis of continuing coal by co-firing the units with natural gas done by Mr. Gagnon also was shown to be more costly on a present value of revenue requirements basis ("PVRR"). By Ms. Armstong's own admission the analysis done by the OUCC only reflects the short term rate impact (Armstrong page 7, 8), while affordability is necessarily a longer term view. If one only looked at short term ratepayer impact, major capital investments needed to modernize the generations fleet would never pencil out. That is why the IRP analysis looks at both the five-year rate impact and the 20-year net present value of revenue requirements.[14]

It is also important to reiterate that the Company and the Commission are charged with balancing all Five Pillars, not just one pillar. My direct and rebuttal testimony addresses the reliability benefits that natural gas provides, which cannot be achieved from continuing to operate on coal. It is apparent that aging units will

[14] As the Commission found in Cause No. 46022 (IURC 11/6/2024): "The 20-year planning horizon, which is required by the Commission's IRP rules, better captures the impact of investment on future generations of Indiana citizens than the ten-year period." at 40.

have more unplanned maintenance issues and reliability concerns. This translates to lower accredited capacity and value for customers in the MISO market, negatively impacting affordability and reliability. Finally, there is no doubt that the most efficient natural gas turbines available today are more environmentally sustainable than continuing to operate on aging coal, as shown in my direct testimony.

Q. WILL THERE LIKELY BE DIFFERENT ENVIRONMENTAL REQUIREMENTS FOR CONTINUED COAL OPERATION COMPARED TO WHAT MAY BE REQUIRED FOR THE CAYUGA CC PROJECT?

A. Yes. First, the Company made a reasonable estimate in the IRP assumptions around what environmental requirements may be necessary to continue coal operation and/or a natural gas conversion at Cayuga. However, the Company has not done a full engineering study on what it would really cost for ongoing environmental compliance or increased maintenance costs to keep a unit running until it is 70 or more years old, as proposed by the OUCC. As Mr. Luke explains, maintaining a unit that is aging and has a slated retirement date so that it can operate reliably until that near date is very different than maintaining an asset that you reasonably expect to operate 15 or more years (as proposed by the OUCC). Mr. Luke discusses additional ongoing maintenance issues that would require significant capital investment to keep the coal units running past their 60 year life.

There is naturally a balance between sinking additional costs into an aging asset that may become stranded and investing in a new modern asset. Normally, and as is the case here, technology advancements also weigh in favor of the new asset. As I explained in my direct testimony, which the OUCC appears to ignore, the Cayuga CC Project is expected to provide the following ancillary services to support the MISO grid: contingency, supplemental, and spinning reserves, and regulating reserves, ramp capability and short term reserves. A Cayuga unit running on coal or converted to natural gas would not provide such flexible services, plus it would continue to struggle with the frequent derates caused by the temperature of the river water discharge, absent major investment.

Continuing to run on coal would also be at significant risk to future additional environmental investments; much more so than an efficient state-of-the-art natural gas facility. As Ms. Armstrong acknowledges (p. 22) the MATS rules have been in place since 2013. Further, the EPA since 1977 under section 304(b) of the Clean Water act has been charged with annually reviewing, and, if appropriate, revising effluent guidelines, and cooling, or river, water intake requirements have been included in NPDES permit regulations under 40 CFR Parts 122 & 125 (Subparts I, J, & N) as far back as 2001. All of these regulations have increasingly become more stringent. While the current administration may relax the most recent updates to these rules, some requirements will likely still be in place and the more stringent versions have increased likelihood of being put back in place with a future change in administration. So, while the GHG Rules have been in a back-and-forth flux between changing administrations, which is why the Company accounted for it in the IRP, the other rules Ms. Armstrong believes will be relaxed have been in place for a number of years. The Cayuga CC Project is the best positioned to deal with any change in the environmental regulatory landscape.

Q. DOES INVESTING IN THE CC PROJECT PROHIBIT THE COMPANY FROM TAKING ADVANTAGE OF TECHNOLOGY ADVANCEMENTS SUCH AS SMALL MODULAR REACTORS, BATTERY STORAGE AND HYDROGEN, AS MS. ARMSTRONG CONTENDS (p. 8, 9)?

A. Not at all. First, I would like to point out that Ms. Armstrong ignores that the CC Project itself is investing in advanced technology – advanced class natural gas that has the dispatchable characteristics needed today. Further, the Company has no intention of missing out on new technologies as they are developed. Regarding battery storage, the Company is currently in negotiations for battery storage projects coming out of its recent RFP. Duke Energy Indiana also has been investigating the potential for nuclear small modular reactors ("SMRs") in Indiana and carbon capture and storage CCS technology (see Cause No. 46038 and Attachment 6-A (NDG) at 18) and Duke Energy enterprise wide has made investments in hydrogen generation and research. The Company is closely following activities at Duke Energy Carolinas for an early site permit for SMRs and has conducted a study with Purdue University on the feasibility of SMRs to meet their load and contribute to the grid. The Company has also performed preliminary nuclear siting studies, setting itself up for nuclear investment in the future, taking into account the learnings of first movers. However, these developing technologies are not ready today and will not be commercially ready for in-service by 2030 and the Company has a need for additive dispatchable generation now.

As this Commission is well aware, these are not the last coal plants on Duke Energy Indiana's system. Both Gibson Station and Edwardsport IGCC continue to run on coal.[15] The Company indicated in its IRP, the Gibson Station investments contemplated by the IRP, which were identified to comply with CAA 111 GHG Rules and were slated to occur later than the Cayuga investments, can be delayed and modified depending on the potential repeal of CAA 111 and other environmental and policy changes.[16] The fact is that we need to both make this investment in Cayuga today (which is not driven by CAA 111, but rather aging infrastructure and reliability concerns) while at the same time, we need to re-evaluate the plans at Gibson Station given the changing policy landscape and to take into account advancements in technology that may occur over the next decade.

Q. EVEN UNDER A RELAXED FEDERAL AND STATE REGULATORY LANDSCAPE IS THERE A RISK OF INCREASED LITIGATION?

A. Yes. The relaxation of federal and state regulation does not make companies, like Duke Energy Indiana, immune to citizen suits. To be blunt, at least one party to this proceeding is linked to interest groups who have frequently participated in such.[17, 18]

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[15] *See* Attachment 6-A (NDG) 2024 IRP, p. 198, Table B-1: Summary of Existing Thermal Units.
[16] *Id.* at pp. 14, 17.
[17] http://www.citact.org/cac-joins-sierra-clubs-appeal-duke-air-permit-granted-idem.
[18] https://www.sierraclub.org/environmental-law/case-updates.

Here are some of the key environmental statutes with citizen suit provisions:

1. Clean Air Act (CAA): Allows citizens to sue violators of emission standards or limitations. Also permits citizens to sue the EPA Administrator for failing to perform non-discretionary duties under the Act.
2. Clean Water Act (CWA): Enables citizens to sue any person (including governmental entities) violating effluent standards or limitations or an order issued by the EPA or a state regarding such standards. Also allows citizens to sue the EPA Administrator for failing to perform non-discretionary duties under the Act.
3. Resource Conservation and Recovery Act (RCRA): Allows citizens to sue those contributing to the mishandling of solid or hazardous waste that poses a risk to health or the environment.
4. Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA): Permits citizens to sue those violating CERCLA standards or requirements. Also allows citizens to sue the President or other federal officers for failing to fulfill non-discretionary duties.

V. <u>CAYUGA CC PROJECT ENVIRONMENTAL COMPLIANCE WITH FUTURE REGULATIONS</u>

Q. SHOULD THE COMPANY HAVE INCLUDED COSTS ASSOCIATED WITH CARBON CAPTURE AND SEQUESTRATION AS PART OF ITS CAYUGA CC PROJECT, AS MR. INSKEEP SUGGESTS (P. 19)?

A. No. CAA 111 has multiple pathways to achieve compliance including CCS or limiting to 40% capacity factor. Because CCS technology is not yet commercialized for natural gas plants and needs further study and development, the Company prudently modeled a 40% capacity factor as CAA 111 compliance. Even with the 40% capacity factor, the model still favored combined cycles as the replacement for coal unit retirements. It would be illogical for the Company to model additional upfront capital costs instead of the operating restriction. Of course, as CCS technology advances, the Company would continue to study and determine if CCS may be a better option for emissions reductions in the future if / when such reductions are required. But this is by no means a near term issue. The Cayuga CC Project is well situated to comply with any change in future environmental regulations due to its flexibility. The IRP modeling shows it's still the right choice with a 40% capacity factor and it could easily be adapted with advancing technology to accommodate CCS or hydrogen depending on which technology develops fastest and is more cost effective at the time we make such investments. While the Company believes there is great value in this flexibility, it is wholly unreasonable to speculate today about mere potential future costs and include them in a CPCN best cost estimate as Mr. Inskeep suggests. If and when the Company chooses to deploy such technology, because it's determined to be in the best interest of customers, the Commission will have an opportunity to review and weigh in on such a decision in a future docketed proceeding.

Q. MR. INSKEEP IS CONCERNED THAT DUKE ENERGY INDIANA DID NOT CONSIDER COMPLIANCE COSTS ASSOCIATED WITH CARBON MONOXIDE ("CO") AND VOLATILE ORGANIC COMPOUNDS ("VOCS") FOR THE CAYUGA CC PROJECT. HOW DO YOU RESPOND?

A. Mr. Inskeep's concern (pp. 18-19) is misplaced. The new units required a best available control technology ("BACT") analysis as part of the major modification for Cayuga's air permit. A technical review was performed to investigate and identify emission controls that have been determined by various permitting authorities across the U.S. to satisfy BACT requirements. The results of this review have been incorporated into Section D.0 and D.9 of the current permit. The oxidation catalyst, which was determined to be BACT, is a passive control. The cost of the oxidation catalyst comes from the infrequent periodic replacement of the catalyst. There are no ongoing costs to include in the IRP modeling for compliance.

Q. BOTH MS. ARMSTRONG (PP. 13-14) AND MR. INSKEEP (P. 13-18) RAISE CONCERNS ABOUT THE CAYUGA CC PROJECT'S ABILITY TO COMPLY WITH FUTURE ENVIRONMENTAL REGULATIONS FOR GREENHOUSE GASES. IS DUKE ENERGY INDIANA DOING WHAT IT

CAN TODAY TO INSULATE ITS CUSTOMERS FROM THE RISK OF FUTURE CARBON REGULATIONS?

