



**Director's Report**  
**for Duke Energy Indiana's 2018-19 Integrated**  
**Resource Plan**  
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IRP submitted by Duke Energy Indiana

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# Director's Report Applicable to Duke Energy Indiana Company's 2018-2019 Integrated Resource Plan and Planning Process

## I. PURPOSE OF IRPS

Duke Energy Indiana LLC's (DEI) 2018 IRP was submitted on July 1, 2019. DEI's statement of purpose is consistent with the Integrated Resource Plan (IRP) statute<sup>1</sup> and rule.<sup>2</sup> In its IRP, DEI states the following about the process.

The Company has a legal obligation and corporate commitment to reliably and economically meet its customers' energy needs. Duke Energy Indiana utilizes a resource planning process to identify the best options to serve customers' future energy and capacity needs, incorporating both quantitative analysis and qualitative considerations. For example, quantitative analysis provides insights into future risks and uncertainties associated with the load forecast, fuel and energy costs, and renewable energy resource options. Qualitative perspectives, such as the importance of fuel diversity, the Company's environmental profile, and the stage of technology deployment are also important factors to consider as long-term decisions are made regarding new resources. The end result is a resource plan that serves as an important guide for the Company in making business decisions to meet customers' near-term and long-term energy needs.

The resource planning objective is to develop a robust economic strategy for meeting customers' needs in a dynamic and uncertain environment. Uncertainty is a critical concern when dealing with emerging environmental regulations, load growth or decline, and fuel and power prices. Furthermore, particularly in light of the rapidly changing environmental regulations currently impacting our resource planning process, the Integrated Resource Plan ("IRP" or the "Plan") is more like a compass than a road map by providing general direction at this time while leaving the specific tactical resource decisions to Commission filings using then current information. (DEI IRP p. 4)

In addition to the over-arching purpose of the IRP to develop short and long-term guidance for utilities to provide economic, safe and reliable electric power, the IRP rule also requires each utility that owns generating facilities to make continuing improvements to its planning process as part of its service obligation. At the outset, it is important to emphasize that these are the utilities' plans. The Director's Report does not endorse the IRP nor comment on the desirability of the utility's "preferred resource portfolio" or any proposed resource action.<sup>3</sup> The IRP Rule requires Indiana's five investor-owned utilities to engage

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<sup>1</sup> Indiana Code § 8-1-8.5-3.

<sup>2</sup> 170 IAC 4-7; see also "Draft Proposed Rule from IURC RM #11-07 dated 10/04/12", located at: <http://www.in.gov/iurc/2843.htm> ("Draft Proposed Rule")

<sup>3</sup> 170 IAC 4-7-2.2(g)(3).

their stakeholders throughout the process. The Commission views a robust stakeholder as being critical to the success of the IRP process.

For those with limited familiarity with IRPs, the analysis is 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.<sup>4</sup> 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.

Indiana utilities and stakeholder anticipate substantial changes in the state's resource mix due to several factors<sup>5</sup> 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 the nation.

As DEI stated, 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, at reasonable costs, 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.

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<sup>4</sup> In addition to forecasting changes in customer use of electricity (load forecasting), IRPs must address uncertainties pertaining to the fuel markets, the future cost of resources and technological improvements in resources, changes in public policy, and the increasing ability to transmit energy over vast distances to access economical and reliable resources due to the operations of the Midcontinent Independent System Operator (MISO) and PJM Interconnection, LLC (PJM).

<sup>5</sup> A primary driver of the change in resource mix is due to relatively low cost natural gas and long-term projections for the cost of natural gas to be lower than coal due to fracking and improved technologies. As a result, coal-fired generating units are not as fully dispatched (or run as often) by MISO or PJM. The aging of Indiana's coal fleet, the dramatic decline in the cost of renewable resources, the increasing cost-effectiveness of energy efficiency as a resource, and environmental policies over the last several decades that reduced emissions from coal-fired plants are also drivers of change.

## II. INTRODUCTION AND BACKGROUND

DEI submitted an IRP that reasonably included five optimized portfolios and four alternative portfolios.<sup>6</sup> The alternative portfolios were based on an evaluation of the optimized portfolios and the results of sensitivity analysis on the optimized portfolios. However, from the Director’s perspective, the IRP did not achieve some of the initial promise of enhancements to DEI’s IRP that was articulated during the six stakeholder workshop meetings,<sup>7</sup> specifically:

1. The limited discussion of load forecasting provided very little detail on how the load forecast was constructed despite early in the document saying that the load forecast is one of the most important parts of the IRP process (DEI IRP p. 22)
2. There was very little information on how energy efficiency (EE) and Demand Response (DR) were modeled. Unfortunately there was more detail, limited as it was, in three of the Stakeholder meetings than was contained in DEI’s **written** IRP. Stakeholders should be able to find the narratives and sufficient detail within the IRPs. In the November 9, 2018 stakeholder workshop for instance, there was a promising discussion of “savings shapes” (daytime, night time, 7X24, seasonal, HVAC, etc.) to construct 20 energy efficiency bundles based on increasing incremental cost. The Director’s belief was that savings shapes would eventually morph into, what is now called, the “Time Value” of EE and other Distributed Energy

<sup>6</sup> The Optimized scenarios are: 1) **Slower Innovation** [Technology progresses more slowly than in the Reference case, extraction costs do not fall as quickly and as a result, coal and gas prices are higher than in the Reference case, higher fuel costs dampens economic growth, no carbon tax/price or regulation]; 2) **Reference Case** [Baseline forecasts for load, gas, coal, and power, carbon tax \$5/ton in 2025, rising \$3/ton per year]; and 3) **High Technology** [technology progresses more quickly than in the Reference Case, extraction costs fall more quickly and as a result coal and gas prices are lower than in the Reference Case, lower fuel costs increases economic growth, carbon tax \$10/ton in 2025, rising \$3/ton per year]; 4) **The Reference Case without Carbon Tax**, and 5) **Current Conditions Continue** [Extrapolations of market curves for gas, coal, and power, Reference Case load forecast, no CO<sub>2</sub> tax or regulation.] . (Pages 5 and 6 of IRP). On Page 42, DEI provided a useful summary table below.

**Table IV.1: Scenario Assumption Summary**

Scenario	Gas Price	Coal Price	Load Forecast	Carbon Price	Cost of Solar & Wind	Cost of EE	PTC & ITC
1) Slower Innovation	High	High	Low	None	High	High	Renewed
2) Reference Case	Mid	Mid	Mid	Mid	Mid	Mid	Expire
3) High Tech Future	Low	Low	High	High	Low	Low	Expire
4) Current Conditions	Market	Market	Mid	None	Mid	Mid	Expire
5) Reference Case, No Carbon	Mid	Mid	Mid	None	Mid	Mid	Expire

<sup>7</sup> Duke filed its IRP on July 1, 2019. The first workshop on November 9, 2017, provided a good discussion of treating Energy Efficiency. The second stakeholder workshop occurred on February 13, 2018. Workshop 3 was April 17, 2018. Stakeholder workshop 4 was held on December 18, 2018. The 5<sup>th</sup> workshop was conducted on May 30, 2019, the 6<sup>th</sup> stakeholder workshop was June 20, 2019.

