Draft Director's Report
For Hoosier Energy's 2023 Integrated Resource Plan

April 28, 2025

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Draft Director's Report Applicable to Hoosier Energy's 2023 Integrated Resource Plan and Planning Process

I. PURPOSE OF IRPS

Hoosier Energy Rural Electric Cooperative's (Hoosier Energy's) 2023 integrated resource plan (IRP) was submitted on April 2, 2024. By statute[1] and rule, integrated resource planning requires each utility that owns generating facilities to prepare an IRP and make continuing improvements to its planning as part of its obligation to ensure reliable and economical power supply to the citizens of Indiana. A primary goal is a well-reasoned, transparent, and comprehensive IRP that will ultimately benefit customers and the utility. At the outset, it is important to emphasize that an IRP is the utility's plan. The Director's report does not endorse the IRP nor comment on the desirability of the utility's "preferred resource portfolio" or any proposed resource action.[2]

The essential overarching purpose of the IRP is to develop a long-term power system resource plan that will guide investments to provide safe and reliable electric power at the lowest delivered cost reasonably possible. Because of uncertainties and accompanying risks, these plans need to be flexible as well as support the unprecedented pace of change currently occurring in the production, delivery, and use of electricity. IRPs may also be used to inform public policies and are updated regularly.

IRPs are intended to be a systematic approach to better understand the complexities of an uncertain future, so utilities can maintain maximum flexibility to address resource requirements. Inherently, IRPs are technical and complex in their use of mathematical modeling that integrates statistics, engineering, and economics to formulate a wide range of possible narratives about plausible futures. The utilities should utilize IRPs to explore the possible implications of a variety of alternative resource decisions. Because of the complexities of integrated resource planning, it is unreasonable to expect absolutely accurate resource planning 20 or more years into the future. Rather, the objective of an IRP is to bolster credibility in a utility's efforts to understand the broad range of possible risks that utilities are confronting.[3] By identifying uncertainties and their associated risks, utilities will be better able to make timely adjustments to their long-term resource portfolio to maintain reliable service at the lowest reasonable cost to customers.

Hoosier Energy, like every Indiana utility and stakeholder, anticipates substantial changes in the state's resource mix due to several factors[4] and, increasingly, Indiana's electric utilities are using IRPs as a foundation for their business plans. Since Indiana is part of a vast interconnected power system, Indiana is affected by the enormity of changes throughout the region and nation.

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[1] Indiana Code § 8-1-8.5-3.

[2] 170 IAC 4-7-2.2(g)(3).

[3] In addition to forecasting changes in customer use of electricity (load forecasting), IRPs must address uncertainties pertaining to the fuel markets, the future cost of resources and technological improvements in resources, changes in public policy, and the increasing ability to transmit energy over vast distances to access economical and reliable resources due to the operations of the Midcontinent Independent System Operator (MISO) and PJM Interconnection, LLC (PJM).

[4] A primary driver of the change in resource mix is due to relatively low-cost natural gas and long-term projections for the cost of natural gas to be lower than coal due to fracking and improved technologies. As a result, coal-fired generating units are not as fully dispatched (or run as often) by MISO or PJM. The aging of Indiana's coal fleet, the dramatic decline in the cost of renewable resources, the increasing cost-effectiveness of energy efficiency as a resource, and environmental policies over the last several decades that reduced emissions from coal-fired plants, as well as their economic value, are also drivers of change.

The resource portfolios emanating from the IRPs should not be regarded as being the definitive long-term plan that a utility commits to undertake. Rather, IRPs should be regarded as illustrative or an ongoing effort that is based on the best information and judgment at the time the analysis is undertaken. The illustrative plan should provide off-ramps to give utilities maximum optionality to adjust to inevitable changing conditions (e.g., fuel prices, environmental regulations, public policy, technological changes that change the cost effectiveness of various resources, customer needs, etc.) and make appropriate and timely course corrections to alter their resource portfolios.

