MI POWER GRID

Making the Most of Michigan's Energy Future

Integration of Resource, Distribution, and Transmission Planning Report Appendix A-G

Michigan Public Service Commission Staff Report

MI Power Grid Phase II

May 27, 2021

Case No. U-20633

MPSC

Michigan Public Service Commission

Appendix A

Meeting Summaries for Advanced Planning Report

SEPTEMBER 24, 2020 (Presentation | Comments | Recording)

The first meeting on the topic of Integration of Resource, Distribution, and Transmission Planning began with opening remarks from Chairman Daniel Scripps. Both Chairman Scripps and Staff leads, comprised of MPSC Staff Naomi Simpson, Jesse Harlow, and Roger Doherty, discussed the overall goal, summary, and timeline of this workgroup. Staff leads, along with Zachary Heidemann and Patrick Hudson, detailed each subsection's current status, plans, and background information. These subsections include: Generation Diversity, Transmission Planning, Alignment, and Forecasting. Richard Blumenstock (CE), Joyce Leslie (DTE), and Andrew Williamson (I&M) then presented on their company's high-level perspective on the direction resource distribution and transmission planning should take. At the end of this meeting, Staff solicited comments from interested parties on whether additional clarification was needed and/or if additional topics should be included.

Staff posed the following written feedback requests to the participants; stakeholder responses are contained in the link.

1. Are there additional areas within the four subjects introduced on 9/24/2020 (Alignment of IRP/DP/TP, Forecasting, Transmission Planning, Valuing Generation Diversity) that need additional clarification?

2. Are there subtopics within these subjects that Staff did not mention, and you would like to see addressed during future meetings?

3. Do you believe Staff adequately introduced the items addressed in the August 20, 2020 order in Case No. U-20633 during the 9/24/20 meeting? If not, please explain.

OCTOBER 21, 2020 (Presentation | Comments | Recording)

This second stakeholder meeting expanded on topics of the importance of aligning the respective regulatory planning processes and was the first to host subject matter experts from national groups. Jeff Smith and Jason Taylor (EPRI) spoke on ways to align distribution planning and IRPs. Also providing information for what should be aligned and why. John Shenot (RAP) spoke to the coordinated efforts of NARUC and NASEO and shared his perspectives on the importance of aligning planning processes. Juliet Homer (PNNL) delved into the planning alignment focused on distributed generation and NWAs. In addition, Governor Whitmer's ED 2020-10 and updated guidance from the Commission, Staff developed a Straw Proposal to present to stakeholders within the MI Power Grid Phase II Advanced Planning workgroup and file a report in the docket summarizing the proposal, other proposals from stakeholders, and recommendation. Staff member Jesse Harlow presented on Staff's initial Straw Proposal towards approaching the state's carbon emission goals.

Staff posed the following written feedback requests to the participants; stakeholder responses are contained in the link.

1. What specific externalities do stakeholders think should be addressed that are not currently addressed in the Michigan Integrated Planning Parameters (MIRPP) document. What specific changes to the MIRPP would address these externalities?

2. In what ways could resiliency be addressed in an IRP?

3. What are appropriate ways to address the disconnect between resource needs in an IRP and future unknown resource locations? Are there studies that need to be performed, communication channels that need to be established, or other possible solutions?

4. Is there any general feedback that you would like to share regarding the October 21 meeting?

NOVEMBER 6, 2020 (Presentation | Comments | Recording)

The third stakeholder meeting continued to dive into perspectives on aligning planning processes. Adam Diamant (EPRI), Bob Thomas (Dominion), and Michael Rib (Duke Energy) shared best practices from their utility perspective. Numerous stakeholders also presented additional proposals and considerations to Staff's Straw Proposal regarding ED 2020-10. Andrew Williamston (I&M) spoke to certain considerations and recommendations for multi-state companies; Douglas Jester (5 Lakes Energy) presented "A Sketch for Construction of IRP Scenarios Reflecting ED 2020-10", on behalf of Joint Commenters: Ecology Center, ELPC, MEC, NRDC, Sierra Club, UCS, and Vote Solar. Staff also led facilitated discussion on questions and clarifications to the responses received in previous feedback requests, including the benefits cost analysis, resiliency, externalities not currently addressed in the MIRPPs, and observations on NWAs.

With respect to resilience regarding aligning planning processes and reflecting that in the MIRPP/Filing Requirements:

1. Is resilience accounted for in sensitivities analysis and risk assessment? If not, should it be and if so, how?
2. Is resilience accounted for through the MISO planning process by meeting PRMR requirements? If not, should it be and if so, how?
3. Is the N-1-1 planning criteria used in transmission planning useful for distribution planning?

1. Should resiliency investments be identified in distribution planning feed into IRP or vice versa? What are the touchpoints between distribution planning and IRP that will align the processes when addressing resiliency?

With respect to externalities regarding the MIRPP/Filing Requirements:

1. To what extent do current scenarios, sensitivities, and risk address externalities?
2. Does a probabilistic risk assessment play a role in addressing externalities?
3. What externalities best lend themselves to a qualitative analysis?
4. To what extent should the analysis of externalities influence the IRP filing? Transmission planning? Distribution planning?

With respect to Non-Wires Alternatives regarding the MIRPP/Filing Requirements and aligning planning processes:

1. Do stakeholders agree that non-wires alternatives include storage, solar, wind, demand response, CVR and energy waste reduction?
2. Do stakeholders agree that a non-wires alternative is location specific and alleviates some traditional investment in a targeted geographic area?
3. Juliet Homer's presentation identified several types of NWA analyses identifying benefits and costs across planning processes. Do stakeholders feel one planning process drives another when evaluating and selecting NWAs?

With respect to general session comments:

1. Please provide any comments related to the expert presentations from EPRI, Duke Energy, Dominion.

2. Please provide comments about the Staff Straw Proposal and alternative proposals.

3. Please provide any comments related to today's presentations.

NOVEMBER 18, 2020 (Presentation | Recording)

The fourth meeting began with a Staff presentation by Naomi Simpson on the feedback received between this meeting and the last. The topics focused on resiliency, externalities, and NWAs. Kwafo Adarkwa and Chuck Marshall from International Transmission Company (ITC) presented on planning integration from a transmission planning view with a focus on the bifurcated nature of the IRP process and the MTEP process. Margrethe Kearney and Nikhil Vijaykar from Environmental Law and Policy Center (ELPC) discussed how distribution planning integrates into integrated resource planning and how critical it is to get the right information from distribution planning to inform an IRP. Brady Cowiestoll (NREL) categorized the grid planning process and discussed the benefits of integrating the planning process. She also gave examples of planning tools used as

NREL and how they can assist with alignment. Sarah Mullkoff from Staff ended the meeting with discussing environmental justice and how the MPSC will be working with EGLE on a statewide plan.

DECEMBER 16, 2020 (Presentation | Comments | Recording)

The fifth meeting focused on forecasting within advanced planning. Aditya Jayam Prabhakar (MISO) presented on MISO's generation fleet breakdown, the changing planning environment, and the importance of developing an accurate load shape. Curt Volkmann, President of New Energy Advisors, discusses why distribution forecasting matters and how climate change and COVID-19 has impacted on load shapes. He proposes new approaches to load and DER forecasting using various analytical tools. Brady Cowiestoll (NREL) joins us again to present on forecasting DER/EVs, how they are leading to a decentralized grid, and how to plan for it. Tom Eckman from Lawrence Berkeley National Laboratory (LBNL) then outlined the limitations and gaps of current forecasting methods and lack of parity in cost-effectiveness analysis planning. He suggested ways to improve valuation of demand flexibility so that DERs can compete with other resources more fairly.

Staff posed the following written feedback requests to the participants; stakeholder responses are contained in the link.

1. Please provide any comments related to today's expert presentations.
2. What is an appropriate growth rate to be used for a high load growth sensitivity? Should there be a different growth rate applied for high load with and without deep electrification? Should the rate be different for the lower peninsula and the upper peninsula? If so, what should they be?
3. What is an appropriate growth rate to be used for low load growth sensitivities? How should the low load growth sensitivity consider customer adoption of distributed energy resources? Should the rate be different for the lower peninsula and the upper peninsula? If so, what should they be?
4. Are there publicly available recommended sources that should be used for technology and fuel price forecasts? Are there other collaborative ways to develop technology and fuel price forecasts that could be used by all Michigan utilities filing an IRP?
5. Are there publicly available recommended sources that should be used for capacity and energy price forecasts?

JANUARY 19, 2021 (Presentation | Comments | Recording)

In the sixth meeting, Marc Keyser (MISO) led the presenters and discussed MISO's transmission planning process and its role in coordinating with municipalities, utilities, and co-ops to form an 18-month plan in the MTEP. Bonnie Janssen, manager of Energy Markets at the MPSC, explained the MPSC's role in transmission planning and participation in MISO, PJM, and FERC. Anish Gaikwad (EPRI) focused his presentation on reliability and resiliency within transmission planning and the impact of implementing risk-based approaches for system reliability. Erin Buchanan and Drew Siebenaler (Xcel Energy) outlined their resource and transmission planning process while encouraging the importance of integrating planning processes. There were then presentations from Kwafo Adarkwa (ITC), Kamran Ali at American Electric Power (AEP), Heather Andrew from American Transmission Company (ATC), and Robert Morton (ATC) on the perspectives from TOs. Heather Andrew and Robert Morton explained ATC's commitment to meeting regularly with customers in planning dialogue meetings to discuss interconnection issues. Kamran Ali outlined the transmission planning process for AEP and discussed their focus for the 2020-2021 request for proposal (RFP). Kwafo Adarkwa detailed ITC and METC transmission coverage in Michigan and what they believe are the five factors for IRP success. Ending the meeting, Zachary Heidemann (MPSC) led a Q&A discussion with input from various stakeholders and Naomi Simpson (MPSC) introduced the questions for the written feedback request which can be found on the website under the comments link.

Staff posed the following written feedback requests to the participants; stakeholder responses are contained in the link.

1. What should be changed within the transmission planning section of the Filing Requirement?
   a) Are there specific changes that stakeholders would recommend based upon the conversation today that would clarify, add, or change the existing Filing Requirements?
   b) What documentation would stakeholders find helpful in the filing?

2. How should transmission constraints be modeled in an IRP?
   a) How should the transmission import capability forecast be developed given that the CIL and CEL are historically volatile?
   b) Should CIL and CEL be used in modeling at all? Or should another measure be the transmission constraint?
   c) How should energy and capacity availability in other zones be modeled and how should the utilities acquire this information? How is this done in a way that doesn't create undue burden or an impossible task for utilities filing an IRP? Should out of state resources be allowed to enter RFPs provided they have firm transmission rights? Given the LCR has been a limiting agent in the last MISO year does it make sense to consider out of state resources?

FEBRUARY 9, 2021 (Presentation | Comments | Recording)

Zachary Heidemann (MPSC) kicked off the meeting with a presentation on generation diversity with a specificity on what diversity means in a utility context and why diversity does not equal resilience. Marc Keyser (MISO) discussed the local reliability issues behind growing renewables and how their reliability imperative and transparency efforts will assist with coordinated enhancements. Then Drew Siebenaler and Erin Buchanan from Northern States Power (NSP) presented on resource diversity's strengths in ensuring reliability and mitigating risks. They describe generic resource profiles as insufficient in showing diversity's value and how additional testing for adequacy is critical. Next, Dr. Michael Mulligan (Grid Lab) discussed how diversity provides flexibility, the changing nature of risk assessment, and the critical role transmission can play in increasing reliability, enhancing markets, and reducing the need to build resources. Tom Eckman (LBNL) focused his presentation on managing the risk when considering resource diversity. He accomplished this by illustrating the use of stochastic risk analysis to value resource diversity. Gary Melow (Michigan Biomass) advocated for biomass as a diverse energy resource by detailing what historically exists, currently exists, and the environmental, social, and economic value of adding more in the future. Tim Lundgren at International Plant Protection Convention (IPPC) presented on examples of hydroelectric power, waste to energy facilities, and landfill gas facilities after which he explained the system benefits, energy value, and ancillary benefits of each technology. Jesse Harlow (MPSC) closed the meeting by asking for feedback requests which are provided below.

Staff posed the following written feedback requests to the participants; stakeholder responses are contained in the link.

1. Should generation diversity be valued through risk assessment in an IRP to assess how different diverse resource portfolios can mitigate various risks? The assumption is that this would allow for a comparison of the costs associated with maintaining diverse resources vs the benefit of mitigating certain risks.
2. Are there other methodologies that stakeholders recommend using to determine the value of generation diversity?
3. Will better alignment of planning processes help to identify the value of generation diversity by identifying benefits across multiple planning processes, such as blackstart capability, grid resiliency, etc.?
4. Should utilities provide a calculation of resource diversity for the proposed course of action assuming a 5-, 10-, and 15-year planning horizon in the IRP filing?

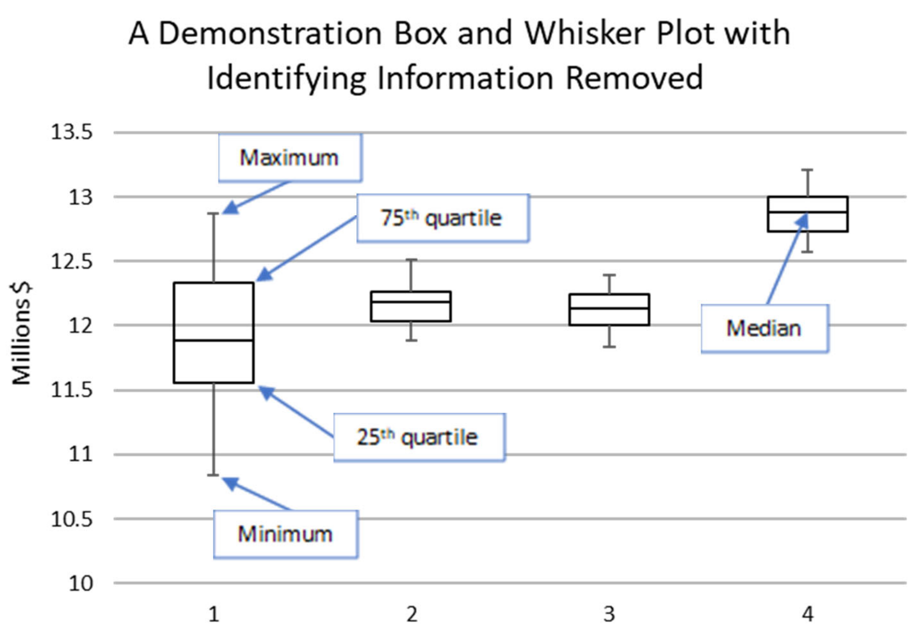
MARCH 2, 2021 (Presentation | Recording)

The eighth and final meeting for this workgroup began with a presentation by Regina Strong (EGLE) on the new MI EJ Screen, which is expected to launch in spring 2021. Jon DeCooman (MPSC) then presented on the "Emissions Reporting Requirements for Utility IRPs" report posted to the docket on December 15, 2020. Naomi Simpson (MPSC) closed the final meeting by discussing the timelines for phase II and III and provided an overview of recommendations that will be included in the draft report.

Appendix B

Box and Whisker Plot

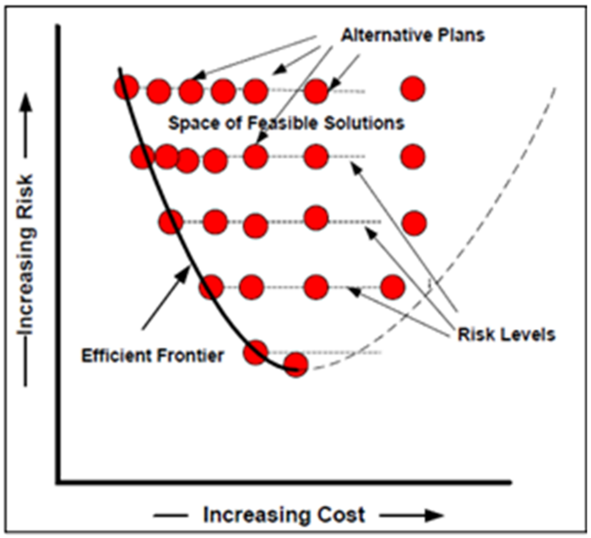
A box and whisker plot, also called a box plot, is a graphing technique that is used to display statistical data. Traditionally, box and whisker plots are comprised of a centerline which denotes the median of the data and the top and bottom of the box are given by the 25th and 75th quartile while the "whiskers" are lines that denote the minimum and maximum of the data. With all five of these data points for a given probability distribution function, the plot shows the skewness of the data.[1] Staff has seen variations of these types of statistical graph where the ends of the whiskers are at the 5th and 95th percentile or where the average is used as the center mark rather than the median. Another variation of this graph is to perform an outlier test and remove the outliers from the "whiskers" and place them as dots beyond the "whiskers".[2] A demonstration box and whisker plot for four sets of data with identifying information removed has been provided below.

