Draft Director's Report

For CenterPoint Energy Indiana South's 2022/2023 Integrated Resource Plan

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on behalf of the Indiana Utility Regulatory Commission

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Draft Director's Report Applicable to CenterPoint Energy Indiana South's 2022/2023 Integrated Resource Plan and Planning Process

I. PURPOSE OF IRPS

Southern Indiana Gas and Electric Company, d/b/a CenterPoint Energy Indiana South (CEI South), submitted its 2022/2023 integrated resource plan (IRP) on May 26, 2023. By statute 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, the utility, and the utility's investors. At the outset, it is important to emphasize that these are the utilities' plans. In the report, the Research, Policy, and Planning (RPP) Director does not endorse the IRP nor comment on the desirability of the utility's "preferred resource portfolio" or any proposed resource action.

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. 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.

Every Indiana utility and stakeholder anticipates substantial changes in the state's resource mix due to several factors 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.

The resource portfolios emanating from the IRPs should not be regarded as being the definitive 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 & BACKGROUND

CEI South's preferred portfolio includes converting F.B. Culley 3 (270 MW) to natural gas by 2027, adding 200 MW of wind resources and 200 MW of solar by 2030, and an additional 400 MWs of wind generation between 2031 and 2032. The preferred portfolio also includes approximately 1.1% of energy efficiency (EE) in the period 2025-2027.

From the Director's perspective, CEI South, like most utilities across the United States, is addressing resource changes in an environment of extreme uncertainty regarding government policy, commodity prices, and technology. To better address these uncertainties, the 2022/2023 IRP included a couple of significant changes compared to the 2019/2020 IRP:

- CEI South used the EnCompass Power Planning Software for portfolio capacity expansion and production cost modeling.

- CEI South expanded the IRP scorecard evaluation metrics for portfolio evaluation, including the addition of more qualitative metrics addressing portfolio execution, resiliency, and stability.

Consistent with the issues discussed above, the Director's report will focus on four broad areas: (1) load forecasting; (2) assessment of demand-side resources broadly defined to include energy efficiency, demand response resources, electric vehicles, and distributed solar; (3) portfolio analysis and the consideration of risk and uncertainty on different resource portfolios; and (4) the Five Pillars[1] of reliability, affordability, resiliency, stability, and environmental sustainability.

III. LOAD FORECASTING

Load Forecast Methodology

CEI South's load forecasting documentation was provided by Itron as has been the case beginning with its 2016 IRP.

CEI South's long-term energy and demand forecasts are generated using a ground-up methodology in which customer class models for Residential, Commercial, Industrial, and Street Lighting determine system energy (after accounting for line loses) and then drive the peak demand model. The system energy and peak are adjusted for behind-the-meter residential and commercial solar adoption as well as electric vehicle charging impacts which is an approach that began with the 2019 IRP.

The residential average use and commercial sales models are statistically adjusted end-use (SAE) models which capture structural changes over time such as appliance ownership trends, efficiency improvements, housing square footage changes, and thermal shell improvements as well as changes in population, economic conditions, prices, and weather. The industrial sales model is a combination of informed judgment and an econometric model relating sales to industrial economic activity and seasonal patterns. The street lighting model is a simple trend and seasonal model.

Residential

The residential sales forecast is the result of a residential customer forecast multiplied by a residential average use per customer forecast from a monthly statistically adjusted end-use model. The customer model is a linear regression model driven by household projections for the Evansville

[1] *See* Indiana Code section 8-1-2-0.6 and IURC GAO 2023-04.

metropolitan statistical area (MSA). The residential use per customer model is a monthly statistically adjusted end-use model in which sales are a function of heating, cooling, other, and a demand side management (DSM) (EE) variable that captures historical DSM savings that are not captured in the other end-use variables. The end-use variables capture the interaction of end-use intensity projections, household characteristics such as size and income, electricity price, and heating and cooling degree days. The residential model also now includes a COVID variable based on Google Mobility Data to account for the jump in residential average use in 2020.

Excluding the impacts of energy efficiency programs, baseline average use per residential customer increases 0.4% annually through the forecast period. CEI South assumes that over the long-term, service area customer growth tracks household growth in the MSA which is larger than the CEI South service territory. The result is that customer growth is projected to be 0.4% annually over the planning period.

With both customers and average use growth at 0.4% annually, projected residential sales average 0.8% annual growth. This residential sales forecast is before adjustments for solar and electric vehicles (EVs).

Commercial
The commercial forecast is the result of a monthly statistically adjusted end-use model in which sales are a function of heating, cooling, other, and a DSM (EE) variable that captures historical DSM savings that are not captured in the other end-use variables. The commercial model, like the residential model, also now includes a COVID variable based on Google Mobility Data. The end-use variables capture the interaction of annual end-use intensity projections, a commercial economic variable, real electricity price, heating degree days (HDD) and cooling degree days (CDD), and DSM activity. The commercial economic variable incorporates the MSA gross domestic product (GDP), employment, and number of households.

The commercial baseline sales forecast for the period 2022-2042 is a compound annual growth rate of -0.2%. The baseline forecast does not include future DSM, solar self-generation, or electric vehicle charging.

Industrial
The industrial forecast is done in two steps. The first three years are based on CEI South's expectation of specific customer activity. They determine a baseline based on history and then adjust it based on expected closures and expansions or new customer additions. The forecast after the first three years is based on a generalized linear regression model relating monthly historical industrial billed sales to manufacturing employment, manufacturing output, CDD, and monthly binaries capturing seasonal load variation and shifts in data. Manufacturing employment and output are weighted in the model. The model excludes one large customer that is meeting most of its load through onsite cogeneration.

Excluding DSM, industrial sales average 1.1% average annual growth, driven by the addition of one large new customer in 2023. After 2025, industrial sales grow at an average annual rate of 0.3%.

Street Lighting
The street lighting forecast is the result of a regression model with a trend and monthly binaries. Projected streetlighting sales decrease at an 0.7% annual rate for the period 2022-2042.

Energy and Demand Forecast

The energy forecast is obtained from the sales forecast by applying monthly energy adjustment factors that account for line losses and any differences in timing of sales estimates and delivered energy (unaccounted for energy).

The peak demand forecast is a monthly linear regression model based on heating, cooling, and base use energy requirements from the class sales models as well as peak day weather conditions.

The final energy and peak forecast are obtained by adding solar and electric vehicle hourly forecast to the baseline forecast. This methodology is new to the 2022 IRP. The prior IRP used coincident peak load factors for photovoltaic (PV) and EV to estimate peak impacts.

Excluding DSM but including the impact of future customer-owned generation and EVs results in energy requirements and summer peak demand growing at an annual rate of 0.7% and winter peak demand growing at an annual rate of 0.5%.

Customer-Owned Distributed Solar

The customer-owned solar facility forecast used to adjust the energy and peak forecasts comes from a payback model that relates solar installations to the length of time required to recover the investment in solar. The payback is a function of system costs, federal and state tax credits, incentive payments, retail electric rates, and how excess generation is treated. CEI South notes that one of the biggest drivers of customer solar adoption is declining system costs. According to CEI South, residential solar system costs decreased from approximately $8.00 per watt in 2010 to $3.80 per watt in 2020. CEI South assumes solar system costs continue to decline 10% annually through 2024 and 3% annually after 2024.

Commercial installations are based on the current relationship between commercial and residential rates because there have been too few commercial installations to estimate a model like with the residential sector. The solar capacity forecast is then calculated as the product of the solar customer forecast and average system size. Monthly solar load factors are used to translate capacity into generation. The factors come from a typical solar profile for Evansville from the National Renewable Energy Laboratory (NREL). Installed customer-owned solar capacity is projected to increase from 1.8 MW in 2022 to 130.9 MW in 2042.

Electric Vehicles Forecasting Methodology

The electric vehicles forecast makes use of the U.S. Energy Information Administration (EIA) and BloombergNEF data and information on registered electric vehicles in CEI South's service area. Total vehicles are modeled as a function of CEI South's customers multiplied by EIA's vehicles per household. The number of electric vehicles is then calculated using EIA's projections of the saturation of battery electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEV) in the service area. EV weighted annual kWh use is calculated based on its current mix of electric vehicles. BEVs consume more energy than PHEVs. EV usage comes from the manufacturer's reported fuel efficiency. EV's impact on peak demand depends on the timing of charging. CEI South assumes most charging will occur during the evening hours since they have not incentivized customers to charge at other times.

Data Sources

CEI South's external data sources are reasonable.

Weather data for Evansville airport is from the National Oceanic and Atmospheric Administration (NOAA). Itron, again, as in the 2019 IRP, allows "normal weather" to change over time instead of holding normal weather constant over the forecast period as has been traditionally done. The trended weather assumption is supposed to capture recent weather activity. Normal HDD are allowed to decrease 0.2% per year while normal CDD are allowed to increase 0.5% per year.

Economic and demographic data is from IHS Markit's June 2022 forecast for the Evansville MSA and Indiana.

Historical electric prices are derived from CEI South's billed sales and revenue data.

Saturations and efficiencies are from EIA and Itron and have been modified to represent CEI South's service area using CEI South's appliance saturation surveys.

