Response of CAC and Earthjustice to the Director's Draft Report for the Duke Energy Indiana 2018-19 Integrated Resource Plan

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We appreciate the Director's Draft Report for the Duke Energy Indiana Company ("Duke") 2018-19 Integrated Resource Plan ("IRP") as well as the chance to respond before the Director's Final Report is issued. Overall, we greatly appreciated that the Director echoed many of the frustrations that we felt as participants in Duke's stakeholder process. Not the least of which were the Director's statements that "the stakeholder process was not as effective or transparent as could have been the case"[1] and that "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."[2] We share the Director's opinion that there was a lack of collaborative and meaningful discussion on topics including DSM and the load forecast. We share the Director's concern that Duke's IRP demonstrates an unrealistic reliance on external resources. A number of these concerns we had hoped to shed additional light on by asking Duke to model our own scenarios, but we could not get System Optimizer to return realistic results.

These comments on the Director's Draft Report are intended to provide more clarity to our comments on Duke's IRP and to add more information to the conversation regarding the application of a monthly reserve margin, the use of UCAP versus ICAP values, and transmission and distribution benefits of DSM, all of which will come up in future IRPs.

Monthly Reserve Margin Requirement

We reiterate our appreciation for the Director's very thorough Draft Report on Duke's 2018-19 IRP. It addressed both issues raised by stakeholders and those identified by the Director. Our primary ask of the Director is to reconsider the Draft Report's language around the seasonal resource adequacy construct or monthly reserve margin. We welcome continued dialogue on this and other issues of importance to IRPs in Indiana.

With regard to the comments CAC made about Duke's application of a monthly reserve margin, the Director states:

> *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]

We agree with the Director that it is likely MISO's resource adequacy construct will change; indeed, it must change in order to respond to a shifting resource mix. However, there is no certainty that MISO will shift to a year-round reserve margin requirement. Oftentimes we view a

[1] Director's Draft Report on Duke IRP, p. 18.
[2] Director's Draft Report on Duke IRP, p. 5.
[3] Director's Draft Report on Duke IRP, p. 27.

resource adequacy construct as synonymous with a planning reserve margin ("PRM") requirement, but that may not be the case going forward. A PRM is normally derived from a loss of load expectation ("LOLE") study but that PRM only produces the same LOLE requirement in practice to the extent that reality and the study assumptions are the same. In December 2019, in a report entitled "Aligning Resource Availability and Need,"[4] MISO categorized its efforts to ensure continued reliability through an "Explore, Decide, Do, Done framework." Modifying its resource adequacy construct was in the Explore category and moving to a seasonal construct was "a serious consideration".[5] This is not adequate grounds upon which to make a wholesale modification to the reserve margin assumptions used in Duke's IRP[6] and is contrary to the requirements of the Commission's IRP rules, including 170 IAC 4-7-4 (25)(D). MISO also said that it would explore modifying its resource adequacy construct by examining whether there is "a need to augment the LOLE metric or consider alternatives. Expected Unserved Energy (EUE) is one alternative metric for assessing reliability risk, which has some support from others in the industry and from several stakeholders."[7]

We have no opposition to performing sensitivities using a range of assumptions about how MISO might measure resource adequacy in the future; indeed, this is a wise idea. That is not what Duke did, however. The entirety of its IRP is predicated on the use of a reserve margin requirement that does not exist. And Duke did not even perform any sensitivities using the *current* MISO reserve margin requirement.

Moreover, Duke self-interestedly did not model changes to MISO's resource adequacy construct that are much more likely to happen. MISO has repeatedly stated that it intends to change its resource accreditation methodology in order to better capture the ability of accredited resources to serve load, and it has already filed for changes to availability reporting and testing requirements of load modifying resources (LMRs).[8] In a November 2019 presentation, MISO presented the changes in accredited capacity by resource type from moving to the current accreditation methodology to one based on the availability of units in the Day-Ahead market. This resulted in a reduction in accredited capacity across most generator types as shown in Table 1, below.

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[4] Retrieved from: https://cdn.misoenergy.org//Aligning%20Resource%20Availability%20and%20Need%20(RAN)410587.pdf

[5] MISO has acknowledged that it would not pursue this option, however, if stakeholders do not support adopting a seasonal construct.

[6] MISO's December 2019 report, which postdates Duke's IRP, is not a departure from its previous position on this issue, but rather a more succinct and clear summary of prior presentations and other materials produced by MISO on this topic.

[7] https://cdn.misoenergy.org//Aligning%20Resource%20Availability%20and%20Need%20(RAN)410587.pdf at page 14.

