INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR COMMENTS ON DUKE ENERGY INDIANA'S 2024 IRP

FEBRUARY 13, 2024

Introduction

The Indiana Office of Utility Consumer Counselor ("OUCC") respectfully offers these comments regarding Duke Energy Indiana's ("Duke") 2024 Integrated Resource Plan ("IRP"). The importance of IRPs continues to grow in planning a flexible, reliable and cost-effective future for Indiana's electric utility customers. The OUCC's comments include recommended improvements to Duke's IRP Stakeholder Process and its Preferred Portfolio development and suggestions to the Indiana Utility Regulatory Commission's ("IURC") Research, Policy, and Planning Division for the benefit of Indiana's consumers.

The OUCC acknowledges and appreciates the significant time, effort, and resources that Duke, its stakeholders, and IURC staff have expended in developing Duke's IRP. The constructive feedback process used during Duke's IRP Stakeholder meetings and the written comments stakeholders provide upon submitted IRPs are essential to the development of Indiana's energy future. All comments should be considered to improve IRPs.

The fact the OUCC does not address specific items in its IRP comments does not suggest tacit support for such matters. Natural constraints and complexities of IRP exercises limit the ability of stakeholders to address every issue and potential opportunity for improvement.

Regarding Duke's 2024 IRP, the OUCC offers the following specific observations and recommendations:

- The stochastic analysis Duke uses to evaluate portfolio performance across various uncertainties, which includes the Enhanced Reliability Evaluation, is an improvement from the 2021 IRP and should be continued in future IRP analyses.
- Duke's portfolio Scorecard also improved from the 2021 IRP, with a comprehensive evaluation of the Five Pillars of Electric Utility Service ("Five Pillars") as defined in Ind. Code § 8-1-2-0.6.
- Duke should evaluate portfolios with more resource variety wherever possible. There was not enough variation across the portfolios modeled to show a significant cost difference among the portfolios.
- Duke should provide additional cost estimate details for the resource options included in each portfolio.
- Duke should also provide more detailed generating unit environmental compliance costs for each regulation.
- Duke's Electric Vehicle ("EV") forecast may overstate EV adoption, but

the OUCC does not recommend specific changes to the forecast.

- Duke should consider non-linear Behind the Meter ("BTM") Solar Adoption growth in future forecasts.
- Duke's adjustment to its load forecast to incorporate sensitivities for economic development is reasonable. However, the OUCC noticed a potential error in Duke's economic development load forecast adjustment. The adjustment is provided in MWhs but perhaps should be in GWhs.
- Duke should also model sensitivities to account for the potential future addition of large data center loads.
- Duke's historical load and energy generation data for 2013-2020 in its 2024 IRP is different from the historical data for the same time period reported in its 2021 IRP. Actual historical data should not change between IRPs.
- The OUCC recommends Duke model sensitivities regarding natural gas availability during cold weather events into its reliability modeling to better address resiliency and stability among portfolios.

Modeling Process, Portfolios, and Scorecard

Duke developed six generation strategies with an additional strategy related to abandoned implementation of Environmental Protection Agency ("EPA") Clean Air Act Section 111 Rule, the "No 111 Strategy." Duke's evaluation of these six strategies under three different scenarios with added sensitivity analyses on specific variables was an insightful approach and should be continued in future IRPs. The new stochastic analysis using the Strategic Energy Risk Valuation Model ("SERVM") to evaluate portfolio performance under real-world uncertainties, which provided power price variability in market purchases,[1] the inclusion of CO_2 emissions and forecasted operating costs are improvements from previous models used in Duke's IRPs.

These analytics led to an updated scorecard, which, from the OUCC's perspective, is an improvement from Duke's 2021 IRP. The scorecard comprehensively evaluated the Five Pillars by examining fifteen metrics. Five of these metrics captured measurements at two distinct points in time across the IRP horizon. The scorecard enhances how each portfolio performs over the 20-year evaluation period. However, the scorecard does not quantitatively measure the Stability Pillar, as Duke notes that it decided to take a narrative approach to evaluating the Stability Pillar after stakeholder recommendations.[2]

The addition of Cost Risk, Market Exposure, and Execution Risk provides additional insight into the weighting Duke used in analyzing its generation strategies. However, Duke's choice of Portfolio Blend 2 as the preferred portfolio was not obvious or transparent to the OUCC because the Present Value Revenue Requirement ("PVRR") and Customer Bill impact metrics do not show significant

[1] 2024 Duke Energy Indiana Integrated Resource Plan Stakeholder Meeting 5, p. 35.
[2] Duke Energy Indiana 2024 IRP, Volume 1, p. 48.

variation among the portfolios to fully support one option over another. This is likely because the resources in each portfolio considered do not vary significantly from the others, with most differences being due to proposed timing of generating unit retirements. All but one portfolio includes the addition of Combined Cycle Natural Gas Turbine ("CCGT") resources. Without much diversity among the resources considered in each portfolio, the costs of each portfolio tend to be very similar.