A. Yes. However, I must note the Company cannot completely protect its customers from the potential of future carbon restrictions. I would add the industry has been expecting carbon regulations at least since 2005. But I could not disagree more with Ms. Armstrong's position (pp. 13-14) that the risk of stranded assets due to environmental regulations from the CC Project is greater than the risk of stranded assets on the coal plants if we have to keep investing in those plants to operate them another 15 years as proposed by the OUCC. As I explained above, the CC Project is the most efficient technology available today and is well positioned to comply with even the strict requirements under the GHG rule. It is also well positioned to avail itself of advancing technology to reduce carbon emissions as CCS technology and hydrogen fuel technology advances in the future. However, continued operation of the coal units would necessitate significant environmental and ongoing maintenance investments on aged units with short remaining life, increasing the risk of stranded costs when the assets eventually retire.

Q. IS OUCC WITNESS ARMSTRONG INCONSISTENT IN HER TIMING PREDICTIONS FOR REGULATORY ROLLBACKS VERSUS NEW MORE STRINGENT REGULATIONS?

A. Yes. Her testimony reads as if the rollbacks will happen almost instantaneously (p. 13) while also predicting (p. 15) the earliest date any new carbon regulation could be implemented will be 8 to 10 years after 2029. While it is true that President Trump has been using Executive Orders as opposed to the traditional rulemaking process to make policy changes, it is unclear what effect the Executive Orders will have and many have been subject to legal challenge. So, I disagree with Ms. Armstrong's suggestion that current environmental regulations could be rolled back over night and will not be replaced until 2037-2039 at the earliest. But as I, and the Company has repeatedly stressed throughout this case, that is why the Company uses its robust IRP process. Such unpredictability is accounted for and under all scenarios the Cayuga CC Project (even at a 40% capacity factor) is the right choice for the Company, its customers, Indiana, and MISO at large. I would note OUCC witness Mr. Latham appears to not be confident in Ms. Armstrong's predictions either, as he bases his recommendation to deny the CC Project (p. 9) on the 40% or lower annual capacity factor to comply with environmental constraints.

Q. DO ALL OF MS. ARMSTRONG'S ARGUMENTS IDENTIFIED ABOVE FOR CONTINUED USE OF COAL ALSO SUPPORT A TRANSITION TO NATURAL GAS?

A. Yes. Although efficient natural gas plants are better positioned than coal to comply with environmental regulations, if those regulations are relaxed, then there is less risk for natural gas plants, as well as for coal plants. The OUCC must think so as well, since its own financial analysis sponsored by OUCC witness Baker (Attachments BLB-12 and 13) appears to support moving the units to co-fire natural gas rather than continued use of coal. While the OUCC's analysis points to converting the units to natural gas, the OUCC does not recommend that, rather opting for a recommendation of more analysis and delay. As my direct testimony and Mr. Gagnon's testimony support, converting the units to natural gas was not shown as an economic option for customers and of course, it does not add incremental generation to the grid or have the reliability and environmental benefits of a new natural gas plant. Such a position would be inconsistent with Indiana's policy focus on the Five Pillars in every respect.

Q. MR. FITZHENRY FOR THE INDUSTRIAL GROUP MAKES SEVERAL PROPOSALS FOR RE-EVALUATION AND STUDY IN CERTAIN CIRCUMSTANCES SUCH AS ENVIRONMENTAL CHANGES, COST INCREASES, ETC. HOW DO YOU RESPOND?

A. What Mr. Fitzhenry's proposals (pp. 10-11, 16-21) ultimately amount to is a conditional approval, which is unreasonable when the CPCN law already contemplates and provides for Commission ongoing review of projects. This is the statutory process to review and oversee whatever might occur in the future. The Company has elected for ongoing review and will be in front of the Commission every six months with updates on construction. Any future concerns that are triggered with construction or costs of the project can be properly raised in that forum.

While the Company has elected for ongoing review, it does not agree to Mr. Fitzhenry's recommendation (p. 21) to update its IRP every time a change occurs in order to support any update during ongoing review. That is unreasonable and has never been required by the Commission. In terms of his recommendations regarding changing environmental rules or regulations, if a utility were to wait for certainty it would simply never act. We need to act with urgency to bring additional reliable, dispatchable generation online and Duke Energy Indiana has demonstrated that the Cayuga CC Project is reasonable given the circumstances known or foreseeable today. As discussed above in response to CAC witness Inskeep, the Commission has a long history of rejecting hind-sight analysis and to the extent Mr. Fitzhenry is proposing a reevaluation in hindsight, the Commission should reject that recommendation. Ongoing review is also the appropriate forum to address any potential cost increases, changes to construction schedule, and future operating and compliance costs which are a concern of witness Inskeep (pp. 8-9).

VI. NECESSARY ENVIRONMENTAL COMPLIANCE AND MAINTENANCE PROJECTS TO EXTEND THE LIVES OF THE CAYUGA COAL UNITS

Q. MS. ARMSTRONG ALSO RAISES CONCERNS REGARDING OTHER ENVIRONMENTAL COMPLIANCE AND MAINTENANCE PROJECTS THE COMPANY IDENTIFIES AS NEEDED FOR CAYUGA TO CONTINUE TO OPERATE ON COAL. PLEASE RESPOND TO HER CONCERNS WITH 316(b) AND ELG, AS WELL AS MR. FITZHENRY'S

CONCERNS WITH THE COMPANY'S ASSUMPTIONS FOR ELG COMPLIANCE.

A. Ms. Armstrong questions whether closed cycle cooling would be required to comply with 316(b) if the Company did not retire the coal units until the 2040 timeframe. Based on the Company's analysis and discussions with IDEM, I disagree. After conducting an extensive review of potential options, the only other potentially feasible alternatives proposed for 316 (b) compliance were a wedgewire screen or fine mesh screen project, both projects had many downsides, including concerns with the feasibility of reconfiguration needed for the cooling, water intake structure and river shoreline impacts, operating and maintenance concerns, potential obstructions of the river, and the uncertainty of future 316(b) best available technology determinations. Beyond those challenges and uncertainties, these alternatives would do nothing to address the river temperature discharge challenges that have resulted in frequent derates of the coal units. And it would also not reduce river water withdrawal and consumption the way a closed cycle cooling system would. Under the 316(b) rule, which as of the date of this rebuttal is not planned for reconsideration by the Trump Administration, Cayuga will be required to implement a closed cycle cooling tower to continue operations past 2030.

Regarding ELG, I note that Duke Energy Indiana has required expenditures required to meet the 2020 ELG rule, not the 2024 ELG rule that the administration has proposed to review. The 2020 rule requires retirement by the end of 2028 in order to avoid any expenditures. The soonest the Company anticipates being able to retire both units is 2030, so the Company plans to invest in treatment equipment for two years of compliance. If the Company was not retiring both units as soon, and continued operations into the 2040s as the OUCC proposes, additional capital expenditures would be required on the order of two to three times as much for permanent continued compliance with the 2020 ELG regulation. Of course, the coal units would be subject to future environmental regulation, such as the 2024 ELG rule or its future replacement.

Q. WHAT IS MS. ARMSTRONG'S SPECIFIC ISSUE WITH THE COMPANY'S ASSUMPTIONS FOR MATS COMPLIANCE AND HOW DO YOU RESPOND?

A. Ms. Armstrong appears to take issue with the Company's plans to comply with the final MATS rule. It is my understanding that the latest iteration of the MATS rule may be reviewed, repealed and/or replaced by the new administration. The Company's proposed MATS expenditures at Cayuga are less than $1 million and consist primarily of routine replacement since existing equipment wears and performance can deteriorate over time. The projects are currently scheduled for implementation in the 2026-2027 timeframe. The Company will continue to monitor the status of the rule and if it can avoid these expenditures, and remain compliant with existing regulations, then of course, we will do so.

Q. ARE THESE THE ONLY ENVIRONMENTAL COMPLIANCE COSTS THE COMPANY WOULD FACE IF IT WERE TO OPERATE THE COAL UNITS UNTIL THE 2040 TIMEFRAME AS SUGGESTED BY THE OUCC?

A. No. As Company witness Mr. Luke discusses, the Company made investments in scrubbers in the 2000s that are also aging and may need structural investment and repairs to maintain compliant operations, just with existing environmental Clean Air Act rules. As discussed above, there is the ongoing risk of tightening environmental restrictions which would likely more heavily impact coal burning units. It is simply not reasonable for the OUCC to take our high level estimate of about $430 M to keep the coal units operating to the mid-2030s and assume those are the only maintenance and environmental costs required to run the coal units into the 2040s and beyond.

VII. CRITICISMS OF RFP PROCESS

Q. DID THE COMPANY, WITH THE ASSISTANCE OF CRA, CONDUCT A FAIR AND ROBUST RFP?

A. Yes. Company witness Mr. Lee, with CRA, thoroughly addresses Ms. Sanka's concerns about the RFP, but I would reiterate that the parameters employed by the Company resulted in a fair, robust RFP. We relied on the advice and support of a third-party administrator, or Independent Evaluator and Monitor to ensure that was the case, and the Company reasonably evaluated the projects that were provided to us by CRA on the ranked-order list.

Q. OUCC WITNESS SANKA TAKES ISSUE WITH THE RFP EVALUATION OF THE <BEGIN HIGHLY CONFIDENTIAL> [redacted] **<END HIGHLY CONFIDENTIAL>. HOW DO YOU RESPOND?**

A. As Mr. Lee describes in his rebuttal testimony, CRA, the independent evaluator and monitor of the Duke Energy Indiana RFP, **<BEGIN HIGHLY CONFIDENTIAL>** [redacted] **<END HIGHLY CONFIDENTAL>**. The Company then performed additional due diligence on this project. That further evaluation determined that there were complications with the ability to **<BEGIN HIGHLY CONFIDENTIAL>** [redacted]

[redacted][19][redacted] **<END HIGHLY CONFIDENTIAL>**. After a thorough due diligence phase, the Company decided **<BEGIN HIGLY CONFIDENTIAL>** [redacted] **<END HIGHLY CONFIDENTIAL>** was not feasible due to the increased cost, complexity, delay and risk **<BEGIN HIGHLY CONFIDENTIAL>** [redacted] **<END HIGHLY CONFIDENTIAL>**.