Resources (DERs). However, DEI did not seem to advance the effort or allay concerns raised by the Citizens Action Coalition, Earth Justice, Energy Matters Community Coalition, Carmel Green Initiative, Environmental Working Group, Distributed Energy Alliance, Sierra Club, and Valley Watch (collectively referred to as “CAC Joint Commenters”). The Director recognizes there are both data and computational limits that are barriers to improved modeling of EE and other DERs but it is not clear DEI has a plan to enhance future analysis as called for by the IRP rule. This is somewhat surprising given DEI’s acknowledgement that “Challenges remain in how EE is included in the load forecasting process, the uncertainty of EE forecasting, and combining EE programs into a bundle that can be modeled with supply side resources like natural gas fired combined cycle or solar resources.” (DEI IRP p. 6)

3. DEI’s stakeholder process was mixed. To DEI’s credit they applied lessons learned from prior IRPs and started the stakeholder process early. DEI hosted six stakeholder workshops and started the process early (Nov. 9, 2017). Unfortunately, some of the meetings did not prove to be as productive as they could have been with more preparation. Delays in providing information resulted in more conference calls. The slide decks in the early stakeholder sessions were especially light on content with limited information presented overall. The presentation content improved in the discussion of modeling resource portfolio results with much of the material in the meetings being used in the IRP report itself.
4. Future improvements to the IRP methods and processes should have been articulated more fully. A more detailed discussion of how DEI intends to develop Advanced Metering Infrastructure (AMI) data should have been included on page 98 of DEI’s IRP. AMI data for basic load research, for end-use load research, and for DERs should be supplemented with other customer data, to improve DEI’s understanding its customers. There was very little mention and specific details of supplemental data such as routine end-use and demographic surveys (DEI IRP p. 22). The improved information should not only enhance the load forecasts as DEI notes but also modeling of EE, DR, and other DERs, and rate design. The general statement of “adoption of new modeling tools” could have provided more detail on what attributes are being considered. Similarly, we appreciate DEI’s recognition of the need for new supply-side resources cost forecasting but more detail would be appropriate. For example, what is DEI considering to mitigate concerns about a lack of transparency in forecasting supply and demand-side costs?
5. DEI’s risk analysis was, however, an exception to the lack of information in the preceding areas of concern. DEI provided a well-reasoned narrative and assessment of risk attributable to DEI’s current resource mix, the integration of risk into their load forecast and a good assessment of potential changes in resource costs, potential load changes, fuel costs, and public policy. As decisions to consider resource changes becomes more immediate, the need for more rigorous analysis becomes greater.

### **III. FOUR PRIMARY AREAS OF FOCUS**

Consistent with the introductory comment, the primary areas of focus of the Director for DEI's IRP include: Load Forecasting, DSM (energy efficiency (EE) and demand response (DR)), Risk/Scenario Analysis, and Stakeholder Process, and, consistent with the previous statement, DEI should provide more specific information regarding plans for continual improvement such as modeling all forms of Distributed Energy Resources (DERs) on a consistent basis to the extent reasonably possible, as well as the potential ramifications of electric vehicles (EVs). Commentary on other matters such as continual improvements will also be offered.

#### **A. LOAD FORECAST**

Comparing the 2018 load forecast with 2015, the total energy and peak capacity need for Duke Energy Indiana decreased across all customer classes primarily due to weak economic growth, low-cost market power, adoption of federally mandated appliance standards, and energy efficiency programs. Although long-term trends point toward recovery, energy demand is expected to grow less than 1% annually for all scenarios. (DEI IRP p. 6)

The general load forecasting framework includes a national economic forecast, a service area economic forecast, and the electric load forecast. The national economic forecast includes projections of national economic and demographic concepts such as population, employment, industrial production, inflation, wage rates, and income. Moody's Analytics, a national economic consulting firm, provides the national economic forecast. Similarly, the histories and forecasts of key economic and demographic variables for the service area economy are obtained from Moody's Analytics. The service area economic forecast is used together with the energy and peak demand models to produce the electric load forecast. In addition, the company conducts customer surveys every three to five years to determine end-use electricity consumption patterns (DEI IRP p. 22).

Energy sales projections are prepared for the residential, commercial, industrial, street lighting, and public authority sectors. Sales projections and electric system losses are combined to produce a net energy forecast.

DEI states in Appendix B of its IRP that the Great Recession, the availability of merchant generation that has reduced sales-for-resale, and the adoption of federally mandated highly efficient residential and commercial sector appliances and utility sponsored programs have worked to reduce electric energy sales growth and even shrink kWh use per residential customer for several years. This forced DEI to move to ITRON's Statistically Adjusted End-Use (SAE) forecasting methodology. DEI says this is the best approach to capture the changing levels of more efficient appliances saturating through residential households and commercial class end-uses. (DEI IRP p. 115)

DEI also performs a High-Low scenario around a Base Case scenario centered on three economic scenarios developed in January 2019 by Moody's Analytics. The low case economic scenario means there is a 90% probability that the economy will perform better and a 10% probability that it will perform worse. The high case scenario is designed so that there is a 10% probability that the economy will perform better than this scenario and a 90% probability that it will perform worse. (DEI IRP p. 116)

## **DIRECTOR'S COMMENTS – LOAD FORECASTING**

The Director, historically, has had general confidence in the load forecasting conducted by DEI. In large part, this confidence was because DEI provided more information in previous IRPs than in this IRP. Unfortunately, there is little information provided on the forecast methodology in Volume 1 or Appendix B of DEI's IRP, other than the change in the forecast bands methodology and a vague intimation of some unspecified change in DEI's use of ITRON's SAE. If there were any improvements in DEI's forecast methods, data, and tools, it was not obvious from the very general discussion of DEI's forecast. DEI provided very little information in either the IRP report or the public advisory process meetings, which is surprising given that DEI describes the load forecast as one of the most important parts of the IRP process (DEI IRP p.22). The high level description of the load forecast methodology in the main IRP document sounds like the same methodology that DEI has used in the past; however, language in Appendix B suggests some key changes that are not discussed or explained.

It appears DEI is now using ITRON's SAE to forecast residential and commercial sectors but no additional information is provided. DEI previously had a SAE-type model as part of its forecasting process, but it is not clear how this revised methodology compares. Appendix B also describes how DEI constructs base, high, and low bands for economic growth. Instead of DEI's more traditional high and low forecast based on equal chances of occurrence, DEI uses the methodology described above.

Did DEI's use of SAE change for any of the classes? If so, the Director hopes that there would be more explicit and detailed discussion of how the load forecasting models were used for all classes of customers. To what extent was the SAE model integrated with Moody's Analytics or other information? Given the importance of load forecasting as foundational to long-term resource planning, the lack of detail and, more importantly, the seeming lack of improvements is of concern even if there are no immediate changes in DEI's resource mix. The Director agrees with the CAC Joint Commenters, that the lack of a reasonable forecast narrative raised questions that should have been addressed in either the IRP filing or in a technical appendix.<sup>8</sup>

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<sup>8</sup> In prior Director's Reports, the concern about the use of binaries was raised. The Director urged utilities to justify the use of binaries. On May 29, 2019, the CAC's posed questions including, but not limited to, the following that should have been addressed by DEI in their IRP: 1) The type of regression model (OLS or another model), 2) How were the variables determined? 3) Explain the variables (naming conventions) used in the customer and sales



Historically, DEI has rightfully discussed the effects of the Great Recession, the loss of sales for resale due to the increased penetration of merchant generation, and the adoption of federally mandated highly efficient residential and commercial sector appliances and utility sponsored programs that spur more efficient use of electricity. These changes over the last 15 years have been significant. So, it is concerning that DEI does not give significant effect to the potential for significant changes in future load, such as the potential for EVs or loss of load due to DERs. That is, there seems to be little difference among the three load forecasts. It is not obvious if the narrowness of the forecasts is based on Moody's Analytics, SAE, or heuristic impressions.

