Memorandum

TO: MICHIGAN PUBLIC SERVICE COMMISSION STAFF

FROM: ARIEL HOROWITZ, PHD & NINA PELUSO

DATE: OCTOBER 5, 2017

RE: COMMENTS ON PROPOSED MICHIGAN INTEGRATED RESOURCE PLANNING PARAMETERS

The draft parameters for Michigan's impending Integrated Resource Planning ("IRP") process represent a productive effort by Michigan's governing agencies to prepare a thorough and realistic long-term planning process. Overall, the proposed parameters are forward-thinking among rules and guidelines for IRPs across the United States. However, they have several important gaps and would benefit from clarification and refinement.

Sierra Club retained Synapse Energy Economics (Synapse) to review the Michigan Public Service Commission (MPSC) staff's proposed planning scenarios, sensitivities, and assumptions. We reviewed the proposed parameters for Michigan's new IRP requirement, and we have identified a number of areas in the draft parameters where changes would benefit both participants in the planning process and customers impacted by its results. We describe these areas in the comments and suggestions below. We thank the Commission for its openness and for providing the opportunity to participate in shaping Michigan's IRP process.

Analytical Structure

- Overall, the scenario definition in Section VIII would benefit from language clarification and improved presentation to ensure clear and consistent understanding between the regulator, utilities, and intervenors. It should be clear what each scenario seeks to investigate and what assumptions must be altered for the investigation. Sensitivity analyses should also be clarified as applying to one or more of the core planning scenarios. The Commission might achieve more clarity using a scenario map or table.

- The proposed guidelines consider transmission and distribution (T&D) improvements and fuel availability, but the connection between the new IRP process and pre-existing T&D and fuel infrastructure planning processes is unclear. Synapse recommends that the Commission clarify the relationship of this IRP process to both T&D and fuel infrastructure planning processes. It should be explicitly stated if planning for these resources will be conducted under the auspices of the IRP process or if they are to be determined externally and used as input assumptions. Crucially, additional T&D resources can contribute to both reliability and resource adequacy, making them an important aspect of resource planning.

- Along similar lines, the IRP process should take into account the ability of demand-side management strategies (such as Energy Waste Reduction), distributed generation, and energy storage to cost-effectively defer or eliminate the need for certain T&D capital investments. The utilities' financial analyses should consider the value of such deferrals even as part of analyses of scenarios focused on generation decisions. For Energy Waste Reduction, T&D deferral value should be built into the resource cost profile used in modeling to allow the model to appropriately optimize procurement of this resource. For new storage resources, T&D deferral value should be treated as either a modification to capital costs or built into post-processing of financial results.

- A shortcoming in the proposed guidelines is that they do not include directives for how the state's utilities should select a preferred portfolio after completing the required scenarios and sensitivity analyses. Portfolio selection has a substantial impact on utilities' proposed action plans. Synapse suggests that the final IRP parameters detail both the metrics used to select a preferred portfolio and outline the process used to calculate those metrics. We further recommend that such metrics adequately incorporate both cost- and risk-related considerations. The Commission should require that the state's utilities define key decision metrics and describe clear and objective methodologies for how these metrics will be calculated prior to the commencement of modeling.

  While metrics for evaluating IRP scenarios vary widely across states, a select set of key metrics may provide clear insight into which resource plan offers the most favorable portfolio. We suggest that the Commission establish metrics to measure the following, similar to structures used in Oregon and Missouri:[1]

  1. Expected Cost: The cost to the system, often measured using present value of revenue requirement (PVRR), is central to identifying a reasonable portfolio that reduces long-term costs for utilities and consumers alike.

  2. Worst-Case Cost: The preferred portfolio should minimize high-end tail risks, and it should demonstrate the probability of extreme costs.

  3. Uncertain Outcomes: A utility should demonstrate the range of possible outcomes of its preferred portfolio, and it should choose a portfolio that has a high likelihood of yielding an acceptable outcome even across variation in scenarios.

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[1] **OPUC IRP Guideline 1c:** "The primary goal [of the IRP] must be the selection of a portfolio with the best combination of expected costs and associated risks." […] "Utilities should use PVRR as the key cost metric." […] "To address risk, the plan should include, at a minimum two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes." https://apps.puc.state.or.us/orders/2007ords/07-002.pdf.