Director's Comments – Load Forecasting

The Director has the following observations:

- The inclusion of the DSM (EE) variable in the residential average use model began with its 2019 IRP. The 2019 and 2022 IRPs both include the language "the energy and demand forecasts do not include future DSM energy savings"; however, the 2019 IRP also states "incremental future DSM is then added back to the model results to arrive at an average use forecast that does not include the impact of future DSM" while the 2022 IRP does not include this language. This is unclear.

- The IRP on page 6 states that the residential model coefficients **bc**, **bh** and **bo** are estimated using linear regression, but it does not mention the coefficient on the DSM (EE) variable **be** for some reason. Why?

- The new residential COVID variable is mentioned in the text but does not appear in the residential equation in Figure 3.

- The new commercial COVID variable is mentioned in the text but does not appear in the residential equation in Figure 9.

- The commercial economic variable incorporates MSA GDP, employment, and number of households. The 2019 IRP showed an equal weighting for output and employment, but the 2022 IRP does not seem to specify what the weights are.

- As with the residential model, the language around how DSM is handled is unclear in the commercial model.

- The commercial write-up on page 14 states "does not include future DSM, solar self-generation, or electric vehicle charging" (since they are added later), but the residential section does not make this clear for residential even though it is also true of residential.

- The "informed judgment" part of the industrial forecast was the first five years in the 2019 IRP but is now only the first three years in the 2022 IRP. This can be viewed as an improvement.

- In the industrial model, manufacturing employment and output were equally weighted in the 2019 IRP, but in the 2022 IRP, employment is weighted 67% and output 33%. This is based on a statistical analysis of alternative weights but represents a significant change.

- The street lighting model was described in the 2019 IRP as "exponential smoothing model with a trend and seasonal component." In the 2022 IRP, it is described as a "regression model with a trend and monthly binaries." It is unclear if the model has changed or is the same.

- The new method for adding solar and EV impacts to the final forecast seems to be an improvement over the previous IRP.

- The electric vehicle forecast in the 2019 IRP used EIA data while the 2022 forecast uses an average of EIA and BloombergNEF.

- Economic data is now from IHS Markit instead of Moody's.

- Normal weather is allowed to vary over time so that HDD decrease while CDD increase.

The 2014 IRP contained low and high forecasts but the 2016, 2019, and 2022 IRPs do not. Were alternative forecast bands calculated?

The Director understands that alternative monthly peak load forecasts were developed based on probability distributions that describe uncertainty. 1898 & Co. developed a set of peak demand scenarios, ranging from low-end expectations to high-end expectations. A similar process was used for natural gas prices, coal prices, CO_2 prices, and renewables capital costs.

The Director recognizes that each utility service territory has a different economic and demographic outlook but thinks that load uncertainty will be an increasing issue across the state and nation. The drivers of this are the divergent impacts of distributed energy resources (DER) penetration, EVs, improving end-use energy efficiency, increased industrial development, and electrification in general. It is unclear to the Director whether the method used in the IRP to develop alternative monthly peak projections is adequate given the drivers that may be outside of historical experience.

IV. ENERGY EFFICIENCY AND DEMAND RESPONSE

2022 Market Potential Study (MPS)

The first step in the process is to prepare a market potential study (MPS). The intent is to find the EE measures having the greatest potential for energy savings and the measures that are the most cost-effective. The 2022 MPS used existing primary market research from the 2019 MPS for the commercial and industrial (C&I) sector for the saturation of energy-using equipment, building characteristics, and the percent of energy using equipment that is already high efficiency. The same research for the 2019 MPS was used to estimate customer willingness to participate in EE programs at different incentive levels and end uses.

The MPS evaluated two achievable potential scenarios: maximum achievable and realistic achievable. Maximum potential is based on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates. Realistic achievable is based on paying incentive levels close to historical levels.

The estimates of potential in the MPS exclude potential savings from customers that have opted-out of EE programs.

A demand response (DR) potential study was also conducted. The methodological approach for the DR potential study closely mirrored the EE analysis.

Energy Efficiency Modeling in the IRP

Energy efficiency for the 2023 and 2024 IRP years were informed directly from the 2021-2023 approved EE Plan (2023) and the anticipated one-year plan extension (2024). These years of EE were treated as a "going-in" resource in the IRP. CEI South used the realistic achievable potential (RAP) identified in the MPS as the starting point for EE to be modeled for the remaining IRP years (2025-2042). As in the 2019 IRP, for the bundling approach the GDS Associates provided the IRP DSM inputs across three sectors (residential, income-qualified, and C&I). Residential and C&I bundles were modeled as selectable resources in the EnCompass model. On the other hand, the income-qualified bundle was treated as a "going-in" resource due to its high costs which would likely prevent its selection in the model.

In addition to the sector segmentation, the annual bundles were grouped into three separate time periods. The different vintage bundles were: 2025-2027, 2028-2030, and 2031-2042. The purpose was to allow the model to optimize the value of EE over the different time periods.

Consistent with prior IRP DSM inputs, the model accounted for full lifetime savings of DSM bundles. For developing the initial sector-level bundles, CEI South applied two savings adjustments and one cost adjustment. The first adjustment converted the EE achievable potential from gross savings to net savings. Since the MPS savings are reported at the meter level, the second adjustment was to provide the program potential savings at the generator level using the average system line loss rate of 6%. On the cost side, GDS provided CEI South with EE costs that have been adjusted to net out the avoided transmission and distribution (T&D) benefit associated with DSM measures. This is done because the capacity optimization model does not calculate the avoided T&D benefit associated with DSM measures.

As another improvement for this IRP, GDS further segmented the residential sector savings into high-cost measures (Tier 2), and low/mid cost measures (Tier 1) across each vintage time-series due to concerns that an aggregate residential sector bundle would not be selected by the model. In addition, residential behavioral EE savings were also segmented into a third residential sector bundle due to its distinct one-year measure life. Then, as part of an iterative process, two further modifications to the sector level EE bundles were ultimately made. One created an additional "enhanced" RAP scenario that increased incentives for select lower-cost C&I measures, resulting in increased estimates of measure adoption. This change was made at the request of the CEI South Oversight Board. The adjustment was based on the overall favorable levelized cost-per-lifetime kWh saved associated with the C&I sector.

A preliminary model run resulted in neither Tier 1 nor Tier 2 residential sector bundles being selected. So, the residential sector bundles were redrawn by moving higher cost measures in the original Tier 1 bundle to the Tier 2 bundle. This change caused the first bundle to be economically selected in the IRP model.

It is important to note that the IRP model assessed the value of energy savings on an hourly basis. Hourly load shapes (across 8,760 hours) that account for various measures and end-use mix in each EE bundle were used in the IRP model. Thus, the 8,760 hourly load shapes are unique for each EE sector and vintage bundle. The shape data was based on the NREL End-Use Load Profiles database.

Demand Response

For demand response, five bundles were included for selection in the IRP Reference Case. The first bundle was included as a fixed adjustment to the total system load. The bundle included current DR capabilities accounting for the historical number of Direct Load Control (DLC) switches on residential A/C units. The second bundle consisted of residential DR-enabled smart thermostats (Bring Your Own Thermostats) above and beyond the current penetration of DR devices. The third bundle contains residential rate options, including critical peak pricing, peak time rebates, and time of use rates. The fourth bundle is based on additional C&I DR Bring Your Own Thermostats above and beyond the current penetration of DR devices. The last bundle is a critical peak pricing rate option for non-residential customers. In the model, the first bundle was a going-in resource; remaining DR options were modeled as a selectable resource.

How the Preferred Portfolio DSM is Used

CEI South states the IRP determines the appropriate level of DSM to include in the preferred resource plan, but the IRP cannot determine the specific programs to include in a DSM plan. To develop a DSM plan, CEI South uses a multi-step process to select programs that meet the level of savings in the preferred portfolio.

The final step of the DSM program development process involves the use of the DSMore cost/benefit modeling tool where the measures and programs are analyzed for cost effectiveness. This tool takes hourly prices and energy savings from the specific measures being considered for the EE program. Inputs into this tool include participation rates, incentives paid, energy and demand savings of the measure, life of the measure, avoided costs, implementation costs, incremental costs to the participant of high efficiency measures, escalation rates, and discount rates. The outputs included: participant cost test, ratepayer impact measure test, utility cost test (UCT), total resource cost test (TRC), etc. The avoided costs reflected the estimated replacement capital and fixed operations and maintenance (O&M) cost of a simple cycle gas turbine. Meanwhile, transmission and distribution capacity were accounted for within the T&D avoided cost. The marginal operating energy costs were based off the modeled system marginal energy cost from the base optimized scenario under base assumptions. This included estimated capital, variable O&M, and fuel costs. CEI South ensures the portfolio passes the TRC test.

Director's Comments – Energy Efficiency and Demand Response

It is worth noting the effort made by CEI South to incorporate adjustments and improvements to the modeling methodology for this 2022 IRP. The further segmentation of the residential sector savings into two cost tiers and the increase of incentives for some lower-cost commercial/industrial measures can enhance the selection and model representation of the actual EE savings programs. Allowing the IRP model optimization to select DSM bundles across two three-year periods 2025-2027 and 2028-2030 and then the period 2031-2042 improves the ability to account for changing cost-effectiveness and resource needs over the planning period. Lastly, greater attention to developing annual hourly load shapes by customer sector and measures enables better analysis of the timing impacts of different portfolios.