VIII. TRANSMISSION AND INTERCONNECTION

Q. CAN YOU PROVIDE AN UPDATE ON THE STATUS OF MISO QUEUE PROGRESSION FOR THE INCREMENTAL CAPACITY ASSOCIATED WITH THE SECOND CC?

A. Yes. OUCC witness Sanka raised concerns (p. 15) about the Cayuga CC Project MISO interconnection, which are misplaced. As discussed in my direct testimony, MISO has already conducted a study for 1040 MW through its Generator Replacement Request ("GRR") study process, finding no adverse impact to the grid. The Company is currently negotiating the terms of the generator interconnect agreement ("GIA") with MISO and expected to have a signed GIA in the

[19] I would note that **<BEGIN HIGHLY CONFIDENTIAL>** [redacted] **<END HIGHLY CONFIDENTIAL>**.

September timeframe. With respect to the additional 500 MW needed to fully utilize both CCs, Duke Energy Indiana applied through MISO's Definitive Planning Phase ("DPP") or interconnection queue process in the 2023 MISO queue over a year ago, prior to even filing the CPCN in order to get ahead of that lengthy process. MISO's current scheduled kickoff for the 2023 DPP queue is in July 2025.

In parallel, the Company has been participating in MISO's stakeholder process and supporting MISO's Expedited Resource Additions Study "ERAS", which was filed and recently denied by the FERC. Notably, the FERC Commissioners encouraged MISO to refile the program with certain enhancements and MISO intends to do so. This process could provide for an earlier GIA for the incremental MWs needed for the second 1x1 CC. In any event, the Company is as well situated as possible for interconnection to the grid due to its advanced application. And the Commission's ongoing review process for CPCN projects provides the ideal forum for the Company to update the Commission and stakeholders on that study process and ultimate costs.

VIII. DEMAND-SIDE MANAGEMENT AND DISTRIBUTED RESOURCES

Q. CAC WITNESS INSKEEP RECOMMENDED (P. 32) A "NO REGRETS" STRATEGY OF INVESTMENT IN DEMAND RESPONSE, ENERGY EFFICIENCY AND DISTRIBUTED GENERATION, RATHER THAN

CONSTRUCTION OF THE CAYUGA CC PROJECT. HOW DO YOU RESPOND?

A. First, I would point out that Duke Energy has a long history of investment in energy efficiency and demand response, as part of our diverse portfolio of resources to serve customers. In fact, a review of the most recent Commission Summer Reliability presentations demonstrates that Duke Energy Indiana's 623 MW of summer demand response or load modifying resource capability is higher than all other utilities in the state. Duke Energy Indiana has invested in energy efficiency for over three decades, with its latest three-year, $175 M plan expected to reduce eligible retail sales by about 1%.

The Company can and has provided incentives to customers to participate in these programs, but it cannot mandate participation. The same can be said for distributed generation resources, such as roof top solar or other creative offerings. The Company can and does offer tariffs like its Excess Distributed Generation tariff and its new Green Source Advantage offering to incent customers to install or contract with third parties to develop solar or wind resources, but it cannot mandate it. One recent example of this is the Company's pilot tariff that allowed customers to avoid the upfront costs of solar installations through the lease of small solar projects at a customer's location. Although available for five years, this pilot program did not reach full subscription, with only about 1 MW of 10 MW subscribed. In the changing policy landscape we are in today, these resources are likely to play a smaller role, not a larger one, given the likely roll-back of federal tax incentives and other public funding for renewable and energy efficiency projects that has been signaled by the new administration.

In its most recent IRP, the Company did include assumptions for distributed solar as a reduction to its load forecast and modeled utility-scale solar as a selectable resource. That modeling still demonstrated a need for the Cayuga CC Project.

The Company relies on these demand side and DER resources today and commits to continue to experiment with offerings to increase participation in the future. They are an important part of our portfolio, but today there is simply not enough potential in demand-side resources or DERS to forego the need for the 1400 MWs of reliable, dispatchable generation that the Cayuga CC Project provides.

Regarding Mr. Inskeep's complaints about the Company's energy efficiency Market Potential Study in particular, I would simply note that the Company disagrees with his criticism of the process and results. The Company provided a response to similar comments CAC, among others, provided on the Company's 2024 IRP, which are attached to Mr. Gagnon's rebuttal testimony as Attachment 13-A (NDG).[20]

IX. HOUSE ENROLLED ACT 1007 (2025)

Q. IN YOUR DIRECT TESTIMONY, YOU REFERENCED INDIANA

[20] While Mr. Gagnon sponsors the entirety of the Attachment for administrative efficiency, I'm sponsoring the "Demand Side Resources and Market Potential Study" Section, pp. 6-14.

GENERAL ASSEMBLY'S HOUSE BILL 1007 (2025) WHICH IN PART IS RELATED TO GENERATION RETIREMENTS. HAS THAT BILL BEEN PASSED INTO LAW?

A. Yes. The final law (Public Law 217-2025) continues to provide that if the Commission makes required findings in a CPCN order, then the future retirement investigation is not required. I have included the final law as Attachment 9-B (KAK).

Q. DO YOU CONTINUE TO BELIEVE THE COMMISSION COULD MAKE THE REQUIRED FINDINGS LISTED ABOVE IN THIS CPCN PROCEEDING?

A. Yes, I do. The Company continues to believe its plan to retire and replace the Cayuga coal units with the Cayuga CC Project is just and reasonable and can fully meet the requirements of HEA 1007's retirement investigation. Mr. Pinegar also discusses the findings the Commission could make under HEA 1007.

X. CONCLUSION

Q. DO YOU CONTINUE TO BELIEVE DUKE ENERGY INDIANA'S REQUESTED RELIEF IN THIS PROCEEDING SHOULD BE APPROVED?

A. Yes. If anything, I believe more strongly today that this is the right project at the right time for our customers. It is the plan that provides dispatchable generation on-system the soonest to meet increasing load growth, it is reliable and flexible, it avoids significant expenditures in aging assets and modernizes our generation fleet.

The project is a cost effective opportunity for customers and the Company's ratemaking proposals will save customers carrying costs over the long term.

Q. ARE YOU FAMILIAR WITH ATTACHMENTS 9-A (KAK) AND 9-B (KAK)?

A. Yes, I am.

Q. DOES THIS CONCLUDE YOUR PREFILED REBUTTAL TESTIMONY?

A. Yes, it does.

VERIFICATION

I hereby verify under the penalties of perjury that the foregoing representations are true to the best of my knowledge, information and belief.

Signed: Kelley Karn ______________________ Dated: 5-29-25
Kelley A. Karn

February 14, 2025

HOUSE CONCURRENT RESOLUTION No. 3

DIGEST OF RESOLUTION

A CONCURRENT RESOLUTION urging regional transmission organizations, the Federal Energy Regulatory Commission, the United States Department of Energy, the North American Electric Reliability Corporation, and the United States Congress to take such actions as necessary to enact reform processes to expedite the approval of electric transmission and generation projects.

Soliday

(SENATE SPONSOR — KOCH)

January 8, 2025, read first time and referred to Committee on Utilities, Energy and Telecommunications.
January 21, 2025, reported — Do Pass.
January 27, 2025, read second time, passed. Yeas 71, nays 23.

SENATE ACTION

January 30, 2025, read first time and referred to Committee on Utilities.
February 13, 2025, reported favorably — Do Pass.

February 14, 2025

First Regular Session of the 124th General Assembly (2025)

HOUSE CONCURRENT RESOLUTION No. 3

A CONCURRENT RESOLUTION urging regional transmission organizations, the Federal Energy Regulatory Commission, the United States Department of Energy, the North American Electric Reliability Corporation, and the United States Congress to take such actions as necessary to enact reform processes to expedite the approval of electric transmission and generation projects.

Whereas, The Indiana General Assembly has established energy policy based on balancing the "Five Pillars" instrumental to the state's long term energy goals: reliability, affordability, resiliency, stability, and environmental sustainability;

Whereas, Energy demand is accelerating across Indiana and the Midwest because of growth in data centers, advanced manufacturing, and other economic development projects;

Whereas, Indiana's regulatory framework has established the Hoosier State as a highly desirable location for economic development projects;

Whereas, The ability to quickly develop and build additive energy infrastructure, including generation and transmission, is critical to the economic development and electric resource adequacy of Indiana and the Midwest;

Whereas, Regional transmission organizations' current generator interconnection review processes are overwhelmed with requests for new resource interconnections, such that the current process has become unworkable, and a process initially *designed to take months to complete now takes many years to complete before incremental transmission infrastructure and generation can be added to the grid;*

Whereas, Regional transmission organizations play a critical role in analyzing the addition of transmission infrastructure and dispatchable generation for large load demand additions;

Whereas, The Indiana Utility Regulatory Commission has long had regulatory responsibility for assuring generation resource adequacy for retail electric customers;

Whereas, The Federal Energy Regulatory Commission has authority to amend regulations and approve tariff changes to grant regional transmission organizations the flexibility to adjust interconnection queue priorities based on resource reliability attributes, grid reliability, and resilience needs; and

Whereas, Indiana's load serving entities, consisting of those electric utilities with a statutory obligation to serve their jurisdictional customers and plan for future load growth through an integrated resource planning process, and the Indiana Utility Regulatory Commission are best positioned to understand and respond to the needs of the electric system and large load additions to the system: Therefore,

Be it resolved by the House of Representatives of the General Assembly of the State of Indiana, the Senate concurring:

SECTION 1. That the Indiana General Assembly urges the regional transmission organizations that operate facilities in Indiana to take the necessary steps to prioritize transmission and generation additions proposed by Indiana's load serving entities and specifically determined by the Indiana Utility Regulatory Commission as necessary for resource adequacy.

SECTION 2. That the Indiana General Assembly determines that solutions must include the establishment of an expedited interconnection review process for Indiana's load serving entities consistent with their integrated resource plans.

SECTION 3. That the Indiana General Assembly determines that solutions must also include an expedited interconnection review process for dispatchable resources that is critical to serving growing load requirements around the clock and that is consistent with the Five Pillars of Indiana's energy policy.

SECTION 4. That the Indiana General Assembly determines that solutions must also include an expedited interconnection review process for incremental generation added at existing generation stations where an electric utility plans to use a generator replacement review process.