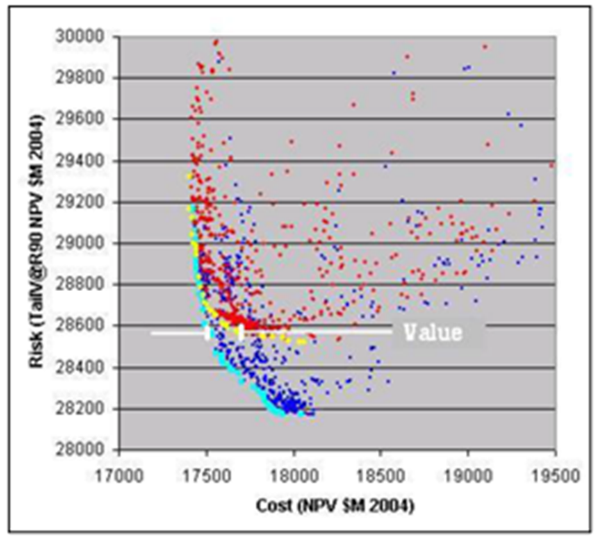


Appendix C

Efficient Frontier

Efficient frontier is a method to display various plans or portfolios where the expected cost is given on one axis and the standard deviation or risk percentage of the statistical data is given on the other axis. Plans should eventually form a curve with a defined edge and other plans scattered behind it. Plans that lie on the edge of the frontier are optimal portfolios and offer the least cost for a given amount of risk. This method allows for the utility to determine the risk-cost combination that is right for it from amongst the optimized plans.3 Two example graphs are provided from the Northwest Council's fifth power plan.4





Appendix D

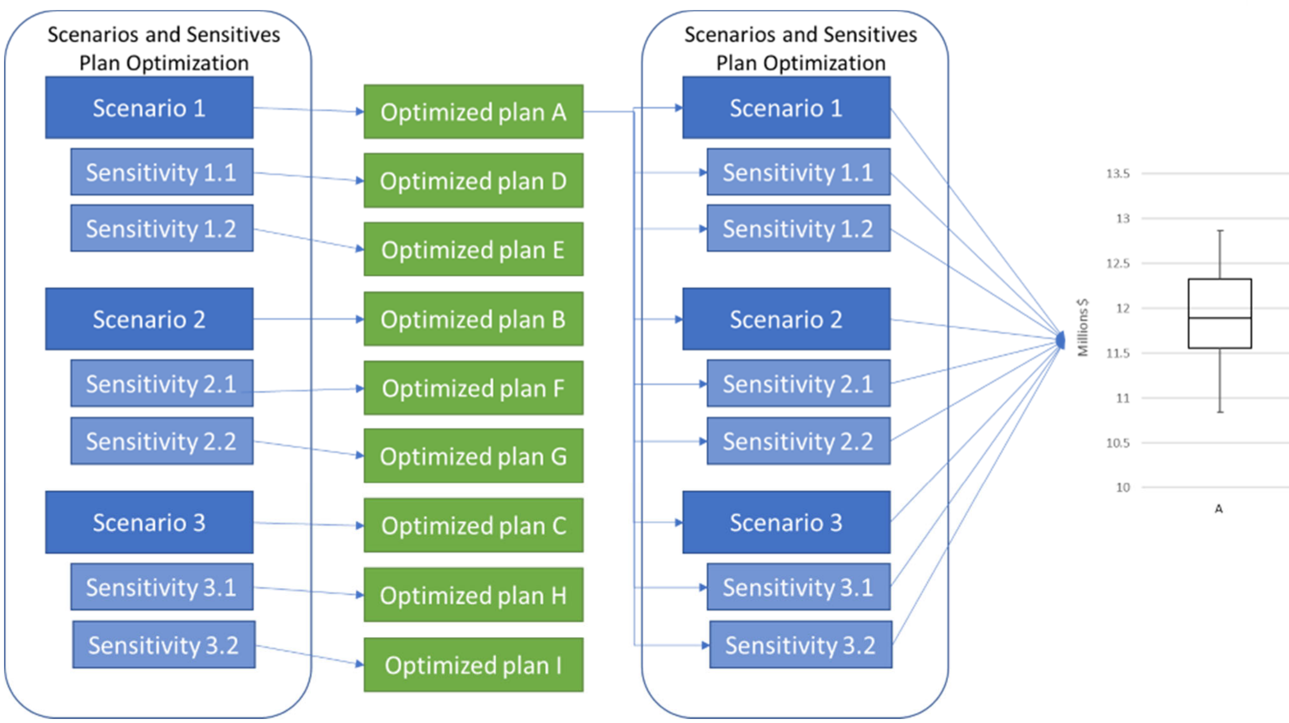
Deterministic vs Stochastic Risk Analysis

When discussing risk assessment, it is important to understand the distinction between deterministic and stochastic analyses. Presented below are several flow diagrams to illustrate these two different methods.

Deterministic

In a deterministic risk analysis, a build plan that has been optimized for a specific scenario is run through the other scenario and sensitivity combinations to test how that plan would perform in those specific future states. A flowchart of this process is shown in Figure 1. Each scenario and sensitivity produce an optimized plan. These plans are then run through all other scenarios and sensitivities. The resulting cost distribution is then represented by a box and whiskers plot. Plans can also be compared by running all the plans through the scenario and sensitivities of the single future deemed most likely to occur.

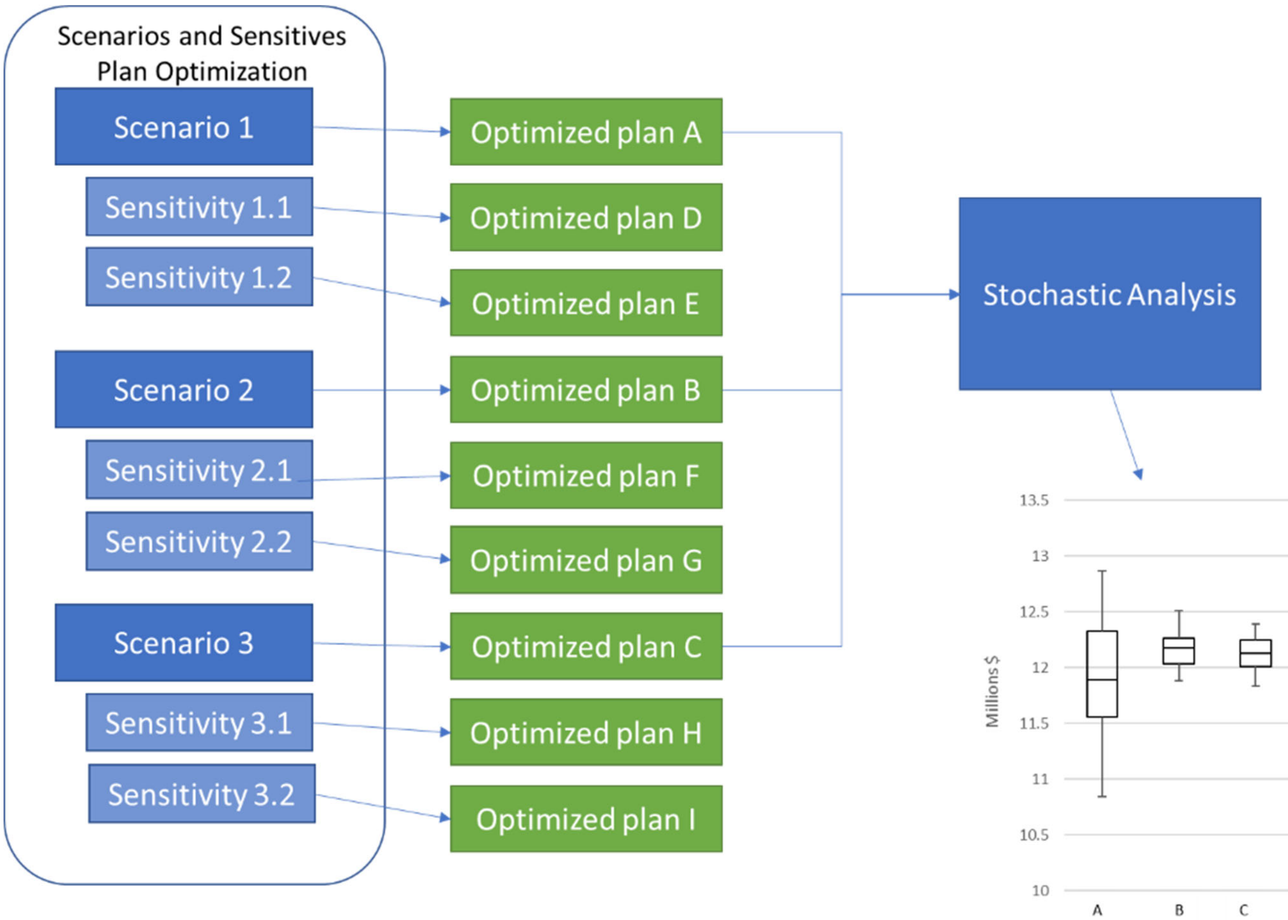
Figure 1 Deterministic Risk Analysis Flowchart



Stochastic

Stochastic analyses begin with the same step as deterministic; plans are optimized for each scenario and sensitivity, shown in Figure 2. However, instead of running those optimized plans through the other futures, each plan is run through many iterations of a run with multiple variables being randomly selected from a probabilistic distribution. Thus introducing randomness into the process. The probabilistic distributions are typically based on historical data for a selected period using standard time-series techniques. Variables can also be linked so one follows the other, such as wind turbine capacity being linked to wind speed. This produces an NPV cost distribution for each plan that can be represented as a box and whisker plot, allowing for comparison of risk.

Figure 2 Stochastic Risk Analysis Flowchart



Appendix E

Diversity Indices

There are three main indices used to quantify diversity and each emphasize various aspects of diversity differently. These indices are non-dimensional numbers that help to quantify diversity. While there are simplistic measures of diversity, such as the number of categories, these metrics provide a calculation that considers all three aspects of diversity. The three main indices used to quantify generation diversity are the Shannon-Wiener Index, the Simpson Index, and the Stirling Index.

Shannon–Wiener Index

The Shannon-Wiener index considers two of the three components of diversity: variety and balance. The Shannon-Wiener Index was originally developed by Bell Telephone to describe information entropy.[1] The equation for the Shannon-Wiener index is given by:

$$Shannon - Wiener\ Index = e^H$$

$$H = -\sum_{i=1}^{n} p_i \ln(p_i)$$

where p_i is the proportion of the population that category *i* occupies out of the total number of categories *n*. The Shannon–Wiener Index, as a measure of diversity, emphasizes smaller contributors more than the Simpson Index described below.[2] This is due to the presence of the natural logarithm of the proportion in the equation, which means that relatively small proportions or "rare species" contributes more than they otherwise would.

Simpson Index

The Simpson Index also does not consider disparity. It was originally developed to examine ecological biodiversity, looking at the concentrations of species.[3] It has the same equation as the Herfindahl-Hirschman Index (HHI), which is a measure of concentration of an industry. The HHI is used by the United State Treasury to determine if a merger will increase market concentration to an unacceptable amount.[4] The equation for this index is as follows:

$$HHI = Simpson\ Index = \sum_{i=1}^{n} (p_i^2)$$

The Simpson Index grows smaller with increasing diversity because it is concerned with concentration rather than diversity. As concentration decreases, its measure (The Simpson

[1] Shannon C. E. (1948) A Mathematical Theory of Communication. *The Bell system Technical Journal*, 27, pp. 379-423,623-656.

[2] Cook H., Keppo I., Wolf S., (2013). Diversity in theory and practice: A review with application to the evolution of renewable energy generation in the UK. *Energy Policy*, pp. 61, 88-95.

[3] Simpson E. H. (1949). Measurement of Diversity. *Nature*, pp. 163, 688.

[4] Cook H., Keppo I., Wolf S., (2013). Diversity in theory and practice: A review with application to the evolution of renewable energy generation in the UK. *Energy Policy*, pp. 61, 88-95.

Index) will decrease as well. In this case, diversity and concentration are inverse of each other. To this end, there is a modified version of the Simpson index where diversity indices are directly correlated with diversity, not inversely correlated. The modified Simpson Index is the inverse of the standard Simpson Index.[5]

$$Modified\ Simpson\ Index = \frac{1}{\sum_{i=1}^{n}(p_i{}^2)}$$

Staff uses this version in the projection of Michigan's generation diversity that is shown later in the paper. This version is preferred because it trends along with the other indices and results in less confusion.

Stirling Index

The Stirling Index is the only index commonly used for electrical generation that includes all three components of diversity: variety, balance, and disparity. It was developed specifically to look at electrical generation and is also the newest of the indices covered here. The equation for the Stirling Index is:

$$Stirling\ Index = \sum_{ij,i\neq j}^{n} d_{ij}(p_i * p_j)$$

This equation compares the proportion of two different categories to one another. Each pair will have a disparity coefficient (d_{ij}) that represents how dissimilar the two different categories are from one another. The lower the disparity coefficient, the more similar two categories are.[6]

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[5] Wu, T. Y., Varun, R. (2017). Quantifying Diversity of Electricity Generation in the U.S. *Model Documentation and Results for ERCOT Scenarios*.

[6] Stirling, A. (2007) A general framework for analyzing diversity in science, technology and society. *Journal of The Royal Society Interface*. pp. 4 ,707-719.

Appendix F

Acronym List

Advanced Planning: Michigan's Integrated Resource/Distribution/Transmission Planning
AEP: American Electric Power
AER: Annual Energy Review
AMI: Advanced Metering Infrastructure
AO: Advisory Opinion
ATB: Annual Technology Baseline
ATC: American Transmission Company
BRA: Base Residual Auction
CE: Consumers Energy
CEL: Capacity Export Limit
CELID: Customers Experiencing Long Interruption Duration
CEMI: Customers Experiencing Multiple Interruptions
CIL: Capacity Import Limit
CONE: Cost of New Entry
CYME: power flow software model
DER: Distributed Energy Resource
DP: Distribution Plan
DR: Demand Response
DTE: DTE Energy
ED 2020-10: Executive Directive 2020-10
ED: Executive Directive
EGLE: Department of Environment, Great Lakes, and Energy
EIA: U.S. Energy Information Administration
EJ: Environmental Justice
ELPC: Environmental Law and Policy Center
EO 2020-182: Executive Order 2020-182
EO: Executive Order
EPRI: Electric Power Research Institute
ESR: Electric Storage Resource
EV: Electric Vehicle
EWR: Energy Waste Reduction
FERC: Federal Energy Regulatory Commission
Filing Requirements: IRP Filing Requirements
FRAP: Fixed Resource Adequacy Plan
FRR: Fixed Resource Requirement
GHG: Greenhouse Gas

HCA: Hosting Capacity Analysis
HHI: Herfindahl-Hirschman Index
I&M: Indiana Michigan Power Company
IEN-P: Integrated Energy Network Planning
IPP: Independent Power Producer
IPPC: International Plant Protection Convention
IRP: Integrated Resource Plan
ISO: Independent System Operator
ISOP: Integrated System & Operations Planning
ITC: International Transmission Company
LBNL: Lawrence Berkeley National Laboratory
LCR: Local Clearing Requirement
LDA: Locational Deliverability Area
LOLE: Loss of Load Expectation
LRR: Local Resource Requirement
LRZ: Local Resource Zone
LSE: Load Serving Entity
MAC EJ: Michigan Advisory Council on Environmental Justice
MEPA: Michigan Environmental Protection Act
METC: Michigan Electric Transmission Company
MIRPP: Michigan Integrated Resource Plan Parameters
MISO: Midcontinent Independent System Operator
MOPR: Minimum Offer Price Rule
MPSC: Michigan Public Service Commission
MTEP: MISO Transmission Expansion Planning
MW: Megawatt
NARUC: National Association of Regulatory Utility Commissioners
NASEO: National Association of State Energy Offices
NERC: North American Electric Reliability Corporation
NPV: Net Present Value
NREL: National Renewable Energy Laboratory
NSP: Northern States Power
NTA: Non-Transmission Alternative
NWA: Non-Wires Alternative
PCA: Planned Course of Action
PEV: Plug-in Electric Vehicle
PNNL: Pacific Northwest National Laboratory
PRA: Planning Reserve Auction
PRM: Planning Reserve Margin
PRMR: Planning Reserve Margin Requirement
PSCR: Power Supply Cost Recovery

PV19: Polar Vortex 2019
RAP: Regulatory Assistance Project
RFP: Request for Proposal
RPM: Resource Planning Model
RTEP: Regional Transmission Expansion Plan
RTO: Regional Transmission Organization
SEA: Statewide Energy Assessment
T&D: Transmission and Distribution
TO: Transmission Owner
TP: Transmission Plan
UMERC: Upper Michigan Resource Corporation
UPPCo: Upper Peninsula Power Company
ZRC: Zonal Resource Credit

Appendix G

Stakeholder Comments

ABATE

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter, on the Commission's own motion, to commence a collaborative to consider issues related to integrated resource and distribution plans.	))))	Case No. U-20633

COMMENTS OF THE
ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY

I. INTRODUCTION

On April 15, 2021 Michigan Public Service Commission ("Commission" or "MPSC") Staff circulated a Draft Report for the Integration of Resource/Distribution/Transmission Planning Workgroup ("Report"). Staff indicated that while it continued to edit the construction, logistics, and content of the Report, it was soliciting comments on the draft circulated.

Below are the comments on that Report of the Association of Businesses Advocating Tariff Equity ("ABATE"). In addition to the more specific comments and recommendations provided below, Staff should ensure its Report and the recommendations contained therein adhere to the following general principles: (i) planning processes should be more transparent, with greater stakeholder participation in decision-making; (ii) decisions should be informed by risk levels and associated risk reductions as well as potential cost reductions, considering customers' risk tolerance; and (iii) estimates of risk levels and associated risk reductions should be based on historical actual data and experience whenever possible. While some of the Report's goals and recommendations appear to reflect these principles to some extent (see e.g. Report at i ("The goal of this report is to evaluate alternatives that provide the best value while resulting in a more efficient system and lower costs for ratepayers")), others should more explicitly address these issues as set out below.

II. COMMENTS

A. Resilience should be more clearly defined in terms of risk avoidance and associated costs.

The Report provided an overview of Commission guidance on the concept of "resilience" and the value thereof, noting the Commission's explanation that ""[u]nderstanding the value of resilience improvements will better inform future Commission decisions on investments targeting resilience improvements." (Report at 4-5 (citations omitted).) The Report did not, however, explicitly discuss considerations for how, in fact, resilience could be valued. This issue should be more directly addressed in the Report.

Staff noted the difficulty of discussing and valuing "the standalone benefits of resiliency among stakeholders, utilities, and Staff," but noted that the concept of resilience discussed in this Report would "include[] both restoration from an outage and avoidance of an outage" and provided examples of metrics which "specifically address recovery and restoration from outages." (See Report at 5-6.) Staff also provided two important aspects of load vulnerability, including "system attacks such as extreme weather or cybersecurity events" and "loads that include vulnerable population areas where people . . . may be more severely impacted by outages." (See Report at 6.) The Report therefore explained various elements of what is meant by "resiliency," but did not substantively address how those elements or resiliency overall should be valued in terms of how they concern or are experienced by customers.

As explained in ABATE's previous comments, after establishing the goals increased resiliency is meant to accomplish (i.e. restoration from an outage and avoidance of an outage), metrics by which to measure progress and strategies (e.g., resource diversity) and tactics for achieving that process can be considered. When analyzing these strategies and tactics, however, the costs and benefits of each must be considered, including the alternative of not acting at all.