The improved consideration of hourly impacts is especially important given the increasing need to address the ability to provide energy across all hours in different seasons. The improved analysis of both EE and DR resources helps change load from being something taken as a given to increasingly something that can be adjusted or modified in the broader context of providing reliable and economic electric service.

The Director appreciates CEI South's willingness to evaluate alternative rate designs, but there is much required to adequately model price-based DR in IRP processes. Considerations include a thorough discussion of the following:

- The types of DR being considered.
- The types of rates.
- Transparency of participation rate assumptions for both opt-in and opt-out forms of DR.
- The assumed load reduction by rate type and customer class.
- The achievable potential of the price-based DR.
- The uncertainty of price-based DR and how it is evaluated.

V. SCENARIO/RISK ANALYSIS

Models

The EnCompass model was used as the central tool in the IRP. The long-term capacity expansion functionality within EnCompass was used to develop portfolios based on the given sets of market input assumptions and portfolio requirements. This includes decisions to build, purchase, or retire plants. The model also uses hourly chronological dispatch over a 20-year period, which means portfolio evaluations are based on all 8,760 hours each year over a 20-year span. This helps to better evaluate intermittent renewable and storage resources.

Method

CEI South started the IRP process with identified objectives. Each objective was quantified by specific metrics, which were used as the basis for evaluation in the balanced scorecard. CEI South then selected a Reference Case and four alternative scenarios for two purposes: The first purpose was to create a least cost portfolio for each of the five scenarios and the second was to test final portfolios against each of the market scenarios to determine how well they perform. In the end, four of the five optimized portfolios were screened out before the final evaluation. The four alternative scenarios are Market Drive Innovation, High Regulatory, Continued High Inflation and Supply Chain Issues, and Decarbonization/Electrification.

Portfolios were developed utilizing EnCompass modeling for the Reference Case, the alternate scenarios, and additional portfolios developed based on stakeholder feedback. Scenario-based portfolios (Reference Case, High Regulatory, Market Driven Innovation, Decarbonization/Electrification, and Continued High Inflation and Supply Chain Issues) were developed to evaluate various regulatory constructs, economic and market conditions, and technological progress. In addition to scenario-based portfolios, deterministic portfolios were created to test various solutions to key decisions needed from this IRP. For example, converting F.B. Culley 2 and/or F.B. Culley 3 to gas, retiring F.B. Culley 2 by 2025, and retiring F.B. Culley 3 by 2029, 2035, or continuing operations were all strategies included in deterministic portfolios. In addition to analyzing different outcomes for F.B. Culley 2 and F.B. Culley 3, A.B. Brown with and without the conversion of the new combustion turbines (CTs) to a combined-cycle gas turbine (CCGT) conversion was considered.

After the scenario-based portfolios and alternatives were created, they were screened to maintain a reasonable number of portfolios to run through the probabilistic risk analysis. Three different categories were identified to screen out portfolios. The first step in screening portfolios was to determine where there were portfolios with significant overlap in resource selection and to include only portfolios in the risk analysis that were different enough to provide insights between different resource options. Next, portfolios were screened based on their size compared to the needs of CEI South and its customers. The portfolio needed to meet seasonal capacity requirements while not significantly overbuilding generation, from either a capacity or energy basis. The final screening category was cost. Portfolios that were significantly higher on cost when run through the Reference Case were removed, along with portfolios that tested adding or replacing a specific resource and that decreased portfolio performance were screened out. After screening out portfolios, there were 10 portfolios left to be further evaluated in the risk analysis.

For risk analysis, all 10 candidate portfolios were modeled in a separate dispatch run for each of the five alternative scenarios first. Several sensitivities were performed on the candidate portfolios to determine whether and how results might change if isolated variables changed. The following sensitivities were valuated:

- Storage options received 85% of the full investment tax credit.
- Higher wind cost.
- Introduction of a carbon tax as a proxy for a potential change in legislation.
- A reduction of battery storage capacity accreditation from 95% to 75% for the period 2028-2037.
- A large industrial load being added in 2028 for the remainder of the planning period.

Additionally, EnCompass was run in a market simulation mode holding each of the CEI South portfolios constant but allowing the input assumptions to vary in each of the 200 draws.

Portfolio Metrics and Scorecard

CEI South developed a scorecard to compare the attributes and risks of the candidate portfolios. Most of the metrics were developed based on probabilistic modeling.

CEI South's IRP objectives were:

1. *Reliability:* The ability to support local system stability and reliably provide power by meeting Midcontinent Independent System Operator (MISO) and North American Electric Reliability Corporation (NERC) standards for reserve margins and resource adequacy. CEI South ensured all portfolios met expected planning reserve margin requirements in all seasons with resources able to meet demand and energy requirements in all operating hours throughout the year. This analysis was supplemented by consideration of the amount of resources with fast start capability and the amount of dispatchable resources with spinning reserve capability. CEI South also performed transmission planning analyses to consider voltage and reactive power support for various portfolios.

2. *Affordability:* The metric is the mean value for the 20-year net present value of revenue requirements (NPVRR). The NPVRR measures all generation related costs (for each asset, the cost of generation including capital, O&M, fuel, and the cost of power and capacity purchases, etc.) for a portfolio over a period.

3. *Cost Uncertainty Risk Mitigation*: The metric is the 95th percentile of NPVRR. According to CEI South, the 95th percentile (approximately two standard deviations above the mean value of NPVRR) is a commonly used benchmark to set a reasonable upper threshold of cost risk under widely varying market conditions. Another metric is the portion of energy generation exposed to gas and coal markets.

4. *Environmental Sustainability:* The metrics included estimated CO_2 emission intensity and CO_2 equivalent stack emissions.

5. *Market Overreliance Risk Minimization:* CEI South used the average annual energy sales and the average annual energy purchases, each divided by the average annual generation. CEI South also calculated the average annual capacity sales and the average annual capacity purchases, divided by average coincident peak demand.

Other metrics considered outside of the scorecard included:

6. *Resource Diversity*: According to CEI South, resource diversity helps to minimize dependence on any one resource type. Recognizing the difficulty of developing a measure to capture resource diversity, CEI South sought to develop portfolios that included a wide range of resource types and fuel sources.

7. *System Flexibility:* CEI South considered performance of resources with the ability to start and ramp quickly and be available for sustained periods when the sun is not shining or the wind is not blowing. CEI South also considered the transmission system and the ability to rely on the wholesale market. An important recognition is that the transmission capability is not unlimited and that transmission upgrades to maintain reliability are necessary for portfolios that use less traditional dispatchable resources.

8. *Resilience:* CEI South defines resilience as the ability of a portfolio to recover from off normal events, like extreme or long duration weather events. For this reason, all portfolios with new gas resources included costs for firm gas supply.

9. *Stability:* CEI South states stability is the ability of the portfolio to maintain system frequency and voltage, thermal limits, and power transfer capability. A portfolio must provide these functions.

10. *Execution:* This metric included an assessment of the challenges of implementing each portfolio.

Director's Comments – Scenario/Risk Analysis

Among the 10 candidate portfolios, only the Reference Case portfolio is a least-cost portfolio from the optimization model. All other portfolios were modified with hard-wired decisions before optimization was performed. As described in the IRP, at the beginning, there were five least-cost portfolios from the five scenarios. However, the Reference Case, Market Driven Innovation, and Decarbonization/Electrification portfolios had similar resource selections. Therefore, the Market Driven Innovation and Decarbonization/Electrification portfolios were removed from consideration because they did not provide any additional insights that could not be derived from the Reference Case portfolio. Later, the scenario-based portfolios (High Regulatory and Continued

High Inflation and Supply Chain Issues) were screened out due to being overbuilt compared to CEI South's capacity needs.

It seems that the scenario design of CEI South was not varying enough to represent different market conditions, resulting in very similar resource selections in various scenarios. In addition, all scenario-based portfolios had issues of overbuild in the near future, while maintaining a few hundred MWs of capacity purchases from the market. Looking closely at the Reference Case portfolio, there were surpluses of capacity in both summer and winter seasons, along with huge amounts of generation beyond need over time. Examining the balance scorecard on page 258, it is observed that the Reference Case portfolio had up to 42% market sales in the near term and 41% market sales in the long term. That means CEI South is adding capacity while being an exporter, indicating that there might be a disconnect between the market price as an input and the value that the model sees when it runs, so the utility acts as a merchant plant – it builds just to sell on the market. Based on the scorecard results, not just the least-cost portfolios, all other modified portfolios selected for risk analysis had the same issue, just at a different level.