For example, DEI might be under estimating its customers' energy usage and demand shape changes for the residential and commercial classes due to EVs and over estimating residential and commercial energy use due to DERs. Since DEI's residential sector constitutes approximately one-third of energy consumption, it behooves DEI to take steps now to improve its understanding of its customers. On Appendix B DEI mentioned:

While DEI has been projecting impacts of roof-top solar and electric vehicles upon the energy and peak demand projections for several years, there are improvements in the works applying actual (more local) solar load shapes and EV "charging time" data to improve our understand these influences upon class hourly load shapes. (DEI IRP p. 115)

In summary, DEI provided little information in the IRP pertaining to the impact on energy demand from increasing ownership of EVs. According to Table B.1 (DEI IRP p.112), the projection of the residential energy demand is flat. While DEI is different from Northern Indiana Public Service Company (NIPSCO) in the likely penetration rate of EVs and DERs, based on the pilot project done by NIPSCO, the average EV consumption was approximately one-third of the average home consumption. The Director appreciates DEI's stated intention in this IRP to improve how DERs (e.g., solar) are modeled as well starting to model EVs. DEI may want to consider some well-designed and narrowly focused pilot programs utilizing their AMI data to improve DEI's IRP and to better understand the potential ramifications on DEI's distribution system infrastructure and not to promote EVs or charging stations.

It must also be noted that the industrial, street lighting, and public authority sector load forecast methodologies are not discussed. It is not clear whether ITRON forecasted load for these customer classes.

## **B. DSM AND OTHER DISTRIBUTED ENERGY RESOURCES**

Duke Energy Indiana has continued to model EE as a supply-side resource and increased the number of EE bundles in this IRP to 70 from the 10 bundles in the 2015

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regression models. 4) Why was a lag term (variable AR(1)) used in the Industrial sales model and the residential, commercial, and industrial customer model. 5) Why was a constant variable only used for the Industrial customers?

IRP. Challenges remain in how EE is included in the load forecasting process, the uncertainty of EE forecasting, and combining EE programs into a bundle that can be modeled with supply side resources like natural gas fired combined cycle or solar resources. (DEI IRP p.6).

For the 2018 IRP, DEI includes implications of new EE and DR programs and modifications to the existing programs. DEI selects EE and DR programs for implementation based on their cost effectiveness, although there may be programs selected due to their educational and/or social benefits. The impact on the generation plan is examined for the portfolio of the current programs and future proposed programs if they were added. The projected load savings of all the EE programs chosen for this IRP are evaluated in the optimization model. For this IRP, EE and DR projected impacts were determined for a forecast horizon of 20 years, from 2018 through 2037.

The modeling of EE is based on the latest Market Potential Study (MPS) performed by Nexant. The MPS represents an assessment of technical, economic and achievable potential for EE and DR within DEI's service territory. For the first three years of the 2018 IRP (2018-2020), the EE base programs portfolio approved by the Commission for the period 2017-2019 are used as projected EE savings options available for selection. It was assumed that the portfolio in 2020 was an extension of the same programs approved within the MPS portfolio for 2019, but with a reduction of their size to reflect the 2018 Measure & Verification (M&V) process. For the subsequent years, each tier of the potential technical, economic and achievable levels of EE programs were divided into bundles with residential and non-residential programs.

The anticipated base EE bundles and incremental bundles are based on the MPS results for the period 2021 through 2037. For this IRP, 150 sub-portfolios (bundles) of EE programs were developed. The EE programs were grouped together within these bundles based on their hourly savings load shapes. Then, three different levels of customer participations (Base, High, and Extra-High cases) were created for each of the hourly shapes. The 150 bundles were then consolidated in a total of 70 EE bundles. This number of bundles represents 60 more bundles than the number of bundles used in the 2015 IRP. The bundles were consolidated by combining Base, High, and Extra-High cases for some bundles of hourly shapes with similar incremental amounts of new EE additions. The annual savings (MWh) and costs for the final set of bundles were used to calculate a levelized cost (\$/MWh) for each bundle. These bundles were designed to be treated as demand-side resources and entered into a resource planning model as any other non-dispatchable resource.

Since the cost of future EE programs is uncertain, annual cost are modeled using three trajectories: Rising real costs, constant real costs and declining real costs. Then the levelized costs and MWh savings of each bundle were modeled for a discrete selection in the economic optimization model alongside traditional supply-side resources options. Here the model selects among all the available resources and estimates the combinations of resources that serve the customer forecasted load at the lowest cost.

DEI provides the optimization model with increased EE bundle granularity in the early part of the forecast period by analyzing bundles with a three-year duration for the periods 2021 to 2023 and 2024 to 2026. In order to reduce the analytical burden in the optimization process, the next two sets of bundles were analyzed with a duration of five years and six years for the periods 2027 to 2031 and 2032 to 2037, respectively.

DEI's DR programs account for pricing programs and customer-specific contract options. DEI offers residential and non-residential DR programs. Non-residential programs include Rider 70 and other special contracts (PowerShare Call Option and Special Curtailment Contracts). DEI's IRP affirms that DR is not selected by the optimization model because any DR additions are forecasted separately maintaining the values consistent across all portfolios.

## **DIRECTOR'S COMMENTS – DSM AND OTHER DISTRIBUTED ENERGY RESOURCES**

Based on limited information, it appears DEI's EE analysis incorporated a number of interesting features. The Director was especially interested in the increased emphasis on the use of energy savings load shapes. Another feature warranting attention is the use of three different price trajectories for EE resources – falling real costs over the forecast horizon, steady real costs, and increasing real costs. Finally, increasing the number of bundles is a worthy exercise.

However, after promising initial discussions in the first three stakeholder meetings in particular, DEI's IRP lacked well-developed narratives to explain its DSM analysis and how the load forecasting process accounted for the effects of EE. In the initial stakeholder workshops, it seemed that DEI was suggesting a significant change in its DSM methodology by trying to ascertain the time value of energy efficiency and demand response. The Director was hopeful that this would be a more efficacious method for evaluating all forms of DERs (and electric vehicles) and enable treating them more comparably to traditional resources.

Although the use of the MPS assessment captures the DSM potential savings based on relatively latest market conditions, there is no detailed explanation regarding the extension of 2019 programs to represent 2020 programs in the IRP. The Director recognizes there will be differences between the IRP and the DSM program projections. However, it would be helpful and reduce controversy if DEI provided a discussion of the potential effect on results due to the gap between the time when the MPS (based on a 2017 load forecast) is released and the IRP is completed.

Although the process of grouping the programs within bundles is needed to have a feasible model and the Director is supportive of experimenting with grouping these programs based on their hourly saving load shapes instead of using their cost, this may be controversial. Specifically, since the model selects the resources based on cost, the same

basis should be used to group the selected EE or other DER measure. Using DEI's construct, would more expensive programs grouped together with cheaper programs make it uneconomic for this bundle to be chosen by the optimization model? Or did DEI group bundles based on a combination of both costs and the hourly saving load shape? For DEI's construct, how are the low-income, educational or social perspective programs selected for implementation modeled? Are these programs part of the bundles considered in the model?

There is a little mention about how DR was modeled (e.g., it appears DR was modeled separately but it is unclear what type of inputs or characteristics DEI considered to project future DR levels). DEI's IRP mentions that avoided costs were used in screening the EE and DR programs in the MPS but there is insufficient detailed information about the assumptions and parameters used in this process to understand how this was done. Especially as DEI moves to provide more discrete load shapes (ideally sub-hourly), the avoided costs becomes increasingly dynamic. Furthermore, future EE, DR and other DERs avoided costs should consider reductions in future load due to building codes, efficiency standards and changes in technology. Hopefully, future IRPs will address these issues.