Data points required to conduct such analyses include the following: (i) the quantified risk (i.e., likelihood) of a particular adverse event; (ii) the quantified consequence (i.e., $ amount) of the particular adverse event; (iii) the cost of various solutions; and (iv) the effectiveness of various solutions (i.e., the risk, or likelihood, that a solution will be less than 100% effective). Only with all four data points can an optimum decision, informed by risk and cost considerations, be reached.

In other words, one way to value resiliency is to quantify the consequences (including opportunity costs) to a customer, class of customers, or community from a loss of service of various extent and duration. The economic consequence of various service loss extents and durations is important to evaluate the reasonableness of various strategies to increase resiliency. For instance, while the loss of a compressor station during a polar vortex is obviously a serious event, determining the appropriateness of various potential solutions requires a quantification of the associated consequence (for example, the cost of rolling blackouts for a certain period of time for a certain number of customers). Such a metric will assist customers and the Commission in evaluating whether certain potential solutions are excessively costly to eliminate or reduce the risk of an adverse event they may be willing to address or insure against in another manner (e.g. self-generation).

The importance of properly quantifying resiliency goals and solutions stems from the fact that market participants, be they potential suppliers or potential buyers, respond to price signals. For an industrial customer to invest in self-generation which could also improve reliability to near-by customers on a microgrid or take actions to improve power factor it will require a price signal. The same is true to provide a regulated utility with unregulated revenues or business model options, or to allow a customer to pay extra for various levels of reliability and allow the utility to figure out the least costly ways to provide that level to that customer. Properly valuing and quantifying resiliency through established price signals is therefore a prerequisite to reasonably and prudently accomplishing resiliency goals.

As such, the Report should note that resiliency will ideally be valued based on (i) the quantified risk (i.e., likelihood) of a particular adverse event; (ii) the quantified consequence (i.e., $ amount) of the particular adverse event; (iii) the cost of various solutions; and (iv) the effectiveness of various solutions (i.e., the risk, or likelihood, that a solution will be less than 100% effective). This will permit customers and the Commission to place a value on resiliency measures and assess their reasonableness and prudence.

B. Distributed energy resources and non-wires alternatives must be appropriately valued when forecasting to be properly compared with traditional resources.

The Report explained that within modeling processes "it is important that [distributed energy resources ("DERs") and non-wires alternatives ("NWAs")] are treated equitably when compared to other resource possibilities." (Report at 8.) The Report went on to state that "[i]f DERs and NWAs are not equitably valued in comparison to other capacity additions, then they will continue to be incorporated into the resource plan as an afterthought and not fully account for the value they provide." (Report at 8.) Building off this point, the Report should also note that ensuring equitable valuation requires consideration of the revenue requirements presented by these resources.

Specifically, equitable valuation should entail using respective resource revenue requirements (meaning the cost to customers) as the basis of utility costs for comparison of traditional utility investments to DERs and NWAs. Simply comparing DER and NWA costs – which reflect cost of debt, cost of equity, federal income taxes, etc. in their prices – to traditional utility costs without these cost components customers must pay will not equitably value DERs and NWAs relative to options funded by utility capital. Without a more comprehensive consideration and estimation of utility costs as customer costs (including all carrying charges), utility capital options will ultimately be favored.

Equitably valuing DER, NWA, and traditional resources therefore requires consideration of all customer costs. Leaving these out of comparative resource evaluations will result in DER and NWA resources being inequitably disfavored.

C. Transmission capacity should serve to address myriad grid planning issues, such as renewable intermittency, decentralization, and resilience, such that expanding the potential role of transmission capacity can further curb potential capital expenditures.

While the Report recommended certain minimum studies performed for the integrated resource plan ("IRP") transmission analysis (e.g. evaluations of the reliability, cost, and resource diversity benefits of transmission alternatives, areas or regions where new resources can interconnect to the transmission system with minimal transmission investment, the cost of upgrades that would increase the local CIL/CEL and impacts to the LCR, and where transmission and non-transmission alternatives are likely to facilitate DERs), its discussion of stakeholder participation on this issue appears limited to participation in IRP cases and RTO/ISO transmission planning meetings. (See Report at 34-35.) In addition to these opportunities for stakeholder involvement the Report should recommend the Commission consider a more robust and broader state-level analysis of transmission resources and planning beyond simply their inclusion in the current utility-specific IRP process.

As explained in ABATE's prior Comments, transmission assumptions in IRPs are guided by the filing utilities and are necessarily colored by utility interests and incentives. Further, through utility-filed IRPs transmission resources and planning are only considered in multiple utility-specific (and thus incomplete) perspectives. To develop optimal analyses and planning for this issue Michigan should also pursue a more comprehensive state-level process for transmission planning in which stakeholders (including utilities) are permitted to provide input. The stakeholder inputs and results of this more expansive planning process can then be integrated into utility generation resource and distribution planning.

As set forth in ABATE's prior Comments, the general structure of this process should entail a Staff-led planning effort to develop a planning framework including the following elements:

- Establish transmission-related goals in the context of the IRP process (e.g. reliability, generation resources, costs, timeframes);
- Identify transmission planning constraints (e.g. existing assets, capacities, characteristics, etc. as well as likely customer changes over time with regard to loads, generation resources, etc.);
- Identify alternatives to reach goals within constraints (i.e. modeling);
    - Central generation options;
    - Transmission options;
    - Customer incentive options (e.g. demand response, pricing, etc.);
- Evaluation of options (the Electric Power Research Institute ("EPRI")'s presentation at the January 19 meeting addressing incorporating risk in transmission planning provided a good framework for planning and project evaluation);
- Options selected based on cost and risk (again, the approach outlined by EPRI for risk-based transmission project evaluation and selection is reasonable and advisable).

The Report should recommend development of a strawman proposal in which the elements above are discussed, stakeholder input is provided, and Staff recommendations are determined. Such an approach would provide a valuable forum and method for cost-effective and forward-looking transmission resource planning, the inputs and results of which could then be incorporated into the broader generation resource and distribution planning process.

~~D.~~ Generation diversity should be valued by considering diverse resource portfolios' utility to address risks of varying likelihood and impact severity along with customers' opportunity costs.

While the Report noted that "[d]iversity itself holds no intrinsic value" and "generation diversity should be valued for its potential to provide cost savings or improve system reliability and resiliency," it did not directly recommend that specific generation unit retirements should be considered through reasonable and transparent analyses which assess the costs and benefits of diversification and demonstrate economic impacts to avoid imprudent portfolio modifications. (Report at 39-51.) Such an analysis should be explicitly addressed in the Report.

In accordance with the Report's assertions that diversity should be valued for its potential to provide cost savings, generation retirements should be coordinated pursuant to a generation retirement analysis akin to the "scorecard" review other utilities (such as the Northern Indiana Public Service Company ("NIPSCO")[1]) have utilized. Considering retirements based on such analyses will ensure decisions regarding what units need to be retired and when such retirements should occur are reasonable and informed. Such a process will also assist with transparency as well as customer expectations and foresight. As such analyses align with Staff's discussion of resource diversity generally they should be specifically discussed and recommended in the Report.

Further, when valuing resource diversity based on its potential to provide cost savings or improve system reliability and resiliency, the considerations discussed above for valuing resiliency

[1] See e.g. NIPSCO's 2018 Integrated Resource Plan at 145, 149-58. NIPSCO's retirement analysis was undertaken to "evaluate the preferred coal retirement strategy over time." https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2018-nipsco-irp.pdf?sfvrsn=15

should also be used. Specifically, the value of generation diversity's ability to avoid risks should consider the following: (i) the quantified risk (i.e., likelihood) of a particular adverse event; (ii) the quantified consequence (i.e., $ amount) of the particular adverse event; (iii) the cost of various solutions; and (iv) the effectiveness of various solutions (i.e., the risk, or likelihood, that a solution will be less than 100% effective). This ensures that a determination of the customer value of resource diversity will include quantifying the consequences (including opportunity costs) to a customer, class of customers, or community from a loss of service of various extent and duration. Determining the economic consequences incurred or avoided by using resource diversity to address risks will provide a meaningful way to value that diversity.

Furthermore, while the Report provided a positive discussion of valuing generation diversity (i.e., that such value derives from risk mitigation and its potential to provide cost savings or improve system reliability and resiliency), it should also address the concept of load diversity. (See Report at 36-51.) Considering not just the value of generation diversity, but also the types of loads the utility must serve and their varying characteristics will also help inform prudent system planning and investment.

One example of considering load diversity is transportation electrification and electric vehicles ("EVs"). Since significant levels of EV charging occur at night (when demand is lowest), large transmission and distribution investments to accommodate EV capacity increases may not be necessary, or at least may not be necessary until much further in the future. Since utilities are unlikely to under-estimate load growth, this is one instance where transparency (for example, into load growth forecast details) could help utilities, stakeholders, and the Commission engage in more prudent planning and investment decisions.

Planning must therefore consider diversity of both a utility's generation portfolio and its various load characteristics. Carefully incorporating the features of various loads and types of usage will assist all parties in evaluating and developing proper system investments to cost-effectively and efficiently meet demand.

E. In terms of emissions and environmental consideration in resource, distribution, and transmission planning the Commission's authority is limited to its statutory powers.

While the Report acknowledged that with regard to environmental determinations "EGLE has ultimate authority as the primary environmental regulator" and "the Commission is limited to the evidence within the record in its review and determination within a utility IRP formal proceeding," it also noted that "the MPSC as a rate regulator is granted some authority over environmental determinations under MCL 406.6t." (Report at 61-67.) It is important the Commission's actions accord with the requirements of that statute.

While MCL 460.6t provides for EGLE to submit advisory information that is not binding on future determinations by the Commission in any proceeding, the Commission "has only the authority granted to it by statute." *In re Consumers Energy Co*, 322 Mich App 480, 490 (2017); *Union Carbide Corp v Public Serv Comm*, 431 Mich 135, 148 (1988) ("The commission is a creature of the Legislature and, as such, possesses only those powers granted upon it by statute"). As such, it is not clear there is adequate legislative authority for the Commission to make determinations in IRP proceedings based on issues like emissions reduction goals set out in Executive Directives or other non-authoritative resources. In essence, as previously stated in this proceeding, the Governor's net-zero goal announcement does not change the Commission's jurisdiction and the Commission is not a carbon regulator.

Further, the Commission's "authority does not include the power to make management decisions for utilities." *In re Consumers Energy Co*, 322 Mich App at 490; *Union Carbide*, 431

Mich at 148 ("The power to fix and regulate rates, however, does not carry with it, either explicitly or by necessary implication, the power to make management decisions"). Directing specific utility action to ultimately reduce carbon emissions or pursue other policy objectives without explicit statutory authority may arguably amount to improperly "order[ing] a utility to follow particular principles of . . . management." *Union Carbide*, 431 Mich at 151-52. The Commission should therefore ensure its actions with regard to environmental determinations in IRP proceedings are consistent with its authorizing statutes.

F. The Report should clarify the utility of the recommendations provided by the NARUC-NASEO Task Force on Comprehensive Electricity Planning.

The Report noted the Commission's participation in the National Association of Regulatory Utility Commissioners ("NARUC") and National Association of State Energy Offices ("NASEO") Task Force on Comprehensive Electricity Planning ("Task Force") and acknowledged the "valuable synchronicity" between that and this proceeding. The Report should clarify, however, how the findings of that effort may be incorporated into planning processes in Michigan.

The Report stated that the work of the Task Force and this proceeding "are aligned on the forefront of grid advancement and such results can be examined and implemented simultaneously." (Report at 52-53.) Given this alignment, the findings and recommendations provided by the Task Force should be utilized in developing Michigan utility planning processes. Indeed, these recommendations are applicable across the spectrum of issues discussed in this proceeding, particularly with regard to aligning distribution planning and IRP assumptions and processes, and the potential provided by are more intentional, strategic, and stakeholder-involved transmission planning process. Given this alignment and applicability the Task Force's findings and recommendation provide important and informed guidance on utility system planning processes here.

AEE and EIBC

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May 3, 2021

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Re: Integration of Resource, Distribution, and Transmission Planning Draft Report Comments

Dear Staff,

The Michigan Energy Innovation Business Council (Michigan EIBC) and Advanced Energy Economy (AEE) appreciate the opportunity to provide feedback to Staff's April 15, 2021 Integration of Resource, Distribution, and Transmission Planning Report.[1] We have been active stakeholders in Phase I and Phase II of the Advanced Planning Process and look forward to working with the Commission and Staff in Phase III of the Work Group. Michigan EIBC and AEE particularly appreciate Staff's commitment to developing more iterative, integrated planning processes that create meaningful opportunities for stakeholders to work with utilities as they develop Michigan's energy future. We intend for the following comments to provide Staff with some specific recommendations to more effectively define the parameters for Phase III of the Advanced Planning process.

If there are any questions or concerns related to these comments, feel free to contact us directly.

Regards,

/S/
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[1] Michigan Public Service Commission. (2021). April 15, 2021 Staff Report in Response to the October 29, 2020 Commission Order in Case No. U-20633.

Utilizing Emerging Approaches & Tools to the Fullest Extent

Staff correctly recognizes that AMI is a powerful platform that provides utilities and other energy market participants with valuable, granular data, critical to producing a complete planning process for each utility. Staff also noted the increased contribution that distributed energy resources (DER) and customer-owned resources will provide to the grid in the future. Staff stated that, "technologies like AMI not only give the utility insight into how the system operates down to the circuit level but eventually can be utilized to allow more demand-side management or control options that provide even greater flexibility for planning."[2] With the implementation of FERC Order 2222 and ongoing improvement of DERs in terms of technology and cost, we expect the deployment of DER and customer-owned generation to increase. Maximizing the capabilities of AMI will be critical to taking advantage of DER and customer-owned generation to create a cost-effective, sustainable energy future for ratepayers.

We recognize that Michigan's largest utilities have already invested the money and resources into widespread deployment of AMI technology. We believe that utilities should be expected to take full advantage of AMI in order to maximize benefits to ratepayers, prevent imprudent future investments, and reach state emissions reduction goals. Thus, as a part of its guidance for Phase III of the MI Power Grid Advanced Planning Work Group, AEE and Michigan EIBC recommend that Staff direct utilities to consider the full range of applications for AMI in their IRP analyses to drive DER deployment. We also recommend that Staff direct utilities to demonstrate how they will use AMI data to drive decision-making in their IRPs. Doing so will allow each utility to effectively develop more granular and accurate load projections and incorporate DERs and customer-owned generation sources in future plans.

Improving Transparency

We appreciate Staff's commitment to providing greater visibility into forecasting methodologies and changes to those methodologies so that stakeholders can understand each utility's forecasting process. We also appreciate Staff's efforts to encourage utilities to use publicly available data for their forecasting methods, when those data are available. Doing so increases transparency in the forecasting process. However, we recommend that Staff require utilities to grant stakeholders access to their forecasting data to perform independent analyses, regardless of whether or not the data are publicly available. We believe this will better serve the interest of all stakeholders, including the utilities and the Commission. We recognize the sensitivities that exist, as utilities may need to use proprietary data to develop forecasts. However, we believe the Commission should pursue all options to make utility data available without compromising its proprietary nature, such as by using non-disclosure agreements. With these data, stakeholders can have a more comprehensive understanding of the inputs and assumptions that utilities will be using in their IRP models and will be able to provide input on forecasts to ensure that they accurately represent Michigan's energy future.

[2] Ibid, 16.

Greater transparency, access to information, and the ability to use all the tools available to a utility allows stakeholder engagement to be more effective and provide better quality review. In Michigan, as part of a settlement agreement in the last IRP case (U-20165), Consumers Energy agreed to provide intervenors with a limited number of licenses to their modeling program for use in the upcoming 2021 IRP proceeding. Although this practice is relatively limited in Michigan, it should be applied more generally and has been in other states. For example, in 2019, the New Mexico Public Regulation Commission directed the Public Service Company of New Mexico (PNM) to develop a plan to replace the generating capacity of units 1 and 4 of the San Juan Generating Station, a 924 MW coal plant.[3] The Commission also directed PNM to provide intervenors in the case access to not just the data used for developing forecasts, but access to their IRP modeling data and software as well. Intervenors used these data run a wide variety of scenarios using the same methodology as PNM.[4] PNM worked with external stakeholders to develop a plan that would replace the plant's generation with 950 MW of solar plus storage.[5] Stakeholders created innovative, alternative solutions to replace the plant that were cost effective and helped PNM meet the emissions requirements outlined in the State's Energy Transition Act. These plans were used in conjunction with PNM's own to create a cost-effective and clean strategy to decommission the plant. This emerging best practice can be a framework for the Staff and the Commission moving forward.

Generation Diversity

We agree with Staff's stance that generation diversity is a form of risk mitigation and that generation diversity should be valued for its potential to provide cost savings and improve system reliability and resilience. As Staff continues to develop its understanding of generation diversity and risk assessment, we recommend that Staff expand its scope of diversity beyond generation sources alone. Grid operators also possess tools beyond generation sources to mitigate risk. Energy efficiency measures, grid improvements and resiliency measures, demand-side management tools, and behind-the-meter generation can contribute to developing a cost-effective, resilient electricity sector. As Phase III of the Advanced Planning Process begins later this year, we encourage Staff to consider generation diversity as a part of a greater conversation on risk mitigation and grid resilience.

We also encourage Staff to develop a framework for updating diversity indices as the inherent nature of generating sources changes. Energy storage resources continue to proliferate and the impact of the variability of renewable sources such as wind and solar decreases with the addition of storage to generating facilities. As the nature of these generation sources changes, we recommend that Staff direct utilities to regularly update the inputs to their diversity indices, as they continue developing iterative distribution planning, IRP, and transmission planning processes. We believe

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[3] New Mexico Public Regulation Commission (2019). Recommended Decision on Replacement Resources, Part II. Case No. 19-00195-UT.

[4] Ibid.

[5] Renewable Energy Magazine (2020). Four Projects Totaling 950MW Could Replace San Juan Generating Station.
https://www.renewableenergymagazine.com/pv_solar/four-projects-totaling-950mw-could-replace-san-20201012

that generation diversity can be a useful tool for developing propitious planning processes when implemented correctly.

Conclusion

AEE and Michigan EIBC value the time and effort Staff is taking to develop a more iterative, transparent planning process. We believe this work is critical to creating a more cost-effective, resilient, and sustainable electricity sector for ratepayers. We look forward to working with Staff and stakeholders in Phase III of the Advanced Planning Work Group.