SECTION 5. That the Indiana General Assembly urges regional transmission organizations, the Federal Energy Regulatory Commission, the United States Department of Energy, the North American Electric Reliability Corporation, and the United States Congress to take such actions as are necessary to enact reform processes to expedite the approval of electric transmission and generation projects to promote Indiana's economic development through the approval and implementation of these solutions.

SECTION 6. That the Principal Clerk of the House of Representatives shall transmit a copy of this resolution to the presiding officers of the Senate and the House of Representatives of the United States Congress, each member of the Indiana Congressional delegation, the Federal Energy Regulatory Commission, the United States Department of Energy, the North American Electric Reliability Corporation, the Midcontinent Independent System Operator, and the PJM Interconnection.

COMMITTEE REPORT

Mr. Speaker: Your Committee on Utilities, Energy and Telecommunications, to which was referred House Concurrent Resolution 3, has had the same under consideration and begs leave to report the same back to the House with the recommendation that said resolution do pass.

(Reference is to HC 3 as printed January 8, 2025.)

SOLIDAY

Committee Vote: Yeas 9, Nays 2

COMMITTEE REPORT

Mr. President: The Senate Committee on Utilities, to which was referred House Concurrent Resolution No. 3, has had the same under consideration and begs leave to report the same back to the Senate with the recommendation that said resolution DO PASS.

(Reference is to HC 3 as printed January 21, 2025.)

KOCH, Chairperson

Committee Vote: Yeas 10, Nays 0

First Regular Session of the 124th General Assembly (2025)

PRINTING CODE. Amendments: Whenever an existing statute (or a section of the Indiana Constitution) is being amended, the text of the existing provision will appear in this style type, additions will appear in **this style type**, and deletions will appear in ~~this style type.~~

Additions: Whenever a new statutory provision is being enacted (or a new constitutional provision adopted), the text of the new provision will appear in **this style type**. Also, the word **NEW** will appear in that style type in the introductory clause of each SECTION that adds a new provision to the Indiana Code or the Indiana Constitution.

Conflict reconciliation: Text in a statute in *this style type* or ~~*this style type*~~ reconciles conflicts between statutes enacted by the 2024 Regular Session of the General Assembly.

HOUSE ENROLLED ACT No. 1007

AN ACT to amend the Indiana Code concerning utilities.

Be it enacted by the General Assembly of the State of Indiana:

SECTION 1. IC 6-3.1-45 IS ADDED TO THE INDIANA CODE AS A **NEW** CHAPTER TO READ AS FOLLOWS [EFFECTIVE JANUARY 1, 2025 (RETROACTIVE)]:

Chapter 45. Small Modular Nuclear Reactor Manufacturing Expense Tax Credit

Sec. 1. This chapter applies to a taxable year beginning after December 31, 2024.

Sec. 2. As used in this chapter, "department" refers to the department of state revenue.

Sec. 3. As used in this chapter, "qualified investment" means a taxpayer's expenditures incurred in the manufacture of a small modular nuclear reactor in Indiana.

Sec. 4. As used in this chapter, "small modular nuclear reactor" means a nuclear reactor that:

(1) has a rated electric generating capacity of not more than four hundred seventy (470) megawatts;

(2) is capable of being constructed and operated, either:

(A) alone; or

(B) in combination with one (1) or more similar reactors if additional reactors are, or become, necessary;

at a single site; and

(3) is required to be licensed by the United States Nuclear Regulatory Commission.

The term includes a nuclear reactor that is described in this section and that uses a process to produce hydrogen that can be used for energy storage, as a fuel, or for other uses.

Sec. 5. As used in this chapter, "state tax liability" means a taxpayer's total tax liability that is incurred under:

(1) IC 6-3-1 through IC 6-3-7 (the adjusted gross income tax);
(2) IC 6-5.5 (the financial institutions tax); and
(3) IC 27-1-18-2 (the insurance premiums tax);

as computed after the application of the credits that under IC 6-3.1-1-2 are to be applied before the credit provided by this chapter.

Sec. 6. As used in this chapter, "taxpayer" means a person, corporation, partnership, or other entity that makes a qualified investment.

Sec. 7. A taxpayer is entitled to a credit against the taxpayer's state tax liability in the taxable year in which the taxpayer makes a qualified investment. The amount of the credit provided by this section is equal to twenty percent (20%) of the amount of the taxpayer's qualified investment.

Sec. 8. (a) If the amount determined under section 7 of this chapter for a taxpayer in a taxable year exceeds the taxpayer's state tax liability for that taxable year, the taxpayer may carry the excess over to the following taxable years. The amount of the credit carryover from a taxable year shall be reduced to the extent that the carryover is used by the taxpayer to obtain a credit under this chapter for any subsequent taxable year.

(b) A taxpayer is not entitled to a carryback or refund of any unused credit.

Sec. 9. (a) If a pass through entity is entitled to a credit under section 7 of this chapter but does not have state tax liability against which the tax credit may be applied, an individual who is a shareholder, partner, or member of the pass through entity is entitled to a tax credit equal to:

(1) the tax credit determined for the pass through entity for the taxable year; multiplied by
(2) the percentage of the pass through entity's distributive income to which the shareholder, partner, or member is entitled.

(b) The credit provided under subsection (a) is in addition to a tax credit to which a shareholder, partner, or member of a pass

through entity is otherwise entitled under this chapter. However, a pass through entity and an individual who is a shareholder, partner, or member of the pass through entity may not claim more than one (1) credit for the same qualified investment.

Sec. 10. To receive the credit provided by this chapter, a taxpayer must claim the credit on the taxpayer's annual state tax return or returns in the manner prescribed by the department. The taxpayer shall submit to the department:

(1) information verifying that the taxpayer's qualified investment was made with respect to a small modular nuclear reactor that will be manufactured in Indiana; and

(2) all information that the department determines is necessary for the calculation of the credit provided by this chapter.

SECTION 2. IC 8-1-7.9 IS ADDED TO THE INDIANA CODE AS A **NEW** CHAPTER TO READ AS FOLLOWS [EFFECTIVE UPON PASSAGE]:

Chapter 7.9. Expedited Generation Resource Plans and Large Load Customers

Sec. 1. (a) As used in this chapter, "acquisition" means a project or an arrangement that is undertaken:

(1) by an energy utility to construct, purchase, lease, or otherwise acquire a generation resource; and

(2) in accordance with an approved EGR plan.

(b) The term includes the purchase of energy or capacity through a power purchase agreement.

Sec. 2. As used in this chapter, "acquisition costs" means the total costs of an acquisition made under an EGR plan, including:

(1) planning;

(2) construction; and

(3) operating;

costs related to the acquisition.

Sec. 3. As used in this chapter, "appropriate regional transmission organization" has the meaning set forth in IC 8-1-8.5-13(b).

Sec. 4. As used in this chapter, "commission" refers to the Indiana utility regulatory commission created by IC 8-1-1-2.

Sec. 5. (a) As used in this chapter, "construction and operating costs" means costs:

(1) incurred or to be incurred by an energy utility under this chapter after the issuance of an order by the commission under this chapter; and

(2) related to an approved or commission modified acquisition or project.

(b) The term includes procurement, contractual, construction, operating, maintenance, financing, legal, regulatory, and project evaluation, analysis, and development costs incurred after the issuance of an order by the commission under this chapter.

Sec. 6. As used in this chapter, "corporation" refers to the Indiana economic development corporation established by IC 5-28-3-1 or its successor.

Sec. 7. As used in this chapter, "energy utility" means:

(1) an electric utility listed in 170 IAC 4-7-2(a) and any successor in interest to that utility; or

(2) a corporation organized under IC 8-1-13.

Sec. 8. As used in this chapter, "expedited generation resource plan", or "EGR plan", means a plan developed by an energy utility for acquiring generation resources to meet load growth that exceeds the lesser of:

(1) five percent (5%) of the energy utility's average peak demand over the most recent three (3) calendar years; or

(2) one hundred fifty (150) megawatts.

Sec. 9. As used in this chapter, "generation resource submittal" means a compliance filing made to the commission for approval of the acquisition of a specific generation resource in accordance with the criteria set forth in an approved EGR plan.

Sec. 10. As used in this chapter, "large load customer" means a new or existing customer of an energy utility, or not more than four (4) multiple new or existing customers of an energy utility, that:

(1) requests new or additional electricity demand that in the aggregate exceeds the lesser of:

(A) five percent (5%) of the energy utility's average peak demand over the most recent three (3) calendar years; or

(B) one hundred fifty (150) megawatts;

(2) plans to make a capital investment that exceeds five hundred million dollars ($500,000,000) in a new or expanded facility in Indiana; and

(3) plans to employ at the new or expanded facility in Indiana at least fifty (50) full-time employees with wages that on average meet or exceed the most recently published annual national average according to the Bureau of Labor Statistics of the United States Department of Labor.

Sec. 11. As used in this chapter, "office" refers to the Indiana

office of energy development established by IC 4-3-23-3.

Sec. 12. (a) As used in this chapter, "planning costs" means costs:

(1) incurred or to be incurred by an energy utility before the issuance of an order by the commission under this chapter; and

(2) related to an acquisition or project.

(b) The term includes study, analysis, pre-engineering, engineering, legal, financing, and regulatory costs.

Sec. 13. As used in this chapter, "pre-filing meeting" means a meeting to review and discuss a filing or submittal by an energy utility in accordance with:

(1) section 18 of this chapter;

(2) section 20 of this chapter; or

(3) section 22 of this chapter;

as applicable.

Sec. 14. As used in this chapter, "project" refers to a project relating to energy infrastructure and generation resources that:

(1) are required primarily to serve a large load customer of an energy utility; and

(2) may be designed to serve more than one (1) large load customer of the energy utility or to meet other customer demand or energy needs.

Sec. 15. As used in this chapter, "project costs" means the total costs of a project, including:

(1) planning costs; and

(2) construction and operating costs;

related to the project.

Sec. 16. As used in this chapter, "reasonable risk premium" means compensation:

(1) negotiated between an energy utility and a large load customer; and

(2) paid by the large load customer.