While there is little discussion of the methodologies used to analyze EE and DR in either the IRP report itself or the stakeholder public advisory meetings, even less is said about other DERs. This failure is noted in the Director's discussion of the DEI load forecast above. The impact of non-EE and non-DR DERs is quite small now but perhaps might become more significant over the forecast period, especially when EVs are added to the mix. The evaluation of both EE and DR will become more complex as potential increasing amounts of DG over time causes the net load, and its shape, to change. As the net load used to evaluate EE and DR changes, so will the avoided costs also become more dynamic used to evaluate EE and DR.

Finally, the Director notes that EE, DR, other DERs, and EVs will increase interrelationships between the distribution system operations and planning and the Midcontinent Independent System Operator's (MISO) operations and planning. Beyond the stated intention to develop better modeling for DERs and EVs, the IRP offered no plan to accomplish this.

### **C. RESOURCE OPTIMIZATION AND RISK ANALYSIS**

The objective of DEI's IRP process was to produce a robust portfolio that meets DEI's obligation to serve load while minimizing the Present Value Revenue Requirements (PVRR) at a reasonable level of risk, subject to laws and regulations, reliability and adequacy requirements, and operational feasibility. The selected plan must also meet MISO's 15.0% reserve margin requirement.

According to DEI, based on its very good performance in scenario and sensitivity analyses, the Moderate Transition Portfolio was selected as the preferred resource plan. This

portfolio stood out to DEI due its combination of relatively low cost, lower carbon emissions, greater fuel diversity with lower exposure to market risk. The Moderate Transition portfolio was also perceived as having the flexibility to adjust for different forms of carbon regulation (including no regulation) as well as changing economics of renewables. (DEI IRP Page 19).

DEI used scenario analyses to explore how nine resource portfolios might perform under a variety of future conditions, and to examine the tradeoffs that may need to be considered among potentially competing objectives. The key variables selected as the foundation for scenario development were natural gas prices, carbon regulation, and the cost of renewable technologies. A Reference Case scenario was developed based on the corporate base case fundamentals forecasts to represent the most likely future conditions.

The High Tech Future scenario was characterized by increased technological innovation and higher economic growth. The Slower Innovation scenario was characterized by decreased technological innovation and slower economic growth. Two additional scenarios were developed based upon stakeholder feedback. They are the Reference Case Scenario without Carbon Legislation and the Current Condition Scenario. For each scenario, an optimized resource portfolio was derived under the assumptions of the scenario. DEI used System Optimizer (SO) as the tool to develop optimized portfolios for IRPs. SO uses a linear programming optimization procedure to select the most economic expansion plan based on PVRR. Both supply-side and demand-side resources were considered in the optimization. Then each optimized portfolio was tested against all five scenarios using the Planning and Risk (PAR) model to see how it would perform under various cases. The PAR model is a detailed production cost model for simulation of the optimal operation over an electric utility's generation facilities.

For sensitivity analysis, additional cases were modeled to assess how individual assumptions could affect resource selections. Variables considered include fuel prices, load, and cost of renewables.

Based on insights from the scenario and sensitivity analysis, DEI designed a few more alternative resource portfolios (DEI IRP pages 8 – 9):

6. Moderate Transition Portfolio - includes three coal unit retirements in the 2020s as well as a CC with solar and wind additions occurring in the mid/late 2020s
7. Aggressive Transition Portfolio - retires Cayuga and Gibson stations (3,800 MW) by the mid-2030s; adds 3 CCs and solar and wind over time
8. Rapid Decarbonization: CT Portfolio - alters the Aggressive Transition portfolio by replacing 2 CCs (2480 MW) with more wind, solar and CTs
9. Rapid Decarbonization: Batteries Portfolio - alters Aggressive Transition portfolio by replacing 2 CCs (2,480 MW) with additional wind, solar and storage

In developing the alternative portfolios, DEI identified areas of focus:

- There are dramatic differences between portfolios optimized for a future with carbon regulation and those optimized without.
- Several of the optimized portfolios rely heavily on wholesale energy market purchases under certain scenarios. DEI wanted to develop a resource plan that limits market exposure while still allowing some potential to benefit from low market prices.

The SO model optimizes around cost but DEI wanted a resource portfolio that better balanced other objectives, particularly the goal of reducing carbon emissions.

Finally, all resource portfolios were evaluated and compared based on cost, risk, market exposure and carbon emissions. The Moderate Transition Portfolio was chosen as the Preferred Portfolio because it leads to considerable carbon reductions while maintaining a moderate cost to the company.

DEI 's IRP's Preferred Plan and action plans limited their risk and maintained flexibility for future resource acquisition. The risk analysis was sufficiently broad to capture most likely scenarios. The IRP's optimized selection of more discrete amounts of resources as needed to maintain adequate reliability and relatively low capital costs seems appropriate given a reasoned assessment of the market conditions. (DEI IRP p. 8-9)

The following limitations were imposed on the optimization modeling:

- No coal-fired unit was permitted to retire before 2024. This reflects the time DEI thought it would take for the company to prepare to take a unit offline (including any regulatory filings and design, permitting, and construction of replacement resources), as well as make any required transmission upgrades. The exception is the retirement of Gallagher Units 2&4 in December 2022, to which DEI is already committed, and for which the necessary up-front preparations have been conducted. The Gallagher retirement is part of all portfolios considered for the IRP. In addition, Edwardsport IGCC (IGCC) was not considered for retirement in this IRP. The plant is the newest on the system and has the longest estimated life (2045), well past the review period in this IRP. According to DEI, the plant has successfully improved operations over the past several years and going forward will be focused on reducing its ongoing maintenance costs. It is DEI's view that a diversified portfolio will continue to be a priority with the IGCC contributing to the fleet's diversity over the planning period.
- Retirement analysis was conducted only on the coal units. Other units were not considered for economic retirement.

- The SO model was permitted to add fractions of nuclear, coal, CC and CT units to better understand how the timing of resource needs is distributed and to reflect ability to partner with other entities on new generating stations.
- Annual capacity additions for each resource type are capped to reflect practical constraints. The caps are: 2,120 MW of ultra-supercritical coal, 2,070 MW of IGCC, 840 MW of nuclear, 3,100 MW of CC, 3,225 MW of CT, 80 MW of CHP, 1,212 MW of reciprocating engines, 2,500 MW of solar, 250 MW of wind, and 250 MW of batteries.
- The time required to permit and construct each unit type is reflected in the first year available shown in Table V.1 in the IRP.
- A variable operating cost of \$5/MWh was imposed on solar additions over 800 MW of nameplate capacity. This reflects DEI's estimate of the additional cost of operating the system with a high penetration of solar resource. The cost is increased by \$5/MWh for each additional 800 MW tranche of solar.
- Solar and wind resources contribute to meeting the planning reserve margin requirement at less than nameplate capacity, reflecting the fact that these resources may not be fully available at the time of peak load. Solar is counted at 50% of nameplate capacity (0% in winter) and wind at 13%, which is consistent with MISO's treatment of these resource types. Battery storage is valued at 80% of installed capacity to reflect the possibility that the battery may not be fully charged at the peak hour.

Generating unit retirements were selected in the SO model using a three-step process. This was necessary because fixed costs are an input to SO, and the model does not calculate these costs in an iterative fashion. The steps include two SO runs and an intermediate step in which future fixed costs are forecast using a separate tool.

1. An initial SO run is conducted in which the system is modeled over the planning period with no units eligible for retirement. The key output of this run is the capacity factor of each unit in each year of the planning period.
2. A spreadsheet tool is used to forecast future maintenance cycles, capital expenditures for maintenance, and fixed operating costs, all based on forecasted run hours (capacity factors) from the initial SO run. These fixed cost forecasts for each unit are used as an input for a second SO run.
3. The second SO run is conducted using the fixed cost forecasts from Step 2 as an input. All other inputs are identical to the initial run. In this final run, SO selects units for retirement when the present value of future fixed and variable costs exceeds the costs associated with retirement and replacement. That is, if the costs that can be avoided by retiring a unit are greater than the cost of running the system without that unit (including the cost of replacement), then the unit is retired.