Consumers Energy
Count on Us®

May 3, 2021

Integration of Resource, Distribution, and Transmission Planning
Draft Report
Comments of Consumers Energy Company

I. INTRODUCTION

On April 15, 2021, the Michigan Public Service Commission ("MPSC" or the "Commission") Staff ("Staff") issued a draft Integration of Resource, Distribution, and Transmission Planning Report ("Report") in the Advanced Planning Workgroup. Staff has requested comments in response to the draft Report by May 3, 2021. Consumers Energy Company ("Consumers Energy" or the "Company") is submitting these Comments in in accordance with Staff's request. The Company appreciates the opportunity to provide Comments.

In the following sections of these Comments, the Company is providing numerous items for consideration in Staff's final Resource Distribution, and Transmission Planning Report. These items include proposed edits and other areas of concern to the Company. For ease of review, the Company has organized the following sections of these Comments to correspond to the sections of Staff's draft Report. The Company's lack of comment on any particular portion of this Report should not be construed as an agreement with that portion of the report.

II. COMMENTS

A. Forecasting (pages 6 through 20):

1. Forecasting components

On page 8, the Report states that:

> *Utility planning has traditionally been focused on serving gross electricity demand and energy by building, or acquiring, centralized baseload generation while constructing distribution and*

> *transmission infrastructure to accompany those resources. However, DERs and NWAs provide a new opportunity for increased reliability and affordability without the costs associated with traditional solutions.*

The Company recommends the Staff remove opinion statements regarding the increased reliability and affordability of Distributed Energy Resources ("DERs") and Non-Wires Alternatives ("NWAs"). The Company recommends wording suggesting continued exploration of the benefits DERs and NWAs may provide additional benefits not yet defined.

Additionally, on page 8, the Report states that:

> *Within modeling processes, it is important that DERs and NWAs are treated equitably when compared to other resource possibilities.*

The Company recommends removing language for treating a resource equitably and instead state the importance of the assumptions for DERs and NWAs, the same as for any technology resource, to support the economic analysis in an Integrated Resource Plan ("IRP").

2. Distributed Energy Resource Forecasts

On page 9, the Report referenced suggestions made by Curt Volkman during a December 16, 2020 presentation and states that "*Staff agrees and recommends utilities should provide additional information in future distribution plan cases on DER and NWA forecasting and/or modeling.*" The Company requests additional clarification as to what additional information is needed and in what forum (e.g. 5-year Distribution Plans). Based on the existing language in the Report, it is unclear exactly what Staff is recommending.

3. Current Time Horizons for Planning Processes

Page 12 of the Report states that:

> *On a regional level, MISO conducts its MTEP process on an annual basis; TOs participate in the MTEP planning process, and will often*

> *propose alternate solutions to transmission needs identified in this process.*

The Company recommends that the Report also acknowledge that various other stakeholders participate in the Midcontinent Independent System Operator, Inc. ("MISO") Transmission Expansion Planning ("MTEP") process in addition to Transmission Owners ("TOs"), including distribution providers, Staff, and others. TOs may propose initial transmission solutions, but it is the other stakeholders that will often propose alternate solutions to the TO proposed transmission solutions. The Company would like to note that, while non-TO stakeholders do have the opportunity to propose alternate solutions to transmission, the current MTEP process is not structured to provide a comprehensive and robust review of alternatives. Transmission owners submit proposed projects each year in September. From there, model development occurs until April and the MTEP team performs an independent analysis with results available in May. Stakeholders are requested to provide final and viable alternative solutions by the end of May, meaning that stakeholders only have a few weeks to review final MISO models, evaluate mitigations, and propose alternative solutions. The Company has supported Integrated Roadmap item IR091 which seeks to resolve this inequity. Additionally, Staff correctly notes that the MTEP process is an annual one. Compare this to the Generation Interconnection Process ("GIP") which regularly takes over 1,000 days, and it is effectively impossible for MISO to evaluate or select a new generation alternative to address a system issue identified in MTEP. The Company has supported Integrated Roadmap item IR092 which seeks to resolve this inequity.

Additionally, page 12 of the Report states:

> *The MTEP model uses a 20-year time horizon, which allows for new transmission solutions to be considered, approved, and constructed given extensive time requirements for new transmission siting.*

The MISO MTEP powerflow models are developed using a 10-year time horizon, rather than a 20-year time horizon. Although the time horizon is 10 years, the majority of approved projects and planned investment falls in the 5-year time horizon. Similarly, the majority of Commercial Operation Dates of generators in the MISO Generator Interconnection Queue also fall in the 5-year time horizon. This adds to the complexity of aligning the time horizons across planning processes. The Company recommends that Staff revise this portion of the Report accordingly. This portion of the MTEP process should be updated to reflect the rapidly changing technology mix of the industry. With such long lead times between transmission project approval and construction, there needs to be a mechanism in place to review projects approved several years prior, but not yet started. It is entirely possible that by the time a transmission project is ready for build out, it is no longer required due to the installation of non-transmission solutions in the interim. To encourage such a change to the MTEP process, the Company supported MISO Issue PAC-2021-2.

4. Current Limitations and Determining Optimal Modeling Granularity

On page 16, the Report states:

> *However, recent advancements in tools and techniques, such as Consumer's newly developed CYME tool, allow for this information to begin to be incorporated into the different planning processes.*

The Company believes that this statement may reflect a potential misunderstanding. The CYME tool is not Consumers Energy's tool, but is instead a tool used by Consumers Energy. Additionally, the tool is not new to Consumers Energy or the electric utility industry. The Company believes that Staff may have intended to refer to work in progress on an Advanced Distribution Analysis Planning Tool ("ADAPT") currently under development by the Electric Power Research Institute ("EPRI"), which is not a tool designed only for Consumers Energy but for those utilities who support the referenced efforts by EPRI.

5. Future Improvement Opportunities Using Nascent Approaches & Tools

On page 16, the Report states that:

> *One way in which AMI data can be used to improve the forecasting process is through the development of a hosting capacity analysis.*

The Company does not agree with, or at least understand, the statement that Advanced Metering Infrastructure ("AMI") data can be used to improve the forecasting process through a hosting capacity analysis. Hosting capacity analysis is a snapshot in time and not a predictor of the future, and would not be a major factor in short to long term forecasting processes. The Company requests clarification from Staff on the above referenced statement.

6. Transparency

On page 18, the Report asserts that *"[i]n the feedback, some utilities mentioned sources that they currently use but none have recommendations for publicly available sources for capacity, energy, technology, or fuel price forecasts."* The Report continue by stating that *"[e]ither they were unaware of any that would be valuable, or they preferred their current source flexibility."* The Company believes that latter statement is unnecessary, and could give the impression that electric utilities do not have the customers interest in mind. The Company recommends deleting, at least, the latter statement. Additionally, a selection of a forecasting source is dependent upon the scope of work and goals of the analysis being conducted that uses that forecast, and therefore a utility recommending a forecast without this defined scope would not be appropriate.

7. Staff Recommendations and Conclusions

On page 20 of the Report, and in the section labeled *"[t]o increase forecasting alignment between distribution plans and IRPs, utilities should include the following in distribution plans,"* the Report recommends: *"[p]erform a resource needs assessment for consideration in distribution* *planning efforts*." The Company requests further clarification from Staff as to what "resource needs assessment" means and entails.

B. <u>**Transmission (pages 20 through 36):**</u>

1. **Stakeholder Feedback and the Role for Transmission in IRPs**

On page 33, the Reports states that:

> *Staff expects that specific IRP transmission analysis needs and assumptions will continue to evolve, so filing requirements should ensure adequate flexibility to incorporate new analyses amid changing system conditions.*

The Company agrees with this statement and looks forward to participating in further discussion to improve the Transmission Analysis Filing Requirements in the next phase of the MI Power Grid Advanced Planning workgroup.

2. **Recommendations for Potential Filing Requirements Update in Phase 3**

Beginning on page 33, the Report discusses recommendations for potential IRP filing requirements updates. The Company agrees with Staff that the non-vertical nature of electric utilities in the state of Michigan creates complications and difficulties. However, responsibility for the transmission requirements, as recommended, solely falls on the utility. The Company continues to recommend that the requirements be modified to show that utilities are dependent on TOs to provide valuable insights and information for a successful IRP filing. Example language for inclusion would be, "<u>The Utility will request that the Transmission Owner provide…</u>" Adding language such as this to the IRP filing requirements will help clarify the type of information that the utility is dependent on the transmission owners to provide and ensure that the level of analysis being performed by the transmission owners provides value to the utility's IRP filing.

Moreover, on page 33, Report states:

> *Therefore, Staff recommends requiring a utility to engage a TO a defined minimum number of months prior to filing to ensure that there is enough time to allow for communication of electric grid details between the TO and regulated utility.*

The Company recommends the Staff not recommend a set minimum number of months prior to filing of an IRP. IRP filings are vast in information and analysis, and while the utility may plan for a certain filing date, it also must have the ability to adjust that filing date to accommodate management decisions or unexpected events. Language should be added to give the utility the ability to adjust this timing to give flexibility and value to work efforts on both the side of the TO and the regulated utility.

3. Staff Recommendations and Conclusions

a. Informed Transparency

Page 35, under "*[s]tudies performed for the IRP transmission analysis should, at a minimum*" of the Report states that *"(1) use the most recent TO reliability planning models made available to all parties with a CEII Nondisclosure Agreement on file with the RTO."* The Company respectfully opposes a requirement to make available confidential transmission information most recently filed with the regional transmission organization ("RTO") due to the timing efforts required to analysis and create an IRP. For example, if the most recently filed transmission analysis with the RTO occurs one month prior to a filing date of an IRP, it would be infeasible to incorporate that information into the IRP analysis and/or in narrative. Instead, the most recent finalized transmission analysis at the time of the IRP development should be used and could be made available to all parties in the IRP's regulatory case proceeding.

On page 35, the Report also states: "(2) *evaluate the reliability considerations of the utility's proposed course of action."* The Company recommends a consideration for the utility to share the utility's Proposed Course of Action ("PCA") with the TO prior to the filing, however it is not necessary to require the TO to complete an analysis of reliability considerations prior to a filing date, otherwise the Company would not have a PCA and would be restarting the process to re-develop one in the event reliability issues arise. The recommendations made by Staff to collaborate with the TO throughout the process of developing an IRP are sufficient in supporting the management decisions made in the process of creating the PCA.

The Company further recommends that Staff adjust its recommendations, on page 35 of the Report, by modifying the requirement that IRP transmission analysis should, at a minimum, "*(3) evaluate the reliability, cost, and resource diversity benefits of transmission alternatives*," to <u>only be required if transmission alternatives are offered to be evaluated</u>. Staff should recognize that transmission alternatives may not always be presented to be evaluated.

Furthermore, the Company recommends that Staff adjust its recommendations, on page 35 of the Report, by modifying the requirement that IRP transmission analysis should, at a minimum, "*(5) identify and estimate the cost of upgrades that would increase the local CIL/CEL and impacts to the LCR*," to <u>only be required if an IRP filing demonstrates a need to increase the local CIL/CEL to meet its objective</u>. In addition, the Company continues to believe that studies to increase the Zone 7 CIL/CEL are best suited for regional planning processes, not any single IRP filing, as CIL/CEL is a shared resource for all LSE's within Zone 7. MISO, as the RTO, is best suited to perform an annual study of the 5-, 10-, and 15-year outlook of the Zone 7 CIL/CEL through an open stakeholder process.

The Company recommends that Staff modify its recommendations, on page 35 of the Report, by removing transmission requirements from individual utility IRP filings that put an undue burden on the IRP filing and are better suited for other forums. Specifically, the following requirements should be removed: "*(4) identify areas or regions where new resources can interconnect to the transmission system with minimal transmission investment*," and "*(6) identify where transmission and non-transmission alternatives are likely to facilitate DERs*." These studies, while informative, are outside the true focus of an IRP which is resource selection. Even if these studies were available, their real-world benefit would be limited because utilities have limited control where generation resources will actually locate. At this time, utilities are heavily dependent on the MISO Generation Interconnection Queue for renewable generation resources. There are various other factors that influence resource siting including, but not limited to, available land, local zoning requirements, etc. In Michigan, specifically, generator developers are not incentivized to site where transmission investment is minimized because transmission network upgrade costs are reimbursed upon the generator going commercially operational. At most, these studies should be suggestions, not requirements. Also, it should be acknowledged that a utility will be heavily dependent on other stakeholders, such as transmission owners, to perform these studies and the statement above about adding language to the requirement to clarify this dependence would apply here.

b. Stakeholder Participation

The Company agrees with Staff that a utility's IRP filing is not the proper forum to debate information or refinements to MISO's resource adequacy construct that establishes the CIL, CEL, LCR, LRR, and other values for LRZ 7. See Report, pages 35-36. The Company agrees with Staff that MISO's public Resource Adequacy Subcommittee and Loss of Load Expectation Working Group are the proper forums to advocate for changes to MISO's resource adequacy constructs.

C. <u>Value of Generation Diversity (pages 36 through 51):</u>

1. **Staff Recommendations and Conclusions**

On page 50, the Report states that *"Staff recommends utilities conduct a stochastic risk assessment for their PCA, all the MIRPP base scenarios, and any utility created scenarios."* The Company does not take issue with this recommendation, currently, however on page iii of the Summary of Recommendations section of the Report, Staff recommends stochastic risk assessment for each plan. This creates a level of confusion regarding what Staff is recommending for evaluation of generation diversity on different plans. The Company recommends the statement on page iii of the Summary of Recommendations section of the Report be modified to state that <u>running stochastic analyses excludes sensitivities, or states that "each plan" is further defined on Page 50 of the Report</u>. Additionally, on pages 50 and 51 Staff recommends specific ways to present the results of stochastic risk analysis, and while helpful to get a perspective from Staff regarding ways to present the results of the analysis, these should only be examples of ways to present results, as opposed to defined requirements. This will give future flexibility for utilities to adjust future presentations of risk analysis results based on the scope and content of the modeling, rather than locking in one specific visual method that may not be as applicable or useful in future IRPs.

III. <u>CONCLUSION</u>

Consumers Energy appreciates the opportunity to submit these Comments and looks forward to the opportunity to participate further in the Integration of Resources/Distribution/Transmission Planning Workgroup. The Company reserves the right to take new and different positions as more information and clarifications becomes available in this workgroup process.

Respectfully submitted,

Consumers Energy Company

DTE Energy

DTE Electric Comments Regarding Staff's
Draft Report circulated 04-15-2021
MI Power Grid– Advanced Planning Phase II
May 3, 2021

On April 15, 2021, Michigan Public Service Commission's (MPSC or Commission) Staff released the draft report on Integration of Resource, Distribution, and Transmission Planning. The report represents the MPSC Staff's review, summary and initial recommendations following eight public forums held between September 2020 and March 2021. DTE Electric (DTE or Company) applauds the MPSC Staff's authorship of this comprehensive report and appreciates the opportunity to provide comments and feedback.

DTE appreciates the effort of the Michigan Public Service Commission (MPSC), MPSC Staff (Staff) and all parties involved in this integrated planning collaborative. DTE views integrated resource, distribution and transmission planning as an opportunity to develop optimized plans to meet future system needs. Further, the results of an IRP and distribution plan analysis should position a utility to make directionally appropriate investment decisions for the benefit of customers. DTE will provide comments on the sections as laid out in Staff's report as well as the recommendations provided.

DTE looks forward to further discussions and collaboration with Staff and industry stakeholders on Michigan's integrated planning process.

DTE Electric Comments Regarding Staff's
Draft Report circulated 04-15-2021
MI Power Grid– Advanced Planning Phase II
May 3, 2021

MI Power Grid Initiative- Introduction, Objectives, and Methodology

DTE agrees with the importance of defining key terms to ensure that stakeholders, Staff, and utilities are all able to understand one another when discussing ideas for aligning the generation, distribution and planning processes. DTE is amenable to adopting the same definitions that were used in the Distribution Planning Stakeholder Process report in Case No. U-20147. DTE also acknowledges that the terms reliability and resilience are often used interchangeably and agree that this makes the concept of resilience difficult to differentiate from reliability. DTE defines resiliency as a part of reliability, to specifically focus on hardening the grid to better withstand storms, and to support faster restoration after a storm has caused outages. It is noted on page 5 in the report that "Staff does find that the concept of resilience is measured as part of existing reliability metrics, along with additional metrics for Customers Experiencing Multiple Interruptions (CEMI) and Customers Experiencing Long Interruption Duration (CELID)…" DTE notes that the process to update the Service Quality and Reliability Standards including sections to address the reporting requirements of reliability indices is still ongoing. DTE supports Staff's recommendation that Staff, stakeholders, and regulated utilities discuss the potential value that the environmental justice screening tool can provide when considering vulnerable populations and the use of CEMI and CELID metrics that could be applied as local reliability and resilience metrics to areas in a future distribution planning stakeholder process. DTE is interested in the opportunity to see and understand this tool and its capabilities.

Forecasting

DTE agrees that the load forecast is the foundational building block that provides the basis for utility system planning and that increasing complexity in the electric system has in turn increased the complexity of load forecasting. It is acknowledged that there is value in aligning forecasts across planning processes recognizing that this alignment is complicated by the fact that the various planning processes are addressing different needs, time periods, and levels of detail. Additionally, the data used to create forecasts will continually change as new or updated information becomes available. Further, forecasting methodologies can vary depending on the approach or problem the process is addressing and should remain flexible to meet the needs and requirements of the specific planning process forecast.

The Company suggests that the word "accompany" in this sentence on page 6 "Utility planning has traditionally been focused on serving gross electricity demand and energy by building, or acquiring, centralized baseload generation while constructing distribution and transmission infrastructure to *accompany* those resources" be modified to *transmit and deliver*.