The OUCC acknowledges a variety of factors may lead Duke to only consider CCGT resources to replace retiring generation. MISO's seasonal resource adequacy requirements tend to favor firm, fast-ramping gas generation over intermittent resources. As explained in the next section, existing coal generation may be constrained by recent carbon emission regulations at the federal level. Nuclear generation has many regulatory and technical hurdles while the development of small modular reactor technology continues. However, Duke should attempt to consider greater variation in the portfolios it models where possible. For example, there does not appear to be a generation strategy where Duke considered adding combustion turbine ("CT") peakers instead of CCGTs. It is possible CTs could be used to support more renewable generation. Furthermore, if CTs are operated below a 20% capacity factor, they are not subject to the same efficiency requirements or potential carbon capture and sequestration ("CCS") requirements CCGTs that operate as intermediate or baseload resources would be under new carbon regulations.

While each proposal requires its own analysis, history has shown, generally, that conversions are more cost effective than retiring units and replacing their capacity. Additionally, the IRP states Duke has the option to convert the existing coal-fired units at Gibson and Cayuga either to 100% natural gas or 50% co-fired with natural gas. Either option would allow the existing units to continue operating beyond the originally projected retirement dates. However, doing so would require a number of additional infrastructure and maintenance projects. It is not clear the Edwardsport conversion achieves the same result because no portfolio considered retiring Edwardsport. Because Duke did not provide enough cost detail regarding the resource options considered, it is unclear if the costs of coal equipment retirement and the environmental remediation at these generating sites were adequately addressed. In a co-firing or conversion scenario, assets can be repurposed, possibly preventing some remediation costs and reducing the amount of new investment. The OUCC recommends additional cost estimate details be provided to clarify the benefits and costs of each resource option modeled.

Environmental Regulations Limiting Existing Asset Lives

Duke's proposed retirement dates contain significant changes when compared to Duke's 2021 IRP because the utility reflects the EPA's Greenhouse Gas New Source Performance Standards ("111 Rule") requirements finalized in April 2024. The final 111 Rule requires: (1) retirement of existing coal-fired units by 2032; or

(2) co-firing 40% natural gas by January 1, 2030, and then retiring those units by the end of 2038; or (3) 90% CCS by January 1, 2032.

In addition to these three compliance strategies under the federal rule, Duke could consider converting its existing coal-fired units to burn 100% natural gas. Existing natural gas-fired power plants are currently exempt from the 90% reduction requirement under the rule.[3] If Duke converted Edwardsport to only combusting natural gas, it would be considered an existing modified unit for purposes of rule applicability under air pollution regulations[4] and, thus, would currently be exempt from the CO_2 rule. This exemption may end in the future with EPA currently holding formal discussions in a non-regulatory docket on how carbon emissions from existing natural gas-fired power plants could be regulated, but the EPA has no planned rulemaking on these plants at this time.[5] Duke would need to decide whether to convert to natural gas by the end of 2030 to comply with the federal rule.

The Section 111 Rule also requires the State of Indiana to develop a state implementation plan for regulation of carbon emissions within two years of the publication of the final Section 111 Rule.[6] The state implementation plan may potentially impact coal units that convert to natural gas, but the state has flexibility under the Section 111 Rule to determine what standards may apply to such units.

No 111 Strategy

Duke considered a resource strategy under which the Section 111 Rule is either overturned by the courts or rescinded by the new Administration ("No 111 Strategy"). Given the Trump Administration's directive to re-evaluate any new regulation impacting the energy sector, this was a reasonable strategy for Duke to evaluate, even though the federal election results were not known at the time it submitted its 2024 IRP. While this portfolio would lead to delays in coal unit retirement or fuel switching dates, Duke would still retire or repower its existing coal units by 2036. Repeal of the 111 Rule would reduce the environmental regulatory burden on coal fired units, but these units will still face environmental regulations on air emissions and coal combustion residuals (CCR) disposal that increase the cost of running these units in comparison to other forms of energy.