According to DEI, the cost of replacing a unit is never as simple as a one-for-one replacement of megawatts based on capital cost (DEI's IRP page 29). Costs may include new capacity from a variety of sources as well as changes to the dispatch of existing units, and these changes may be realized over multiple years. Furthermore, total replacement capacity will not equal the capacity of the retiring unit due to differences in unit size and changes to peak load over time. The SO model considers all of these factors and their interdependencies over the planning period when selecting resource retirements and additions.

DEI's approach for developing its scenarios and portfolios is to predict what the future might be like over the 20-year planning horizon – recognizing a range of uncertainties - and then design the best resource portfolio possible given that vision. The various resource portfolios were evaluated on four characteristics as described on page 56 of DEI's IRP:

- Ability to provide adequate, reliable, efficient, and economic service. Primary metric is present value revenue requirements (PVRR).
- Ability to maintain flexibility and alter plans as circumstances change. All else equal, portfolios with larger, singular resources decisions are generally less flexible.
- Ability to minimize environmental impact, including carbon emissions.
- Ability to minimize risks with particular attention on over-reliance on net-energy purchases from the MISO energy market. (DEI IRP page 56)

## **DIRECTOR'S COMMENTS – RESOURCE OPTIMIZATION AND RISK ANALYSIS**

The scenarios and portfolios were reasonable and encompassed a reasonable range of risks. The graphic representations (beginning with Figure 1.1 on page 10 to page 18) of the several portfolios was very helpful. But some figures in other parts of the report are too compressed even though the side-by-side comparison is helpful. The figures shown on pages 63, 65, 67, 69, and 71 are good examples of nice side-by-side comparisons but too compressed such that some information presented might be overlooked or misinterpreted. DEI also provided a thorough discussion of its conclusions or key takeaways from the various steps of the resource optimization and portfolio analysis, and how the results at one stage influenced the analysis conducted at the next stage.

Since the IRPs are illustrative, they provide an opportunity to develop scenarios and portfolios that test risk boundaries. DEI missed the opportunity to objectively evaluate the potential accelerated retirement of the IGCC or the possibility of closing the gasification-related facilities and running the IGCC on natural gas. The Director appreciates that the IGCC is relatively new but failure to consider these options for the IGCC by *hardwiring* it into the scenarios is not appropriate. Economic and technological changes are too



significant to assume that any resource is beyond question or otherwise subject to modified operations. The Director urges DEI to fully and holistically evaluate the current resources or future resources. This recommendation to include the IGCC is despite the fact that the Director recognizes the complexity of evaluating the early retirement of Edwardsport or the closing of the gasification-related operations.

The Director recognizes that DEI may not have sufficient confidence in its current models to conduct this analysis. The Director also recognizes there is a limit to how quickly a facility can be retired and that this might vary depending on the facility being considered, However, the Director thinks it helpful to evaluate a couple of optimizations allowing the model to retire generation facilities without a time constraint. The Director recognizes that the models did not select to retire a unit until 2026, a full two years after the model was provided the option. Also, the Director thinks any time constraint would likely be shorter if the IGCC was to be operated only on pipeline natural gas, without use of the gasification facilities.

The Director appreciates the attention given by DEI to the risk associated with potentially excessive reliance on MISO market energy purchases. It is clear that this was a major consideration in DEI's development of the four alternative resource portfolios. However, there are aspects of the analysis that give pause, if not concern, that more serious critical consideration is warranted.

The concern is best exemplified by two scenario optimization results – the Reference Scenario and the High Tech Scenario, both include a price or tax on carbon. In each scenario the resulting optimized resource portfolio includes extensive reliance on net purchases from the MISO energy market which might unduly drive future resource decisions. For the Reference Scenario the optimized portfolio has net energy market purchases increase significantly over the forecast period (DEI IRP p. 63) The optimized portfolio for the High Tech Future Scenario shows a big one-step increase in energy purchases from the MISO market that slowly decreases over time while remaining proportionately large.

The Director's concern is that this indicates a fundamental disconnect between the wholesale market results and DEI's company-specific results. These results seem to imply that the long-run marginal costs reflected in the wholesale market price are disconnected from the long-run marginal costs faced by DEI in its potential resource options. If this is the case, then it calls into question how long this disconnect can exist in the analysis. If this disconnect is real, then much thought must be given to the interpretation of the results of the IRP analysis.

To say the market purchases are a proxy for resource decisions to be made over time fails to address this critical question of reliance on market purchases. The Director also understands that the optimization model might plausibly select to keep coal units operating as a source of cheap capacity while also purchasing large amounts of low cost energy in the MISO energy market. This might especially be the case when the coal capacity would have to be replaced with a resource that requires a significant upfront

capital investment. Resolving these questions probably requires greater attention be devoted to understanding the modeling of the broader regional market, the drivers of the regional results, and how changes in this part of the IRP analysis affect the more specific DEI operational and resource decisions. Again, it is not the existence of the wholesale energy purchases and their extent at any given point in time; rather, it is the existence of this circumstance over so many years of the forecast period.

DEI developed a very brief Short-Term Action Plan entitled a “Moderate Transition Portfolio” that contemplates “a measured approach with renewable generation progressively added and coal units retired over time.” (DEI IRP p. 19). Especially if there are significant changes in market dynamics, the Director would expect considerably more discussion on the implications for the Short-Term Action Plan.

#### **D. THE STAKEHOLDER PROCESS**

DEI conducted six stakeholder meetings (workshops), several conference calls, and numerous email correspondence for this IRP. DEI started the process early to accommodate the stakeholders’ requests which resulted in greater stakeholder participation. DEI also made its subject matter experts available to the stakeholders. DEI also made a concerted effort to increase the diversity of stakeholders.

#### **DIRECTOR’S COMMENTS – STAKEHOLDER PROCESS**

DEI hosted six stakeholder meetings, several conference calls, numerous one-on-one meetings, and email exchanges which is highly commendable. DEI always had top management and subject matter experts in attendance during stakeholder meetings that provided excellent information. The Director sincerely appreciates the hospitality and recognizes the significant dedication of time and resources to DEI’s stakeholder meetings.

The Director commends DEI for the substantial efforts to improve the stakeholder participation. In addition to the six stakeholder workshops and the other conversations throughout the IRP process, DEI’s efforts to increase the participation of commercial and industrial customers was excellent and added to the quality of the stakeholder discussions. DEI’s subject matter experts provided excellent information on the development of their scenarios / portfolios and the resulting risk and uncertainty analysis.

However, it is the Director’s observation that the stakeholder process was not as effective or transparent as could have been the case. This was particularly notable in the DSM discussions that started on a very promising trajectory and then seemed to be almost non-existent after the first three (or so) stakeholder meetings. For another example, there was no discussion of the load forecast methodology. If there were changes to the load forecast methodology, there should have been a discussion of the rationale and how the load forecast accounted for energy efficiency.

To the extent material must be kept confidential then alternative means need to be explored to make such material more accessible to those parties with appropriate non-disclosure agreements in place. DEI relies excessively on the voluminous nature of material and states the material will be made available only at company offices during business hours. Avoided costs, for example, are critical to the development of an IRP, but DEI limited access to this information to on-site review because it was thought too voluminous to make otherwise available. DEI, at a minimum, needs to evaluate the use of computer portals that other Indiana utilities have used to make such information available to appropriate stakeholders. That is not to say this process has been without problems, but it is a clear step up from DEI's current practices.