DTE notes that the following sentence on page 8 "DERs and NWAs provide a new opportunity for increased reliability and affordability without the costs associated with traditional solutions" is yet uncertain. Distributed energy resources (DERs), or sources of electric power and its associated facilities that are connected to a distribution system, are at varying stages of adoption and the potential applicability, values, benefits, and integration costs are still being determined and understood. In addition, DER resources may often require specific grid upgrades in order for the grid to function properly with different power flow for which it was not designed, or may need to be paired with elements of traditional distribution solutions to ensure functionality and provide the benefits of an upgrade deferral. As a reminder, a non-wires alternative (NWA) is an electricity grid investment or project that uses distribution solutions such as DER, energy waste reduction (EWR), demand response (DR), and grid software and controls, to defer or replace the need for distribution system upgrades. NWAs, with the exception of energy waste reduction (EWR) and demand response (DR) which are a bit more mature, are in similar stages of development and adoption. The referenced paragraph then states that "To adequately assess the value of these resources and determine the role various technologies should play in serving load, utilities must start with an accurate net load forecast that identifies the needs of the utility's system." The electric industry is entering a period of high uncertainty with respect to the adoption of DERs. For example, there is a wide range of forecasted EV adoption rates over the next 10 -20 years that are likely to be driven by policy decisions made outside of Michigan. Due to the wide range of possible outcomes, the Company believes that the focus for load forecasting should be on a robust planning framework that can provide meaningful information in the face of uncertainty.

Distributed Energy Resources Forecasts

DTE recognizes that with increased adoption of DERs and NWAs there is an opportunity to consider and evaluate how these types of investments may impact or inform planning processes. DTE does not agree, as stated on page 9, that there is a lack of specific data about the customers and their location that are enrolled in EWR programs. While it is true that utilities are just beginning to use this data to identify and create solutions to substation or even circuit level loading constraints, most EWR programs gather specific customer data and track the exact location of where measures are installed. This is true for most utilities in Michigan since this information is needed for required Evaluation, Measurement and Verification (EM&V) purposes. Exceptions may include retail-based programs where utilities know the quantity and store location of measures sold. It is important to note that although utilities may not know the specific customer for every measure sold in a retail-based program, customer information is still gathered through in-store intercept surveys. In addition, DTE acknowledges that although EWR and DR programs are impacted by customer behavior, the Company does know the general distribution of when the savings are occurring. An end-use load shape is applied to every measure installed by DTE when calculating an 8760 hourly savings profile. DTE and Consumers Energy are currently working together to further calibrate the end-use load shapes using primary data from both utilities.

On page 9 Staff recommends "utilities provide additional information in future distribution plan cases on DER and NWA forecasting and/or modeling. Treating DERs and NWAs as resource options in modeling requires granular data collection at the user level for a utility's customer base. This data includes temporal load profile, location on the grid, and avoided cost calculations." DTE is amenable to Staff's recommendation on pages 9/10 that recommends utilities explore more granular DER and NWA forecasting programs or tools for modelling these specific resources, however, NWAs can consist of solutions such as DER, EWR, DR, and grid software and controls. Since DTE considers DR as a supply side resource, these resources will have no impact on the load forecast. In addition, EWR programs are already accounted for in the load forecast as a reduction to sales at the system level and their use as an NWA simply directs their contribution to a particular project and does not impact the overall load forecast.

For distribution planning, DTE suggests that tools and models that calculate avoided cost are not yet mature and available enough to be incorporated into the process. Other DERs such as distributed solar and battery storage may or may not be accounted in the load forecast, depending on the location (behind the meter or front the meter) and intended application (non-exporting and exporting resources). In addition, for utilities to track the DER data accurately, they will need either the DER providers' coordination on data sharing or need access to separate metering or submetering.

Forecast Time Horizons

On page 11 DTE suggests that the word model in the following sentence "The time horizon, or the length of time over which the *model* performs its analysis, of each process has impacts on the results of these processes and has the potential to complicate the integration of the different processes or the results together" be modified to *utility* to accurately reflect who is performing the analysis.

Forecast Granularity

The Company suggests the following sentence on page 13 "The proper level of forecast granularity is determined by both the function of the model, as well as the granularity of the available source data" should also include the processing time required by the model.

As stated on page 14, "one of the major limiting factors for allowing the equitable consideration of DERs and other non-traditional resources is the capability of the modeling software to accurately model the operations and value of these resources." The report then states "Updating the modeling software and data used will allow for the level of granularity necessary to perform a full analysis of these resources…" DTE doesn't agree that updating the capacity expansion modeling software and data used to perform a full analysis of DERs will result in a more accurate IRP optimization. Upgrading these large models to be capable of handling this extra data and granularity would likely result in a higher level of resources (people, computing time) required to run them, much more input data to collect, and many more outputs to check for defects. The benefit of including DERs explicitly in the optimization do not outweigh the costs.

Future Improvement Opportunities Using Nascent Approaches and Tools

DTE suggests the following sentence on page 16 "While some of the software and other tools used for this planning have been updated or replaced by utilities, oftentimes these new tools are used in a way that limits their ability to model the system" be restated to "Utilities are in the process of upgrading or replacing their software and other tools used for this planning and are implementing best practices that fully utilize these updated or new tools so that their ability to model the system is not limited."

In addition, DTE suggests clarifying the sentence on page 16 "One way in which AMI data can be used to improve the forecasting process is through the development of a hosting capacity analysis" by changing it to "AMI data can be used to improve forecasting and hosting capacity granularity and accuracy by providing more localized insight into the distribution of load on circuits."

DTE would like to point out that the statement on page 17 "Forecasts that are accurate are best for everyone; it prevents utilities from overspending and customers from overpaying" could also result in underspending and recommends this be updated to recognize both possibilities.

Forecasting - Staff Recommendations and Conclusions

While DTE fundamentally agrees with most of the recommendations and conclusions detailed on pages 18- 20 and mentioned in this section, a few points of clarification are addressed below:

(1) Utilities should take a component or modular approach to forecasting and provides a list of key components that should be included. DTE will respond to each component individually.

- Gross demand and energy forecast; *DTE is amenable to providing this in the IRP.*
- Gross load shape; *DTE is amenable to providing this in the IRP filing.*
- Load shapes for EWR, DR and other load modifying resources that are not being modeled as resources. Examples could include already implemented EWR or EWR achieved outside of utility EWR programs; *As mentioned previously in this document, a loadshape study being conducted for EWR programs is currently underway with Consumers Energy and will be available to Staff upon completion. All other loadshapes available and utilized in modeling could be made available in future IRP filings.*
- EV adoption and charging profiles; *DTE is amenable to providing this in the IRP.*
- Behind-the-meter resources and DER forecasts that include customer owned photovoltaic and storage; *DTE is amenable to providing behind-the-meter forecasts in the IRP filing.*

(2) Use publicly available data sources but allow utilities flexibility to use data available to them to generate the most accurate forecast for each process (e.g. NREL for technology costs and EIA for price forecasting).

DTE supports this however recommends allowing more flexibility than requiring the EIA Annual Energy Outlook due to concerns that the assumptions underlying the EIA forecast may be misaligned with the assumptions specified in the MIRPP scenarios.

(3) Utilities should provide clear details on how the forecast has changed as well as an explanation on why the forecast has changed. This should be done from one case to

the next, always referencing back to the most recent, previously filed case forecast vs the current filing in question.

DTE is amenable to providing details for the load forecast provided in IRP filings back to the most recent filed forecast.

(4) Staff and stakeholders should have visibility into forecasting methodology and changes/evolution of forecast from one plan to the next (for example, from IRP to subsequent IRP or from IRP to transmission planning to distribution planning to IRP). Forecast inconsistencies from one process to the next should be identified and justified. If anything has been changed, it should be explained. Forecasts should be synchronized or reconciled from process to process… Understanding that different processes and utility functions call for forecasts with different time horizons and granularity. Relationships, where they exist or why they do not, should be clear.

DTE believes this request to be overly burdensome. Providing forecasting methodology and changes/evolution from IRP to IRP or IRP to distribution plan to IRP is overly burdensome due to the extended cadence between filings, which may be up to five years, thus encompassing multiple different updates to forecasts. To support all the changes, the sheer volume of exhibits, backup data, and workpapers provided to support an IRP filing, which would have to be tied back to the large volume of the same from the last IRP filing and explained, would be substantial. This is in addition to the extensive updates to various IRP analysis methodologies including obtaining new capacity expansion or production cost modelling software between IRP filings, which simply do not align.

(5) To increase forecasting alignment between distribution plans and IRPs, utilities should include the following in distribution plans:

As has been noted distribution plan forecasts are primarily short term and by nature focused on apparent power (i.e., MVA) in relationship to ratings of specific system elements (transformers, circuits, feeders, etc.) in worst case scenarios. These forecasts are built from the bottom up and are location specific (e.g., circuits, circuit segments). Conversely, forecasts contained in IRPs are much longer term in nature, focused on real power and energy consumption (i.e., MW and MWh), and are far less geographically granular. While the Company agrees both forecasts should be based on consistent assumptions for major components such as load growth, EV and DER adoption rates just to name a few, there are other factors as listed above driving the differences between distribution and IRP forecasts. In addition, the Company supports further discussions to align forecasts in future distribution planning workgroups.

- Assessment of historical forecast accuracy using statistical measures such as mean absolute percentage error; *DTE does not support providing an assessment of historical forecast accuracy in the distribution plan. Load forecast accuracy is reported in all rate case and IRP filings and should remain there and not required as a separate requirement in distribution plans.*

- Perform a resource needs assessment for consideration in distribution planning efforts; *DTE requests clarification on what a resource needs assessment is and what information is provided. Please see the Alignment of Distribution, IRP, and Transmission Planning section of this document for additional comments on this recommendation.*

- Use scenario analysis within distribution plans (using scenarios aligned with IRP scenarios). *DTE supports this recommendation.*

- Improved stakeholder communication (distribution plan technical conferences with stakeholders prior to filings). *DTE supports with this recommendation and has been holding technical conferences and engaging stakeholders prior to its August 2021 Distribution plan filing*

- Align assumptions between planning processes for DERs, NWAs, EVs, and electrification *DTE supports with this recommendation*

Transmission, Resource Adequacy, and External Zone 7 Resources

In the Integration of Resource, Distribution, and Transmission Planning Report, Staff provides an accurate representation of the opportunities and challenges associated with relying on capacity imports for IRP planning. Staff describes these challenges as significant, but not insurmountable. Further, Staff suggest that tested and vetted solution sets that can cost effectively increase CIL or imports should be considered in the IRP. To this characterization of the present situation, DTE is highly supportive of working on future improvements to the MISO resource adequacy construct to allow for the most accurate accounting of the transmission system capabilities and upgrade opportunities. DTE however is concerned with reliance on resources external to Zone 7 in the IRP planning process or any future large transmission investment exclusively to increase capacity import limits due to the substantial financial and reliability risks to customers as described more fully below.

The MISO resource adequacy construct continues to undergo significant changes as does the process for modelling capacity import limits (CIL). Most recently, MISO adopted a new methodology for calculating CIL that resulted in an 1,688 MW or 53% increase over the prior year.[1] Through the Loss of Load Expectation Working Group (LOLE WG) MISO stakeholder process other feedback has been provided regarding potential future modifications to the CIL calculation methodology. A shift to a seasonal resource adequacy construct may also result in the need to calculate a seasonal CIL that could have varying limits and constraints.

The Company has consistently seen great variability in forecasted CIL. MISO CIL transfer studies have not historically provided a consistent view on the constrained transmission system locations or constraint amounts as shown in the Table 1 below:

Table 1: Zone 7 Transmission Constraints

Study Year	Transmission Constraint	Capacity Import Limit	Source
2020	Monroe- Brownstown 345kV	4,097	MI CIL Study Scenario 2(+12 yrs)*
	Monroe - Brownstown 345kV	5,278	MI CIL Study Scenario 1 (+5 yrs)*
	Palisades - Argenta 345 kV #2	4,888	LOLEWG Study Limit (2020)*
2019	Pioneer 120 kV bus voltage	3,211	LOLEWG Study Limit
2018	Hager 120 kV bus voltage	3,785	LOLEWG Study Limit
	Lafayette 138 kV bus	3,143	Out Year Limit
2017	Brownstown 345 kV Bus	3,320	LOLEWG Study Limit
	Pioneer 120 kV bus voltage	3,316	Out Year Limit
2016	Argenta - Battle Creek 345 kV	3,406	LOLEWG Study Limit
	Zion Station to Zion 345 kV	4,536	Out Year Limit
2015	Clifty Creek - Trimble County 345 kV	3,813	LOLEWG Study Limit
	Newton - Casey 345 kV	5,389	Out Year Limit
2014	Zion Station to Zion 345 kV	3,884	LOLEWG Study Limit
	Zion Station to Zion 345 kV	2,922	Out Year Limit

The Company also notes that out-year CIL determination depends on the uncertain future generation siting assumptions and availability of dispatchable generation within and external to Michigan. As observed in the MISO Michigan CIL-CEL study, small changes in generation siting assumptions by a few hundred megawatts can drastically increase or decrease future CIL.[2] DTE

[1] 20201020 LOLEWG Item 04 PY2021-2022 CIL-CEL Update484437.pdf (misoenergy.org)
[2] 2020.11.17 Michigan Capacity Import / Export Limit Study TSTF

has further observed that MISO no longer publishes the out-year CIL Projections in the LOLE WG report because the forecast is not reliable.

Resources external to Zone 7 within MISO that have Network Resource Interconnection Service (NRIS) or external to MISO with approved firm Transmission Service Requests (TSR) may be considered in an IRP, but also require assignment of a risk premium to account for a potential local clearing requirement (LCR) shortfall driving the zone to cost of new entry (CONE) or a potential future import limit constraint. When the LCR is not met, Zone 7 is not capable of achieving the federal standards of a maximum of 1 day in 10 years loss of load event, yet resources located in Zone 7 would help to meet this reliability standard. The cost of these external Zone 7 resources should be made on a comparable basis to in-state resources including the base resource cost external to Michigan, cost of transmission service, and potential procurement of additional capacity if the resource does not count for capacity under a scenario in which Zone 7 does not meet LCR. Resources in renewable-rich regions are also more likely to sell into markets with low marginal energy prices. Any lost energy revenues and economic curtailment associated with out of state resources should also be accounted for in a financial comparison of options.

The Effective Capacity Import Limit (ECIL), calculated as the ECIL = PRMR-LCR, establishes the amount of non-Zone 7 resources with firm transmission services that may be counted for capacity used to meet the Planning Reserve Margin Requirements (PRMR) for Zone 7. Importing capacity above the ECIL provides no benefit from a resource adequacy perspective (providing the Zone 7 customers the reliability to meet federal standards). The major issue with relying on ECIL is that it has been very volatile over the years. Some may contend that the ECIL can be effectively managed upward by increasing the capacity import limits to reduce the LCR as the LCR = LRR-CIL. This view is short sighted as it neglects to account for potential increases to the Local Reliability Requirements (LRR) driven by new in-state renewables integration or fluctuating transmission system constraints within or external to MISO lowering CIL.

It would not be prudent to procure non-Zone 7 resources that would potentially not count towards DTE customer resource adequacy requirements without accounting for this risk financially and in reliability planning. Procuring external capacity could result in customers paying for capacity at CONE and/or a need to procure additional in-state capacity to cover the shortfall. This expense is in addition to paying for the external Zone 7 resources.

ECIL is further not allocated to utilities within a local resource zone and cannot be reserved, which creates a significant liability risk for any Zone 7 utility that plans to rely on non-Zone 7 resources for capacity planning. Accordingly, for the purposes of the IRP, some other approach should be used that financially accounts for the risk associated with an LCR shortfall or a binding ECIL constraint to protect customers from unreasonable financial risk associated with procuring out of state resources. This would still not alleviate the increased reliability risk. DTE believes it would be exceedingly difficult to develop such a financial framework that fully protects customer economic and reliability interests but remains open to suggestions from stakeholders and continuing to advocate for improvements to the MISO resource adequacy construct.

Finally, Staff recommends on page 31, that "If a transmission project increases the CIL and meets the required criteria for RTO approval, it should proceed through the MTEP process for evaluation and be incorporated into IRP modelling and evaluations". DTE believes that Staff's position neglects to account for the many concerns described above about relying on capacity imports for resource adequacy. Also, suggesting that any transmission project that increases CIL should proceed to the MTEP process for evaluation presupposes that all transmission investments to increase CIL will benefit customers. DTE maintains that the IRP process is not a forum for regional transmission expansion planning and that RTOs are in the best position to facilitate discussions around the timing and appropriateness of transmission projects to mitigate CIL constraints considering the broader regional transmission planning needs.

FERC Orders 841 and 2222

DTE agrees that Orders 841 and 2222 will open up new opportunities in the coming years for distributed energy resources including distributed energy storage facilities. High penetration of DERs and DER aggregations, promoted by FERC orders, will also bring additional challenges to integrated resource, transmission and distribution planning, particularly in the absence of the tools, systems or methodologies to automate many aspects of the planning processes.

As the resource portfolio shifts to more renewable and intermittent resources, storage in particular will play an increasingly important role in the grid of the future. Contrary to the comments in the draft report, DTE believes that increasing levels of storage deployment has the potential to improve transmission system reliability and may facilitate the deferral or avoidance of traditional transmission investments. With that said, DTE agrees that the evaluation of storage to serve a transmission function will add complexity to state integrated resource planning processes as transmission reliability planning is ultimately the domain of MISO.

DTE agrees that compliance with Order 2222 will be a complex undertaking, and it's one that is still in its nascent stages. As such, the impact on the need for additional transmission investment, generation investment, or distribution investment is still unclear. However, the discussion in the draft report warrants a few clarifications:

- The FERC Order is specific to DER aggregation exceeding 100 kW size threshold (in other words, DERs or DER aggregations below the 100 kW threshold would not be able to participate in the ISO markets). The draft report should clarify that aggregation is necessary to facilitate the market participation of small DERs. The introduction of more entities into both long-range planning and operational coordination will increase the level of complexity in both arenas.
- The draft report's definition of DERs is also somewhat divergent from the definition of DERs that FERC provided in the Order. Specifically, FERC defined DERs to include not just generation and storage, but also demand side resources. FERC also did not put any size restrictions on its definition of DERs, and distribution-connected resources of several megawatts or more could still fall under FERC's definition of a DER. To avoid any confusion, discussion of DERs in the context of Order 2222 should ensure consistency with the scope of DERs that FERC has defined.
- DTE requests clarity on this statement "Whether an ESR is proposed to perform a transmission function, a market function, or obviate the need for a traditional resource or project, it is expected that ESRs will be evaluated in future IRPs." It is unclear how, if an ESR is proposed to perform a transmission or market function, DTE would be aware of the feasibility and operational capabilities of the projects. DTE agrees with Staff, as noted on page 28, that performing comparative analyses of ESRs that may address similar issues, are planned as an NTA, or against other resource types, may add additional complexity to integrated resource planning.
- On page 29, DTE recommends striking "that participate in a retail program". Order 2222 does not require DERs enrolled in retail programs to have access to the wholesale markets. Rather, state regulators retain the authority to determine whether it is appropriate to allow participation by a single DER or DER aggregation in both retail programs and wholesale markets.