Missouri 4 CSR 240-22.010: "Use minimization of the present worth of long-run utility costs as the primary selection criterion in choosing the preferred resource plan." [Additionally, the IRP should consider mitigating:] "1. Risks associated with critical uncertain factors that will affect the actual costs associated with alternative resource plans; 2. Risks associated with new or more stringent environmental laws or regulations that may be imposed at some point within the planning horizon; and 3. Rate increases associated with alternative resource plans."
https://www.sos.mo.gov/cmsimages/adrules/csr/previous/4csr/4csr0511/4c240-22.pdf.

Ideally, the Commission would also require utilities to evaluate portfolios based on the "best-case" or lowest cost outcome as well as the worst case. However, this metric may be of greatest use as a secondary piece of evidence in cases where the utility's analysis has produced several closely performing portfolios.

- Scenario 3, under Section VIII, does not explicitly state how the referenced 30 percent carbon reduction will be achieved—for example, as a result of a hard cap on emissions or through the application of a carbon price. Synapse recommends that Staff clarify this distinction and note explicitly that the results of this scenario must *achieve* the stated reduction in emissions.

- Across the proposed structures, pricing targets seem inconsistent and rigidly defined. As proposed, the targets unnecessarily restrict modeling methodologies and may not give sufficient insight into the distribution of risk. For example, if a utility's reference case gas price forecast already trends low, the proposed "300% above" and "half" bookends for this forecast will not adequately represent the asymmetry of the risks associated with gas prices that deviate from reference case expectations. Synapse recommends that pricing targets be more flexible and subject to both utility and intervenor input. Some utilities[2] rely on probabilistic standards (e.g. "within the 95th percentile"), which may be more subjective but also more flexible with respect to representing the distribution of risk. At a minimum, the IRP should include a discussion of the methodology used for risk analysis, and of the utility's justification for choosing such methodology over other approaches to evaluating risk.

Assumptions

Scope

- The analysis period proposed in Section IX reflects the periods required by MCL 460.6t, which states that the filed IRPs will "provide a 5-year, 10-year, and 15-year projection of the utility's load obligations and a plan to meet those obligations…" While the statute only requires these shorter periods, utilities frequently consider depreciation lives of 20 years or longer. Thus, to ensure the IRP represents all potential decisions, Synapse would recommend a modeling period of at least 20 years, with measurements at the previously defined 5-year intervals.

- Section IX, Item 2 only requires modeling within Michigan. Synapse suggests that the Commission require that the modeling region extends beyond the state itself, to either the northern or full MISO region. This will ensure that all available resources are included in the optimization. Michigan actively participates in energy transactions across the MISO landscape. Additional adjacent regions (e.g. the northwestern PJM territory) should be included as deemed necessary by the utility but may be adequately represented by import/export schedules.

- Additionally, under Section IX, Item 2, the Commission should require utilities to adequately represent the exchange of energy between Michigan and Canadian regions.

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[2] Examples include: TVA, PacifiCorp, Omaha Public Power District, and Idaho Power.

- In Item 7 of Section IX, the Commission should encourage utilities to use plant-specific coal transportation prices to the greatest extent possible. Additionally, utilities should rely on existing contracts for analysis wherever available. These requirements capitalize on existing utility data to ensure more accurate coal pricing and forecasting. As with other listed assumptions, these assumptions should be made available to all intervening parties.

Generation Resources

<u>Firm Resource Additions</u>

- Reasonable assumptions about firmly planned units should be made through collaboration between utilities and intervenors. Synapse recommends that the Commission explicitly require the state's utilities to develop a reasonable, informed assumption as to the likelihood that units currently listed on the MISO interconnection queue will become operational. This assumption should be based on historical precedent and expert review, and it should be disclosed to intervenors for critique. The utilities' assessment of resource adequacy and forecast of capacity pricing in MISO should take these assumed future resource additions into account. Additionally, as already written in the scenario definitions "specific new generating units [should be] modeled if under construction or with regulatory approval (i.e., CON or signed GIA)."