II. INTRODUCTION AND BACKGROUND

Hoosier Energy is comprised of 18 rural electric membership cooperatives (REMCs) or "distribution cooperatives" serving 48 counties located in central and southern Indiana and 11 counties in southeastern Illinois. The number of residential customers increased from 277,913 in 2010 to 286,480 in 2019. Hoosier Energy projects that the number of residential customers will increase 9.7 percent to 314,217 by 2040. The total number of commercial and other consumers grew from 13,683 in 2010 to 14,868 in 2019. The number of commercial and other consumers is forecasted to increase 18 percent to 17,542 in 2040. The total number of consumers from the industrial sector, which is defined as loads requiring greater than 1,000 kVA, increased from 197 to 232 during the 2010 through 2019 period, for a net gain of 17.8 percent. The forecast number of 226 consumers in the year 2040 indicates a decrease of 2.6 percent. *(See Hoosier Energy IRP, p. 12)*

Hoosier Energy operates within both the Midcontinent Independent System Operator (MISO) and the PJM Interconnection, LLC (PJM) regional transmission organizations (RTOs) to provide reliable and economic power that Hoosier Energy could not achieve on its own. Hoosier Energy stated, "Membership in the regional transmission organizations allows reliance upon the RTOs' reliability tools, such as the state estimator, real-time contingency analysis and regional outage coordination. In addition, membership in the RTOs allows management of generation facilities that are connected to other RTO utilities but still benefit Hoosier Energy." (*See Hoosier Energy IRP, pp. 205-206*)

III. PRIMARY AREAS OF FOCUS

The Director's primary areas of focus include the interrelated topics of load forecasting; demand-side management (DSM), which includes energy efficiency (EE) and demand response (DR); resource optimization and risk analysis; and the treatment of the Five Pillars.

A. Load Forecast

Hoosier Energy complies with the Rural Utilities Service (RUS) requirements for a *Power Requirements Study* (PRS) that is done on a two-year cycle. The development of the PRS is a joint effort between Hoosier Energy's staff and its member systems, with contributions and review from RUS. The PRS provides an analysis of the need for electric energy and demand for the territory served by Hoosier Energy's member systems over a 20-year period. *(See Hoosier Energy IRP, p. 20)*

Econometric models were developed for each member system's residential and commercial energy use, peak demands, and number of consumers. According to Hoosier Energy, the residential energy models are statistically adjusted end-use models and were specified to include these factors: average use, real average price, service area real per capita income, heating and cooling degree days, energy efficiency codes and standards, and service area population and households. Future values of these variables are based on various government sources, consulting firms as well as local area knowledge provided by REMC representatives. (*See Hoosier Energy IRP page 20*)

The Commercial Energy Model was specified to include average use and customer growth. Commercial consumer growth was directed by economic drivers (examples: total employment, non-manufacturing employment, gross domestic product, etc.) that Hoosier Energy thought best aligned with past growth patterns. Future values of these variables are based on various government sources, consulting firms as well as local area knowledge provided by REMC representatives. (*See Hoosier Energy IRP, p. 20*)

Results from the residential energy model and the commercial energy model were combined with projections for growth in the industrial and other sectors to provide a forecast of total energy sales for each member. Aggregation of the members total energy sales, adjusted for distribution line losses, yields the total member-system energy purchases. (*See Hoosier Energy IRP, p. 20*)

Five energy forecast scenarios were developed to examine each of the members' requirements and their sensitivity to weather variances and economic conditions. The five scenarios are Base-Normal case, Base-Severe case, Base-Mild case, High-Normal case, and Low-Normal case. All load cases are presented with DSM impacts included. The Base-Severe and Base-Mild are the energy extreme weather sensitivity cases, while the High-Normal and Low-Normal cases represent varying economic conditions. Economic variation in the models was simulated via the variation of the member-specific economic drivers for the residential and commercial classes. The results of each scenario were aggregated to provide different scenarios for Hoosier Energy as a whole. (*See Hoosier Energy IRP, p. 20*)

The method used to develop the demand forecast aggregates the individual member 60-minute coincident system demand forecast. The total generation demand results were developed by combining the Hoosier Energy 60-minute demand results (excluding the special "pass-through" contractual peak) and transmission losses. The individual member-system peak demands forecast coincident and non-coincident peaks were developed using a statistical model driven by the electric energy forecast and peak producing weather. (*See Hoosier Energy IRP, pp. 21-22*)