Sec. 17. (a) The commission may expedite, in accordance with this chapter, the review of filings and submittals made by an energy utility to meet the energy infrastructure and generation resource needs of customers. An energy utility may request an expedited review by the commission under either or both of the following:

(1) Sections 18 through 21 of this chapter (concerning EGR plans).

(2) Sections 22 through 24 of this chapter (concerning large

load customer projects).

(b) This chapter does not preclude an energy utility from petitioning the commission under other applicable statutes for approval of a generation resource acquisition to meet the needs of its customers.

(c) This chapter does not preclude an energy utility from petitioning the commission under, or in conjunction with, other applicable statutes, including:

(1) IC 8-1-2-24;
(2) IC 8-1-2-42;
(3) IC 8-1-2.5;
(4) IC 8-1-8.5;
(5) IC 8-1-8.8; or
(6) IC 8-1-39;

for approval of a project to meet the needs of large load customers.

Sec. 18. (a) This section applies to an energy utility that petitions the commission for approval of an EGR plan.

(b) An energy utility may file a petition with the commission for approval of an EGR plan to acquire generation resources to meet the extraordinary needs for electricity by the energy utility's customers.

(c) In a petition under this section, an energy utility must do the following:

(1) Describe the energy utility's EGR plan for acquiring generation resources to meet the anticipated extraordinary growth in the load of its customers.

(2) Demonstrate a need for generation capacity that exceeds the lesser of:

(A) five percent (5%) of the energy utility's average peak demand over the most recent three (3) calendar years; or

(B) one hundred fifty (150) megawatts.

(3) Provide a load growth forecast for a minimum of five (5) years from the date of the petition.

(4) Describe the status of customer contracts and commitments that support the load growth forecast described in subdivision (3).

(5) Explain how the EGR plan is consistent with or differs from the energy utility's most recent integrated resource plan.

(6) Propose the accounting authority needed from the commission to support the EGR plan.

(7) Propose the manner in which the capital costs and operating and maintenance expenses related to the EGR plan

will be included in the energy utility's revenue requirement.
(8) Identify the type and amount of capacity and energy:
(A) that is included in the EGR plan;
(B) that does not exceed seventy-five percent (75%) of the energy utility's peak capacity over the forecast period described in subdivision (3); and
(C) with respect to which the energy utility may request expedited approval in a subsequent generation resource submittal.
(9) Identify the criteria to be included in a generation resource submittal that must be met for the acquisition to be approved by the commission.
(10) Certify that at least thirty (30) days before the filing of the petition the energy utility held a pre-filing meeting with the commission and the office of utility consumer counselor to review the EGR plan.
(11) Describe how the energy utility considered implementing grid enhancing technologies to defer or minimize the need for additional investment in generation.
(12) Describe how the EGR plan will support the provision of electric utility service with the attributes set forth in IC 8-1-2-0.6, including:
(A) reliability;
(B) affordability;
(C) resiliency;
(D) stability; and
(E) environmental sustainability.
(13) Describe how the EGR plan reasonably protects existing and future customers and is consistent with:
(A) the provision of safe, reliable, and affordable electric utility service; and
(B) economical rates.
(14) Include:
(A) verified testimony; and
(B) exhibits;
supporting the petition and constituting the energy utility's case in chief.
(15) Include a proposed order for the petition.

Sec. 19. (a) This section applies to an energy utility that petitions the commission for approval of an EGR plan.

(b) Notwithstanding IC 8-1-8.5 or any other statute, the commission may approve an energy utility's EGR plan to

construct, purchase, lease, or otherwise acquire generation resources under this chapter for purposes of meeting the needs of the energy utility's customers. The commission shall make its decision based on whether the relief requested is just, reasonable, and in the public interest.

(c) The commission may:

(1) approve the energy utility's petition in its entirety;

(2) deny the energy utility's petition in its entirety; or

(3) modify the petition, subject to the energy utility's acceptance of the modification.

(d) The commission shall issue a final order on the petition not later than ninety (90) days after receiving the energy utility's complete petition. A petition is considered:

(1) complete unless the commission provides a notice of deficiency to the energy utility not later than five (5) business days after the filing of the petition; and

(2) approved if the commission does not issue a final order on the petition within the ninety (90) day period set forth in this subsection.

Sec. 20. (a) This section applies to an energy utility that submits to the commission for approval a generation resource submittal in accordance with an approved EGR plan.

(b) An energy utility may submit a generation resource submittal to the commission for approval of an acquisition that the energy utility intends to make in accordance with an approved EGR plan.

(c) In a generation resource submittal under this section, an energy utility must do the following:

(1) Describe:

(A) the type of technology used in the generation resource to be acquired;

(B) the amount of capacity and energy to be acquired;

(C) key contractual terms for the acquisition; and

(D) the estimated acquisition costs.

(2) Demonstrate that the acquisition meets the criteria set forth in the energy utility's approved EGR plan.

(3) Explain how the acquisition is consistent with or differs from the energy utility's most recent integrated resource plan.

(4) Detail the status of customer contracts and commitments that support the acquisition.

(5) Certify that at least thirty (30) days before the filing of the generation resource submittal the energy utility held a

pre-filing meeting with the commission and the office of utility consumer counselor to review the acquisition.

(6) Describe how the energy utility considered implementing grid enhancing technologies to defer or minimize the need for additional investment in generation.

(7) Describe how the acquisition will support the provision of electric utility service with the attributes set forth in IC 8-1-2-0.6, including:

(A) reliability;

(B) affordability;

(C) resiliency;

(D) stability; and

(E) environmental sustainability.

(8) Describe how the acquisition reasonably protects existing and future customers and is consistent with:

(A) the provision of safe, reliable, and affordable electric utility service; and

(B) economical rates.

(9) Include supporting affidavits and exhibits.

(10) Include a proposed order for the submittal.

Sec. 21. (a) This section applies to an energy utility that submits to the commission for approval a generation resource submittal in accordance with an approved EGR plan.

(b) Notwithstanding IC 8-1-8.5 or any other statute, the commission may approve an energy utility's generation resource submittal to construct, purchase, lease, or otherwise acquire generation resources under this chapter for purposes of meeting the needs of the energy utility's customers. The commission shall make its decision based solely on whether the submittal meets the criteria and requirements set forth in the energy utility's approved EGR plan.

(c) The commission may:

(1) approve the energy utility's generation resource submittal in its entirety;

(2) deny the energy utility's generation resource submittal in its entirety; or

(3) modify the energy utility's generation resource submittal, subject to the energy utility's acceptance of the modification.

(d) The commission shall issue a final order on the energy utility's generation resource submittal not later than:

(1) sixty (60) days after receiving the energy utility's complete generation resource submittal, if the acquisition is a clean

energy project (as defined in IC 8-1-8.8-2); or

(2) one hundred twenty (120) days after receiving the energy utility's complete generation resource submittal, if the acquisition would otherwise require a certificate under IC 8-1-8.5-2.

A generation resource submittal is considered complete unless the commission provides a notice of deficiency to the energy utility not later than five (5) business days after the filing of the generation resource submittal. A generation resource submittal is considered approved if the commission does not issue a final order on the generation resource submittal within the period set forth in subdivision (1) or (2), as applicable.

Sec. 22. (a) This section applies to an energy utility that petitions the commission for approval of a project to serve a large load customer.

(b) An energy utility may submit to the commission a petition for approval of a project to serve a large load customer only if the following are satisfied:

(1) The petition concerns serving the energy needs of a large load customer.

(2) The large load customer commits to significant and meaningful financial assurances that must:

(A) include reimbursement by the large load customer of at least eighty percent (80%) of the project costs reasonably allocable to the large load customer; and

(B) afford protections for the energy utility's existing and future customers from project costs reasonably allocable to the large load customer regardless of whether the large load customer ultimately takes service in the anticipated amount and within the anticipated time frame.

(3) At least thirty (30) days before the energy utility's submission of the petition to the commission, the energy utility held at least one (1) pre-filing meeting with:

(A) the corporation;

(B) the office;

(C) the office of utility consumer counselor;

(D) the appropriate regional transmission organization; and

(E) the large load customer;

to review the project.

(c) An energy utility may petition the commission for approval of a project to serve:

(1) one (1) or more large load customers at one (1) or more locations; or

(2) not more than four (4) customers whose aggregate demand satisfies the amount set forth in section 10(1) of this chapter.

In any case in which more than one (1) large load customer is to be served by a project, a reference in this chapter to one (1) large load customer is a reference to all large load customers to be served by the project, in accordance with IC 1-1-4-1(3).

(d) In submitting a petition to the commission under this section, an energy utility must demonstrate that the large load customer and the associated projects meet the requirements of this chapter.

Sec. 23. (a) This section applies to an energy utility that petitions the commission for approval of a project to serve a large load customer.

(b) In a petition under this section, an energy utility must include, at a minimum, the following:

(1) The energy utility's complete case in chief, which must include, at a minimum, the following:

(A) An agreement from the large load customer that describes the financial assurances:

(i) that afford protections for the energy utility's existing and future customers; and

(ii) to which the large load customer has committed regardless of whether the large load customer ultimately takes service in the anticipated amount and within the anticipated time frame.

(B) A description of:

(i) the demand side management and self-generation options reviewed with the large load customer; and

(ii) the investments the large load customer will undertake to reasonably minimize the amount of incremental and other costs incurred by the energy utility.

(C) A description of how the energy utility considered implementing grid enhancing technologies to defer or minimize the need for additional investment in generation.

(D) A description of how the energy utility may provide for the requisite amount of electricity needed by the large load customer, including the estimated project costs.

(E) A description of how the expected project solution will support the provision of electric utility service with the attributes set forth in IC 8-1-2-0.6, including:

(i) reliability;
(ii) affordability;
(iii) resiliency;
(iv) stability; and
(v) environmental sustainability.

(F) A description of how the expected project solution and its implementation, if approved by the commission, reasonably protects existing and future customers and is consistent with:
(i) the provision of safe, reliable, and affordable electric utility service; and
(ii) economical rates.

(G) A description of the changes that the energy utility will make to the energy utility's:
(i) submissions under IC 8-1-8.5; or
(ii) filings under IC 8-1-39;
or both, that are necessary to update the energy utility's plans under those statutes to incorporate the project.

(H) Information concerning each:
(i) large load customer; and
(ii) economic development project;
included in the petition.

(I) A letter to the energy utility from the corporation supporting the petition's request.