For the preferred portfolio, it was stated in the IRP report that the preferred portfolio does not over-rely on either purchases or sales of energy or capacity. However, based on the balance scorecard on page 258, the average share of market purchases over total energy plus sales reached 24%, with 31% for the near term and 32% for the long term. Meanwhile, the average share of market sales over total energy plus sales was as high as 20%, with 24% for the near term and 27% for the long term. In addition, the average share of capacity market sales over the coincident peak demand reached 13%. On page 263, it is stated that "The reference case, generated by computer modeling, is overbuilt for CEI South customer needs and relies on vastly more market energy sales to lower the NPVRR well below all other portfolios. The Indiana Commission instructed that this is a risky proposition for a company of this size in Cause No. 45052. CEI South's preferred portfolio complies with this view." This statement acknowledged the issue with the modeling. Rather than fixing the model and letting the model shed insights regarding the planning process, the company just revised the results directly to comply with the Indiana Utility Regulatory Commission's instruction by saying "CEI South does not plan to convert either or both CTs to a combined cycle in the absence of a large load addition."

VI. THE FIVE PILLARS

As described above, the portfolio metrics and scorecard explicitly included the Five Pillars of affordability, reliability, stability, resiliency, and environmental sustainability. The discussion of the metrics and the scorecard results was helpful. Understanding how CEI South interpreted and applied the results is critical.

Indiana utilities use a set of performance metrics in a scorecard to compare and evaluate the performance of alternative resource portfolios to develop the preferred portfolio. All recent IRPs use a framework based on the five pillars or attributes as initially defined by Indiana's 21st Century Energy Policy Development Task Force and now embodied in law in 2023 in Indiana Code section 8-1-2-0.6 and the Commission's general administrative order, GAO 2023-04. It is important to keep in mind that the use of a scorecard by Indiana utilities to evaluate candidate resource portfolios long predates the 21st Century Energy Policy Task Force.

Using a scorecard to compare alternative portfolios across a range of metrics drives home that the metrics often conflict with each other. This is especially the case when considering affordability versus the other metrics.

<u>Affordability</u>
CEI South used the mean value for the 20-year NPVRR to evaluate affordability of the different candidate portfolios. The NPVRR measures all generation related costs (for each asset, the cost of generation including capital, O&M, fuel, and the cost of power and capacity purchases, etc.) for a portfolio over a period.

For cost uncertainty risk mitigation, CEI South used the 95th percentile of NPVRR, expressed in millions of dollars. Each candidate portfolio was subjected to 200 dispatch model runs and a distribution of the corresponding NPVRR portfolio costs was created. The 95th percentile was selected as it is seen as a reasonable upper threshold of cost risk under widely varying market conditions.

Director's Comments

The Director appreciates the debate over how best to analyze the affordability of the candidate portfolios. Evaluation of affordability requires judgment because it is contingent on maintaining desirable performance on the other pillars, and other objectives more generally.

The Director understands the difficulty of evaluating the affordability of different resource plans over a 20-year planning horizon. The cumulative NPVRR of a portfolio over the planning horizon is informative but does have limitations: one being that the difference between the candidate portfolios is often only a few percentage points. A useful complement is to show the annual revenue requirement of a candidate portfolio for each year of the planning period, both in nominal dollars and real dollars. This was not done by CEI South.

One limitation of the use of the 95th percentile of NPVRR is that it focusses attention on upside risks and provides no insight into the potential under different portfolios for costs to be lower. It is understandable to focus on risks for costs to be higher, but it is helpful to understand the potential for costs to be lower when evaluating the performance of different portfolios.

The Director is open to other means of evaluating affordability but finds the information provided by CEI South was helpful albeit limited.

<u>Reliability</u>
The traditional focus for reliability was on a utility's ability to meet the annual peak hourly demand for electricity, usually the summer in Indiana. The planning target was a given planning reserve margin at the summer peak load hour. The assumption was that, if this target was met, then there would be sufficient resources across all hours of the year. However, this perspective of reliability is changing to include an explicit evaluation of the resource portfolio's ability to provide energy in all hours over the planning period. This change in perspective is driven by the impact of increasing penetration of intermittent generation and the recognition of correlated mechanical or equipment failures caused by extreme weather conditions.

The discussion by CEI South of reliability closely follows the MISO process for evaluating necessary system reliability attributes. These attributes are:

1. *System Adequacy* which MISO defines as the ability to meet electric load requirements during periods of high risk. The factors included are availability, energy assurance, and fuel assurance.
    a. Availability is the consistent and predictable ability to call on capacity at the time of need.

    b. Energy assurance is the ability of the system to adequately manage and deliver energy supply on a 24-hour, seven days a week basis, especially in the presence of variable energy or energy limited resources.

    c. Fuel assurance is the ability of resources to access primary or backup fuel for electric power production at the time of need.

    MISO notes that these aspects of system adequacy are interrelated. Also, MISO's implementation of the seasonal resource auction process is based on how seasonal risks and resource capabilities vary throughout the year.

2. *Flexibility* is defined by MISO as the extent to which a power system can adjust electric production or consumption in response to changing system conditions. These changing conditions can be expected (variable) or unforeseen (uncertainty). MISO is currently focusing on rapid start-up and ramp-up capability. Rapid start up is the ability to quickly start up offline generation. Ramp up is the ability to follow load and resource imbalance to track intra- and inter-hour load fluctuations within a scheduled period.

3. *System Stability* which MISO defines as the ability to maintain a state of operating equilibrium under normal operating conditions and to also recover from disturbances.

CEI South states that it is not independently responsible for all elements of reliability but must be prepared to meet changing market rules and standards. CEI South notes that MISO has been studying the impacts of growing intermittent generation penetration, and, as a result, CEI South has included those reliability attributes identified by MISO in the IRP.

To evaluate reliability, CEI South focused on the measure of unserved energy. The preferred portfolio was dispatched in the EnCompass model using Reference Case inputs as well as the inputs from the four alternative scenarios. In each of the deterministic dispatch runs, the preferred portfolio was found not to have a significant number of hours of unserved energy. Thus, CEI South concluded that the preferred portfolio provided reliable service in meeting expected load requirements over the 20-year planning period.

CEI South emphasizes the preferred portfolio includes two highly dispatchable CTs (460 MW) that have quick start, fast ramping capability that can be turned on within 10 minutes. CEI South notes the portfolio also includes 180 MWs of older CTs that can be turned on within 30 minutes and Culley 3 converted to natural gas. CEI South emphasizes these thermal dispatchable resources are needed to maintain reliable service in multiday periods of cloud cover and no wind, facilitating a smooth transition to higher levels of renewables across the system. According to CEI South, the preferred portfolio is designed to meet the needs of CEI South customers in the worst weeks of each season, consistent with the MISO's guidance.

Director's Comments

The Director believes the use of unserved energy as a key metric is helpful. However, the discussion in the IRP would have benefitted from a clear definition of unserved energy, how it is determined, and how this metric compares to other widely used resource adequacy metrics. The Director recognizes that the topic is complex, but a clear discussion combined with a cite to a more comprehensive paper on resource adequacy metrics would help the reader better understand why unserved energy is useful. Also, the IRP referenced the number of hours of unserved energy but included no discussion of the magnitude of the energy not being served, the range of unserved energy across the planning period, and how it varied across resource portfolios or scenarios. What did CEI South consider an acceptable level of unserved energy? Also, unserved energy can be the same across two events, but the two events can have very different characteristics.

Stability

CEI South states that stability is the ability of a portfolio to help maintain system frequency and voltage, thermal limits, and power transfer capability, and that all portfolios must provide these essential functions. To evaluate the stability of the system, CEI South performed a multitude of transmission planning analyses to study a wide range of potential futures. CEI South used the latest 2022 MISO Transmission Expansion Plan (MTEP) model series, which includes future transmission system projects and approved generation interconnections. The primary focus was on the peak and off-peak five-year planning horizon. The renewable resources used for CEI South's analysis were projects already in the MISO queue and existing in the MISO models. The analysis accounted for the new CTs at CEI South's Brown power plant.

Converting Culley 3 to natural gas was used as the base case. CEI South states that no issues were found for this case. Retirement of Culley 3 required the lowest number of transmission system network upgrades for alternate cases. These upgrades were for voltage and reactive power support. The all imports and all renewables cases presented voltage issues and would require additional network upgrade projects to add reactive power support. CEI South noted additional study will be required on the preferred portfolio once specific projects are identified and sited to determine any further impacts on the CEI South transmission and distribution system.

Director's Comments

The Director believes that CEI South provided a helpful discussion. The discussion made clear that stability is a characteristic of the regional transmission system, not something that a single utility can provide on its own. It would be helpful to better describe what the utility can do to promote regional stability and if the necessary actions differ across candidate portfolios.

The Director recognizes that for generic new resources, siting considerations are not usually taken into account in the IRP models, so considerations that are dependent on the operation of the transmission system are hard to incorporate in the analysis.

Resiliency

CEI South emphasized that the preferred portfolio provides dispatchable resources that will be able to back up intermittent renewable resources when needed. The CTs being added at Brown will provide quick start/fast ramping capability, and Culley 3 switching to natural gas will be available for long duration peaking support, both with firm gas supply and access to multiple regions of gas supply. According to CEI South, the CTs can be black started, offering an additional degree of increased resiliency and operational flexibility.

Director's Comments

The Director thinks the discussion of the firmness of natural gas supply is less than clear in several places. However, CEI South clearly states on page 275 that currently CEI South uses non-firm pipeline delivery and gas storage for existing gas-fired peaking units. CEI South goes on to say that the future CTs at Brown and F.B. Cully, when converted to natural gas, will utilize firm pipeline supply contracts.