Four additional scenarios were developed according to RUS standards. Hoosier Energy defined the scenarios as Base-Severe, Base-Mild, Low-Normal, and High-Normal. These reflect Base, High, and Low economic conditions and Normal, Severe, and mild weather conditions. Normal weather is a 30-year average; Severe and Mild weather are based on a one in ten scenario. Base economics used Woods and Poole's long-term forecast, created in 2021, and the High and Low economic forecasts capture faster and slower than anticipated economic growth. (*See Hoosier Energy IRP, p. 22*)

Hoosier Energy developed an upper bound on peak demand. The Base-Extreme case reflects the third coldest day in the last 30 years for the peak winter month and, similarly, the third hottest day in the last 30 years for the peak summer month. Hoosier Energy says the system is relatively balanced between the winter and summer peaks. That extreme weather can easily cause the system's peak season to swing. (*See Hoosier Energy IRP, p. 22*)

Based on the results, Hoosier Energy states the winter seasonal peak demand requirements will be the dominating factor from 2020 through 2040. (*See Hoosier Energy IRP, p. 22*)

According to Hoosier Energy, future load uncertainties include electric vehicle (EV) adoption and distributed generation installations such as solar and battery storage. Hoosier Energy says EV adoption rates are low and have no clear trend. Therefore, the impacts on the short-term range of the load forecast are expected to fall well within the alternative scenarios presented. Current distributed generation technologies are tracked within the service territory and are considered in the residential energy model. Hoosier Energy argues the current levels of distributed energy resources (DER) adoption do not have a statistically significant impact on the energy model. (*See Hoosier Energy IRP, p. 35*)

Director's Comments – Load Forecasting

While the figures and tables in the load forecast section provide a lot of information on the results of the forecast, there is little information on the details of the models and the projections for the model drivers. The modeling is done at the member level, so providing details for each member's models is probably not realistic. Regardless, more information would be desirable. For example, other Indiana utilities provide the complete load forecast report as an appendix to supplement a reasonably detailed discussion in the body of the IRP document of the load forecast methodology, data requirements, and major sources of load uncertainty.

Hoosier Energy's residential sales model is the summation of each individual member's econometric residential model. The modeling approach seems to have changed since the last IRP. In the 2020 IRP, Hoosier Energy detailed a residential model consisting of three equations: average residential use, average residential price, and number of residential customers that were solved simultaneously. In the 2023 IRP, these equations seem to have been replaced with Itron's statistically-adjusted end-use (SAE) models. The SAE models account for average use, real average price, service area real per capita income, heating and cooling degree days, energy efficiency codes and standards, and service area population and households. Itron's usual document explaining SAE models was not included in the IRP and it should have been for readers not familiar with them.

At a general level, the specific end uses modeled in the SAE models are not provided.

The commercial sales per customer are based on average use per customer, but no other detail is provided, and it does not appear to account for heterogeneity of building type and size. It is evident from Table 3 (*See Hoosier Energy IRP, p. 39*) that commercial use per customer varies throughout the forecast, since the customer count forecast and the energy forecast do not have identical growth rates. Table 3 also indicates that the use per customer varies across the low, base, and high economic scenarios, while the weather-based sensitivities do not affect sales in the commercial sector.

There are no details provided on how the industrial and "other" forecasts are created aside from stating that industrial is customized for each customer based on knowledge provided by the member system and "other" is a simple trend and judgment process. These "analyst judgment" forecasts may be reasonable in the short term but are not likely to have much value over the long term. The 2020 IRP contained language explaining the reasoning for using an informed judgment approach. The language has been removed from the 2023 IRP, but the heavy use of informed judgment has not.

Also, the number of industrial customers drops in the forecast despite robust growth in the last ten years of history. Table 3 shows that the forecast of the number of industrial customers and the electricity use per customer do not vary across scenarios.

High-Normal and Low-Normal are economic scenarios capturing faster or slower economic growth than the Base-Normal scenario. The economic scenarios seem to only apply to the residential and commercial models. This is likely because the industrial forecast is developed using informed judgment, but it also highlights the limitations of that approach. Industrial energy consumption would also be affected by changing economic conditions.

Seasonal demands are produced for each member system. The peak forecasts are based on a statistical model that uses the energy forecast and peak producing weather as drivers. Peak producing weather comes from modeling historical peak demand and weather data. There is no explanation of how peak producing weather is determined in the body of the report or even a reference to where it can be found; however, it can be found in Appendix B in a document provided by Itron.