(J) A letter to the energy utility from the office certifying that a pre-filing meeting took place and that at the meeting:
(i) the large load customer's proposed project; and
(ii) the expected project solution proposed by the energy utility;
were adequately discussed.

(K) A description of the communications and information sharing that:
(i) took place with the appropriate regional transmission organization before the pre-filing meeting described in clause (J); and
(ii) concerned the capacity and energy needs of each large load customer included in the petition.

(L) A proposed order for the petition.

(2) A copy of a notice of filing with:
(A) the corporation;
(B) the office;

(C) the office of utility consumer counselor; and

(D) the appropriate regional transmission organization.

A notice that is delivered electronically to the parties set forth in this subdivision satisfies the notice requirement under this subdivision.

Sec. 24. (a) This section applies to an energy utility that petitions the commission for approval of a project to serve a large load customer.

(b) The commission may approve a petition in whole or in part. The commission shall make its decision based on whether the relief requested is just, reasonable, and in the public interest. The commission shall issue its final order on the petition not later than one hundred fifty (150) days after receiving the energy utility's complete petition and case in chief. A petition is considered:

(1) complete unless the commission provides a notice of deficiency to the energy utility not later than seven (7) business days after the filing of the petition; and

(2) approved if the commission does not issue a final order on the petition within the one hundred fifty (150) day period set forth in this subsection.

(c) If an energy utility files a petition that includes one (1) or more large load customers and one (1) or more proposed projects, the commission may:

(1) approve the energy utility's petition in its entirety;

(2) deny the energy utility's petition in its entirety; or

(3) modify the petition, subject to the energy utility's acceptance of the modification.

(d) The commission may approve a reasonable risk premium for a project if requested in an energy utility's petition and if the commission finds that the reasonable risk premium is appropriate. If the commission approves a reasonable risk premium:

(1) the large load customer is responsible for the amount of the reasonable risk premium; and

(2) the reasonable risk premium may not be:

(A) included in the energy utility's:

(i) revenue requirement;

(ii) authorized net operating income; or

(iii) calculations under IC 8-1-2-42(d)(3) or IC 8-1-2-42(g)(3)(C); or

(B) otherwise considered for purposes of setting the authorized return in any future general rate case or other regulatory proceeding involving the energy utility.

(e) The commission may approve an energy utility's request to construct, purchase, lease, or otherwise acquire an energy generation resource under this chapter (notwithstanding and instead of under IC 8-1-2.5, IC 8-1-8.5, or IC 8-1-8.8) for the purpose of serving one (1) or more large load customers. In approving an energy utility's request under this chapter to acquire an energy generation resource to serve one (1) or more large load customers, the commission must find that:

(1) the information provided by the energy utility under section 23 of this chapter is complete;

(2) reasonable and demonstrable consideration was given to nongeneration alternatives by the parties involved;

(3) existing and future customers of the energy utility will be adequately protected if the request is granted; and

(4) the energy utility has considered the impact of the request on the energy utility's preferred resource portfolio in the energy utility's most recent integrated resource plan.

(f) An energy utility shall promptly notify the commission if, after the commission has approved a petition under subsection (e), one (1) or more of the large load customers with respect to whom the petition was approved:

(1) no longer requires service from the energy utility or materially alters or terminates the large load customer's service requirements; and

(2) the project is incomplete.

(g) The commission may, not later than sixty (60) days after receiving a notice under subsection (f), conduct an investigation under IC 8-1-2-58 through IC 8-1-2-60 to determine whether the public interest would still be served by completion of the project. An investigation under this subsection does not preclude the energy utility from continuing construction of the project to serve the large load customer or from continuing to serve the large load customer. If the commission finds that completion of the project is no longer in the public interest, the commission may modify or revoke the order approving the petition.

Sec. 25. (a) The commission shall review an energy utility's:

(1) estimated acquisition costs submitted under section 20(c)(1)(D) of this chapter; or

(2) estimated project costs filed under section 23(b)(1)(D) of this chapter;

as applicable.

(b) If the commission approves, with or without modification, an

energy utility's generation resource submittal or petition for approval of a project, the energy utility may recover:

(1) acquisition costs; or

(2) project costs;

as applicable, that have been reviewed and found reasonable by the commission, with a return at the energy utility's weighted average cost of capital.

(c) If the commission denies an energy utility's generation resource submittal or petition for approval of a project, the energy utility may recover planning costs that have been reviewed and found reasonable by the commission, without a return.

(d) Absent fraud, concealment, or gross mismanagement, an energy utility may recover:

(1) acquisition costs; or

(2) project costs;

as applicable, with a return at the energy utility's weighted average cost of capital, that the energy utility has incurred or contractually will incur in reliance on a commission order issued under this chapter.

Sec. 26. (a) Upon request by an energy utility, the commission shall determine whether the information and related materials filed or submitted, or to be filed or submitted, by an energy utility under this chapter:

(1) are confidential under IC 5-14-3-4 or are trade secrets under IC 24-2-3;

(2) are exempt from public access and disclosure by Indiana law; and

(3) must be treated as confidential and protected from public access and disclosure by the commission.

(b) The parties to a pre-filing meeting under this chapter shall execute a nondisclosure agreement to review or discuss information or materials considered confidential under IC 5-14-3-4 or to be trade secrets under IC 24-2-3.

(c) If the corporation is in negotiations with an industrial, research, or commercial prospect about a potential economic development project and, based on communications related to those negotiations, determines that the potential economic development project for a new or expanded facility in Indiana may result in the economic development project requiring new or increased energy demand of at least twenty (20) megawatts, the corporation shall notify the affected energy utility not later than fifteen (15) days after making the determination. All

communications of the corporation, including notice under this section to an affected energy utility, regarding a potential economic development project are considered confidential and exempt from disclosure under IC 5-14-3-4(b)(5). Upon the corporation's provision of the notice required by this subsection, any subsequent:

(1) meeting;
(2) pre-filing meeting;
(3) communications; or
(4) information sharing;

involving the corporation, the affected energy utility, or the industrial, research, or commercial prospect about a potential economic development project may be subject to a nondisclosure agreement with respect to information or materials considered confidential under IC 5-14-3-4 or to be trade secrets under IC 24-2-3.

(d) An energy utility may request, and the commission may approve, financial incentives under IC 8-1-8.8-11(a) for:

(1) an acquisition; or
(2) a project;

that qualifies as a clean energy project (as defined in IC 8-1-8.8-2).

(e) An energy utility may request that review of an arrangement under IC 8-1-2-24 and any related rates and charges under IC 8-1-2-25 that are:

(1) submitted with a generation resource submittal; or
(2) filed with a petition for a project;

under this chapter be reviewed and approved or denied by the commission not later than ninety (90) days after the date of submittal or filing, as applicable.

(f) Notwithstanding IC 8-1-8.5 or any other applicable statute, an energy utility may begin construction of an acquisition or a project before filing a petition or submittal under this chapter.

(g) The commission may require an energy utility to file with the commission progress reports and updates with respect to an acquisition or project under this chapter. Any required progress reports or updates under this subsection shall be made in a form and at a frequency that the commission determines to be reasonable.

SECTION 3. IC 8-1-8.5-2.1, AS AMENDED BY THE TECHNICAL CORRECTIONS BILL OF THE 2025 GENERAL ASSEMBLY, IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2025]: Sec. 2.1. (a) This section does not apply to the retirement, sale, or transfer of:

(1) a public utility's electric generation facility if the retirement, sale, or transfer is necessary in order for the public utility to comply with a federal consent decree; or
(2) an electric generation facility that generates electricity for sale exclusively to the wholesale market.

(b) A public utility shall notify the commission if:
(1) the public utility intends or decides to retire, sell, or transfer an electric generation facility with a capacity of at least eighty (80) megawatts; and
(2) the retirement, sale, or transfer:
(A) was not set forth in; or
(B) is to take place on a date earlier than the date specified in;
the public utility's short term action plan in the public utility's most recently filed integrated resource plan.

(c) Upon receiving notice from a public utility under subsection (b), the commission shall consider and may investigate, under IC 8-1-2-58 through IC 8-1-2-60, the public utility's intention or decision to retire, sell, or transfer the electric generation facility. In considering the public utility's intention or decision under this subsection, the commission shall examine the impact the retirement, sale, or transfer would have on the public utility's ability to meet:
(1) the public utility's planning reserve margin requirements or other federal reliability requirements that the public utility is obligated to meet, as described in section ~~13(i)(4)~~ **13(n)(6)** of this chapter; and
(2) the reliability adequacy metrics set forth in section ~~13(e)~~ **13(h)** of this chapter.

(d) Before July 1, 2026, if:
(1) a public utility intends or decides to retire, sell, or transfer an electric generation facility with a capacity of at least eighty (80) megawatts; and
(2) the retirement, sale, or transfer:
(A) was not set forth in; or
(B) is to take place on a date earlier than the date specified in;
the public utility's short term action plan in the public utility's most recently filed integrated resource plan;
the commission shall not permit the public utility's depreciation rates, as established under IC 8-1-2-19, to be amended to reflect the accelerated date for the retirement, sale, or transfer of the electric generation asset unless the commission finds that such an adjustment is necessary to ensure the ability of the public utility to provide reliable service to its customers, and that the unamended depreciation rates

would cause an unjust and unreasonable impact on the public utility and its ratepayers.

(e) The commission may issue a general administrative order to implement this section.

(f) This section expires July 1, 2026.

SECTION 4. IC 8-1-8.5-13, AS AMENDED BY P.L.93-2024, SECTION 68, IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2025]: Sec. 13. (a) The general assembly finds that it is in the public interest to support the reliability, availability, and diversity of electric generating capacity in Indiana for the purpose of providing reliable and stable electric service to customers of public utilities.

(b) As used in this section, "appropriate regional transmission organization", with respect to a public utility, refers to the regional transmission organization approved by the Federal Energy Regulatory Commission for the control area that includes the public utility's assigned service area (as defined in IC 8-1-2.3-2).

(c) As used in this section, "capacity market" means an auction conducted by an appropriate regional transmission organization to determine a market clearing price for capacity based on the planning reserve margin requirements established by the appropriate regional transmission organization for a planning year with respect to which an auction has not yet been conducted.