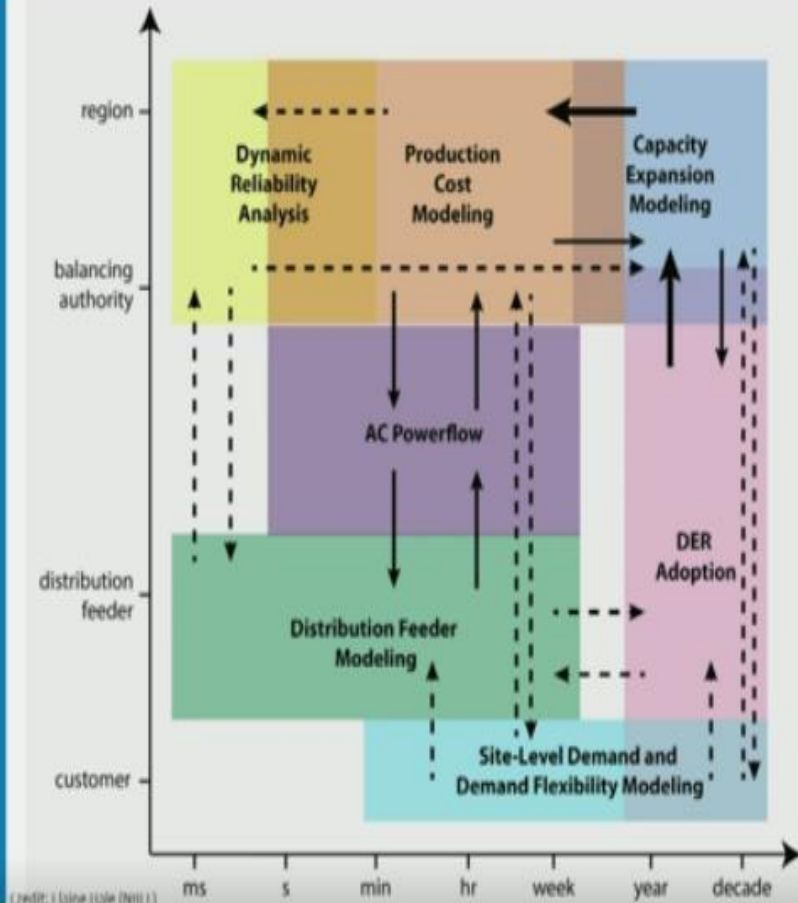
DEI asserted, without pertinent details of commercial value or harm to customers, that release of this information would harm DEI's customers by depriving DEI's customers the market value of this product. The Director urges DEI to use confidentiality sparingly. In the rare instance that DEI is contractually obligated to protect information, DEI should provide a narrative that explains the justification. To the extent reasonably possible, DEI should find methods that would provide information that is *blended* to disguise the confidential information or increase reliance on publicly available information – including information from stakeholders.

#### **IV FUTURE ENHANCEMENTS TO DEI'S IRP PROCESSES**

The IRP rule encourages utilities to continually evolve their IRPs' scope and quality to improve the credibility of the IRP. As noted previously, DEI mentioned (DEI's IRP page 98) its intention to improve its IRP process by developing: 1) More detailed load forecasting informed by data from advanced meters (AMI); 2) Adoption of new modeling tools better equipped to capture the complexities of the changing power industry; and 3) improved cost forecasting for supply-side resources. Statements by DEI on page 115 of its IRP note they intend to obtain more information about EE, DR (and we assume all forms of DERs) and EVs are consistent with the IRP rule. Specifically, DEI said it has "been projecting impacts of solar and electric vehicles upon the energy and peak demand projections for several years." DEI continued "there are improvements in the works applying actual (more local) load shapes and EV 'charging time' data to improve our understand[ing of] these influences upon class hourly load shapes." (DEI IRP p. 115)

DEI has appropriately informed its IRP with information from the MISO. Increasingly, it will be beneficial to DEI, MISO, and customers to better integrate information from the MISO's planning and operations with DEI's distribution system planning and operations and with its IRPs. The National Renewable Energy Laboratory (NREL) graphic below is illustrative of the evolution of IRP.

## NREL's Power System Modeling Capabilities



The IRP rule encourages continuing improvements in methodologies, analytical tools, and data. Improvements in the quantity and quality of customer information is critical to the success of the IRPs. The Director, while recognizing the enormity of the data from AMI, urges DEI to develop plans to fully utilize information gained from AMI for improved load shapes that can be used for load forecasting, understanding the operational and planning effects of DERs, more accurate rate design options, and improved distribution system planning. In addition to DEI's use of AMI, DEI should supplement the customer load data with more detailed survey data. For commercial customers, customer identification using the North American Industrial Classification System (NAICS) would be beneficial.

## V. STAKEHOLDER COMMENTS

Public participation in the stakeholder process and the extensive interest shown in DEI's IRP has been gratifying. Duke's stakeholder process, despite concerns that it could have been more responsive, deserves much of the credit. The following comments are intended to be a representative sampling of the public input into DEI's 2018-2019 Integrated Resource Plan. There were similar comments raised by more than one commenter. To reduce redundancy, the Director selected some of the more salient and representative commentary.

### Clean Grid Alliance (CGA)

CGA's comments address the following seven points: [1] Duke's Plan is overly conservative on renewable development and does not account for growing customer demand for renewable generation; [2] Duke's modeling should be modified to reflect more reasonable assumptions on renewable generation, evaluate system needs on an hourly or sub-hourly basis, and should procure a balanced mix of renewable resources and not continued reliance on natural gas resources; [3] Duke should use verified third-party data sources for cost and performance assumptions; [4] delaying wind additions until 2024 misses an opportunity to benefit from the production tax credit; [5] Duke should use an all-source RFP on an annual basis; [6] Duke should offer a well-designed green tariff program; and [7] Duke should plan transmission expansion to deliver electricity from its forecasted generation to its customers at the lowest overall production cost of electricity. (CGA cover page)

### The Director's Comments

*The Director appreciates CGA's thoughtful comments and hopes that CGA will be an active participant in future IRPs. It is possible that different assumptions about the delivered cost of renewable resources and a more expansive risk analysis (e.g., greater than expected load growth) by DEI might have resulted in greater consideration of renewable resources. As a caution, though, the lengthy IRP process that is intended to maximize stakeholder input may result in outdated data (e.g., GCA's comments on the AEO's 2019 data on page 7 may not have been available to DEI at the time the modeling was being conducted). The problem of potentially outdated data might have been made worse by the eight month delay in the development of the IRP. There is always tension between incorporating the best most recent data available and the ability to reasonably include this data in the modeling process without undue delay of IRP completion.*

*The on-going analysis conducted by the MISO such as its "Reliability and Need" (RAN) and the "Renewable Integration Impact Assessment" (RIIA), combined with the rapid transformation of the state's and regional resource mix argues for cautious and regular evaluation of how one utility's changing resource mix interacts with the broader regional market. Because of the significant uncertainties and attendant risks, the Director has consistently urged utilities to maintain optionality in its resource commitments. Excess purchases of any resource runs the risk of imposing unnecessary costs on customers.*

*In the absence of near term resource needs, the Director does not believe it is useful to have utilities conduct regular Requests for Proposals (RFPs). RFPs, without an intent by the utility to procure resources emanating from the RFP, are unlikely to be taken seriously by potential bidders. Similarly, unless there is a demonstrated need for resources and unless there is a specific location for the source and a specific delivery point, it seems premature to engage in several potential transmission studies that may adversely affect the RTO's transmission planning queue.*

*As market dynamics result in changes in DEI's resources and its projected needs, the Director expects DEI to conduct a robust IRP with state-of-the-art data, modeling, and analysis and to do so in conjunction with an all-source RFP.*

*Broadly, the Director shares your concern that some data used by DEI does not warrant confidential treatment (CGA Comments, p. 21). DEI has been asked to provide justification for confidential treatment in this IRP and future IRPs. While CGA can sign a Non-Disclosure Agreement (NDA), the IRP Rule requires a high degree of transparency. The Director asks DEI to give greater consideration and justification to confidential treatment including your comment raising questions about the confidentiality of the time used for modeling permitting and construction of each unit type as reflected in Table V.1 on page 58 of DEI's IRP.*

### **Indiana Advanced Energy Economy (AEE)**

AEE makes 4 main points: 1) by deploying additional renewable energy and storage on a more expedited timeline, DEI could realize greater savings; 2) DEI should add more renewable and storage capacity to its preferred portfolio to account for near-term commercial and industrial demand; 3) demand side resources could be incorporated more heavily into DEI's preferred portfolio; and, 4) the Commission should closely scrutinize DEI's plan to invest in combined cycle gas plants against cost-effective advanced energy alternatives. (AEE's Comments pages 1 and 2).