To comply with Sections 316(a) and (b) of the Clean Water Act ("CWA"), Duke states it will likely need to install a closed-cycle cooling system to limit the impacts

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[3] US EPA Fact Sheet, Carbon Pollution Standards for Fossil Fuel-Fired Power Plants Final Rule; https://www.epa.gov/system/files/documents/2024-04/cps-111-fact-sheet-overview.pdf.
[4] 40 C.F.R. Part 60, Subpart UUUUa §§60.5700a-60.5805a (https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-60/subpart-UUUUa).
[5]https://www.epa.gov/stationary-sources-air-pollution/nonregulatory-public-docket-reducing-greenhouse-gas-emissions.
[6] US EPA Fact Sheet, Carbon Pollution Standards for Fossil Fuel-Fired Power Plants Final Rule, State Plan; https://www.epa.gov/system/files/documents/2024-04/cps-111-fact-sheet-state-plans-2024.pdf

to aquatic life at Cayuga.[7] Duke does not explain why such a system will be required for the existing coal units but not also required for a new CCGT constructed onsite. These requirements apply to all steam-fired generating units, including the heat recovery steam generating portion of a CCGT unit. Duke provides no compliance cost comparison for CWA Sections 316(a) and (b) compliance to burn coal versus replacement with natural gas-fired units at Cayuga. Gibson already has a closed cycle cooling system in place, so this is not an issue for the Gibson units.

The full impact of environmental compliance costs used in the IRP modeling is unknown. In addition to any potential increased costs from CWA Sections 316(a) and (b), continuing to burn coal would have increased environmental compliance costs due to coal combustion residuals disposal and continued operation of emission controls for sulfur dioxide, mercury, and other air toxics. These costs would not be required for natural gas burning units. Duke modeling inputs do not provide a breakdown of environmental fixed operating and management costs ("FOM") and environmental capital expenditures costs ("CAPEX"). The modeling data shows a significant reduction in these expenditures across multiple scenarios after the closure or conversion of coal units,[8] but the exact cost impact associated with each regulation cannot be determined from the materials Duke supplied.

Load Modifiers

Duke identified three primary uncertainties in its load forecasts: 1) EV adoption, 2) BTM solar adoption, and 3) economic development. Duke developed three cases for load forecasts: Low, Base, and High.

EV Adoption:

With changing administrations and slowing EV sales, Duke's projected EV adoption forecast appears overly optimistic.[9] Among Duke's 792,000 residential customers, each household possesses, on average, between two and three cars. Duke's EV forecast appears to assume about 75% of Duke's current residential customers are expected to replace one car with an EV by 2040. Duke states, "In 2023, ~7.5% of new vehicles sold in the U.S. were electric, compared to ~5.9% in 2022 and ~3.2% in 2021. This adoption trend is expected to continue and accelerate, especially considering federal initiatives, automaker goals, and the federal goal to have EVs make up at least 50% of new vehicle sales by 2030.[10] This is a very optimistic goal as well. While current federal incentives and regulations are aimed at improving EV sales, future policy changes or shifts in political leadership may impact EV adoption rates. Duke's EV model assumes the federal incentives stay

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[7] Duke 2024 IRP, Short Term Action Plan, p. 16.
[8] Duke 2024 IRP, Confidential Attachment, 111 Generation Strategies and No 111 – Ongoing CAPEX – FOM.
[9] https://apnews.com/article/stellantis-joint-venture-battery-plant-loan-kokomo-cc31d5f903e10d493b6ae9ea4663fa5e
[10] Appendix D: Load Forecast, p. 361.

consistent through the entirety of the forecast. The OUCC recommends Duke account for potential changes and/or improvements/enhancements to the existing policies such as changes to the Inflation Reduction Act ("IRA") in different scenarios. Duke also needs to consider the rate of the U.S. charging network expansion. Additionally, charging stations in the U.S. have an average reliability score of only 78%, meaning that about one in five do not work.[11] Therefore, network reliability would need to improve for customers to adopt EVs at this rate.