The Director recognizes that resiliency is a relatively new metric for IRP processes with little current agreement across the industry on informative measures. The importance of blackstart capability is one key component of resiliency in the bulk power system.

Based on the discussion by CEI South, the Director does not see how resiliency is different from the flexibility component of reliability. Both seem to come down to fast start and fast ramping.

<u>Environmental Sustainability</u>

The environmental sustainability objective was evaluated with stochastic analysis and measured in two ways: CO_2 intensity (tons of CO_2/kWh) and by CO_2 equivalent emissions (stack emissions) in tons of CO_2 equivalent (CO_2e) over the planning period. CO_2e measures not only CO_2 but other emissions, such as methane and nitrous oxide.

According to CEI South, the preferred portfolio performed very well, reducing annual CO_2e emissions by more than 19 million tons over the period 2023-2042 compared to the Reference Case and saves approximately 8.4 million tons of CO_2e compared to continuing to run F.B. Culley on coal.

Director's Comments – Five Pillars

Figure 8-35 – IRP Portfolio Balanced Scorecard on page 258 captures the quantitative performance of the different portfolios, but the discussion or comparison of different portfolios performance across the qualitative metrics is largely missing. The discussion of the qualitative metrics in Section 9 is from the perspective of the preferred portfolio, with little mention of the other candidate portfolios.

Also, the discussion of the scorecard metrics is informative while also being confusing. For example, as noted above, the Director has questions about the discussion around unserved energy. The lack of clear communication is highlighted by a comparison of a metric shown for reliability in Figure 8-35. In the scorecard the specific metric is described as "Must Meet MISO Planning Reserve Margin Requirement in all Seasons (MW)." The associated footnote describes the data shown as the "[m]aximum seasonal capacity deficit in summer/winter from 2030 – 2042." However, the description of the preferred portfolio's performance regarding reliability discusses unserved energy. In fact, it looks like CEI South only did the unserved energy analysis for the preferred portfolio. If this is the case, CEI South could not include unserved energy in the scorecard or discuss how the preferred portfolio performed relative to the other candidate portfolios.

Another disconnect arises with the use of the qualitative metric System Flexibility in Figure 2.2 – CEI South Scorecard for IRP Objectives and Metrics on page 92, but the discussion of metric performance for the preferred portfolio in Section 9 of the IRP addresses future flexibility and operational flexibility.

The purpose of portfolio performance metrics and the use of a scorecard is to highlight the tradeoffs across the various metrics for different portfolios under different scenarios and circumstances. Despite the basic difficulties discussed above, CEI South provided a reasonable discussion of the modeling results and the key takeaways as perceived by CEI South. Nevertheless, the discussion clearly leaves room for improvement.

The fault does not lie solely with CEI South. Rather, the concepts embodied in the Five Pillars and the other scorecard metrics are themselves less definitive than they once might have been. For example, a critical component of the reliability pillar experiencing significant debate across the industry is how to define, measure, and interpret different concepts of resource adequacy. Also, the Director has previously commented on the difficulty a utility and state regulators encounter when evaluating resource plans in the context of a broader region undergoing large changes in resource portfolios. The utility must make numerous consequential assumptions about the actions of surrounding utilities to determine how its own choices could be better. This is a difficult concept that is hard to comprehend, much less understand, the implications for any one utility's resource choices.

VII. STAKEHOLDER COMMENTS

The following comments are intended to be a representative sampling of the public input into CEI South's 2022/2023 integrated resource planning. There were similar comments raised by more than one commenter. To reduce redundancy, the Director selected some of the more salient and representative commentary.

Advanced Energy United

Advanced Energy thinks there are some aspects of CEI South's preferred portfolio that overlook important benefits that certain resources and services can offer which are beneficial to CEI South's customers.

<u>Be Careful not to Over-Value the Reliability and Under-Value the Risk of Fossil Fuel Generation</u>
Advanced Energy thinks that CEI South's preferred portfolio relies too heavily on natural gas and that the IRP includes general benchmarks that lack specificity. One example of a lack of specificity is that the IRP states the contract with Alcoa for Warrick Unit 4 ends in just a few months and alludes to a possible contract extension. Advanced Energy believes this is an excellent opportunity to implement a planned transition since the ending of the contract has been known for years. Another example of a lack of specificity is CEI South's stated plan to explore the use of a DR aggregator for C&I customers through a future pilot. United Energy supports development of DR, but a single pilot only scratches the surface. Also, Advanced Energy thinks residential and small commercial DR needs to be deeply explored.

Winter Storm Elliott demonstrated, according to Advanced Energy, that thermal resources such as combined cycle and combustion turbine gas generators are not as reliable as is typically assumed. Converting Culley 3 to natural gas exposes CEI South and ratepayers to reliability risk, and CEI

South to expensive penalties if the thermal units fail to perform when needed. The natural gas market is also subject to major price volatility.

Adding gas resources also exposes customers to unnecessary stranded asset risk. The operation and maintenance of new gas plants could make these resources uneconomic, especially as more zero-marginal cost renewable resources enter the MISO market.

According to Advanced Energy, taking these risks is unnecessary given that there are alternatives in the form of clean energy resources that can offer predictability, cost-effectiveness, and resource diversity because they are inherently different resource types.

Advanced Energy recommends that CEI South provide additional details of how Inflation Reduction Act (IRA) incentives and programs were factored into the analysis of energy storage. CEI South was also encouraged to more thoroughly explore the impact that the energy community bonus could have over the term of this IRP.

<u>CEI South Should Plan for more C&I Demand for Clean Energy in the IRP</u>
According to Advanced Energy, a growing number of businesses, municipalities, and organizations have set corporate clean energy and sustainability goals. These organizations have limited options to pursue these goals. So, businesses and municipalities are interested in requesting that CEI South implement a renewable energy tariff so that large customers can purchase new renewable energy directly from CEI South. Customers use renewable energy tariffs to acquire cost-competitive renewable energy from the utility without imposing costs on non-participants.

Advanced Energy thinks CEI South's IRP should include corporate-driven renewable additions, and to the extent that corporate commitments offset costs of acquiring new resources, those contributions should be factored into calculations of the costs of different portfolios to the full customer base.

<u>CEI South should Better Utilize Distributed and Demand-Side Resources to Serve Both Customer and Grid Needs</u>
According to Advanced Energy, CEI South's 2023 IRP should properly value and address system resilience and flexibility by expanding integration of customer-sided resources to take advantage of these attributes. DERs like customer-owned solar and storage can be aggregated to be a solution to capacity issues, voltage control, and more. The best way to do this is to treat DERs as supply resources, and appropriately planning for their increasing adoption.

Advanced Energy says the 2023 IRP does not appear to properly consider behind-the-meter DERs. Advanced Energy argues that costs associated with behind-the-meter DERs are borne by the system owner, and clearly impacts a cost-effectiveness analysis from the utility's perspective.

Advanced Energy released a report in September 2022, titled "Indiana Opportunities for Demand-Side Resources." The findings indicate it is beneficial to expand consideration of DSM in the IRP. There is a meaningful potential to increase load flexibility using time-varying rate designs and examining the trade-offs between different rate design decisions.

The report suggested how best to model DR so that IRP models do not undervalue DR resources.

Lastly, Advanced Energy says it is important for utility IRPs to recognize how the value of different EE resources changes as load shapes change over the planning horizon.

Director's Response

The Director shares with Advanced Energy the perspective that DERs should be viewed more as an opportunity and a resource in the IRP process. The Director looks forward to implementation of new analysis in the next IRP.

The Director wants to highlight Advanced Energy's discussion of the benefits of using time-varying rate structures to increase load flexibility. The potential impact of different rate designs is often underappreciated. As discussed above, CEI South did include rate designs as options in the IRP process, but there is much room for improvement. Analysis of the role of rate design in long-term planning is a weakness across the industry. Increased use of time varying rates and the resulting data will provide a base on which to improve the modeling of time-varying rates.

The Director recognizes how customers respond to different rate structures has a certain level of uncertainty but the use of diverse rate structures to increase demand flexibility can be used to respond to other sources of uncertainty.

Load, both the magnitude and hourly shape, needs to be seen as a variable that can be influenced by utility actions. The type of information necessary to properly evaluate different pricing structures was discussed above in the Director's Comments for the Energy Efficiency and Demand Response section.

Solar United Neighbors, Vote Solar, and Citizens Action Coalition of Indiana

Solar United Neighbors (SUN) et al. believe the CEI South IRP is missing some critical inputs that could ensure more reliable, sustainable, and affordable electric service.

1. *Allow distributed generation (DG) solar and other DERs to be included as resources eligible for selection in modeling.* According to SUN et al., the conventional utility planning approach for DERs is to treat them as an exogenous variable to the capacity expansion modelling. SUN et al. believes that CEI South used the conventional approach in which forecasted EE and distributed solar adoption is subtracted from the utility's gross load forecast to arrive at a net load forecast. The net load forecast is then used to model system capacity expansion through supply-side resources.

   SUN et al. recognizes that CEI South treated future EE as a selectable resource in the model optimization. SUN et al. argues that other types of DERs should be modeled as selectable supply-side resources, similar to that used to model EE. While the CEI South IRP does include a rooftop solar adoption model, SUN et al. believe a more robust modeling process is appropriate and beneficial.