#### **Director's Comments**

*The situation faced by DEI is significantly different from other Indiana utilities. As a result, each utility has to tailor its long-term resource plans to meet its unique set of short and longer-term imperatives.*

*The Director agrees, in concept, that DEI might be able to cost-effectively increase the penetration of energy efficiency and demand response resources (e.g., AEE Comments, page 7). However, at some point greater integration of EE, DR, and other DERs will necessitate greater coordination of planning and operations between the MISO and DEI to better ensure that these are cost-effective. One important measure will be the dynamic nature of avoided costs at the wholesale market level and / or at the distribution system level. It is becoming increasingly clear that single point avoided costs based on the MISO's (or a utility's) coincident peak demand does not accurately capture the value of all forms of DERs and sub-hourly calculations of avoided costs are more accurate. However DEI, like most utilities, does not have the requisite data and may not have the needed software. Duke is installing advanced metering infrastructure that will provide much needed data.*

## Indiana Coal Council

The Indiana Coal Council (ICC) summarized DEI's on-going evaluation of its existing resource mix. ICC urged DEI to consider "Life Cycle Analysis" (LCA), continued assessment of carbon capture, and alternatives to retirements of future coal-fired power plants. ICC also expressed concern that DEI did not consider transmission expenses associated with procurement of renewable resources, and a scenario where "natural gas prices rose significantly and coal prices did not." (ICC's Comments page 2)

### **The Director's Comments:**

*The Director appreciates the value of LCA. However, there is general recognition of the objective difficulty in identifying all of the relevant variables that, to the maximum extent possible, should be quantifiable over the relevant long-term planning horizon. It is the Director's understanding that Vectren is evaluating the use of LCA in the development of Vectren's upcoming IRP, so hopefully this will provide greater insight into the question. There are numerous related questions that arise when considering the use of LCA, among these are the use of the social cost of carbon or trying to incorporate the potential health impacts associated with improved energy efficiency or other renewables.*

*Consistent with the IRP rules, utilities are expected to consider a broad range of potential futures and their attendant risks and uncertainties. The Director believes DEI has satisfied this requirement for this IRP and expects that future IRPs will also provide an objective analysis using increasingly sophisticated planning models, data, and analysis. While the ICC is correct that DEI did not have a high gas price and a low coal price among the core five optimized scenarios, DEI's analysis was broader than the ICC suggested.*

The economic competitiveness of our coal assets is heavily influenced by the price of coal relative to the price of natural gas. The price of coal is a major driver of our cost of generation, and the price of gas is a major driver of price of energy in the MISO market. The relative economics of coal generation are an important factor in retirement analysis, so it is necessary for us to analyze both high gas prices relative to coal and low gas prices relative to coal. We expect coal prices to be very stable throughout the planning period, so we focus on gas prices, which are much more volatile, for this analysis. Because coal prices are stable, our Slower Innovation scenario is essentially a "high gas" case. Similarly, our Current Conditions scenario is a "low gas" case. The other assumptions are similar enough between those two scenarios for us to be confident that comparing the respective optimized portfolios can tell us whether we need to explore the question of fuel prices further. Since the two optimized portfolios are nearly identical, we conclude that fuel prices alone will not be a major driver of coal retirements. No additional sensitivity analysis is required. (Pages 72 and 73 of the IRP)

*The Commission has encouraged Indiana utilities to maintain flexibility in their resource options to the extent possible, including new resources as well as existing resources. An emphasis on optionality requires a thorough consideration of the alternative courses of action available for existing resources. With regard to an all-source analysis, the Director is surprised that the ICC does not recognize the importance of renewable resources as*

*competitive alternatives to both natural gas and coal, especially since renewable resources were prominent in the recent IRPs and actionable RFPs of NIPSCO and Vectren.*

*Given the recent experience of other Indiana utilities that conducted all-source RFPs that included consideration of transmission and the integration issues of all resources, the Director has every confidence DEI will also construct all source RFPs to obtain a high level of price transparency that will inform DEI's future resource decisions. These factors, combined with the IRP rule as well as the Certificate of Need statute, reasonably ensure that DEI will give due consideration to the delivered costs of electricity from specific resources with specific locations as opposed to reliance on the analysis of generic options.*

### **Indiana Office of Utility Consumer Counselor**

The OUCC states "With regard to environmental regulations or concerns, Duke appears to have conducted a thorough analysis of environmental regulations likely to impact its existing and future generating resources." (OUCC Comments page 1)

The OUCC is growing concerned with the trend of Indiana electric IOUs delaying IRP filings to coincide with the filing of a rate case or a certificate of public convenience and necessity (CPCN) filing. In Duke's case, it waited to file its 2018 IRP until after it filed a new rate case where it introduced projects into the future test year that were allegedly supported by its IRP. However, with the timelines imposed on the Commission, the OUCC and intervenors to complete a rate case, the OUCC and Intervenors were unable to consider the Director's report in their analysis of the rate case... The OUCC has already noted above why this is problematic in the context of a rate case or CPCN filing, but it is also problematic because a utility could use an active filing before the Commission to avoid questions, comments, or discussion of a relevant topic at an IRP stakeholder meeting for fear of violating ex parte rules due to a Commissioner or Commission staff attending the meeting. (Page 1 of 1 of OUCC's comments)

### **The Director's Comments:**

*With regard to the timing of the IRPs and Certificate of Need Cases, the Director appreciates the OUCC's concerns and recognizes the added burden on all of the stakeholders. However, having an IRP that is more contemporaneous with a Certificate of Need case has benefits. Often in Certificate of Need cases, the "staleness" of data or assumptions can be highly contentious. Also, as the Director understands the circumstance, the long IRP submittal extension sought by DEI was necessitated by unforeseen problems with the regional models that are critically important for an IRP analysis. The Director prefers the IRP analysis be well done and thoroughly vetted rather than meeting an arbitrary date for IRP submission.*



## Industrial Group

The Industrial Group witness Michael P. Gorman's testimony is that Duke's IRP has not demonstrated that the continued operation of Edwardsport IGCC as a gasification plant is reasonable and prudent. Mr. Gorman noted the total 2020 costs of O&M at the IGCC is \$106 million. These costs include \$99.4 million of O&M, plus \$6.6 million of annualized major seven year outage costs (IG's Comments page 1)

### **The Director's Comments:**

*DEI should have conducted a thorough evaluation of all its generating resources including both the potential retirement of the Edwardsport IGCC facility and in the alternative the operation of the facility on natural gas only with the gasification facilities no longer operating. Mr. Gorman offered suggested scenarios; however, the Director will defer to DEI. Regardless of the specific scenarios, DEI's next IRP should conduct the analysis of the IGCC unit. For the sake of the objective integrity of the IRP analysis, it is important to avoid, where possible, the hardwiring of existing or future resources.*