(d) As used in this section, "fall unforced capacity", or "fall UCAP", with respect to an electric generating facility, means:

(1) the capacity value of the electric generating facility's installed capacity rate adjusted for the electric generating facility's average forced outage rate for the fall period, calculated as required by the appropriate regional transmission organization or by the Federal Energy Regulatory Commission;

(2) a metric that is similar to the metric described in subdivision (1) and that is required by the appropriate regional transmission organization; or

(3) if the appropriate regional transmission organization does not require a metric described in subdivision (1) or (2), a metric that:

(A) can be used to demonstrate that a public utility has sufficient capacity to:

(i) provide reliable electric service to Indiana customers for the fall period; and

(ii) meet its planning reserve margin requirement and other federal reliability requirements described in subsection ~~(l)(4);~~ **(n)(6);** and

(B) is acceptable to the commission.

(e) As used in this section, "MISO" refers to the regional transmission organization known as the Midcontinent Independent System Operator that operates the bulk power transmission system serving most of the geographic territory in Indiana.

(f) As used in this section, "planning reserve margin requirement", with respect to a public utility for a particular resource planning year, means the planning reserve margin requirement for that planning year that the public utility is obligated to meet in accordance with the public utility's membership in the appropriate regional transmission organization.

(g) As used in this section, "refuel" or "refueling" means a planned fuel conversion from one fuel source to another fuel source with respect to an electric generation resource with a nameplate capacity of at least one hundred twenty-five (125) megawatts by a public utility.

~~(g)~~ **(h)** As used in this section, "reliability adequacy metrics", with respect to a public utility, means calculations used to demonstrate all of the following:

(1) Subject to subsection ~~(q)(2)(B),~~ **(u)(2),** that the public utility:
(A) has in place sufficient summer UCAP; or
(B) can reasonably acquire not more than:
(i) thirty percent (30%) of its total summer UCAP from capacity markets, with respect to a report filed with the commission under subsection ~~(l)~~ **(n)** before July 1, 2023; or
(ii) fifteen percent (15%) of its total summer UCAP from capacity markets, with respect to a report filed with the commission under subsection ~~(l)~~ **(n)** after June 30, 2023;
such that it will have sufficient summer UCAP;
to provide reliable electric service to Indiana customers, and to meet its planning reserve margin requirement and other federal reliability requirements described in subsection ~~(l)(4).~~ **(n)(6).**

(2) Subject to subsection ~~(q)(2)(B),~~ **(u)(2),** that the public utility:
(A) has in place sufficient winter UCAP; or
(B) can reasonably acquire not more than:
(i) thirty percent (30%) of its total winter UCAP from capacity markets, with respect to a report filed with the commission under subsection ~~(l)~~ **(n)** before July 1, 2023; or
(ii) fifteen percent (15%) of its total winter UCAP from capacity markets, with respect to a report filed with the commission under subsection ~~(l)~~ **(n)** after June 30, 2023;
such that it will have sufficient winter UCAP;
to provide reliable electric service to Indiana customers, and to

meet its planning reserve margin requirement and other federal reliability requirements described in subsection ~~(l)(4).~~ **(n)(6).**

(3) Subject to subsection ~~(q)(2)(B),~~ **(u)(2),** with respect to a report filed with the commission under subsection ~~(l)~~ **(n)** after June 30, 2026, that the public utility:

(A) has in place sufficient spring UCAP; or

(B) can reasonably acquire not more than fifteen percent (15%) of its total spring UCAP from capacity markets, such that it will have sufficient spring UCAP;

to provide reliable electric service to Indiana customers, and to meet its planning reserve margin requirement and other federal reliability requirements described in subsection ~~(l)(4).~~ **(n)(6).**

(4) Subject to subsection ~~(q)(2)(B),~~ **(u)(2),** with respect to a report filed with the commission under subsection ~~(l)~~ **(n)** after June 30, 2026, that the public utility:

(A) has in place sufficient fall UCAP; or

(B) can reasonably acquire not more than fifteen percent (15%) of its total fall UCAP from capacity markets, such that it will have sufficient fall UCAP;

to provide reliable electric service to Indiana customers, and to meet its planning reserve margin requirement and other federal reliability requirements described in subsection ~~(l)(4).~~ **(n)(6).**

(i) As used in this section, "retire" or retirement" means a planned permanent ceasing of electric generation operations with respect to an electric generation resource with a nameplate capacity of at least one hundred twenty-five (125) megawatts by a public utility.

~~(h)~~ **(j)** As used in this section, "spring unforced capacity", or "spring UCAP", with respect to an electric generating facility, means:

(1) the capacity value of the electric generating facility's installed capacity rate adjusted for the electric generating facility's average forced outage rate for the spring period, calculated as required by the appropriate regional transmission organization or by the Federal Energy Regulatory Commission;

(2) a metric that is similar to the metric described in subdivision (1) and that is required by the appropriate regional transmission organization; or

(3) if the appropriate regional transmission organization does not require a metric described in subdivision (1) or (2), a metric that:

(A) can be used to demonstrate that a public utility has sufficient capacity to:

(i) provide reliable electric service to Indiana customers for

the spring period; and
(ii) meet its planning reserve margin requirement and other federal reliability requirements described in subsection ~~(l)(4);~~ **(n)(6);** and
(B) is acceptable to the commission.

~~(i)~~ **(k)** As used in this section, "summer unforced capacity", or "summer UCAP", with respect to an electric generating facility, means:
(1) the capacity value of the electric generating facility's installed capacity rate adjusted for the electric generating facility's average forced outage rate for the summer period, calculated as required by the appropriate regional transmission organization or by the Federal Energy Regulatory Commission; or
(2) a metric that is similar to the metric described in subdivision (1) and that is required by the appropriate regional transmission organization.

~~(j)~~ **(l)** As used in this section, "winter unforced capacity", or "winter UCAP", with respect to an electric generating facility, means:
(1) the capacity value of the electric generating facility's installed capacity rate adjusted for the electric generating facility's average forced outage rate for the winter period, calculated as required by the appropriate regional transmission organization or by the Federal Energy Regulatory Commission;
(2) a metric that is similar to the metric described in subdivision (1) and that is required by the appropriate regional transmission organization; or
(3) if the appropriate regional transmission organization does not require a metric described in subdivision (1) or (2), a metric that:
(A) can be used to demonstrate that a public utility has sufficient capacity to:
(i) provide reliable electric service to Indiana customers for the winter period; and
(ii) meet its planning reserve margin requirement and other federal reliability requirements described in subsection ~~(l)(4);~~ **(n)(6);** and
(B) is acceptable to the commission.

~~(k)~~ **(m)** A public utility that owns and operates an electric generating facility serving customers in Indiana shall operate and maintain the facility using good utility practices and in a manner:
(1) reasonably intended to support the provision of reliable and economic electric service to customers of the public utility; ~~and~~
(2) reasonably consistent with the resource reliability requirements of MISO or any other appropriate regional

transmission organization; **and**

(3) reasonably maximizes the economic value of the electric generating facility.

~~(l)~~ **(n)** Not later than thirty (30) days after the deadline for submitting an annual planning reserve margin report to MISO, each public utility providing electric service to Indiana customers shall, regardless of whether the public utility is required to submit an annual planning reserve margin report to MISO, file with the commission a report, in a form specified by the commission, that provides the following information for each of the next three (3) resource planning years, beginning with the planning year covered by the planning reserve margin report to MISO described in this subsection:

(1) The:

(A) capacity;

(B) location; and

(C) fuel source;

for each electric generating facility that is owned and operated by the electric utility and that will be used to provide electric service to Indiana customers.

(2) With respect to a report submitted to the commission after December 31, 2025, the amount of generating resource capacity or energy, or both, that the public utility plans to retire and that is owned and operated by the public utility and used to provide retail electric service in Indiana, including the:

(A) capacity;

(B) location;

(C) fuel source; and

(D) planned retirement date;

for each electric generating facility. The public utility must include information as to whether the planned retirement is required in order to comply with environmental laws, regulations, or court orders, including consent decrees, that are or will be in effect at the time of the planned retirement. In addition, the public utility must provide its economic rationale for the planned retirement, including anticipated ratepayer impacts, and information concerning the public utility's plan or plans with respect to the amount of replacement capacity identified to provide approximately the same accredited capacity within the appropriate regional transmission organization as the amount of capacity of the facility to be retired.

(3) With respect to a report submitted to the commission after December 31, 2025, the amount of generating resource capacity or energy, or both, that the public utility plans to refuel, including the:
(A) capacity;
(B) location;
(C) existing fuel source;
(D) proposed fuel source; and
(E) planned completion date of the refueling;
with respect to each electric generating facility that the public utility plans to refuel. The public utility must provide its economic rationale for the planned refueling, including anticipated ratepayer impacts, and information concerning the public utility's plan or plans with respect to the extent to which the refueling will maintain or increase the current generating resource accredited capacity or energy, or both, that the electric generating facility provides, so as to provide approximately the same accredited capacity within the appropriate regional transmission organization.
~~(2)~~ **(4)** The amount of generating resource capacity or energy, or both, that the public utility has procured under contract and that will be used to provide electric service to Indiana customers, including the:
(A) capacity;
(B) location; and
(C) fuel source;
for each electric generating facility that will supply capacity or energy under the contract, to the extent known by the public utility.
~~(3)~~ **(5)** The amount of demand response resources available to the public utility under contracts and tariffs.
~~(4)~~ **(6)** The following:
(A) The planning reserve margin requirements established by MISO for the planning years covered by the report, to the extent known by the public utility with respect to any particular planning year covered by the report.
(B) If applicable, any other planning reserve margin requirement that:
(i) applies to the planning years covered by the report; and
(ii) the public utility is obligated to meet in accordance with the public utility's membership in an appropriate regional transmission organization;

to the extent known by the public utility with respect to any particular planning year covered by the report.

(C) Other federal reliability requirements that the public utility is obligated to meet in accordance with its membership in an appropriate regional transmission organization with respect to the planning years covered by the report, to the extent known by the public utility with respect to any particular planning year covered by the report.

For each planning reserve margin requirement reported under clause (A) or (B), the public utility shall include a comparison of that planning reserve margin requirement to the planning reserve margin requirement established by the same regional transmission organization for the 2021-2022 planning year.

~~(5)~~ **(7)** The reliability adequacy metrics of the public utility, as forecasted for the three (3) planning years covered by the report.