   SUN et al. cited activity where the Minnesota Public Utility Commission and the Michigan Public Service Commission directed utilities to develop methodologies to incorporate DG as a supply-side resource in their IRPs.

2. *Incentivizing customers to adopt DERs can lower system costs while increasing resilience.* SUN et al. argue there is a growing body of evidence that local and clean grid resources are the most cost-effective way to deliver power reliability while meeting environmental

sustainability, resiliency, and stability goals consistent with the Five Pillars of Indiana energy policy.

SUN et al. cite as evidence the June 2020 report prepared by Lawrence Berkeley National Laboratory (LBNL) completed for the 21st Century Energy Policy Development Task Force titled, "Indiana 21st Century Energy Policy: Emerging Technologies on the Electric Distribution System Impact on Rates, Reliability, and Resilience." SUN et al. note that LBNL concluded a high PV and storage scenario resulted in the greatest annual cost reduction relative to its modeled baseline while maintaining slight improvements to system reliability.

Based on these results, CEI South should consider an upfront incentive for customers who install new distributed solar capacity, as well as alternative compensation that more fairly values the electricity that solar customers share with their neighbors.

3. *Further integrating distribution level planning into the IRP process to optimize the grid for increased DER adoption.* According to SUN et al., better coordinated planning efforts between distribution system, transmission system, and generation resources is essential for meeting affordability, reliability, and sustainability goals. They request that CEI South conduct distribution system planning as part of the next IRP process.

   SUN et al. thinks CEI South should work with stakeholders to take the following actions to align traditional IRP and distribution planning processes:

   - Set DER deployment targets consistent with current IRP high adoption scenarios.
   - Conduct advanced forecasting to better project the levels of DER deployment at a feeder level.
   - Proactively plan investments in hosting capacity and other system capacity to allow DG and EV additions consistent with DER deployment targets.
   - Improve non-wires alternative analysis.
   - Plan for aggregated DERs to provide system value including energy/capacity during net peak hours in all seasons.

Director's Response

The move to seeing DERs as a tool to provide economic and reliable electric service necessitates an expansion of the IRP planning process to include distribution planning. FERC Order 2222 also increases the need to evaluate distribution planning in a more integrated fashion. Much thought and discussion need to be given to how best to implement this type of improvement.

Citizens Action Coalition, Earthjustice, Solar United Neighbors, and Vote Solar (Joint Commenters)

The Joint Commenters had the following main concerns:

- The MPS did not consider the avoided cost of carbon regulation when evaluating cost effectiveness.

- The translation of EE savings from the meter to the generator did not appropriately apply the line loss factor.

- The C&I enhanced bundle only modestly increased savings even though additional incentives could have been considered.

- The MPS did not adequately account for emerging technologies.

- IRA funding and effects were not included in the MPS.

- Unclear information on the capital and pipeline costs for the Culley 3 conversion to natural gas.

- Treating capital costs as a stochastic variable and only applying to renewable and battery storage resources.

- Failure to evaluate the potential to repower existing wind resources.

- DR potential is underrepresented. The IRP included modeling a limited set of DR products, lacked accounting for interactions between DR and EE, and omission of winter season DR potential.

<u>Stakeholder Workshops and Material Provided</u>
The Joint Commenters desired a smoother exchange of information surrounding modeling inputs with a schedule for what data will be released and when. The Joint Commenters recommended CEI South use a process like that used by AES Indiana for the last two IRPs.

<u>Market Potential Study for Energy Efficiency</u>
The Joint Commenters argue a notable inconsistency between the IRP and the MPS in that the MPS does not consider the avoided cost of carbon emissions regulation. Several IRP scenarios account for carbon regulation. Inclusion of carbon regulation in the MPS would have improved the UCT scores of all measures, causing more measures to be cost-effective.

According to the Joint Commenters, it is unclear if the 6% line loss rate applied by CEI South to convert meter-level savings to generator-level savings is an average or marginal line loss rate. The correct rate to use is the marginal line loss rate. Also, CEI South incorrectly applied the calculation causing the generator energy savings to be modestly understated by 0.4%.

The Joint Commenters believe the list of emerging technologies included in the MPS is relatively limited, and many of these technologies are well established and not typically considered as emerging. That the MPS analysis does not allow for any emerging technology to be included in later years in the analysis when the measure becomes cost-effective, the result is an overly conservative and unrealistic view of the potential savings.

It was noted that additional funding opportunities provided by the IRA were not considered in the MPS since the MPS was largely completed before the IRA became law.

Given the problems identified here, the Joint Commenters think the level of EE savings modeled and selected in the IRP is inappropriately low.

Director's Response

The Director appreciates the detailed review by Joint Commenters of EE in the CEI South IRP. It is the Director's perspective that the importance of projecting the impact of EE resources over the full 20-year planning horizon is less significant than it once was.

Generation facilities today can be brought online in three to five years compared to the 8-10 years for more traditional generation facilities. The average size of utility scale generation additions is also much smaller today. Generation additions are 300 MW or less, and often in the 100 MW to 150 MW range. This compares to 500 MW to 800+ MW for coal-fired facilities. Shorter periods of commercial operation for new units and smaller capacity increments lessens the importance of projections of EE for the full 20-year planning horizon.

Given this circumstance, it is critical that the EE potential over the next five to eight years be thoroughly evaluated in both the MPS and the IRP optimization process. It is important to capture in both the MPS and the IRP the interactions between EE resources and other forms of DERs. EE potential is reassessed in every iteration of the IRP cycle.

Also, the Director thinks EE should be evaluated to better understand how it can lessen or otherwise modify utility and customer exposure to the potential implications of uncertainty and the resulting risks. The Director thinks this is an area that is generally overlooked and underappreciated.

Recognizing that the MPS and the IRP analysis are related but also performed sequentially, it is desirable that the MPS be as consistent with the IRP assumptions and scenarios as reasonably possible given the difference in time when the MPS and IRP processes are conducted.

Demand Response

The Joint Commenters commend the inclusion of additional DR products in the MPS and as resource bundles included in the IRP model optimization. However, there are several factors that cause unrealistic and underestimated DR potential. The factors include:

1. *Incomplete DR products included in the MPS.* The Joint Commenters acknowledge CEI South expects to reevaluate interruptible rates in the upcoming rate case. However, the failure to include interruptible rates in the MPS means CEI South fails to account for the realistic value of the potential of interruptible rates. Also, the Joint Commenters say that there are several common DR products excluded from the MPS.

   - EV time of use rates (TOU)/managed charging
   - Behind the meter storage
   - Behavioral demand response
   - TOU with enabling technology
   - Non-residential water heating direct load control (DLC)
   - Non-residential lighting DLC
   - Non-residential auto-DR
   - Non-residential time varying rates (TOU, real time pricing (RTP))

- Thermal (ice-based) energy storage
- Winter potential for DLC and rate options

2. *Limited DR options included in the preferred IRP bundle.* The Joint Commenters state it appears that the preferred scenario included only DLC programs in the IRP bundle. That it is unclear why other DR bundles were not included, such as residential rate options (critical peak pricing (CPP), peak time rebates (PTR), and TOU), bring-your-own-thermostat, and non-residential CPP.

3. *Understated potential for interruptible rate programs.* The Joint Commenters think a fuller discussion of the factors affecting DR acquisition through interruptible rates would cause a more favorable assessment of its potential.

4. *Overly conservative PTR participation assumptions.* The Joint Commenters think the MPS models residential PTR based on an opt-in program design but should be offered as an opt-out option. The result is that the potential of PTR as an opt-out design is underestimated.

5. *Unnecessary delay of time-varying rate option implementation.* According to the Joint Commenters, there is no reason to delay implementation of time-varying rates (TVR), CPP, PTR, and TOU because these programs are well established across the country, and CEI South has the necessary advanced metering infrastructure (AMI) deployment.

6. *Lack of accounting for winter season DR potential.* The MPS does not quantify the winter season DR potential.

7. *Lack of accounting for increased deployment of electric, DR-capable equipment through interactions with EE and IRA programs.* According to the Joint Commenters, it is unclear whether the achievable potential estimates of DR account for interactions with other energy programs. The MPS does not include the impact of IRA funding. These interactions will impact measure co-deployment, with increased recruitment and adoption potential for DR products, and increase delivery of electric equipment and show higher estimates of DR potential.

8. *Lack of consideration of possible co-deployment opportunities that would increase DR program adoption.* Co-deployment is the ability to leverage existing products, programs, and systems that encourage a combined deployment of resources, achieving more cost-effective delivery of interactive measures. Deployment of EE and IRA programs increases the potential of electric loads that can be curtailed through DR.

Director's Response

As noted in other places, DR and alternative rate designs need to be fully considered in the IRP planning process. Greater attention should be given to the interactions between DERs, more generally, and various forms of DR and alternative rate designs. The Director recognizes that IRP optimization models have limits on what can be included as a selectable resource. The exercise of judgment in how best to perform this analysis within these limitations is unavoidable. Clarity of the discussion of how the associated analysis is performed is key.

EnCompass Modeling

The Joint Commenters acknowledge the challenges CEI South encountered in trying to keep modeling inputs up to date. However, the Joint Commenters generally have several concerns about the lack of detail in the plan regarding the conversion of F.B. Culley 3 to natural gas in 2027.