There is very little information provided about the peak models and, strangely, there is slightly more in the Executive Summary than the body of the report.

Overall, the load forecast write-up in the 2023 IRP has noticeably less detail on the models than in Hoosier Energy's 2020 IRP.

B. Energy Efficiency

The DSM programs available for inclusion in the IRP resulted from work with GDS Associates (GDS) and Summit Blue Consulting groups that prepared the 2023 DSM Market Potential Study (MPS). As in the previous two IRPs, GDS prepared the MPS report for Hoosier Energy. This report identified the list of potential energy efficiency (EE) and demand response (DR) resource options for residential and commercial/industrial customers. According to Hoosier Energy, these options were reduced to those resources that demonstrated economic viability, operational reliability, and enough flexibility to meet expected environmental standards.

<u>2023 DSM Market Potential Study</u>

The MPS assessed the potential to reduce electric consumption and peak demand through the implementation of DSM measures throughout Hoosier Energy Members' service territories over 20 years (2024-2043). Three types of DSM potential were distinguished in the study: (1) technical, (2) economic, and (3) achievable. There were two types of achievable potential: maximum (MAP) and realistic (RAP). Based on the results of the analysis for RAP, GDS and Hoosier Energy developed estimates of program potential savings from EE and DR. Then, benefit/cost screening tools were used to assess the cost effectiveness of the DSM measures.

For the residential sector, a bottom-up approach was considered for modeling, whereby measure-level estimates of costs, savings, and useful lives were used as the basis for developing the potential estimates. Program design and budget constraints were then factored into these estimates. Similarly, for the commercial/industrial sectors, a bottom-up modeling approach was used to first estimate measure-level savings and costs, and then cost-effective measure savings were applied to all applicable shares of energy load. For the analysis, utility non-incentive costs (e.g., delivery, administrative, marketing, evaluation, etc.) were included in the overall assessment of cost-effectiveness for the MAP and RAP scenarios.

The initial step of the analysis was to define the appropriate market sectors, market segments, vintages, saturation data, and end uses. This information served to complete a forecast disaggregation and market characterization for all the sectors. For the development of the baseline forecasts, disaggregated forecasts were produced by sector and end-use. Then, the potential EE savings available, estimates of the current saturation of baseline equipment and EE measures were used to determine the equipment saturation. The remaining factor is the proportion of a given market segment that can still be converted into an efficient alternative.

The EE measures considered in this study included current in-use EE programs and additional measures based on existing knowledge and current databases of end-use technologies. In total, 332 measure types were analyzed where many measures required multiple permutations (2,179) for different applications, such as different building types, efficiency levels, and replacement options. For the DR measures, an analysis was conducted using the GDS DR Model, which determines the estimated savings for each DR program by performing a review of all benefits and costs associated with each program. This model was developed to determine the value of future programs and to help facilitate DR program planning strategies.

Finally, the program potential estimated in this study was a subset of the RAP and reflected constraints on the portfolio of offered programs and funding levels. The constraints were developed based on total incentive spending targets and expected interest in future program offerings. Program potential was calculated by assigning measures to different program-level offerings and scaling the achievable potential level incentive costs (and savings) down to the targeted incentive-spending levels. Measures/programs that were not selected for inclusion in the estimate of program potential were eliminated. The program potential was selected for inclusion in Hoosier Energy's IRP process.

Director's Comments – Energy Efficiency

Energy efficiency and demand response resources are hard coded into the planning model. Thus, EE and DR resources were not considered on a comparable basis with supply-side resources.

Comparable treatment requires a discussion about how the EE and DR might be organized into bundles. The use of bundles organized by cost, by similarity of load shapes, or other criteria to be modeled as a selectable resource within the optimization model would represent an upgrade to the current modeling approach.

There is little information on the assumptions used to determine the utility avoided costs and how these costs were used in the MPS to select the potential EE and DR measures for implementation. Hoosier Energy states the calculation of avoided demand and energy costs for the years 2024 through 2043 was based on the cost of a generic combustion turbine and consistent with the Indiana Utility Regulatory Commission's administrative rule methodology for a qualified facility. Were transmission and distribution costs considered in the avoided cost calculation? If yes, how much were these costs? How were these avoided T&D costs calculated?