Transmission - Staff Recommendations and Conclusion

The transmission IRP filing requirements as currently constructed contain open ended objectives that are challenging to comply with. The unique business structure in the State of Michigan where many utilities are not vertically integrated makes complying with the current requirements highly subjective and open to interpretation. Specifically, per the current requirements utilities shall:

- *"Include an analysis of potential new or upgraded electric transmission options for the utility"* despite having limited information regarding physical attributes of the transmission system and being unable to organize regional transmission planning

- *"Assess the need to construct new, or modify existing transmission facilities to interconnect any new generation and shall reflect the estimated costs of those transmission facilities in the analyses of the resource options"* despite not knowing specific generation interconnection locations many years in the future and being unable to fully perform generator interconnection studies

- Include *"Any information provided by the transmission owner(s) indicating the anticipated effects of fleet changes proposed in the IRP on the transmission system"* and include any information relating to import/export capabilities, facilitating PPAs, and efficiency enhancements among other items

These requirements impose a large burden on non-vertically integrated utilities to provide information they may have little insight into, are unable to obtain, or cannot thoughtfully incorporate into the IRP for the benefit of customers. Even with positive cooperation and engagement between parties, jurisdictional boundaries are challenging as the requirements only apply to utilities and not to transmission owners.

Traditional utilities have information on most physical aspects of the electric delivery system from the power source to the end-use customer. The State of Michigan is faced with a unique situation where significant elements of the electric grid are operated and controlled by separate entities that have specific obligations to their respective customers, employees and shareholders. As revisions to the transmission analysis IRP filing requirements are contemplated and given the foregoing limitations, further recognition of this structural arrangement is needed to ensure optimal outcomes for customers. This could involve developing a framework that promotes use of the Pareto Principle where the transmission analysis performed seeks to identify the vital few issues that will result in the most significant cost drivers for customers. Recognition is also needed that the IRP cannot be a substitute for robust regional and sub-regional transmission planning that can only be efficiently coordinated and implemented by a regional transmission organization. Given that regional transmission planning cannot efficiently occur within an individual utility IRP, DTE believes that the purpose of the IRP transmission studies should be to provide suggestions and information, rather than a specific list of firm requirements that must be complied with to demonstrate a comprehensive future resource plan.

DTE encourages the MPSC to consider how the filing requirements can be modified to clearly define roles and responsibilities of each party, what analysis is to be performed, the process for performing the analysis, and how results should and can be incorporated in the IRP planning process. Having such a framework will provide a common understanding of the expectations for all stakeholders and a basis for making incremental improvements to the process over time as we work collaboratively together on ensuring resource and transmission investment decisions are optimized for Michigan customers.

Enhanced Communications

To enhance communications and facilitate bidirectional flow of information, Staff recommends on page 30 for regulated utilities to coordinate with transmission owners to schedule a biannual meeting that serves two purposes:

1. Focus on distribution system needs and expected fleet changes that are likely to occur for the regulated utilities that facilitates discussion about how the transmission system may best support those changes, including potential transmission investment
2. Transmission needs and potential non-transmission alternatives that may be reasonable and economic replacements to transmission investments

Responding to the first point, the Company agrees that transmission owners and distribution owners must coordinate and plan for system needs on a regular basis but struggles to see the need of focusing a biannual meeting on how the distribution system will affect transmission investments. DTE is in regular communication with ITC regarding how transmission can support future distribution system needs including customer connections, capacity planning and DER's impacts on transmission systems. Several recent examples include the transmission projects at MISO relating to the City of Detroit Cable project (MTEP # 15981), the Nitro project (MTEP #12443), the Stone Pool – Temple project (MTEP #17998), and the Cato-Corktown project (MTEP #20167). The first two projects in this list are examples of transmission investments providing both transmission and distribution system benefits. The last two projects are driven almost entirely by distribution system reliability enhancement needs. These projects resulted from significant planning and coordination between DTE and ITC on how the transmission system can support the distribution system. This planning took place within the regular planning meeting cadence between the two companies and was reviewed within the MISO MTEP stakeholder process. The MISO stakeholder process provided the framework for stakeholders to publicly ask questions about these investments and propose alternatives. Hence, DTE considers it a duplicate effort to add biannual meetings on how the transmission system may best support distribution system needs.

Relating to regular discussion on expected fleet changes, recognition is needed around the sensitivity of holding discussions on the timing of facility retirements and decommissioning ahead of communications with internal employees. The structural arrangement of Michigan utilities (non-vertically integrated) makes such conversations untenable in most circumstances absent a highly prescriptive framework guiding the conversation. Accordingly, DTE requests further clarification on:

- What are the boundaries for these discussions?
- Who should be involved in the dialogue? Are the meetings to be public or private? If private, how can utilities or transmission owners be assured that sensitive information shared will remain confidential?
- What are the responsibilities of each party before, during and after these meetings?
- How will these meetings differ from other planning meetings held between utilities and transmission owners?
- How is compliance with this recommendation measured or determined?

Laying out a clear definition of the structure envisioned for these discussions will enable a more productive and rich dialogue.

Informed Transparency

Staff recommendations around informed transparency describes six minimum requirements for studies performed for the IRP transmission analysis on page 35. DTE offers the following comments relating to each of these areas:

(1) use the most recent RTO reliability planning models made available to all parties with a CEII Nondisclosure Agreement on file with the RTO

DTE is supportive of this recommendation as it will promote greater transparency for all parties. DTE suggests for further clarification on the models to be included in the IRP analysis. For example, should the standard summer peak and summer shoulder models for IRP planning be used, or the more comprehensive collection of Michigan sensitivities that are currently utilized for MISO reliability planning?

(2) evaluate the reliability considerations of the utility's proposed course of action

DTE requests for Staff to consider describing what reliability evaluation should be performed. For example:

- Should TOs provide a realistic cost estimate for addressing transmission system issues for all thermal overloads (>100%) and voltage issues for first and second contingencies (n-1, n-1-1) per NERC-TPL planning standards as MISO would do in the MTEP process?
- What studies should be performed beyond steady-state analysis (e.g. voltage stability, transient stability, short-circuit, etc.)?
- What timeframe should the studies focus on (e.g. 5 years, 10 years, 15 years, etc.)?
- How is this evaluation accomplished within the timeline of the IRP development process?

(3) evaluate the reliability, cost, and resource diversity benefits of transmission alternatives

DTE requests clarity on which parties would be responsible for providing such inputs. DTE further requests clarity on how the reliability and resource diversity benefits of applicable transmission alternatives should be quantified and considered in the IRP process.

(4) identify areas or regions where new resources can interconnect to the transmission system with minimal transmission investment

DTE believes transmission owners are in the best position to suggest interconnection locations that cause the least impact and cost to the transmission system.

(5) identify and estimate the cost of upgrades that would increase the local CIL/CEL and impacts to the LCR

As was seen in the Michigan CIL/CEL study, there is no shortage of potential options to increase CIL/CEL in any given year. The fundamental issue remains with what should be done with this information given the myriad of issues associated with relying on CIL for resource adequacy as more fully described in other sections of this feedback. A framework is needed to guide the IRP development process related to CIL/CEL that ensures customer interests are protected and to provide a feasible path to complying with the filing requirements for utilities.

(6) **identify where transmission and non-transmission alternatives are likely to facilitate DERs.**

DTE requests clarity on what transmission and non-transmission alternatives are referred to with this recommendation, what issues are being solved with these alternatives, and the role of the utility and transmission owner in answering questions like this. Once such questions are answered, further definition is also needed regarding what metric(s) should be used to define better or worse alternatives from a DER integration perspective. Without this requested clarity, DTE is uncertain of how to study, evaluate and include these inputs in an IRP.

Stakeholder Participation

DTE fully agrees and supports Staff's recommendation encouraging utilities to participate in applicable RTO planning processes. In this report, Staff contends that current RTO planning processes potentially fall short of facilitating the needed communications between non-vertically integrated utilities. Specifically, it is stated on page 29 that "The current MTEP and RTEP process allow for some transfers of information; however, those are largely focused on specific transmission system needs… These processes may not take a holistic look at Michigan's electric grid or promote bidirectional information flow…". It is the Company's view that RTOs have the important role to facilitate regional grid planning and there is a need to work within these processes rather than outside of them. Regional transmission operators have the broadest view of the electric grid and greatest visibility into future system needs. While not perfect, the annual MISO MTEP reliability planning process provides a forum for stakeholders to share information on upcoming grid changes in the next decade and plan collaboratively for system needs. The MTEP process contemplates long-term distribution needs, generation additions & retirements, and other system changes to arrive at a coordinated transmission expansion plan for the next decade.

Outside annual reliability planning processes, RTOs facilitate long-term transmission planning to consider expansion needs beyond required NERC upgrades in the next decade. Efforts like the MISO LRTP (Long Range Transmission Planning) are specifically intended to facilitate bidirectional flow of information between a diverse group of stakeholders that allows for holistic and long-term transmission planning. As an active stakeholder in these planning processes, DTE has observed some shortcomings and continues to work with MISO to foster a more inclusive, iterative and holistic approach to transmission reliability planning. These improvement efforts are currently being advanced through the MISO integrated roadmap development process and include topics relating to enhancing stakeholder participation protocols, inclusion of non-transmission alternatives in MTEP planning, and other enhancements to generation retirement planning. The Company believes that the RTO planning process are the best forum to explore regional transmission expansion and that strong focus should remain on improving these processes to achieve the desired outcomes. These processes contain stakeholder groups within and external to Michigan allowing for comprehensive planning as opposed to one-time transmission analysis performed for an individual utility IRP.

Value of Generation Diversity

DTE agrees that a robust risk assessment performed as part of the IRP will test portfolios against a wide range of alternative future conditions and will more accurately value a portfolio's diversity than the use of a diversity index. Care must be taken in the risk assessment to incorporate the differing risks and values of future portfolios that will contain more renewables as well as demand-side resources.

DTE generally agrees with the assessment of the current state of diversity in Michigan's electric system that begins on page 37 of the report. However, DTE disagrees with the operational characteristic example given (i.e., distributed customer owned solar vs. utility owned, centralized solar.) Nuances between ownership structures are not captured in a risk assessment that utilizes a stochastic model.

On page 39, the first paragraph in this section stated "Therefore, generation diversity should be valued for its potential to provide cost savings or improve system reliability and resiliency". DTE suggests either striking the phrase "provide cost savings or", or rewriting as "Therefore, generation diversity should be valued for its potential to improve system reliability and resiliency in addition to potentially providing cost savings over a variety of futures."

It is noted in the report on page 42 that DERs may not place the same burden on the T&D system, as these resources are by nature dispersed over the utility's service territory. Additionally, while siting DERs at one location may increase stress on the system, at another location, it may alleviate stress and the necessity for future T&D investment. The Company notes that while DERs may be dispersed, they are also more dynamic and variable, and depending on the location may increase stress on the system or alleviate a problem. In addition, the planning and operational efforts for distribution utilities to monitor, manage or control the dispersed, high volume of individual DER resources in the future cannot be underestimated.

DTE generally agrees with the recommendation on page 43 of "Staff recommends that the Commission requires utilities supplement the scenario and sensitivities analysis specified in the MIRPP by including a stochastic risk assessment for all required scenario optimized plans and any additional plans developed by the Company." Specifically, the limitation to "all required scenario optimized plans." However, to maintain value-added analysis only and keep the number of model runs reasonable, the Company suggests a re-write to "Staff recommends that the Commission requires utilities supplement the scenario and sensitivities analysis specified in the MIRPP by including a stochastic risk assessment for *all required scenario optimized plans, any optimized plans* arising from scenarios developed by the Company, as well as the PCA."

On page 44, DTE suggests a rewrite of the following sentence "Another reason that it may be unwise to pursue diversity for diversity's sake is that these indices do not directly consider other generation attributes, such as generator inertia, ramp rate, minimum up time etc." to "Another reason that it may be unwise to pursue diversity for diversity's sake is that these indices do not directly consider other generation attributes *that are required for a stable, functional grid, including voltage support*, generator inertia, ramp rate, minimum up time etc."

Diversity - Staff Recommendations and Conclusion

DTE agrees with not requiring the use of indices in IRPs.

(1) Utilities conduct a stochastic risk assessment for their PCA, all the MIRPP base scenarios, and any utility created scenarios

DTE recommends this sentence be modified to: "As such, Staff recommends utilities conduct a stochastic risk assessment on their PCA, *on all top plans generated from* the MIRPP base scenarios, and *top plans generated on any* utility created scenarios." Stochastic risk assessments are run on plans, not scenarios.

(2) For presenting the results of stochastic risk analysis, staff recommends box and whisker plots of each plan's NPV outputs, as they succinctly illustrate probability distributions; the wider the distribution, the more susceptible the plan is to risk under the conditions.

DTE is amenable to presenting the results of stochastic risk analysis as box and whisker plots of each plan's NPV outputs and using a matrix when comparing each plan based on deterministic risk assessment (where each plan is run through each combination of scenario and sensitivity).

(3) Continued collaboration with stakeholders to further develop Staff's understanding of generation diversity and risk assessment

DTE is happy to collaborate with other stakeholders to further develop Staff's understanding of generation diversity and risk assessment as well as our own understanding of this evolving area.

(4) Utilities propose deterministic scenarios to evaluate specific futures and still conduct their own deterministic analyses in addition to stochastic and prescriptive deterministic scenarios.

DTE is supportive of this recommendation as it is necessary in robust IRP modelling.

Alignment of Distribution, IRP, and Transmission Planning

Staff provides an overview of the potential opportunities and challenges associated with increased alignment of the distribution, generation and transmission processes and notes that these are surmountable challenges, but they will take time to overcome. Noted by Staff on page 54, data availability, information technology infrastructure, personnel skill sets, and insufficient modelling tools limit alignment. These are a few areas that pose challenges that will need to be addressed. This is not an easy task or one to be taken lightly. DTE agrees that increased alignment between the planning processes is beneficial to customers and will take time to address and that alignment as opposed to full integration of the processes is an opportunity that DTE will focus on in the coming years.

DTE suggests expanding the sentence on pg. 51 "The MPSC and the relevant ISOs currently have several processes in place to assess resource, distribution, and transmission planning" to "The

MPSC and the relevant ISOs currently have several processes in place to *ensure and* assess resource, distribution, and transmission planning."

DTE agrees that generation and distribution planning impact each other. DTE also believes that RTOs play a significant role in leading the ultimate integration of these planning activities. The Company identified enhanced alignment as an opportunity and throughout 2020 and 2021 the teams have been focusing on putting in place processes to do so. The, resource and distribution and planning teams met in 2020 to collaboratively develop common planning objectives, building on the Planning Principles that were developed for the 2017 CON and 2019 IRP. The planning teams frequently share information cross-functionally, collaborate on projects and initiatives, and work effectively together. The distribution and resource planning teams along with the internal DTE transmission team will continue to build on this foundation to strengthen communication, collaboration, and alignment around forecasts and scenarios, as well as common planning objectives. The Company does not believe, as stated on page 54 and again on pages 57 and 60, that a prescribed organizational structure, integrating the planning teams into a single group, is necessary to facilitate increased sharing of information and will keep the groups aligned with what the other groups are planning.

Staff also addresses the request by stakeholders for increased transparency into the distribution planning process, which would provide insights into how NWAs can be more fully considered in an IRP. It's stated in the report on page 56 that "Utilities in Michigan are beginning this process by looking at NWAs in their distribution planning, and they have resources in their IRPs that could form the basis for NWAs." Ensuring system needs are met for its customers is the responsibility of the utility and DTE agrees that increased transparency between the distribution and resource planning processes could provide insights in potential resource opportunities to meet those system needs. DTE believes it is prudent for utilities to learn more about NWAs through pilots where the uses, costs and benefits can be measured and validated.

Further, it is noted on the same page that "A full needs assessment in distribution planning could support IRP resources and the general iterative process. Information on DERs and NWAs shared between all planning processes can provide transparency and integrate them into the decision-making process for the future grid." DTE requests clarification on what is considered and included in a "full needs assessment". It is important to remember that distribution planning proposes strategic investments that have multiple joint benefits including safety, reliability and resiliency, load relief, cost effectiveness and affordability, and accessibility. DTE uses a Global Prioritization Model (GPM) model that leverages historical reliability and system data, incorporates up to date assessments of the asset and system conditions, assigns values and a weighting system to analyze both monetized and non-monetized benefits and prioritizes projects and programs among the investment portfolio. NWAs may address just a portion of grid needs around capacity. Additionally, NWAs are typically sized to be the minimum necessary to resolve the current constraint and are often time bound on the ability to deliver kWh. Unlike traditional investments, where standardized equipment provides additional capacity, operational margins have to be carefully planned for. In cases where the constraint is unlikely to change or load can be eliminated entirely, this is an optimal investment, however if the situation changes, the incremental approach may fail to meet the need and require additional solutions.

DTE would like to emphasize its agreement with the Staff's position in Case No. U-20417 on page 20 of the final report that says, "Staff does not support the suggestion that aggregate stakeholders replace utilities as the lead actors proposing Michigan electric distribution investment plans." DTE appreciates the feedback obtained through the collaborative stakeholder process, but would like to further reiterate that, the utility is ultimately responsible for identifying system needs, managing the distribution and resource planning processes and making the investment decisions to support the aligned objectives for the benefit of all of our customers.

Staff Recommendations

(1) **Staff states on page 58 that it is critical that consistent objectives and assumptions are applied to distribution plans, transmission plans, and IRPs to ensure that the results from all planning processes are aligned. They also recommend increased consistency throughout the planning processes and coordination of timing between processes.**

DTE also recognizes that the planning cycles for distribution plans, transmission plans, and IRPs are different and should not all start and end at the same time. DTE agrees it is important to have the distribution and resource plans align to have consistent forecasts, scenarios, and planning objectives and that planning efforts should be coordinated, where possible. As noted above, The State of Michigan is faced with a unique situation where significant elements of the electric grid are operated and controlled by separate entities that have specific obligations to their respective customers, employees and shareholders. DTE will continue to work collaboratively with the transmission owner to ensure a regular line of communication via already well-established protocols.