While automakers have announced ambitious EV targets, they are struggling with production challenges, battery supply chain issues, and fluctuating customer demand. Several major automakers such as Ford and GM have already scaled back their EV rollout plans. In July 2024, GM reduced its 2024 EV production forecast, lowering the upper estimate from 300,000 to 250,000 units. Toyota also announced it is postponing its plans to build EVs in the U.S. from 2025 to 2026, in addition to lowering its goal by 500,000 EVs.[12] With these industry setbacks, Duke's projection of reaching just over 600,000 EV units by 2040[13] is overly optimistic.

Regarding the charging behavior and load profiles, the forecast integrates charging load shapes based on national tools and averages. While this is beneficial, it may not accurately represent the specific conditions in Indiana. Incorporating data from Duke's ongoing managed charging pilot programs to refine the load profiles for peak demand forecasting will help improve Duke's forecast. The OUCC recommends Duke include local adoption barriers or facilitators such as charging infrastructure availability and urban-rural adoption disparities beyond the data provided by NREL, VAST, EVI-Pro, etc. While this data is comprehensive, Duke's forecast would benefit from incorporating more regionally specific data.

BTM Solar Adoption:

It appears Duke did not use a sigmoid annual growth rate as it did with EV adoption. Instead, it assumed a linear relationship. Anticipated rising energy costs and trending downward solar panel costs could lead to accelerated BTM solar adoption, so assuming linear BTM growth may understate its impact on reducing Duke's load. Greater BTM adoption could offset the significant projected load growth from EVs.

Economic Development Activity:

Unlike previous IRPs, Duke performed an ex-post modification to the energy forecast for economic development activity. Duke's load forecasting team screens potential economic site openings based on a sizing threshold of 20 MW and project

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[11] The state of EV charging in America: Harvard research shows chargers 78% reliable and pricing like the 'Wild West': https://www.hbs.edu/bigs/the-state-of-ev-charging-in-america

[12] Automakers that pushed back EV goals and plans in 2024: https://www.foxbusiness.com/markets/automakers pushed-back-ev-goals-plans-2024.

[13] Appendix D: Load Forecast, p. 365.

maturity. The largest potential projects were added to the energy forecast. These were scaled down to reflect these plans are uncertain and some of the economic development may already be incorporated into Moody's service area forecasts. The OUCC agrees with Duke's approach of reducing the size of possible economic development projects within different scenarios to capture the uncertainty relating to whether projects actually come online. This in turn leads to a more accurate load forecast. For the Low load forecast, Duke assumes 25% of these screened economic development projects will be realized; for the Base load forecast, Duke assumes 60% will be realized; and for the High load forecast, Duke assumes 90% will be realized. The following table shows adjustments Duke made to the Base forecast reflecting economic development:[14]

Table D-5: Adjustments in the Base Load Forecast for Large Site Developments Year	**Adjustment (MWh [sic])**
2024	399
2025	917
2026	1,538
2027	2,055
2028	2,087
2029-2044	2,081

However, it appears the above Table D-5 contains an error showing megawatt-hours ("MWh") instead of anticipated gigawatt-hours ("GWh"). In terms of MWhs, 399 to 2,081 will make very little difference to load, and so it seems this table should reflect GWh. In addition, while economic development adjustments are provided in MWhs, it is unclear how these additions contribute to the system peak. The OUCC recommends Duke include peak MW additions for the economic development projects to show the system-wide impact of these projects. If these values in MWh were used in the load forecast for the preferred portfolio modeling, they should be corrected to properly capture economic development activity.

Large Load Customers

Duke did not adequately evaluate the emerging issue of hyper-scalers or large load customers / data centers ("DC"). The current Meta data center development in its service territory was not included in Duke's base analysis. Duke tested only 500 MW of new data center load sensitivity. Duke completed four of its five IRP stakeholder meetings before it became apparent that Indiana could become the home to larger DCs. Not long after Duke's November 1, 2024, IRP submission, Meta announced it was considering six phases at the LEAP Lebanon Innovation

[14] Table D-5, p. 356.

District.[15]

The OUCC recommends better characterization of market potential for large load customers and testing new large load demands. This could be achieved with higher load sensitivity analyses adding multiple 500 MW to 1,000 MW data centers loads in increments up to a total of 5,000 MW.