C. Resource Optimization and Risk Analysis

Hoosier Energy for this IRP switched from its previous consultant, Charles River Associates and the Aurora optimization software, to a new consultant, Horizon Energy and the Encompass optimization software, to find the optimal portfolio to meet the projected demand for electricity.

Method

Hoosier Energy used three broad criteria to guide the resource planning process:

1. *Affordability and Stability*: Limit wholesale rates and provide a level of rate certainty over the 20-year planning horizon.

2. *Environmental Sustainability*: Limit environmental risk over the 20-year planning period.

3. *Risk and Opportunity*: Evaluation of resource portfolios for the risk and opportunity associated with cost exposure ranges in shifting environments, market interaction and exposure, and generation diversity.

These considerations were included in a scorecard to guide the planning process.

According to Hoosier Energy, another important consideration that guided the IRP development was reliability – the ability of Hoosier Energy's resource portfolio to provide operational reliability and grid stability.

Hoosier Energy developed seven scenarios representing seven potential future states of the world. The scenarios were built around the projected price of natural gas, the price of electricity in the wholesale markets, potential carbon regulation through the EPA Clean Air Act 111 rule, a potential carbon tax, and future generating technology costs. A high-level summary of each scenario is shown in the following figure and table.

Figure 1:

Status Quo	EPA Rule	Carbon Tax	EPA Rule + Carbon Tax	Aggressive Environmental	High Price Environment	Low Price Environment
• Tax credits per the IRA • No carbon legislation • Technology costs benchmarked to market • Base power and gas prices	• Capacity factor limits for new and existing resources per EPA 111(b) and 111(d)	• Federal Carbon Tax Starting in 2028	• Capacity factor limits for new and existing resources per EPA 111(b) and 111(d) • Federal Carbon Tax Starting in 2028	• Low Renewable & Storage Costs to reflect IRA extension, additional incentives • High natural gas prices with upstream regulations • EPA Rule • Carbon Tax starting in 2028	• High cost of replacement resources offset IRA benefits • High natural gas prices • EPA Rule • No Carbon Tax	• Supply chain, inflationary pressure subside by 2025 • Low natural gas prices • Tax Credits extended per IRA

Table 9: Scenario Assumptions

	Natural Gas Prices	Renewable & Storage Cost	Carbon Tax	EPA
Status Quo	Base	Base	-	No
Base + EPA 111(b)	Base	Base	-	2030
Carbon Tax	Base	Base	2028	No
Carbon Tax + EPA	Base	Base	2028	2030
Aggressive Environmental	High	Low	2028	2030
High Price Environment	High	High	-	2030
Low Price Environment	Low	Low	-	-

Additional scenarios were developed to evaluate the impact of different load forecasts using the Status Quo scenario assumptions.

The modeling framework produced seven unique portfolios; each portfolio optimized for one of the seven scenarios. Hoosier Energy was not faced in this IRP with having to make decisions around any retirements of existing or contracted resources.

For all portfolios, certain resources were locked in.

1. *Palisades Nuclear*: The 400 MW Palisades contract is in all portfolios and assumed to be online in 2026.

2. *Existing Natural Gas resources*: The Holland, Lawrence, and Worthington facilities are all expected to reach the end of their age-based life at the end of 2039.

3. *Lincoln Land Combined Cycle*: A 1,040 MW combined cycle facility under development in Sangamon County, Illinois. A 200 MW capacity-only power purchase agreement (PPA) with a 20-year term is assumed for each portfolio. The PPA is expected to begin in 2027.

4. *Invenergy Nelson PPA*: A capacity-only PPA with Invenergy's Nelson Energy Center in Rock Falls, Illinois is assumed in each portfolio. The PPA is expected to begin in 2026, with a capacity value of 157 MW and a 10-year term.

Hoosier Energy modeled these resources as best-case assumptions while saying the Palisades and Lincoln Land resource decisions are tentative and that there is a possibility that one or both could be replaced in the portfolio by other resources if Palisades and Lincoln Land prove uneconomic and fail to become operational.

The resource portfolios optimized for each set of scenario assumptions were locked and cross-run through each scenario. The idea was to see how portfolios would perform if the future was different than the conditions for which the portfolio was optimized. Table 18 contains 20-year present value of revenue requirement (PVRR) in millions for each portfolio and scenario combination.