### **Citizens Action Coalition (CAC), Earth Justice, Energy Matters Community Coalition, Carmel Green Initiative, Environmental Working Group, Distributed Energy Alliance, Sierra Club, and Valley Watch (Referred to as "Joint Commenters")**

Joint Commenters' review of DEI's 2018-2019 IRP and their participation in DEI's pre-IRP stakeholder workshops raised the following main categories of concern:

- DEI applies its reserve margin requirement to all months of the year rather than just the MISO coincident peak (CAC Joint Commenters' Comments Section 3.1);
- DEI requires the model to self-supply capacity in all months of the year rather than purchasing from other utilities (CAC Joint Commenters' Comments, Section 3.2);
- DEI tries to solve the problem of unrealistic market purchases by imposing a hurdle rate on purchases, but this is a band-aid on the problem and an imperfect one at that (CAC Joint Commenters' Comments, Section 3.2);
- Coal unit retirements are unnecessarily limited to 2024 or later and only to DEI's existing pulverized coal units (CAC Joint Commenters' Comments, Section 5.2);
- DEI's energy efficiency bundles are unreasonably high in cost and suffer from other flaws that prevent the selection of the optimal portfolio of energy efficiency measures (CAC Joint Commenters' Comments, Section 3.5);
- Capital costs for renewables are higher than is justifiable (CAC Joint Commenters' Comments, Section 5.1);
- Capital costs for combined cycles are lower than is justifiable (CAC Joint Commenters' Comments, Section 5.1);
- Wind and battery storage is limited to 250 MW per year without basis (CAC Joint Commenters' Comments, Section 3.4);

- A \$5/MWh adder for new solar resources is based on a study for Duke's Carolina service territory that has no relevance to Indiana and was rejected by the North Carolina Utilities Commission (CAC Joint Commenters' Comments, Section 3.4);
- DEI refused to provide copies of the System Optimizer and Planning and Risk model manuals except in person despite having done so in its prior IRP (CAC Joint Commenters' Comments, Section 1);
- DEI did not deliver the modeling files required for the Technical Appendix in Indiana's IRP rule (CAC Joint Commenters' Comments, Section 1); and
- DEI's pre-IRP stakeholder process was frustrating in a number of respects including the tendency of Duke to push stakeholder recommendations off to the next IRP filing (CAC Joint Commenters' Comments, Section 2.1).

Joint Commenters' suggested that DEI's technical appendix was significantly incomplete at the time of the IRP filing.

CAC Joint Commenters' Comments had to request the System Optimizer ("SO") capacity expansion model files and the Planning and Risk ("PaR") production cost model files from Duke through discovery. When DEI responded to our request for the modeling files, it initially just provided CAC with the modeling input and output files for its preferred portfolio - the so-called Moderate Transition portfolio. As a result, CAC had to follow up with Duke to obtain the modeling input and output files for the other portfolios Duke modeled in the 2018 IRP. This process of having to request the modeling files and then following up with Duke delayed our review of the modeling files.

Finally, CAC asked Duke for copies of the System Optimizer and Planning and Risk model manuals in Informal CAC Data Request 11.2, but Duke objected to this request. In response to Informal CAC Data Request 11.2, Duke stated, "Duke Energy Indiana objects to this request to the extent it seeks documents that contain copyrighted, proprietary information belonging to third parties. Duke Energy Indiana will make the information available for on-site review at its Plainfield, Indiana offices upon reasonable notice and advanced arrangements made with Duke Energy Indiana's counsel." **This was despite the fact that Duke had previously provided these documents to CAC as part of the 2015 IRP process.** [emphasis added]

During the pre-IRP submission phase, Duke provided stakeholders with a workbook titled "Data Summary for Stakeholders". This workbook included the model inputs for load, commodity prices, CO<sub>2</sub> price forecast, energy efficiency costs, resource unit characteristics, capital cost forecasts, and renewable production forecasts. However, this workbook was not part of Duke's IRP filing and, since it was originally provided in December of 2018, we do not know how much of the information changed, if any, between then and the July 1, 2019 IRP filing date.

Joint Commenters' noted:

Throughout the IRP stakeholder process and the stakeholder portfolio exercise, CAC provided numerous suggestions on modeling improvements that Duke either did not agree with or said it would consider in its next IRP. Some of the suggestions made by CAC and its consultants included modeling on a UCAP rather than an ICAP basis, removing the monthly reserve margin constraint, lowering the capital costs of solar and wind resources, not applying a market hurdle rate to limit market purchases, and modeling energy efficiency ("EE") in a decrement approach. We believe most of these would have a material impact on Duke's results. (CAC Joint Commenters' Comments page 7)

**The Director's Comments:**

*DEI should be commended for the initial "Data Summary for Stakeholders." However, DEI should have provided an update in the technical appendix. More generally, the Director agrees with CAC Joint Commenters' concerns about DEI's lack of transparency in providing important information to the stakeholders. After years of increased transparency, DEI seems to have made a retrograde move to protect information that lessens the stakeholder process and impairs the ability of stakeholders to conduct a reasonable analysis in a timely manner.*

- 1. The Director is not convinced that "Modeling renewables and DERs on a UCAP rather than an ICAP basis" is somehow better. It is, however, a worthy topic for debate. Historically, traditional resources had significant statistical information on their operations (such as outage rates). With the transformation of the generating fleet, the data is increasingly mixed. DERs have even less operational data. Since the load shapes are changing, it is difficult to have confidence in that the time value of these resources would be accurately reflected in the modeling.*
- 2. Similarly, the Director is not certain that, for this IRP, it matters whether DEI remove[s] the monthly reserve margin constraint, especially since, outside of the peak demand, the constraint is not binding. As MISO's RAN suggests, increasingly there are reliability issues and, often, increased costs in months outside the system coincident peak demand so it may be useful for DEI to model the monthly reserve margins. Finally, given DEI's current resource mix and the significant changes in resource mix throughout the MISO and Eastern Interconnection, a more expansive definition of the reserve margin may be appropriate.*
- 3. The CAC Joint Commenters' may be right that DEI could have a "lower capital costs of solar and wind resources", but DEI's analysis does not seem to be outside the realm of reasonableness. In general we would prefer a broader risk band and using the best most recent data available consistent with timely completion of the IRP. As stated in the Director's Report, DEI's EE modeling was not clear. However, as the Director said in prior Director's Reports, we are not convinced there is a decided comparative advantage to bundling or the Joint Commenters' decrement approach. It seems there is some agreement that AMI, related survey data, the development of load shapes, as well as more accurate and comprehensive avoided cost information*

*often on a sub-hourly basis, may prove a better approach to resolving this impasse but that remains to be seen.*

4. *The CAC Joint Commenters' on Page 8 of their Reply Comments state: "IRPs are not intended to merely examine the steps a utility ought to take to fill an anticipated need but are also an examination of whether existing resources are economic to operate or should come offline early. The lack of any near-term retirement analysis and the stasis in its resource portfolio happens precisely because it chose to so drastically narrow the resource choices in the next five years that the model would be unlikely to make changes to Duke's existing portfolio."*

*The Director's response to the Joint Commenters' concern about the lack of near-term retirement analysis is that the Director has consistently urged DEI and other Indiana utilities to maintain maximum - albeit reasonable optionality - in the long run, and the same holds true for the short-term. If, for instance, a utility makes a decision to retire a power plant this limits their options; perhaps unreasonably so. Given the rapid transformation of the resource mix across the region, a case can be made for a slower approach if there are uncertainties and risks which should be examined in considerable detail. Nevertheless, DEI should have more thoroughly reviewed unrestricted retirement of all coal-fired units, including Edwardsport, in the IRP.*