Historical Data Integrity

The OUCC also discovered historical data in this 2024 IRP that differs from what was provided in the prior 2021 IRP, detailed in Appendix C – Section 4. In the current 2024 IRP, Duke reports:[16]

Table D-12: Historical Actual System Peak, Generation, and Load Factor

Year	System Peak (MW)	Total System Generation (MWh)	Load Factor
2013	5,703	31,567,683	63.19%
2014	5,728	32,696,951	65.16%
2015	5,807	33,226,985	65.31%
2016	6,165	34,138,499	63.04%
2017	5,699	32,112,787	64.33%
2018	5,795	33,282,230	65.56%
2019	5,876	31,732,228	61.65%
2020	5,746	30,450,488	60.33%
2021	5,952	31,328,230	60.09%
2022	5,938	31,896,082	61.32%
2023	5,930	29,499,157	56.79%
2013-2023 Growth	227	-2,068,527	-0.89%
2013-2023 CAGR	0.26%	-0.68%	-1.72%

[15] Meta set to develop 1,500-acre data center campus outside Indianapolis, Indiana; https://www.datacenterdynamics.com/en/news/meta-set-to-develop-1500-acre-data-center-campus-outside-indianapolis-indiana/

[16] Table D-12, p. 371.

However, Duke's 2021 IRP reports the following historical values (note that Summer Actual MW corresponds to the System peak):[17]

2021 IRP				
Year	Energy Actual GWh	Energy W/Normal GWh	Summer Actual MW	Summer W/Normal MW
History:				
2011	33,625	33,749	6,749	6,490
2012	31,028	31,369	6,494	6,510
2013	33,104	34,106	6,229	6,461
2014	32,063	31,728	5,830	6,084
2015	32,131	32,003	5,863	6,008
2016	32,318	32,267	6,079	6,181
2017	32,097	32,039	5,838	6,049
2018	31,532	31,547	5,904	5,895
2019	32,191	31,964	5,896	5,686
2020	31,447	31,678	5,755	6,029

The GWh energy and peaks do not line up, which is puzzling since these are historical numbers. For instance, Duke's 2024 IRP reports the 2013 peak as 5,703 MW, while the 2021 IRP reports the 2013 peak as 6,229 MW. Historical data is crucial for developing a baseline for the load forecast. While the load forecast is future oriented and incorporates more than a utility's historical data, historical data is a part of what is used to determine future rates of growth within the different rate classes. In addition, the IRP process is valuable as a record of where a utility is at a particular point in time, which is useful even when an IRP is superseded by the next edition. These values allow stakeholders to see how the utility's needs have evolved over time, and this is undercut when Duke uses different "actual," historical system usage between IRPs.

Analysis of The Five Pillars

Reliability, Resiliency, and Stability:

New to this IRP, Duke introduced "Enhanced Reliability Evaluation" modeling to assess whether Duke's candidate portfolios can maintain reliability and meet capacity obligations in light of the evolving resource mix of the wider MISO market. Duke describes that traditional conventional resource planning sought to accommodate peaks and valleys of customer electricity demand, but "with the evolution of the projected resource mix in MISO, available energy from these resources will vary with time and weather. Remaining electricity demand, after accounting for that variation, must be served in real-time by dispatchable sources

[17] Duke 2021 IRP, Sec. 5. (A)(3), p. 153.

to maintain system reliability."[18] Furthermore, Duke describes increasing operational uncertainty associated with renewable generation, stating that because of "unavoidable uncertainty" in day-ahead and real-time weather forecasting, future forecast errors are predicted to grow, and Duke will need adequate resources to prepare for this uncertainty.[19] In order to evaluate the candidate portfolio's ability to meet customer demand under a range of futures, Duke made use of the same model used in the Midcontinent Independent Service Operator's (MISO) probabilistic analysis, the SERVM.[20] While Duke's owned generation will be dispatched by the MISO, the SERVM model allows Duke to assess how its portfolio would perform under a range of weather patterns, unit availability, economic load forecast errors, and hourly dispatch availability. This allows Duke to estimate the Expected Unserved Energy ("EUE") or, in other words, how much customer demand would not be served if Duke's energy system was isolated from the wider MISO market. While it is unlikely that there will be no imports available from the market, this analysis allows Duke to determine how much its portfolios rely on market purchases and whether it makes disproportionate demands on MISO's electrical system relative to comparably sized companies. This approach marks an improvement from Duke's 2021 IRP and should be continued in the future.