[8] https://cdn.misoenergy.org/2018-12-21%20Docket%20No.%20ER19-650-000303667.pdf

Table 1. Comparison of Current Accreditation Methodology to Day-Ahead Offer Accreditation[9]

Unit ID	Unit Class	Status Quo-XEFORd (MW)	Day-Ahead Offers* (MW)	Delta (MW)
1	Steam - Coal (100-200 MW)	179	193	14
2	Steam - Coal (200-400 MW)	209	208	-1
3	Combustion Turbine (20-50 MW)	24	15	-9
4	Steam - Coal (0-100 MW)	59	55	-4
5	Pumped Storage	374	273	-101
6	Steam - Oil	607	558	-49
7	Nuclear	1068	1036	-32
8	Combustion Turbine (0-20 MW)	9	11	2
9	Steam - Coal (600-800 MW)	610	458	-152
10	Steam - Coal (800-1000 MW)	834	796	-38
11	Combined Cycle	123	106	-17
Totals		**4,096**	**3,709**	**-387**

The table postdates Duke's IRP submission so these values could not have been used by Duke. But it certainly could have adjusted the accredited capacity of one or more of its units based on the expectation that a new methodology has to reduce accredited capacity, not increase it. If emergency events are happening because generators are not available, then by definition for a new accreditation methodology to be impactful, it must reduce the accredited capacity of most generators. Duke did not even reduce the capacity contribution of the unit that will most obviously be hurt by a change in accreditation methodology – Edwardsport. In Duke's modeling, Edwardsport's capacity contribution is equal to its summer and winter nameplate ratings. This is despite the fact that, between 2016 and 2019, Edwardsport's forced outage rate averaged 15.7 percent - well in excess of its class average of 5.53 percent.[10]

As to the question of why this matters, the Director is absolutely correct—that in Duke's Reference Case, for example, the reserve margin outside of the summer peak is often well in excess of the 15 percent reserve margin requirement. However, that does not necessarily mean that the reserve margin requirement in winter months was not binding on the optimization. It is difficult to tease out the impact of every assumption of significance without having access to

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[9] *See* page 13 of https://cdn.misoenergy.org/20191106%20RASC%20Item%204b%20RAN%20Capacity%20Accreditation397077.pdf

[10] IURC Cause No. 45253, Cross-Answering Testimony of David Schlissel, p. 14.

System Optimizer ourselves, but there are multiple reasons to believe the monthly reserve margin influenced Duke's modeling. For example, as the Director observed about the level of reliance on market purchases, "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 anlaysis [sic]." This pattern of keeping units, but not running them in favor of market purchases, could well be driven by the monthly reserve margin requirement. Clearly, System Optimizer is expressing a preference for market energy, but the model still must meet the minimum reserve margin requirement, and there is no option to purchase market capacity in Duke's modeling. This benefits the retention of existing generators. Further, in the optimized scenarios, System Optimizer *never* picked new wind.[11] This seems to be unrelated to the assumed cost of wind because, even in the run Duke performed for CAC and for which we specified a lower cost of wind, System Optimizer picked just 50 MW of wind and only in 2030.

System Optimizer also never picks a combined cycle unit except in the High Tech scenario. We suspect this is driven by (1) the higher carbon price used in the scenario which probably creates a preference for gas-based energy over coal and (2) the fact that 2,070 MW of coal is retired in the period from 2024 through 2028 which would definitely make the winter reserve margin requirement binding. Combined cycle and combustion turbine units are the only units in Duke's modeling with any significant amount of accredited capacity in the wintertime. Even in this scenario, no solar is picked until 2027, which is not surprising since Duke assumes solar has no capacity value outside of the months of April through September.

The Duke Energy Indiana 2018-19 IRP is completed – we are under no illusions that Duke will amend or change its IRP in any way and recognize that this issue will have to be revisited in the next IRP, as well as in any resource-related dockets in the interim. However, we are very concerned about the precedential value of the Director's language on this topic. Vectren has indicated that it intends to use nearly the same approach to modeling a reserve margin requirement in its upcoming IRP. We expect that its IRP modeling will serve as the basis for a Certificate of Need application, and we are greatly concerned that the language in the Director's Draft Report gives Vectren the green light to reinterpret MISO's reserve margin requirement throughout its IRP modeling.

[11] *See* Tables V.2 – V.6 of Duke's 2018-19 IRP Volume 1.

Modeling Using UCAP Rather Than ICAP

We also wanted to provide additional clarification about why we have now asked Duke in each of the last two IRPs to switch to modeling its system on a UCAP, rather than an ICAP, basis. As the Director knows, MISO measures compliance with its resource adequacy construct on a UCAP basis, so if Duke had also prepared its IRP on a UCAP basis, it would have been very easy to compare how it matches up to existing requirements. Duke has argued that this would require it to make long-term forecasts of forced outage rates, but Duke has to do this either way since IRP models require this input.

Furthermore, we think it is possible that switching to a UCAP convention might produce a different optimization (when combined with other changes to Duke's modeling including removing the 15% monthly reserve margin requirement). Figure 2, below, shows the difference between the ICAP and UCAP values for Duke's coal units based on its response to the 2018 OMS-MISO survey. The percentages above the bars in the graph represent the percentage difference between the ICAP and UCAP values. That difference is not uniform across units. This means that certain units, e.g., Cayuga 1 and 2 and Edwardsport, are much less valuable from a capacity standpoint than is captured by just using each unit's nameplate rating. The difference in ICAP versus UCAP values is effectively "socialized" across all units by increasing the reserve margin requirement from the UCAP Planning Reserve Margin (PRM) of 7.9%[12] to a value of 15%, which muddies the picture that the IRP can paint of the value of each individual unit.