Table 18: IRP Scenario Matrix (20-Year PVRR, $MM)

Scenarios →

Portfolios ↓	Status Quo	EPA Rule	CO2 Tax	EPA + CO2 Tax	Aggressive Environmental	High Price	Low Price
Status Quo	$7,792	$8,835	$8,343	$9,340	$10,205	$8,684	$6,896
EPA Rule	$7,970	$7,994	$8,400	$8,400	$9,042	$8,817	$7,150
CO2 Tax	$7,925	$8,626	$8,330	$8,626	$9,218	$8,743	$7,102
EPA + CO2 Tax	$8,038	$8,419	$8,409	$8,414	$8,941	$8,847	$7,241
Aggressive Environmental	$8,082	$8,107	$8,435	$8,445	$8,888	$8,897	$7,300
High Price	$8,122	$8,148	$8,528	$8,534	$9,255	$8,816	$7,320
Low Price	$7,759	$10,092	$8,330	$10,598	$11,397	$8,675	$6,838

Portfolios were evaluated using three categories of measurement:

1. Affordability and Stability
    a. Reference Case 20-year PVRR ($MM)
    b. 10-year average supply cost ($/MWh)
    c. 20-year average supply cost ($/MWh)

2. Environmental Sustainability
    a. Reference case cumulative carbon emissions
    b. Average carbon emissions across scenarios
    c. Percentage of zero-carbon generation

3. Risk and Opportunity
    a. Lowest PVRR across scenarios
    b. Highest PVRR across scenarios
    c. Average market interaction
    d. Maximum percentage of generation from a single resource type

The risk and opportunity category focused on cost exposure ranges in shifting environments, market interaction and exposure, and generation diversity.

Hoosier Energy recognizes that reliability is not included in the scorecard, but that it was important to understand the portfolios' impacts on operational reliability. Quanta Technology prepared a reliability analysis of the portfolios for Hoosier Energy. Nine reliability categories were evaluated to assess the ability of the portfolios to balance energy (ramping, dispatchability, and flexibility), the ability to control frequency (inertial response and primary response), the ability to provide adequate short circuit strength to integrate inverter based resources and mitigate flicker-induced concerns, and the ability to supply dynamic reactive power required by loads to avoid motor stalling and ensure rapid transient voltage recovery. According to Hoosier Energy, the analysis demonstrated that all scenarios scored relatively similarly with a demonstrated need for geographic proximity of generation to load.

Director's Comments – Resource Optimization and Risk Analysis

As much as 857 MW of capacity that comes online before 2027 is preselected outside of the optimization process, this would seem to minimize the value of the model optimization if such a large part of the portfolio is left outside of the process.

In regards to the 400 MW PPA with the Palisades nuclear power plant, given that the restarting of the plant is uncertain, as Hoosier Energy notes on page 182 of the IRP report, it would have been reasonable for Hoosier Energy to evaluate the implications of this uncertainty. One or more scenarios could have been run analyzing a significant delay in the commercial operation of the Palisades plant or even its never coming online. The projected 400 MW of the Palisades plant coming on in 2026 is so substantial that its potential absence is bound to have material effects on the supply mix of the preferred portfolio. The same is true, albeit to a lesser degree, of the 50 MW from the Clinton nuclear power plant.

Energy efficiency and demand response resources were hard coded into the portfolios, meaning these resources were not offered as a resource choice in the model optimization. Hoosier Energy explains this choice as based on its being a wholesale provider and not involved with retail customers.

Hoosier Energy's short-term action plan is vague. The three action items in Section 1.4 (*See Hoosier Energy IRP, p. 15*) seem more like a restatement of the IRP objectives.

1. Add reliable intermediate load resources through the changing dynamics of MISO's generation mix.

2. Balance market opportunities to meet short-term needs.

3. Create a balance between affordability and stability in order to mitigate regulatory risk exposure.

Once the preferred portfolio is determined, there is no discussion of the short-term action plan. The Director infers that this is because 757 MW out of 857 MW of supply-side resource additions through 2028 were locked in across all portfolios. This does not include the EE and DR resources locked in as well.