<u>Existing Units & Potential Retirements</u>

- MCL 460.6t requires IRPs to represent "the most reasonable and prudent means of meeting the electric utility's energy and capacity needs" by balancing several factors including "competitive pricing." This language compels the Michigan utilities to assess the cost and operation of both existing and potential new resources to choose a least-cost portfolio. As key planning parameters such as load patterns, fuel prices, technology costs, and regulatory environments change, utilities cannot form clear and objective conclusions regarding the relative costs of potential new resources versus the existing fleet without actually testing the economics of existing units. As such, unit economics should be evaluated on an ongoing basis rather than only based on age or the necessity of a large capital upgrade. The IRP parameters should ensure that all units are properly assessed, and that utilities have a mechanism for identifying and planning retirements of non-economic resources. Sensitivities specifically testing changes such as retirement of the entire coal fleet are useful for providing insight into potential operational changes, transmission needs, and other factors associated with major changes to the composition of the state's resource mix.

- Synapse recommends that the Commission require retirements of existing units to be "endogenously optimized,"[3] with the exception of units with publicly announced

[3] Endogenous optimization means that resource additions and retirements are chosen by a model which freely attempts to find a solution, with no pre-determined outcomes ("endogenously"). The model selects an optimal solution with the lowest total system cost ("optimization"). While endogenous optimization requires utilities to have reasonable analytical and post-processing capabilities, it also represents the state-of-the-art in optimized and objective long-term system modeling.

retirement dates. This recommendation is in accordance with language in Item 12 of Section X:

> "In modeling each scenario and sensitivity evaluated as part of the IRP process, the utility shall allow the model to select retirement of existing generation resources, rather than limiting retirements to input assumptions."

However, the language regarding unit retirements is inconsistent across the proposed IRP parameters. To ensure that the written parameters reflect the standards outlined above, we recommend that the Commission use the language above across all assumptions guidelines and scenario definitions.

In the event that the Commission does not require endogenous retirement of existing units, we recommend that the utilities be required to include a comprehensive slate of targeted, unit-specific retirement studies. Such studies should evaluate unit retirements at a range of different numbers of years earlier than currently planned, along with an analysis of how such earlier retirements would alter the net present value of revenue requirements results.

- Synapse recommends that all non-Michigan MISO unit additions and retirements should be determined using endogenous optimization, apart from those associated with firm unit additions and announced unit retirements as described above.

<u>Optimized Additions of Generic New Resources</u>

- Currently, each scenario includes language reading:

> "Generic new resources (market and company-owned) are assumed consistent with scenario optimizations considering the current resources in the MISO generation queue."

As above, we recommend that the utilities arrive at a reasonable and realistic assumption regarding which resources on the interconnection queue will actually become operational. This will avoid misrepresenting the resource adequacy of the MISO region in future years. We recommend that resource additions over and above the resources included in this assumption should be based on generic cost and performance parameters and that such additions should be optimized as part of the utilities' modeling of their own service territories and of the greater region.

Synapse recommends a language clarification to specify that additions of these generic new resources (I.E., resources additions that are not associated with a specific project or proposed project) must be optimized for each scenario. Utilities should use the MISO interconnection queue as a source of data for the operational and sizing parameters of generic new resources. We recommend that this language remain consistent across all scenarios, and explicitly require that modeling results including additions of generic resources be shared with intervenors.

Renewable and Alternative Resources

- Synapse suggests that the Commission clarify Item 10 of Section IX to ensure that Energy Waste Reduction costs reflect program administrator costs only and do not include participant costs.

- To accurately represent renewable performance, Synapse recommends that the Commission encourage the use of hourly, location-specific data for solar and wind resources. Location-specific and hourly data ensures accurate representation of the emerging renewable capabilities in Michigan and across the Midwest. The Commission should include this guideline both in Item 13 of Section IX and Item 5 of Section X.

- Within the IRP parameters, the Commission should explicitly encourage utilities to include MISO's capacity credit for renewable resources based on electric load-carrying capability (ELCC) in their calculation of load-resource balances.

Load Assumptions

- In scenario analysis, Synapse recommends that hourly load assumptions should reflect the relevant scenario. This includes considerations related to demand response, Energy Waste Reduction, electric vehicle adoption, and load growth by customer class.

- The proposed framework does not explicitly address the portion of Michigan's electric load that takes service under an alternative energy supplier arrangement. The Commission should require analysis of the extent to which utilities may have to provide firm capacity for retail choice load based on current law.