[12] This value was established in MISO's Loss of Load Expectation "LOLE" report published on November, 1, 2018 and is referenced here because it is the value that would have been in place at the time Duke was performing its modeling.

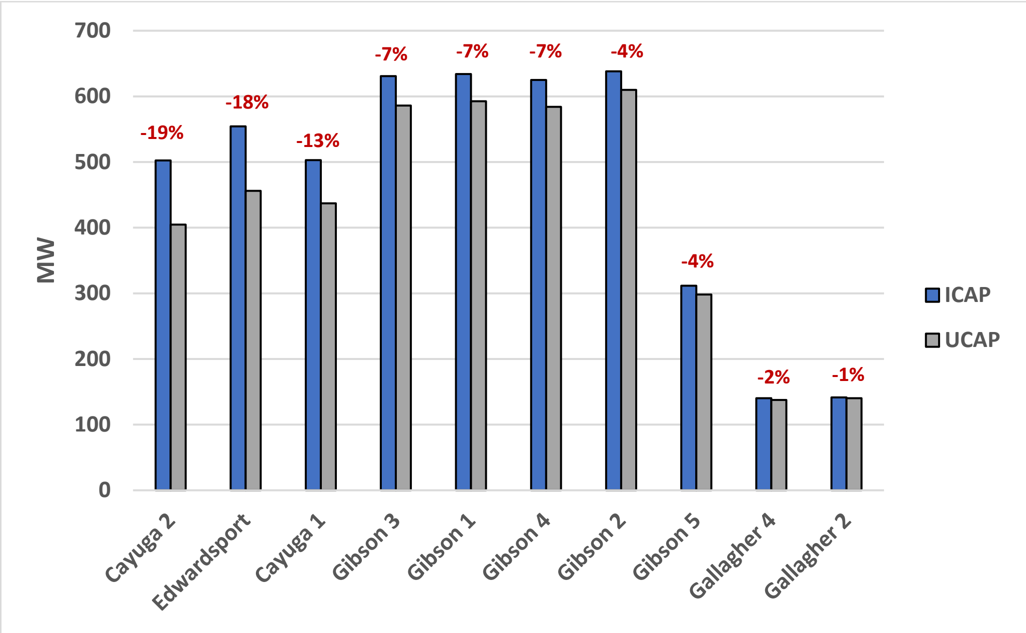

Figure 2. ICAP and UCAP Comparison of Duke's Coal Units[13]

It is standard practice amongst the MISO utilities we are aware of to model on a UCAP basis. Duke should join in that standard practice.

[13] Based on Duke's Informal Discovery Attachment CAC 3.4-A in the 2018 IRP Stakeholder Process.

Transmission and Distribution Benefits of DSM

We appreciate that the Director's Draft Report summarized a number of concerns with Duke's treatment of DSM, and we concur with those concerns. We present these additional comments to reinforce the idea that serious changes to the manner in which Duke models DSM are needed.

Since our comments on Duke's 2018-19 IRP were filed, Duke has responded strongly to the idea that its avoided transmission and distribution (T&D) cost should have been part of the optimization of DSM in the IRP. To demonstrate why avoided T&D costs are so important, we calculated the levelized avoided T&D benefit for each of the bundles picked by System Optimizer in Duke's preferred plan in 2021. As an output, System Optimizer produces annual peak impacts for each selected bundle. There is no other source for this information, so the analysis was necessarily limited to selected bundles. After multiplying each bundle's peak impact by the appropriate avoided T&D cost,[14] we levelized this benefit using exactly the same methodology Duke used to calculate the levelized costs of its bundles.[15] This analysis demonstrates that avoided T&D costs are between 18 and 91 percent of bundle costs.

Table 2. Avoided T&D Benefit as a Percentage of Bundle Cost

Bundle	% of EE Bundle Cost
Flat Daytime - Non-res	55%
Flat Daytime - Non-res	**55%**
Mode 3 Non-res	29%
Mode 3 Non-res	**24%**
Lighting Outdoor - Res	91%
Behavioral - Old - Res	**18%**

To say these benefits are significant is an understatement. Undoubtedly, their inclusion in the optimization would have resulted in the selection of more DSM. And even if System Optimizer or its successor model cannot accommodate an explicit avoided T&D cost forecast, it can still be modeled as a reduction in bundle cost and produce the same impact. This analysis underscores how critical it is for Duke and, for that matter, the other Indiana utilities to account for the full range of benefits that accrue from the implementation of DSM.

[14] We used Duke's avoided T&D cost trajectory supplied in Duke's Response to OUCC Data Request 1.2 in Cause No. 43955 DSM 8.
[15] *See* Duke's Confidential Attachment CAC 3.1-A provided in the 2018 IRP Stakeholder Process, tab "Res Base Calc," for example.