One concern being that CEI South assigned capacity accreditation values in the IRP modeling that are higher than would be received based on MISO's current resource adequacy rules. Also, the Joint Commenters believe the planning cost estimates used by CEI South in the analysis will be exposed to inflation and supply chain pressures.

According to the Joint Commenters, it is not clear whether costs around natural gas pipelines and firm gas transportation are included in the Culley 3 refueling project. The Joint Commenters recommend that CEI South be clear and explicit in the IRP about how cost assumptions are developed and whether certain cost categories were excluded from the analysis. It is also not clear whether CEI South has confirmed if sufficient firm, unsubscribed pipeline capacity is available on assessable natural gas pipelines.

The Joint Commenters also argue that operation of the refueled Culley 3 at a 1% capacity factor is lower than they had expected and understates the costs and emissions associated with operating the unit if the capacity factor is in the range of 10-15%.

CEI South evaluated alternate candidate portfolios that evaluated replacing Culley 3 with a combination of renewable resources and/or battery storage. A major difference between these alternative portfolios and the preferred portfolio is that when Culley 3 is not retired and converted in 2027, the unit operates until its retirement in 2029. In other words, the analysis considers earlier retirement of Culley 3 only if the unit is going to be converted to gas.

The Joint Commenters recommend that CEI South stop treating capital costs as a stochastic variable and evaluate capital cost through sensitivities and scenarios.

The Joint Commenters also recommend that CEI South include long duration and multi-day storage resources for selection in the capacity expansion model.

The Joint Commenters also put forward a recommendation for CEI South to include an equity metric in the scorecard given the high proportion of low-income ratepayers in the service territory and the impact of emitting industries on the service territory.

Director's Response

The move by MISO to a seasonal resource adequacy methodology and to a seasonal resource accreditation process introduces considerable complexity to an already complex planning and resource acquisition process. It is the Director's understanding that the seasonal resource accreditation for specific resources can vary across time for reasons that are hard to account for in the IRP modeling. Utilities will improve in their ability to adequately model the seasonal resource adequacy methodology, but reasonable assumptions will probably be required to address resource accreditation variability over time. A better appreciation will be helpful of how sensitive IRP modeling results are to changes to resource accreditation assumptions.

The Director agrees with the Joint Commenters that CEI South could have been clearer about the assumptions included in the modeling of the conversion of Culley 3 to gas. Specificity as to the cost assumptions for different resources and how these cost assumptions are developed is a significant part of any IRP process, but there is always room for improvement.

The modeling of long duration and multi-day energy storage resources is difficult. It is the Director's understanding that the technologies are not commercially available, and it is not clear when these technologies will be available, at what cost, and with what operating characteristics. Consideration of developing technologies requires judgment over which reasonable people can disagree. Perhaps analysis of developing technologies is best handled as a sensitivity to understand the potential impacts. The uncertainty around these potential impacts can be then given appropriate consideration when considering near-term resource choices.

Sierra Club

Sierra Club has four recommendations.

1. *The costs and risks of burning coal at Culley and Warrick exceed the benefits, and CEI South should end coal-burning operations as soon as possible.* Sierra Club presented several interrelated points to highlight the risks and costs of concern. First, environmental requirements will increase the cost of burning coal at Culley and Warrick. Second, coal burning units are increasingly unreliable. Third, coal plants, including those that rely on Illinois Basin coal, expose ratepayers to risk from fuel price volatility and seller-side market power as coal production and the number of mines decrease.

2. *As CEI South transitions from coal, CEI South should minimize its pivot towards gas resources.* Sierra Club believes CEI South should be careful to adhere to CEI South's plan to operate gas-fired units as primarily capacity resources, not energy resources. Sierra Club strongly urges against the future conversion of the two new combustion turbines to combined cycle units. Such a conversion would expose CEI South to fuel price volatility and stranded asset risk.

3. *CEI South should engage in proactive procurement of renewables to limit the harm of interconnection and other delays toward achieving the lowest-cost, lowest-risk plan for customers.* Just-in-time resource planning is increasingly inadequate to meet the needs of customers. It is important to recognize the energy value of renewable resources and push to bring renewables online on a rolling basis and whenever these resources are economically available, rather than trying to align resource additions perfectly with capacity needs. Sierra Club believes CEI South should push for reform in the MISO interconnection queue to enable the timely addition of renewables in the future.

4. *CEI South should continue to evaluate and take advantage of the benefits that the Inflation Reduction Act can provide to its customers.*

Director's Response

The Director agrees it is important for the interconnection process to become more predictable and that new resources enter commercial operation in a timely manner. The current circumstance takes what is normally a complex resource acquisition process and increases the uncertainty and risks for all involved. The Director understands the desire to move away from just-in-time resource acquisition and to bring resources online on a rolling basis and whenever they are economically available, rather than trying to align resource additions perfectly with capacity needs. However, the ability to add resources on a rolling basis is also constrained by the interconnection backlog and supply chain delays. If every utility tried to do this across the region, it seems likely to increase prices for resources in the near term and not increase the supply of generation over the longer term.

Indiana Office of Utility Consumer Counselor

The Indiana Office of Utility Consumer Counselor (OUCC) reviewed the CEI South IRP with the Five Pillars in mind.

Resource Options

OUCC states that it is very concerning that CEI South is understating the costs of renewable generation in the model inputs and that CEI South's assumed "high" renewable costs are lower than the costs to construct solar and wind projects it has recently requested from the Commission. Also, the OUCC thinks part of the difference between recently approved renewable energy projects and CEI South's IRP costs for solar and wind generation could be due to the inclusion of owner's costs and contingency in the estimates for Commission-approved renewable projects. They note the IRP included owner's costs and contingency for the costs of new gas, coal, and nuclear generation. The OUCC says it is reasonable to consider owner's and contingency costs in all generation resource estimates included in the model.

Director's Response

The Director appreciates the OUCC's thoughts but is not clear on how the OUCC accounted for several other factors described by CEI South in the IRP and the appendices.

1. CEI South used information from an all-source request for proposal (RFP) issued in May 2022 to inform cost assumptions for wind, solar, solar plus storage resource options through 2027.

2. A technology assessment was performed by 1898 & Co. for resource options for which bids were not received in the RFP and for resource options beyond 2027.

3. Costs from the technology assessment were combined with cost curve estimates to develop cost estimates for resources beyond 2027.

4. If no bid was received for a resource type, technical assessment costs were used as the default.

The cost curves came from the 2022 Annual Technology Baseline from the National Renewable Energy Laboratory. CEI South also had the RFP respondents provide updated proposals when the IRA became law.

It could be clearer in the IRP what costs for each resource option are included in the IRP optimization, but the 2022 IRP Technology Assessment does breakout by technology or resource type detailed projections of performance data and costs. The costs include owner's costs broken out by type and an owner's contingency.

The OUCC's comments highlight the dynamic changes impacting the resource acquisition and planning process. Market information is changing continuously and necessitates constant monitoring and appropriate updates to modeling analyses. The Director agrees that all resource options should be evaluated on as consistent a basis as possible.

Environmental Considerations

The OUCC has several criticisms of the environmental discussion contained in CEI South's IRP. First, CEI South did not provide the model inputs for NOx and SO_2 allowance prices for all fossil-fuel fired generation analyzed. The OUCC states information on annual NOx and seasonal NOx allowances is necessary for understanding future gas generation operational costs.

Second, CEI South had only two scenarios that included CO_2 prices, with each assuming a carbon tax beginning in 2024 and 2026, respectively. The OUCC notes the timing in the two scenarios for a CO_2 tax is highly unlikely. The OUCC believes it is more realistic to have a scenario with a carbon tax beginning around 2030.

Third, the EPA proposed new greenhouse gas (GHG) standards for new and existing fossil-fueled electric generating units that will significantly impact utility planning, if implemented. The OUCC acknowledges the proposed rule was issued too late for consideration in CEI South's IRP.

Fourth, the OUCC argues that decommissioning costs need to be included for all new resource options as these costs are an important consideration over the expected life of a resource. According to the OUCC, CEI South excluded decommissioning costs for new gas CTs, CCGTs, and reciprocating internal combustion engines. The OUCC says it is unclear if decommissioning costs were included for new nuclear units, coal units, solar, wind, or battery storage.

Director's Response

To the Director's knowledge, it is not normal practice to include projected decommissioning and net salvage costs as part of the costs for generation resources in the IRP resource selection process. Regardless, the inclusion and treatment of costs, whether capital or operating, for consideration in resource planning models needs to be reasonably consistent across resources.

Transmission and Distribution System Planning

The OUCC has several criticisms of the transmission and distribution system planning discussion included in the IRP, but these criticisms come down to the alleged failure to include a discussion of the affordability of transmission and distribution systems accounting for the impact of larger distributed, utility-owned renewable resources on the grid in the portfolio evaluation.

The OUCC recommends a comprehensive discussion and analysis of transmission and distribution be included in future CEI South IRPs and that this analysis should include both quantitative and qualitative scorecard metrics of proposed generation portfolios and the effect on each of the Five Pillars as defined in Indiana Code section 8-1-2-0.6 that was added by House Enrolled Act 1007 (2023).