The discussion of the various metrics considered in the selection of the preferred portfolio is confusing. This confusion is in part because Hoosier Energy considered a wide range of factors that go well beyond the scorecard metrics. Consideration of a wide variety of metrics or "influences" on the preferred portfolio is desirable but does place a heavy burden on Hoosier Energy to present a thorough and well-organized discussion. A scorecard is primarily presenting metrics that can be quantified based on model outputs while any consideration of resource choices must account for those more qualitative factors.

The System Reliability Assessment of Hoosier Energy's 2023 IRP Portfolios by Quanta Technology has extensive information and analysis but is barely discussed in the IRP. The reliability assessment analyzed eight reliability attributes:

1. Resource Adequacy
2. Energy Adequacy
3. Operational Flexibility and Frequency Support
4. Short Circuit Strength
5. Power Quality (Flicker)
6. Dynamic VAR Support
7. Dispatchability and Automatic Generation Control
8. Predictability and Firmness of Supply

The Quanta study states that Hoosier Energy relies on the market to provide many of the required reliability services such as the dispatch of its resources, balancing its energy requirements, and frequency control. While some reliability services, such as frequency responsive reserves, voltage support, and short circuit strength, are local and not procured through a market, other services are planned by Hoosier Energy and approved by MISO. It is noted that most of the time the RTO markets work as planned and provide the required reliability services. However, according to Quanta, the available resources can be severely restricted during extreme weather or emergency events. Given this circumstance, Quanta states that the ability of Hoosier Energy to continue to serve its baseload customers needs to be assessed. Hoosier Energy does not appear to address this issue in the IRP.

The Quanta study focused on 2030 as a year when significant portfolio changes take place. Quanta notes a distinct feature of Hoosier Energy's portfolios is that much of the planned resources will be outside its service territory and demonstrate Hoosier Energy's reliance on tie line connections to external systems. This does not appear to be addressed in the primary IRP document except for Hoosier Energy stating in a single sentence that all scenarios demonstrated a need for geographic proximity of generation to load. (*See Hoosier Energy IRP, p. 201*)

Hoosier Energy stated that reliability was an important consideration that guided IRP development, but reliability was not included in the scorecard as a metric nor is the discussion of reliability coherent. The discussion of reliability is scattered across several locations in the IRP (*See Hoosier Energy IRP, pp. 171, 201, 205, and 209*), and there does not appear to be a single place where the different aspects of the reliability discussions are tied together.

D. Hoosier Energy's Consideration of the Five Pillars

Indiana Code section 8-1-2-0.6 declares five attributes of electric utility service, commonly called the "Five Pillars", that must be considered in decisions concerning, as applicable here, Indiana's electric generation resource mix. The Five Pillars are reliability, affordability, resiliency, stability, and environmental sustainability.

Consideration of the Five Pillars seems to be treated as an afterthought in the IRP report and analysis development process. Only two of the Five Pillars specified in the statute are explicitly represented in the scorecard metrics presented above. The two pillars are affordability (by metrics 1a-1c and 2a-2b) and environmental sustainability (by metrics 2a-2c).

As discussed above, reliability is briefly discussed in several locations but lacks a structure to provide insights or understanding for the reader.

The explicit discussion of the Five Pillars is contained in three short paragraphs on page 209. This conversation states that reliability and stability are addressed in the Quanta study for each portfolio but little more is said.

E. General Comments

The lack of a stakeholder advisory process places a significant burden on Hoosier Energy to provide a well written, thorough discussion of the IRP's methodology, data, assumptions, and models. More importantly, it is critical that Hoosier Energy helps the reader to understand how information at various steps of the process was used to inform the analysis and the selection of the preferred portfolio. The comments above note several places where information was not presented at all or was presented in a disjointed or confusing fashion. This is particularly the case when addressing the topic of reliability and the Five Pillars.

The IRP report also includes numerous mistakes that unnecessarily distract the reader from what is being presented. The following are several examples:

- Figures and tables mislabeled (Figures 30 and 31 on page 199 and Table 21 on page 205) or with the wrong title (Figure 1 on page 174).
- Figures included without titles or numbers (see pages 173 and 174).
- Tables/figures referred to in the text but located several pages later (Figures 30 and 31 are referred to in the text on page 176 but are located on page 199).
- Incorrect color ranking (Table 18 on page 198). The Low-Price portfolio is shown in dark green for the EPA Rule and the EPA + Carbon Tax scenarios despite having the highest PVRR. Similar issues occur elsewhere in the table.