While the Enhanced Reliability Evaluation also demonstrates the resiliency and stability of the portfolios Duke modeled, the OUCC recommends incorporating a range of assumptions regarding the availability of natural gas into Duke's reliability modeling to better address these Pillars. As MISO's generation mix evolves to include a larger portion of gas resources, there will be greater demand for natural gas that can affect whether a generator will be available for dispatch in extreme circumstances. Both Winter Storm Uri in 2021 and Winter Storm Elliot in 2022 highlighted the important role natural gas deliverability plays in grid reliability. With Winter Storm Elliot, PJM operators had to implement emergency procedures and a public appeal to reduce energy use to maintain reliability in the PJM footprint. Many gas generators expected to be available to meet the load were unable to comply with dispatch orders due to natural gas supply limitations. With Duke's preferred portfolio containing a significant addition of new natural gas fueled generation, it is important to account for the risk of natural gas supply disruptions during cold weather events.

Affordability

Duke measured affordability through two metrics: PVRR and project customer bill Compound Average Growth Rate ("bill CAGR"). The PVRR is intended to measure the long-term cost to customers, and the bill CAGR is intended to capture the near-term impacts to customers. For example, the Retire portfolio shows the

[18] Duke Energy Indiana 2024 Integrated Resource Plan, Volume 1, p. 399.
[19] *Id.*, p. 401.
[20] *Id.*, p. 406.

lowest PVRR of all portfolios but has the highest bill CAGR in 2035.[21] The resulting PVRRs and bill CAGRs show little variability among the portfolios, meaning one portfolio does not appear to have a clear cost advantage over others. However, the OUCC notes that Blend 1, where Cayuga Units 1 and 2 would be converted to natural gas rather than be replaced by a CCGT, has the second lowest PVRR, the second lowest bill CAGR in 2030, and the lowest bill CAGR in 2035.

Projected bill CAGR, taken from Duke's IRP, assumes the base rate amount on a typical residential bill will compound 4% from 2025 until 2030 and 3.1% from 2025 to 2035. The table below shows the projected base rate cost increase until 2035 of a 1,000-kWh electric bill for Duke's Preferred Portfolio (Blend 2).

<table>
<tr><th colspan="8">Table OUCC-1: Duke Future Electric Base Rate</th></tr>
<tr><td colspan="8">1000 kWh Residential Bill</td></tr>
<tr><td>Rate Change</td><td rowspan="2">March 2024</td><td>25.75% Rate Case</td><td rowspan="2">March 2025</td><td>4.0% CAGR</td><td rowspan="2">March 2030</td><td>3.1% CAGR</td><td rowspan="2">March 2035</td></tr>
<tr><td>Amount Change</td><td>$33.72</td><td>$35.69</td><td>$23.12</td></tr>
<tr><td>Total</td><td>$130.99</td><td></td><td>$164.71</td><td></td><td>$200.40</td><td></td><td>$223.52</td></tr>
</table>

The initial figures in this chart are based on Duke's current tariff and Step 1 Compliance Filing in IURC Cause No. 46038, and do not include trackers. However, the base rate figures alone paint a concerning picture regarding the preferred Blend 2 Portfolio Strategy's impact on bill affordability, as they show the potential for base rate increases totaling more than 70 percent within the next 10 years.

Environmental Sustainability

The OUCC appreciates that Duke based its assessment of CO_2 reductions using 2025 as a benchmark instead of a past year such as 2005. Using 2025 as a benchmark more clearly shows the attributable CO_2 emission reduction for each portfolio by not incorporating reductions that have already occurred through coal unit retirements made in the last decade.

Duke also appeared to take some stakeholder feedback to retire coal fired generation faster and add more renewable generation and battery storage resources through adding the Exit Coal Earlier (Stakeholder) generation strategy to its analysis. Even though the Company did not select this portfolio as its preferred resource plan, Duke showed a willingness to work with those stakeholders to incorporate their environmental sustainability concerns into Duke's IRP analysis.

It appears Duke considered the cost impact of environmental regulations assumed

[21] Duke 2024 IRP, Vol. 1, pp. 133-134.

for each of its portfolios. The 111 Rule drives the retirement dates for Duke's portfolios, and CWA Sections 316(a) and (b) also impact continued operation at Cayuga Units 1 and 2. However, as noted earlier, the OUCC recommends Duke provide clearer details on the costs associated with CWA Sections 316(a) and (b) compliance both for Cayuga Units 1 and 2 to remain operating as steam units and a new CCGT at the Cayuga site.

Conclusion

The OUCC appreciates the opportunity to submit these comments.