Director' Response

The OUCC mentions the discussion by CEI South of transmission considerations in section 6.4 of the IRP. In that section, CEI South states that it performed a multitude of transmission planning analyses to study a wide range of potential futures. The models utilized were from the 2022 MISO Transmission Expansion Plan, which includes future transmission system projects and approved generation interconnections. The analysis determined the need for facility upgrades and voltage support under scenarios with the retirement of Culley Unit 3 and the integration of renewables. The range of total system reinforcements was identified depending on the scenario being evaluated. However, this analysis is not addressed by the OUCC.

The Director appreciates the desire for a fuller discussion of the transmission and distribution investments and other costs associated with the candidate resources, but thinks the stated desire is overly broad and lacks specificity. Rather, the Director thinks it is preferable to have a discussion to better understand how T&D planning can be more fully included in the IRP and how this might be accomplished in stages while moving forward with other aspects of the IRP processes.

A critical piece of any conversation is to develop a better understanding of when different T&D impacts can reasonably be evaluated. It is the Director's understanding, for example, certain transmission considerations can only be evaluated with a specific location on the system in mind. The point is that T&D impacts are important to evaluate but the question is when and how this is best accomplished. This question requires discussion amongst the stakeholders and the utility.

<u>MISO Market</u>

The OUCC states that CEI South's IRP analysis recognizes MISO's changing capacity accreditation for both thermal and renewable resources and attempts to model the new seasonal resource adequacy construct. The OUCC also says that CEI South recognizes costs will increase both for current and proposed portfolios because of the changing MISO construct.

The OUCC recommends CEI South test the current accreditation assumptions and inform stakeholders of the impacts and that these impacts should be defined in how the need for additional capacity will change, what the available options will be to add capacity, and how much that capacity may cost ratepayers. According to the OUCC, CEI South should also detail the costs or risks if capacity cannot be procured within a portfolio's required timeline resulting from the simulated tests.

Director's Response

The Director assumes that the OUCC is asking CEI South to test how sensitive the IRP modeling results are to different assumptions about the resource accreditation assumptions over the planning horizon. The Director thinks this might be an informative exercise, but it is necessary to be sure the new MISO resource adequacy methodology is accurately and reasonably modeled before evaluating different assumptions about future movements of resource accreditation. The variability of accreditation for specific resources needs to be more fully understood and the modeling needs to address this in an appropriate manner.

Load Research, Load Forecasting, and Methodology

The OUCC recommends that CEI South include historical data to illustrate trends in load growth. According to the OUCC, historical energy and demand data maintained by CEI South in an internal database are listed in the IRP as a main driver of the load forecast. However, the OUCC says the IRP's modest level of historical data within the load forecasting report does not support the projected long-term growth.

Given CEI South's declining energy and demand requirements since 2011, the IRP should include a discussion of drivers of new growth, in addition to the comments currently provided on the sources of the load forecast. The OUCC believes it is problematic that much of the projected load growth after 2030 is driven by EVs given the OUCC's concerns with the EV forecast. The OUCC argues that historical data on energy usage and peak demand, as well as the contribution of EVs and DERs on CEI South's load, should be included in future filings to contextualize the projected long-term growth.

Director's Response

The Director agrees that historical energy and peak demand data broken out annually and by customer class should be provided to better inform the load forecast discussion. The historical data should be presented both with and without the effects of utility program energy efficiency removed.

Demand-Side Resource Options

The OUCC thinks the MPS does not discuss major changes in federal efficiency standards for residential lighting and HVAC systems, effective 2023, or how CEI South will adjust to these changes. The OUCC notes that retail sales of incandescent bulbs and halogen general service lamps or screw-in bulbs are now prohibited and that the base seasonal energy efficiency ratio (SEER) standard for heating, ventilation, and air conditioning (HVAC) systems is increasing from 13 SEER to 14 SEER.

The OUCC states the MPS identifies lighting and HVAC as significant contributors to potential residential savings. The OUCC believes the predicted annual savings may no longer be accurate due to the changes in federal standards. Given this possibility, the OUCC argues the final portfolio options should be tested to account for these conditions.

Director's Response

The Director agrees that the discussion of the treatment of federal efficiency standards MPS could be clearer. For example, the discussion in the MPS is limited:

> "Although this analysis does not attempt to predict how energy codes and standards will change over time, the analysis does attempt to reflect the latest legislated improvements to federal codes and standards. Where possible, improvements to baseline equipment standards can typically be met with incremental improvements to efficient equipment standards. However, in select cases, such as screw-in lighting improvements to the baseline standard effectively were expected to eliminate the efficient technology from future consideration." *(Page 11, Attachment 6.2 2019 DSM Market Potential Study)*

The Director notes the title of the appendix refers to the 2019 MPS even though the MPS is the 2022 MPS with a publication date of May 2023.

Effects of EVs and DERs on Load
The OUCC notes that CEI South does not seem to have included refreshed data relating to its service territory and EV usage. The OUCC states that CEI South uses the same estimation from the 2019/2020 IRP and that there are 238 registered EVs in the counties served by CEI South. The OUCC believes it is unclear whether CEI South updated the number of battery electric vehicles and the number of plug-in hybrid vehicles in the current IRP.

The OUCC states that CEI South should confirm whether Itron's EV forecast includes the most up-to-date territory-specific data available and that CEI South should include more information explaining how regional and national forecasts are adjusted to account for CEI South service territory demographics.

Director's Response
The Director agrees that the discussion in both the IRP and the Itron report included in the appendix needs to be improved so that interested stakeholders can have a greater understanding of what was done by Itron and how the resulting forecast is used.

Reliable Energy

Reliable Energy believes it is "appropriate for the Executive Director, who generally addresses issues as he deems relevant, to consider the Five Pillars in his report. This is particularly appropriate, given that these pillars were first discussed in the context of IRPs more than three years ago by Indiana's 21st Century Energy Task Force."

Given this perspective, Reliable Energy's comments on CEI South's IRP are structured around the Five Pillars. According to Reliable Energy, CEI South "merely changed the name of its historic Net Present Value (NPV) analysis to an 'Affordability' analysis. Reliable Energy states that CEI South's discounted revenue requirement provides no information as to the relative impact of each scenario on customer rates…The only way to assess affordability is to estimate rates under each case."

Reliable Energy argues the plain definition of affordability is whether the price of power to customers is manageable. A NPVRR analysis bears no meaningful relationship to affordability in the opinion of Reliable Energy. Reliable Energy asserts that NPVRR and affordability analyses are "two separate analyses and should not be conflated into one." Reliable Energy says CEI South should be required to develop annual estimates of rates at least for residential customers for the first 10 years of the planning period.

Reliable Energy recognizes that utilities approach reliability differently and that they believe it is more common now to use loss of load expectation (LOLE) as a proxy for reliability. Reliable Energy states that it appears that CEI South did not perform its own LOLE analysis, choosing instead to rely on MISO's Planning Reserve Margin Requirement (PRMR).

Reliable Energy says that CEI South recognizes that stability is increasingly important with the transition to intermittent resources and that MISO is spearheading much of the effort to address stability.

Reliable Energy notes that CEI South defines environmental sustainability as providing "environmentally responsible power, leading to a low carbon future with fewer impacts to air and water quality and less waste generated." Reliable Energy argues that CEI South's commitment to this goal is unclear.

The Greenhouse Gas Protocol categorizes a company's GHG footprint into three scopes: Scopes 1, 2, and 3. According to Reliable Energy, CEI South intentionally did not account for Scope 3 GHG emissions related to the production and transport of natural gas consumed at CEI South power plants. Reliable Energy argues that Scope 3 GHG emissions will be reportable in the future so CEI South should account for these emissions when evaluating future investments in gas resources.

Director's Response

The Director disagrees with Reliable Energy that there is no relationship between NPVRR and affordability.

Evaluation of affordability requires judgment because it is contingent on maintaining desirable performance on the other pillars. For resource acquisition, determination of affordability requires a comparison of different resource portfolios over a 20-year period over a range of alternative potential futures. The primary methodology is to use net present value revenue requirement to evaluate choices on a comparable basis. The process involves identifying known costs of various portfolios over a planning period and determining the revenue requirement effect of these costs in each year of the planning period then discounting to account for the time value of money. Calculating the NPVRR for different portfolios allows a comparison of the overall cost of the portfolios on all customers over the planning period.

The calculation of the revenue requirement is the foundation for setting rates in a rate case. To argue that there is no relationship between the revenue requirement and resulting customer class rates is a mistake. In general, the revenue requirement and the overall impact on customer rates is in the same direction.

The Director appreciates the debate over how best to analyze the affordability of the candidate portfolios. The Director understands the difficulty of evaluating the affordability of different resource plans over a 20-year planning horizon. The cumulative NPVRR of a portfolio over the planning horizon is informative but does have limitations: one being that the difference between the candidate portfolios is often only a few percentage points. A useful complement is to show the annual revenue requirement of a candidate portfolio for each year of the planning period, both in nominal dollars and real dollars. The Director thinks additional affordability metrics can be informative but does not see these as substitutes. Rather, these other potential affordability metrics would complement the two described above.