(2) **It is noted on page 60 that utility-stakeholder technical meetings between, before, and during cases ensure that stakeholders are aware of the latest opportunities and challenges. Staff is recommending that there be a clear conversation happening at regular intervals, such that stakeholders and Staff can follow from one planning case or activity to another, that establishes linkages between all planning processes.**

DTE agrees that increased touchpoints on distribution and generation planning could be mutually beneficial to all parties and will determine what opportunities there may be to do so.

(3) **Staff recommends that utilities engage in planning as an iterative process, providing a clear link about how each planning process impacts another, and identify where there are opportunities for distribution and transmission to support resource development, investment in resources to support the distribution and transmission grid, and how distribution and transmission planning can be used to support one another.**

DTE recognizes and acknowledges that the planning processes are iterative and will continue to explore opportunities where resource, distribution, and transmission planning processes may be able to support each other as well as how investment in resources could support the transmission grid.

(4) **Staff suggests that all planning processes should in essence speak to one another. Stakeholders, staff, and utilities should be able to trace how assumptions, inputs, and plan outputs flow into and out of all planning processes**

As stated above, DTE agrees that increased alignment between the planning processes is beneficial to customers and that alignment, as opposed to full integration of the processes, is an opportunity that DTE will focus on in the coming years. The recommendation that parties should be able to trace how assumptions, inputs, and plan outputs flow into and out of all planning processes would impose a large burden on non-vertically integrated utilities to provide information they may have little insight into, and are unable to obtain.

Emissions and Environmental Considerations

With respect to the recommendation that "Staff recommends that further consideration be given to counting market carbon during the Advanced Planning workgroup during Phase 3, when the draft MIRPP and IRP Filing Requirements are discussed." DTE agrees and would like to note that care must be taken that counting market carbon does not result in double counting of CO_2 emissions. Utilities supply power to the market and report direct emissions. Carbon accounting should be done based on the overall energy produced and sold to our customers.

DTE comments pertaining to the second and fourth bullets on page iv of the Summary recommendations, and third bullet on page 67 requesting "additional environmental and emissions data", the scope of this additional environmental data should be based on fact based and necessary information to provide context and support for the IRP and not a blanket request for any/all data. The Company requests that a list of the "additional environmental data" be made available to us to review and comment upon. Please also clarify the difference between "environmental" and "emissions" data.

Conclusion

DTE appreciates the opportunity to participate in and provide the above comments and suggestions for consideration to the MPSC Staff regarding the integration of resource, distribution, and transmission planning. We look forward to continuing to work with the MPSC and industry stakeholders on this topic.

ELPC

Ms. Naomi Simpson
Michigan Public Service Commission
7109 W. Saginaw Hwy.
Lansing, MI 48917

Via email to simpsonn3@michigan.gov

May 3, 2021

Re: MPSC Staff Request for Feedback on Draft Report for the Integration of Resource/Distribution/Transmission Planning Workgroup

Ms. Simpson,

These comments are focused on the section of MPSC Staff's draft report addressing the "Alignment of Distribution, IRP, and Transmission Planning" (pages 51-61).

ELPC and Vote Solar strongly agree that there is value in aligning distribution, resource and transmission planning processes in Michigan. The draft report states that "fully aligning these planning processes would facilitate grid solutions and efficient integration of new technology and distributed generation and ensure that ratepayers are able to access all the benefits of a fully integrated electric system." Draft Report at 54. ELPC and Vote Solar agree. Research shows that *co-optimizing the distribution and bulk systems* can lead to significant ratepayer savings as the state decarbonizes to meet Governor Whitmer and President Biden's climate goals.[1] In order to "co-optimize" these systems, distribution, resource, and transmission planning (and the persons involved in those efforts) must share data, common assumptions, and overlapping goals, among other items. ELPC and Vote Solar offer the following comments in response to Staff's specific recommendations:

Grid Needs Assessment: The draft report states: "One way to better identify areas where [non-wires alternatives] should be considered would be to include a circuit level needs assessment that identifies circuits where there is known constraints and where the system age and condition is not a concern." Draft Report at 55. The report goes on to say that a "full needs assessment in distribution planning could support IRP resources and the general iterative process. Information on DERs and NWAs shared between all planning processes can provide transparency and integrate them into the decision-making process for the future grid. Staff recommends distribution planning

[1] Local Solar Roadmap, https://www.localsolarforall.org/roadmap.

include a needs assessment that supports these resources and identifies the grid needs discussed above." Draft Report at 56.

ELPC and Vote Solar agree. A full and transparent assessment of near-term distribution grid needs—including thermal, voltage, capacity and other constraints—that describes the timing and magnitude of the need, would help "non-wires alternatives" compete with traditional grid upgrades (particularly if the utilities allow third-parties to bid projects that would meet the grid needs). Going a step further, ELPC and Vote Solar support projections of longer-term grid needs under various load, DER and electrification scenarios, so that stakeholders develop a more transparent understanding of the grid upgrades necessary to support those scenarios. ELPC and Vote Solar support Staff's recommendation that the utilities include a complete grid needs assessment in their long-term distribution plan filings going forward.

Increased Consistency and Coordinated Timing: The draft report states that "consistent assumptions throughout planning processes will advance the efforts to align those processes, while coordinated timing will ensure that the information provided in one plan can directly link to another." Draft Report at 59. ELPC and Vote Solar agree and recommend that Staff (1) detail the minimum assumptions that should be aligned across planning processes and (2) suggest a staggered planning cycle that would allow information from one planning process to flow meaningfully into the others.

Communication and Iterative Planning: Staff recommends "a clear conversation happening at regular intervals, such that stakeholders and Staff can follow from one planning case or activity to another, that establishes linkages between all planning processes." Draft Report at 60. ELPC and Vote Solar appreciates Staff highlighting the importance of stakeholder input in ensuring that planning process are iterative and aligned. ELPC and Vote Solar recommend that Staff suggest a specific mechanism for continuing conversations at "regular intervals" beyond the MI Power Grid Advanced Planning workgroups. ELPC and Vote Solar would support a dedicated technical utility planning workgroup that meets on a regular basis and provides specific input on planning assumptions and parameters.

DER Forecasting: Staff recommends that utilities provide additional information in future distribution plan cases on Distributed Energy Resources forecasting methodology. Staff Report at 9. ELPC and Vote Solar agree that DER forecasting at an increasingly granular level is important to understanding DER and NWA costs and benefits and support this recommendation.

Conclusion

ELPC and Vote Solar appreciate Staff's work on facilitating the Advanced Planning Phase II workgroup and developing a draft report. ELPC and Vote Solar look forward to continuing to work with stakeholders and MPSC Staff to better align Michigan utilities' system planning processes—both through the Advanced Planning Workgroups as well as through other future stakeholder-driven efforts.

GridLab

May 3, 2021

Naomi Simpson
Manager, Resource Optimization and Certification
Michigan Public Service Commission
7109 W. Saginaw Highway
Lansing, MI 48917

Dear Naomi:

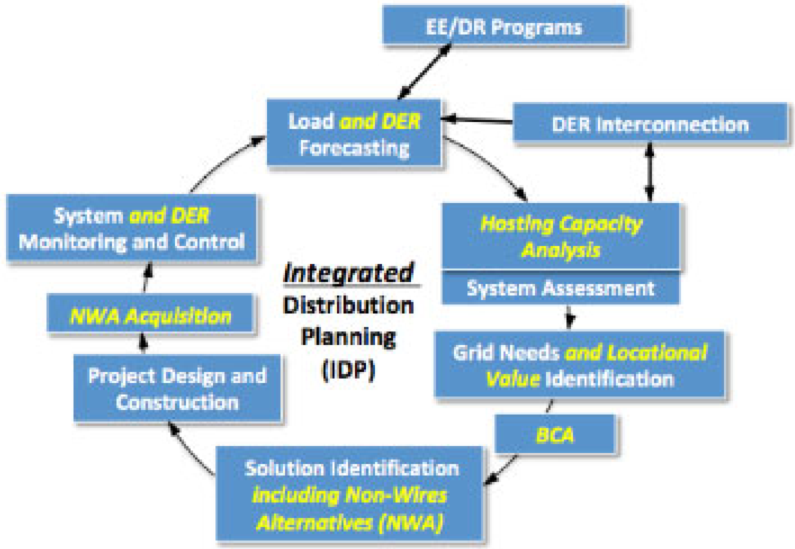
On behalf of GridLab, I appreciate the opportunity to provide brief comments on the 4/15/21 Draft Report from the Integration of Resource/Distribution/Transmission Planning Workgroup. My comments, which are primarily focused on the Forecasting section of the report, are the following:

- The Summary of Recommendations beginning on p. ii should include Staff's recommendations on p. 9 related to additional utility load and Distributed Energy Resources (DER) forecasting information.

- In the second to last paragraph on p. 8, I suggest modifying the sentence to: "Forecasting components could include building electrification, electric vehicle adoption, behind-the-meter resources, existing ***and new*** EWR, and any demand side resource that is ***or is*** not directly controlled by the utility and dispatched by the market."

- In the discussion of DER forecasts on p. 9, it is important to clarify the relationship between Forecasting and Non-Wires Alternatives (NWA). As defined of p. 4 of the Draft Report, NWA are combinations of DER and load-modifying resources deployed to address grid needs in lieu of conventional utility capital investment. Load and DER forecasts are the basis for identifying grid needs, and NWA are designed to address the needs. In other words, NWA are not forecasted, but rather deployed in response to load and DER forecasts.

  GridLab illustrated this relationship in the Integrated Distribution Planning presentation I gave at the 9/18/19 MPSC Distribution Planning stakeholder session, and the relevant graphic is shown again below.



BCA = Benefit/Cost Analysis

I therefore recommend modifying the text on p. 9 as follows:

> "DER ~~and NWA~~ forecasts in IRP have traditionally been done with a "top-down" ***approach*** and the specific locations of grid connection for DERs, EWR, and DR are often unknown …
>
> The ability to forecast adoption rates of different DER technologies separately from one another is also important … Curt Volkman~~n~~ suggested during his presentation, on December 16, 2020, that the Commission require a series of questions to be answered in utilities next 5-year distribution plan to improve forecasting. These questions include:
>
> 1. How are they forecasting ***load and*** DER ~~and NWA~~?
>
> 2. How ***do*** they plan to improve ***load and*** DER ~~and NWA~~ forecasting going forward?
>
> 3. How ~~is it incorporated in~~ ***are DER and*** load forecasts ***integrated***?
>
> 4. How ***do*** they incorporate stakeholder engagement ***into forecasts***?
>
> Staff agrees and recommends utilities provide additional~~ly~~ information in future distribution plan cases on ***load and*** DER ~~and NWA~~ forecasting and/or

> modeling. Treating DERs and NWAs as resource options in modeling requires granular data collection at the user level for a utility's customer base …"

- I believe the citation noted in the last paragraph on p. 14 was from Tom Eckman's presentation, not mine.

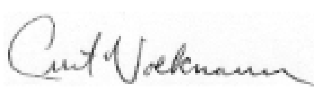
- In the last paragraph on p. 28, please note that FERC has defined distributed energy resources as "any resource located on the distribution system, any subsystem thereof or behind a customer meter. These resources may include, but are not limited to, resources that are in front of and behind the customer meter, electric storage resources, intermittent generation, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment."[1]

- In the discussion of FERC Order 2222 on pp. 28-29, it is important to note that the Order also has implications for new distribution utility functions and capabilities. These include, but are not limited to, new processes for determining DER eligibility to participate in an aggregation, new processes for determining and communicating the impact of circuit reconfigurations on an aggregation, changes to existing or new IT systems, and potentially the need for new metering and telemetry.

  For your information, GridLab and Advanced Energy Economy are jointly facilitating an industry task force to more fully define the implications of FERC Order 2222 for distribution utilities, with a report to be published in the fall of 2021. DTE is currently a task force participant.

Thank you again for the opportunity to provide comments.

Sincerely,



Curt Volkmann
President
New Energy Advisors, LLC

[1] FERC Order 2222, paragraph 114, p. 91

I&M

INDIANA MICHIGAN POWER

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BOUNDLESS ENERGY

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May 3, 2021

To: Naomi Simpson, Michigan Public Service Commission

Re: Comments on the Integration of Resource, Distribution, and Transmission Planning Draft Report

Indiana Michigan Power Company (I&M or Company) submits these comments on the Michigan Public Service Commission (MPSC) Staff's Integration of Resource, Distribution, and Transmission Planning Draft Report issued April 15, 2021. I&M appreciates this opportunity to comment on Staff's proposal.

I. Introduction

I&M is a multi-jurisdictional public utility that is regulated in the States of Indiana and Michigan. I&M serves approximately 600,000 retail customers in total, with approximately 470,000 in Indiana and 130,000 in Michigan and serves approximately 390MW of wholesale generation load under long-term full-requirements contracts. The Company's service territory in the State of Michigan encompasses portions of six counties.[1] I&M's Michigan retail customers comprise approximately 15% of the total generation load served by I&M. The remaining customers are wholesale or Indiana retail. Importantly, I&M uses all of its generation resources to meet the needs of all of its customers. For example, I&M's Cook nuclear power plant is located in Michigan, but it serves (and is reflected in the rates of) customers in Indiana as well as Michigan. This allows all customers to realize the greatest benefits by being part of a larger whole, enabling greater resource diversity, economies of scale, and lower costs.

Historically, I&M has developed its IRP based on the needs of, and resources available to serve, all of its customers on a multistate basis. I&M is required to submit and has submitted a multistate IRP to the Indiana Utility Regulatory Commission (IURC) and to the Michigan Public Service Commission (MPSC) under MCL 460.6t(4). I&M's IRP process is a reasonable and prudent system resource plan that balances cost objectives with planning flexibility, asset mix considerations, risk management, conformance with applicable North American Electric Reliability Corporation (NERC) and RTO criteria. In particular, I&M's IRP has historically analyzed a variety of scenarios that could occur in the future that would provide adequate supply and demand resources to meet projected peak load obligations at a reasonable cost for a twenty year planning period. Scenarios are developed as part of a robust stakeholder process that includes the Commission staff and allows diverse perspectives to be considered.

[1] Berrien, Cass, St. Joseph, Van Buren, Kalamazoo, and Allegan.

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A team of planning experts at AEP, who have performed similar work in multiple AEP system states, develop the I&M IRP using an appropriate modeling and methodologies to meet the IRP requirements under the law in both Indiana and Michigan. The multistate utility provision in MCL 460.6t (4) is based, in part, on the policy that multi-state companies providing service in two states, like I&M, in fact operate as a single, integrated electric company. For the reasons outlined above, I&M encourages the Staff to acknowledge the IRP provisions granted to multi-state jurisdictional companies as part of its report in this matter.

As a regulated public utility, I&M has an obligation to serve customers in multiple jurisdictions with safe and reliable power and the responsibility to manage the business it owns and operates to ensure investments are reasonable and necessary for the provision of service to its customers. No other party to the workgroup process has such an obligation and duty to serve. Equally important to I&M is its responsibility to efficiently and effectively balance and implement Indiana and Michigan's state energy and environmental policies. This requires I&M to continue providing safe, reliable and affordable power to businesses and residences alike, while transitioning to a clean energy economy.

Recognizing the role of the public utility, the preparation of the evolving IRP, along with distribution and transmission planning, is a complex and dynamic analysis of a utility's resources, reliability, and resiliency needs and strategy during a time of significant change in electricity market conditions, environmental and energy policy, and customer engagement.

In this time of significant change and uncertainty within the electric utility industry and markets, utility resource planning should reflect actions that recognize and manage risk and uncertainty, balance the interests of present and future customers, and allow for course corrections as industry evolution comes into greater focus. With this background, it is important to keep in mind that utility planning, such as resource, distribution, and transmission planning, provides a road map for providing reliable, cost effective and least risk electric service to the utility's customers, consistent with state and federal energy policies, while addressing, and planning for, uncertainties. The primary outcome of the integrated resource planning process is the selection of a preferred portfolio of resources that represents the most likely combination of resource actions and expected costs that are necessary for the utility to continue to meet the long-term needs of its customers.

The integration of resource, distribution, and transmission planning should be flexible, rather than prescriptive. The uncertainty associated with utility planning is greater today than in the past. First, there are far greater supply-side and demand-side resource options available and technology continues to change rapidly. Resource options are more distributed in nature and customers have increasingly more economic options available to provide some of their own energy needs. The way customers use energy continues to change and is likely to change more rapidly in the future, this impacts consumption patterns and load assumptions. The result is that system planning is more dynamic than in the past and there are increasing challenges to predicting the future. Lastly, regulatory, environmental and legislative energy policy directives that impact energy plans are more common today, in some cases, defining new energy directives that must be met over fairly short time horizons. These considerations support the need for utility planning to remain flexible in nature. As such, the integration of resource, distribution, and transmission planning should recognize that system planning is not confined to the processes outlined in the Staff's draft report. Whereas the IRP represents a snapshot in time, it is necessary to recognize that system planning and decision making are dynamic and fluid utility functions and responsibilities.

Last, the IRP is an important process and input into the utility business, however its inherent limitations must also be recognized. Most importantly the IRP is a snapshot in time that requires nearly two years to complete in Michigan. The IRP process should not be a burden to responding to changing system needs or resource options which is why it is an excellent planning tool. It should not be prescriptive in nature and not override or delay management judgement. The integration of resource, distribution, and transmission planning adds multiple layers of additional complexity to the process and thus should also consider the need to balance competing considerations. There needs to be a balance between the desire to make resource, distribution, and transmission planning a coordinated, open and transparent public process and the need to consider confidential, proprietary information in the process; the extensive and separate planning processes that are already in place, the technical competence that is necessary to plan and make sound decisions for complex and unique electrical systems and the obligations that only the utility has to serve its customers.