~~(m)~~ **(o)** Upon request by a public utility, the commission shall determine whether information provided in a report filed by the public utility under subsection ~~(l):~~ **(n):**

(1) is confidential under IC 5-14-3-4 or is a trade secret under IC 24-2-3;

(2) is exempt from public access and disclosure by Indiana law; and

(3) shall be treated as confidential and protected from public access and disclosure by the commission.

~~(n)~~ **(p)** A joint agency created under IC 8-1-2.2 may file the report required under subsection ~~(l)~~ **(n)** as a consolidated report on behalf of any or all of the municipally owned utilities that make up its membership.

~~(o)~~ **(q)** A:

(1) corporation organized under IC 23-17 that is an electric cooperative and that has at least one (1) member that is a corporation organized under IC 8-1-13; or

(2) general district corporation within the meaning of IC 8-1-13-23;

may file the report required under subsection ~~(l)~~ **(n)** as a consolidated report on behalf of any or all of the cooperatively owned electric utilities that it serves.

~~(p)~~ **(r)** In reviewing a report filed by a public utility under subsection ~~(l),~~ **(n),** the commission may request technical assistance from MISO or any other appropriate regional transmission organization in determining:

(1) the planning reserve margin requirements or other federal

reliability requirements that the public utility is obligated to meet, as described in subsection ~~(l)(4);~~ **(n)(6);** and

(2) whether the resources available to the public utility under subsections ~~(l)(1)~~ **(n)(1)** through ~~(l)(3)~~ **(n)(5)** will be adequate to support the provision of reliable electric service to the public utility's Indiana customers.

(s) With respect to a report submitted under subsection (n) after December 31, 2025, commission staff shall review the reports submitted by public utilities and shall, not later than ninety (90) days after the date of submission of the reports, submit to the commission a staff report concerning any planned retirements included in the reports under subsection (n)(2). The report must make recommendations to the commission based on whether each planned retirement:

(1) is consistent with the standards set forth in subsection (m);

(2) will be replaced with an amount of replacement capacity that will provide approximately the same accredited capacity within the appropriate regional transmission organization as the amount of capacity of the facility to be retired;

(3) will not adversely and unreasonably impact a public utility's ability to provide safe, reliable, and economical electric utility service to the public utility's customers;

(4) will result in the provision to Indiana customers of electric utility service with the attributes of:

(A) reliability;

(B) affordability;

(C) resiliency;

(D) stability; and

(E) environmental sustainability;

as set forth in IC 8-1-2-0.6; and

(5) is required in order to comply with environmental laws, regulations, or court orders, including consent decrees, that are or will be in effect at the time of the planned retirement.

(t) The commission shall make the staff reports prepared under subsection (s) publicly available by posting the staff reports on the commission's website. Upon the posting of a staff report on the commission's website, the commission shall accept public comments on the report for a period not to exceed thirty (30) days after the date of posting.

~~(q)~~ **(u)** If, after reviewing a report filed by a public utility under subsection ~~(l),~~ **(n) and any staff report prepared with respect to the public utility under subsection (s),** the commission is not satisfied that the public utility can **either:**

~~(1) provide reliable electric service to the public utility's Indiana customers; or~~

~~(2) either:~~

~~(A)~~ **(1)** satisfy both:

~~(i)~~ **(A)** its planning reserve margin requirement or other federal reliability requirements that the public utility is obligated to meet, as described in subsection ~~(l)(4);~~ **(n)(6);** and

~~(ii)~~ **(B)** the reliability adequacy metrics set forth in subsection ~~(g);~~ **(h);** or

~~(B)~~ **(2)** provide sufficient reason as to why the public utility is unable to satisfy both:

~~(i)~~ **(A)** its planning reserve margin requirement or other federal reliability requirements that the public utility is obligated to meet, as described in subsection ~~(l)(4);~~ **(n)(6);** and

~~(ii)~~ **(B)** the reliability adequacy metrics set forth in subsection ~~(g);~~ **(h);**

during one (1) more of the planning years covered by the report, the commission ~~may~~ **shall** conduct an investigation under IC 8-1-2-58 through IC 8-1-2-60 as to the reasons for the public utility's potential inability to meet the requirements described in subdivision (1) or ~~(2), or both.~~ **provide sufficient reason as to that inability, as described in subdivision (2). In addition, if the public utility has indicated in its report under subsection (n)(2) that it plans to retire an electric generating facility within one (1) year of the date of the report, the commission must conduct an investigation under IC 8-1-2-58 through IC 8-1-2-60 as to the reasons for the public utility's potential inability to meet the requirements described in subdivision (1) or provide sufficient reason as to that inability, as described in subdivision (2). However, a public utility may request, not earlier than three (3) years before the planned retirement date of an electric generation facility, that the commission conduct an investigation under IC 8-1-2-58 through IC 8-1-2-60, for the purposes described in this subsection, with respect to the planned retirement. If the commission conducts an investigation at the request of a public utility within the three (3) year period before the planned retirement date of an electric generation facility, the commission may not conduct a subsequent investigation that would otherwise be required under this subsection with respect to the retirement of that same electric generation facility unless the commission is not satisfied, as of the time that an investigation would otherwise be required under this subsection, that the public**

utility can meet the requirements described in subdivision (1) or provide sufficient reason as to that inability, as described in subdivision (2). If a certificate is granted by the commission under this chapter for a facility intended to repower or replace a generation unit that is planned for retirement, and the certificate includes findings that the project will result in at least equivalent accredited capacity and will provide economic benefit to ratepayers as compared to the continued operation of the generating unit to be retired, the certificate under this chapter constitutes approval by the commission for purposes of an investigation required by this subsection. However, if the commission finds that facts and circumstances regarding the planned retirement have changed significantly since the certificate was granted and that those changes concern the public utility's ability to meet the requirements described in subdivision (1), the commission may conduct an investigation into the planned retirement of the unit.

~~(r)~~ **(v)** If, upon investigation under IC 8-1-2-58 through IC 8-1-2-60, and after notice and hearing, as required by IC 8-1-2-59, the commission determines that the capacity resources available to the public utility under subsections ~~(l)(1)~~ **(n)(1)** through ~~(l)(3)~~ **(n)(5)** will not be adequate ~~to support the provision of reliable electric service to the public utility's Indiana customers, or~~ to allow the public utility to satisfy both its planning reserve margin requirements or other federal reliability requirements that the public utility is obligated to meet (as described in subsection ~~(l)(4))~~ **(n)(6))** and the reliability adequacy metrics set forth in subsection ~~(g),~~ **(h),** the commission shall issue an order:

(1) directing the public utility to acquire or construct; **or**

(2) prohibiting the retirement or refueling of;

such capacity resources that are reasonable and necessary to enable the public utility to provide reliable electric service to its Indiana customers, and to satisfy both its planning reserve margin requirements or other federal reliability requirements described in subsection ~~(l)(4)~~ **(n)(6)** and the reliability adequacy metrics set forth in subsection ~~(g).~~ **(h). The commission shall issue an order under this subsection not later than one hundred twenty (120) days after the initiation of the investigation under subsection (u). If the commission does not issue an order within the one hundred twenty (120) day period prescribed by this subsection, the public utility is considered to be able to meet the requirements described in subsection (u)(1) with respect to the retirement of the electric generation facility under**

investigation. Not later than ninety (90) days after the date of ~~the commission's~~ **an** order **by the commission** under this subsection, the public utility shall file for approval with the commission a plan to comply with the commission's order. **Notwithstanding IC 8-1-3 or any other law, any appeal of an order by the commission under this subsection is entitled to priority review and shall be given expedited consideration in accordance with Rule 21 of the Indiana Rules of Appellate Procedure.**

(w) With respect to a report submitted under subsection (n) after December 31, 2025, if the commission issues an order under subsection (v) to prohibit the retirement or refueling of an electric generation resource, the commission shall create a sub-docket to authorize the public utility to recover in rates the costs of the continued operation of the electric generation resource that was proposed to be retired or refueled. The commission must find that the continued costs of operation are just and reasonable before authorizing their recovery in the public utility's rates. The creation of a sub-docket under this subsection is not subject to the one hundred twenty (120) day time frame for the commission to issue an order under subsection (v).

~~The~~ **(x) A** public utility's plan **under subsection (v)** may include:

(1) a request for a certificate of public convenience and necessity under this chapter; or

(2) an application under IC 8-1-8.8;

or both.

~~(s)~~ **(y)** Beginning in 2022, the commission shall include in its annual report under IC 8-1-1-14 the following information:

(1) The commission's analysis regarding the ability of public utilities to:

(A) provide reliable electric service to Indiana customers; and

(B) satisfy both:

(i) their planning reserve margin requirements or other federal reliability requirements; and

(ii) the reliability adequacy metrics set forth in subsection ~~(g);~~ **(h);**

for the next three (3) utility resource planning years, based on the most recent reports filed by public utilities under subsection ~~(l).~~ **(n).**

(2) A summary of:

(A) the projected demand for retail electricity in Indiana over the next calendar year; ~~and~~

(B) the amount and type of capacity resources committed to meeting the projected demand;

(C) beginning with the commission's annual report due before October 1, 2026, and in each subsequent annual report, the planned retirements or refuelings of electric generation resources and the plans to replace or retain the capacity or energy, or both, of the electric generation resources planned to be retired or refueled; and

(D) beginning with the commission's annual report due before October 1, 2026, and in each subsequent annual report, the reports of commission staff under subsection (s).

In preparing the summary required under this subdivision, the commission may consult with the forecasting group established under section 3.5 of this chapter.

(3) Beginning with the commission's annual report filed under IC 8-1-1-14 in 2025, the commission's analysis regarding the appropriate percentage or portion of:

(A) total spring UCAP that public utilities should be authorized to acquire from capacity markets under subsection ~~(g)(3)(B);~~ **(h)(3)(B);** and

(B) total fall UCAP that public utilities should be authorized to acquire from capacity markets under subsection ~~(g)(4)(B).~~ **(h)(4)(B).**

~~(t)~~ **(z)** The commission may adopt rules under IC 4-22-2 to implement this section.

SECTION 5. **An emergency is declared for this act.**

Speaker of the House of Representatives

President of the Senate

President Pro Tempore

Governor of the State of Indiana

Date: ____________________ Time: ____________________