II. Comments on Staff's Draft Report and Recommendations

I. Forecasting

Staff Recommendation: Utilities are consistent across planning efforts and transparent with stakeholders on electrification component within their load forecasts. (Staff Report, pg. 10)

I&M Comment: I&M agrees with the intent of staff's recommendation for consistency across planning efforts, while also recognizing the unique circumstances and requirements of the various planning disciplines that may require distinct load forecasts. For example, projections of the total number of electric vehicles may be sufficient for generation planning in an IRP, but distribution planners need to predict where those EVs will be located and for how long (before the owner moves to a different residence and begins charging the same vehicle at a new location.)

As a multi-state utility, I&M must also maintain consistency in its forecasting approaches across all jurisdictions.

Staff Recommendation: Curt Volkman suggested during his presentation, on December 16, 2020, that the Commission require a series of questions to be answered in utilities next 5-year distribution plan to improve forecasting. These questions include:

1. How are they forecasting DER and NWA?
2. How they plan to improve DER and NWA forecasting going forward?
3. How is it incorporated in load forecasts?
4. How they incorporate stakeholder engagement?

Staff agrees and recommends utilities provide additional information in future distribution plan cases on DER and NWA forecasting and/or modeling. (*Id.* at pg. 9)

I&M Comment: I&M agrees with the general intent of the recommendations in describing the load forecasting process and various inputs that inform that process as it relates to distribution planning. Further, I&M is open to describing its efforts to mature and advance its processes that will leverage enhanced forecasting and modeling in the future. However, I&M recommends the guidelines not to be overly prescriptive about the specific questions that must be answered as part of the 5 year distribution plan submittals for evolving areas of work such as these.

Staff Recommendation: Staff agrees and recommends that utilities explore more granular DER and NWA forecasting programs or tools for modeling these specific resources. (*Id.* at pgs. 9-10)

I&M Comment: Although I&M agrees with the general intent of enhancing forecasting and modeling, it is worth recognizing that enabling technologies (such as AMI) are a prerequisite to support this objective. I&M is open to describing pertinent considerations as part of the 5 year plan submittals. However, I&M cautions against the adoption of rules or requirements that necessitate tools that would require costly investment and resource support that may not be reasonable or necessary at the time.

Staff Recommendation: Utilities should take a component or modular approach to forecasting. Key components should include:

- Gross demand and energy forecast;
- Gross load shape;
- Load shapes for EWR, DR and other load modifying resources that are not being modeled as resources. Examples could include already implemented EWR or EWR achieved outside of utility EWR programs;
- EV adoption and charging profiles;
- Behind-the-meter resources and DER forecasts that include customer owned photovoltaic and storage. (*Id.* at pgs. 18-19)

I&M Comment: I&M appreciates staff's desire to use a modular approach to forecasting. However, it also recognizes that some of the components described in Staff's report are conditional on the utilities deployment of the latest interval meter technology (AMI). Without full deployment of AMI meters in both Michigan and Indiana, the Company may be challenged to develop a fully modular approach to forecasting.

Without AMI, the Company has developed a proven load forecasting methodology that is accurate and reliable for system planning and setting rates. The Company's load forecasting staff is capturing the impacts of several dynamic inputs such as changing saturations of energy efficient technologies, saturation of customer owned distributed energy resources, adoption of electric vehicles, impact of economic development activities, etc.

Staff Recommendation: As forecasts change, utilities should provide clear details on how the forecast has changed as well as an explanation on why the forecast has changed. This should be done from one case to the next, always referencing back to the most recent, previously filed case forecast vs the current filing in question. (*Id.* at pg. 19)

I&M Comment: Staff's recommendation is vague and ambiguous in that it seeks utilities to provide "clear details" from case to case. Load forecast information is included in many regulatory filings, for example PSCR Plan filings, general rate case filings, IRPs, etc. I&M's load forecast is already supported in detail for IRP filings through stakeholder meetings and the actual IRP. In addition, the Staff's recommendations set forth in the draft report do not and should not replace other aspects of a contested regulatory proceeding which are designed and intended to allow Staff and other parties to question, study, and contest the substance of the relief requested, such as Staff audit, discovery, evidentiary hearings, and briefing. I&M is further concerned that the requested additional detail is unclear and could require a utility to provide voluminous information.

A. Transmission

Staff Recommendation: To facilitate enhanced information sharing and communication between Michigan's regulated utilities and transmission owners, Staff recommends that a process for regular discussion of current and future system needs be established. (*Id.* at pg. 34)

I&M Comment: All transmission investments made by I&M and its AEP affiliates are subject to FERC's jurisdiction and comply with the FERC-approved PJM OATT. These investments are planned and reviewed pursuant to the procedures set forth in the OATT.

Under the OATT, all projects affecting the topology of the grid – both PJM-identified projects and AEP-identified projects (called "Owner Projects") – are subject to the stakeholder process within PJM. Projects are reviewed with the Transmission Expansion Advisory Committee ("TEAC") and Subregional RTEP Committee – Western ("SRRTEP") on a regular basis. All TEAC and SRRTEP meetings are open, and any entity can attend and participate. Any stakeholder concerns regarding specific projects can be vetted through this PJM committee meeting process.

Furthermore, AEP meets with stakeholders annually outside of the PJM process to identify needs that directly affect customers. Any needs identified in those meetings, along with the developed solutions, go through the same thorough PJM process.

Staff Recommendation: Staff recommends requiring a utility to engage a TO a defined minimum number of months prior to filing to ensure that there is enough time to allow for communication of electric grid details between the TO and regulated utility. (*Id.* at pg. 33)

I&M Comment: Many of the Staff's recommendations center on communication and transparency. The following Staff recommendations, however, are misplaced: 1) a process for "regular engagement" to facilitate bidirectional flow of information between Michigan's regulated and transmission utilities; 2) requiring utility to "engage a TO a defined minimum number of months prior to filing to ensure that there is enough time to allow communication of electric grid details between the TO and regulated utility"; 3) requiring utility to engage a TO a defined minimum number of months prior to filing to ensure enough time to allow for communication of electric grid details between TO and regulated utility ; and 4) coming to an "agreed upon meeting schedule and timeline for performing transmission analysis, providing feedback, and evaluating alternatives."

It is important to note that I&M is a vertically integrated utility in that it owns and has responsibility for all levels of the supply chain: generation, transmission and distribution. For I&M, the transmission planning process is a partnership between AEP Transmission and its stakeholders, including I&M. I&M and AEP Transmission work together to identify needed investments on the transmission system and collaborate on optimizing capital expenditures among all competing needs. The Staff's comments regarding information flow between utility and transmission utilities is not applicable to utilities like I&M that maintain ownership of their transmission facilities. These Staff comments and recommendations should be directed solely to Michigan utilities that do not have transmission organizations as part of their regulated business.

Staff Recommendation: Staff also recommends that meeting minutes be provided along with pertinent details about utility requests for studies, discussions about assumptions and any conclusions made during the meetings, alternatives that were reviewed, and any other pertinent information that can be made public or provided through typical contested case confidentiality agreements. (*Id.* at pg. 34)

I&M Comment: This requirement should not apply to PJM participating utilities. All SRRTEP and TEAC material, including stakeholder feedback provided to PJM and Transmission Owners, is available on the public PJM website.

Staff Recommendation: Staff recommends that regulated utilities and transmission owners, with the participation of the Staff, come to an agreed upon meeting schedule and timeline for performing transmission analyses, providing feedback, and evaluating alternatives. (*Id.* at pg. 34)

I&M Comment: See previous comments regarding recommendations on Staff's report at page 33.

Staff Recommendation: Also, given the interest of Stakeholders in fully understanding the impact the transmission analysis has on the utility's proposed course of action in its IRP, Staff recommends that additional items be included. Information should include any recent studies that identify general areas or regions where resources are able to be interconnected with minimal transmission investment, any studies that indicate ways in which the CIL/CEL can be increased or may change coupled with how those changes may impact the LCR, and any information that identifies areas where generation solutions are being proposed to increase transmission system reliability. (*Id.* at pg. 34)

I&M Comment: This requirement should not apply to PJM participating utilities. This process is covered by PJM's IPP Interconnection queue, whereby any upgrades associated with new interconnections are documented on the PJM website.

Staff Recommendation: Staff recommends that regulated utilities and transmission owners coordinate to schedule a biannual meeting that serves two purposes. First, these meetings should focus on distribution system needs and expected fleet changes that are likely to occur for the regulated utility that facilitates discussion about how the transmission system may best support those changes, including potential transmission investment. Second, the meeting should also focus on transmission system needs and potential non-transmission alternatives that may be reasonable and economic replacements to transmission investment. (*Id.* at pg. 34)

I&M Comment: See previous comments.

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Staff Recommendation: Staff recommends that the Commission consider IRP filing requirements that require all studies used to inform a resource decision be included in the IRP. Studies performed for the IRP transmission analysis should, at a minimum:

(1) use the most recent RTO reliability planning models made available to all parties with a CEII Nondisclosure Agreement on file with the RTO,
(2) evaluate the reliability considerations of the utility's proposed course of action,
(3) evaluate the reliability, cost, and resource diversity benefits of transmission alternatives,
(4) identify areas or regions where new resources can interconnect to the transmission system with minimal transmission investment,
(5) identify and estimate the cost of upgrades that would increase the local CIL/CEL and impacts to the LCR, and
(6) identify where transmission and non-transmission alternatives are likely to facilitate DERs.

(*Id.* at pg. 35)

I&M Comment: See previous comments regarding the PJM transmission planning process. I&M is also concerned that the requirement to include "all" studies is overly broad.

Staff Recommendation: Staff recommends that the Commission consider requiring that all documentation that supports the utility's proposed course of action or the transmission owner's analysis and suggested alternatives should be provided. All requests for transmission studies and information should be documented by the regulated utility and included in IRP materials. (*Id.* at pg.35)

I&M Comment: Transmission studies and cases are considered Critical Energy Infrastructure, and it may not be possible for I&M to release them through the IRP absent a protective order. Providing final results and summaries of any studies undertaken to support the IRP should be included. In addition, non CEII references may be publicly available that stakeholders can obtain directly so do not need to be provided. Staff's recommendations also do not address possible copyright issues. The discovery process is the appropriate place to seek additional information that is of interest to stakeholders.

B. Value of Generation Diversity

<u>**Staff Recommendation:**</u> Value of Generation Diversity

- More accurately values risk mitigation.

<u>I&M Comment:</u> "More accurately" implies not optimal. I&M suggests a modification to "Review and include risk mitigation valuation with support for the selected methodology as an accurate valuation tool." Regarding "Box and Whisker Plots", this should not be the only option available.

<u>**Staff Recommendation:**</u> Staff recommends that the Commission requires utilities supplement the scenario and sensitivities analysis specified in the MIRPP by including a stochastic risk assessment for all required scenario optimized plans and any additional plans developed by the Company. (*Id.* at pg. 43)

<u>I&M Comment:</u> Given the computation requirements for stochastic analysis, requiring such an assessment of every plan may result in limitation of the number of plans considered.

<u>**Staff Recommendation:**</u> Staff recommends utilities conduct a stochastic risk assessment for their PCA, all the MIRPP base scenarios, and any utility created scenarios. (*Id.* at pg. 50)

<u>I&M Comment:</u> Given the computation requirements for stochastic analysis, requiring such an assessment of every plan may result in limitation of the number of plans considered.

<u>**Staff Recommendation:**</u> For presenting the results of stochastic risk analysis, staff recommends box and whisker plots of each plan's NPV outputs, as they succinctly illustrate probability distributions; the wider the distribution, the more susceptible the plan is to risk under the conditions. Efficient frontier plots also present the risks and NPV of each plan in a manner conducive to comparison and selection of optimal plans. Further information on these two types of plots can be found in Appendix B and Appendix C. (*Id.* at pgs.50-51)

<u>I&M Comment:</u> Regarding "Box and Whisker Plots", this should not be the only option available.

Staff Recommendation: Staff also recommends continued collaboration with stakeholders to further develop Staff's understanding of generation diversity and risk assessment. (*Id.* at pg. 51)

I&M Comment: I&M has no objection to continue to discuss these matters with Staff and other stakeholders as part of the I&M IRP stakeholder process.

C. Alignment of Distribution, IRP and Transmission Planning

Staff Recommendation: Staff recommends that further consideration be given to counting market carbon during the Advanced Planning workgroup during Phase 3, when the draft MIRPP and IRP Filing Requirements are discussed. (*Id.* at pgs. iv and 63)

I&M Comment: Staff's use of "market carbon" is not defined.

Staff Recommendation: Information on DERs and NWAs shared between all planning processes can provide transparency and integrate them into the decision-making process for the future grid. Staff recommends distribution planning include a needs assessment that supports these resources and identifies the grid needs discussed above. (*Id.* at pg. 56)

I&M Comment: I&M has no objection to describing our current needs assessment process in distribution planning and the efforts to evolve and integrate the planning efforts across generation, transmission, and distribution. As these efforts mature, the Company's current distribution planning efforts will advance to support a more holistic and integrated approach.

Staff Recommendation: Staff recommends utilities engage regional transmission owners by continued communication throughout all phases of resource and distribution planning. Continued communication between transmission owners and utilities is necessary because planning between distribution, transmission, and IRPs should be iterative. No one planning process feeds solely into another, rather all the planning processes feed into all others, and establishing a consistent line of communication is key to information sharing. (*Id.* at pg. 58)

I&M Comment: See previous comments regarding recommendations on Staff's report at page 33.

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Staff Recommendation: Staff recommends increased consistency throughout the planning processes and coordination of timing between processes. These two items go hand in hand. Consistent assumptions throughout planning processes will advance the efforts to align those processes, while coordinated timing will ensure that the information provided in one plan can directly link to another. (*Id.* at pg. 59)

I&M Comment: I&M's ability to plan and coordinate the submission of resource planning and distribution planning filings is impacted by regulatory requirements in its Indiana jurisdiction. Indiana utility regulation requires I&M to file an IRP every three years. I&M conducts its IRP planning process on a total company basis. Even with a three year cycle, when including the Michigan contested case timeline, I&M is in a continuous cycle of planning, preparing and supporting its IRP filings, with the next cycle beginning often times before the prior IRP cycle has been completed.

Staff Recommendation: Staff also recommends that utilities consider aligning their organizational structure to better facilitate aligned planning. Staff's recommendation for coordinated timing should not be misconstrued to mean that planning cycles for distribution plans, transmission plans, and IRPs should all start and end at the same time; rather, the timing of the planning efforts should be coordinated to ensure the information flow from one process to another is consistent and accurate, so that a link between processes can be made between various inputs, outputs, and resulting decisions, allowing all parties to clearly identify how one plan feeds into another and vice versa. (*Id.* at pg. 60)

I&M Comment: I&M conducts its generation, distribution and transmission planning in a coordinated and combined effort with AEP's service company. Effective January 1, 2021, AEP reorganized its planning functions with the formation of the Grid Solutions business unit that has combined integrated generation, transmission and distribution planning together in the same organization.

Staff Recommendation: Staff recommends that utilities engage in planning as an iterative process, providing a clear link about how each planning process impacts another, and identify where there are opportunities for distribution and transmission to support resource development, investment in resources to support the distribution and transmission grid, and how distribution and transmission planning can be used to support one another. In essence, Staff is recommending that there be a clear conversation happening at regular intervals, such that stakeholders and Staff can follow from one planning case or activity to another, that establishes linkages between all planning processes. Identification of distribution system, transmission system and resource needs and opportunities will allow for locational benefits, increased reliability and resilience, and technology advancements to be fully realized for all customers. (*Id.* at pgs. 60-61)

I&M Comment: I&M supports transparency in its planning processes and is committed to continuous improvement. As discussed in previous comments, I&M benefits from being a fully integrated utility which facilitates regular discussion amongst all functions of the business. AEP and I&M have taken significant steps since the last IRP to further enhance coordination. However, Staff's recommendations must also recognize that there are many factors that influence or determine how resource, distribution and transmission planning occurs. For example, transmission is subject to rules and requirements imposed by FERC and PJM, resource planning is subject to rules and requirements of Michigan, Indiana and PJM and distribution plans are filed separately in Michigan and only by I&M, DTE and Consumers.

III. Conclusion

I&M appreciates the opportunity to comment on Staff's recommendations. As discussed above, the topics addressed are important, complex, and evolving. I&M and AEP have significant experience and expertise in the areas contemplated in Staff recommendations. In addition, I&M and AEP have taken recent steps to enhance the coordination of system planning activities that align well with many of Staff's objectives. Ultimately, it is important that we approach planning in a flexible manner that allows the utility to retain control and discretion that aligns with and recognizes the unique responsibilities it has to its customers and the business it owns and operates. I&M is also uniquely situated as a multi-jurisdictional company, which the majority of its customers are located outside the state of Michigan. This presents unique challenges and opportunities which also must be considered in Staff's recommendations to the Commission.

Northern States Power Company

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May 3, 2021

Naomi Simpson
Michigan Public Service Commission
Via email to simpsonn3@michigan.gov

Re: Integration of Resource, Distribution and Transmission Planning – Draft Report

Dear Ms. Simpson:

Northern States Power Company, a Wisconsin corporation and wholly owned subsidiary of Xcel Energy ("NSP-W" or the "Company"), appreciates the opportunity to review the Draft Report of Commission staff regarding Integration of Resource, Distribution and Transmission Planning. NSP-W has two brief comments on the Draft Report.

Regarding carbon accounting (discussion on page 63), NSP-W believes its plans align with desired carbon reduction levels, however, the Company notes that the framework it uses for carbon accounting today appears materially different from the framework described in the Draft Report. NSP-W agrees with those that raise questions regarding how to account for market interactions in carbon accounting methods, and agrees with Staff's proposal to consider further in future stakeholder processes. Additionally, NSP-W notes that considerations for electrification will be important, and asks that stakeholders continued to be involved in discussions regarding best practices and ways to assess carbon emissions from electrification load growth.

Regarding the Commission's expectations regarding stochastic modeling (discussed both in the main report and Appendix C), NSP-W notes that for a large, multi-state system such as the NSP System, probabilistic modeling would be more time consuming and complicated. The Company believes it already captures a large amount of variety by modeling a vast number of deterministic sensitivities and believes that leaving stochastic modeling as optional would be most appropriate.

Please feel free to contact me by email at Deborah.E.Erwin@xcelenergy.com if you have any questions regarding these comments.

Respectfully submitted,

Dell Erwin

Deborah E. Erwin
Manager, Regulatory Policy