BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file their distribution investment and maintenance plans and for other related, uncontested matters.	))))))	Case No. 20147

Introduction

Advanced Energy Economy and the Michigan Energy Innovation Business Council (AEE/Michigan EIBC) appreciate the opportunity to comment on the recent utility distribution system plans, in response to the Commission Order in Case Nos. U-21122 and U-20147.[1] As the Commission noted in its order establishing Case No. U-21122, two of the largest storms in the last 135 years have occurred within the past four years. We share the Commission's concern that there is an urgent need to examine utility planning processes and improve upon existing methods to prepare for a future that may look very different than the past. The distribution planning process, which is the subject of Case No. U-20147, is a suitable venue for addressing this issue in conjunction with other important changes affecting the utility business model, and we welcome the opportunity to bring specific attention to the issues of resilience and emergency preparedness.

AEE/Michigan EIBC previously provided detailed comments in Case No. U-20147 on both the Consumers Energy Draft Electric Distribution Infrastructure Investment Plan ("EDIIP") and the DTE Electric Draft Distribution Grid Plan ("DGP"). Below we provide answers to the following questions the Commission posed in its Order from August 25, 2021, in Case Nos. U-21122 and U-20147:

- Are the measures focused on improving distribution system reliability identified in the respective distribution plans commensurate with the scale of the challenge?
- Are the metrics identified by the utilities to reduce the number and duration of outages and the number of customers experiencing multiple outages appropriate?

[1]Michigan Public Service Commission Order. August 25, 2021. Case No. U-21122. Available at: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000SStwQAAT.

- Do the financial incentives and penalties identified by the utilities align the respective utility's financial goals with the goals of this Commission in reducing outages and improving distribution performance?
- Do the distribution plans filed reflect the appropriate balance between needed investments and customer affordability? Are there alternatives that would better strike this balance?

The comments below support previous comments submitted by AEE/Michigan EIBC in Case No. U-20147 in response to Consumers Energy's draft EDIIP and DTE Electric's draft DGP. As a result, our answers to these questions focus on these two investor-owned utilities.

1. **Are the measures focused on improving distribution system reliability identified in the respective distribution plans commensurate with the scale of the challenge?**

General Comments

AEE/Michigan EIBC are concerned that both Consumers Energy's and DTE Electric's proposed distribution investments may not effectively account for the changing climate and weather patterns in Michigan. The Commission rightly points out in its August 25, 2021 Order in Case No. U-21122 that "The realities of a changing climate make it likely that Michigan will experience storms that are more extreme and will experience them more frequently than it has in the past." With this in mind, we provided brief comments in Case No. U-21122 related to how utilities should incorporate improved climate and weather modeling into their planning processes.[2] We believe that the incorporation of climate modeling data will allow utilities to make better-informed decisions when it comes to improving distribution reliability and preparing for storms like those seen this summer.

In this vein, and consistent with what we believe is one of the Commission's goals with respect to changing the way that utilities conduct distribution planning, it is important for Michigan's utilities to recognize the ways in which new technologies, such as distributed energy resources

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[2] AEE/Michigan EIBC Comments. September 24, 2021. Case No. U-21122. Available at: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000U28SUAAZ.

(DERs),[3] are not simply changes that the utility must accommodate but rather are resources that the utility can integrate effectively to enhance reliability and resilience. For example, DERs can provide a range of grid services that are valuable during normal operations and under severe weather conditions.

AEE/Michigan EIBC are also concerned that utilities in Michigan do not always sufficiently incorporate all the technology, financing, and partnership options available to them in their distribution planning processes. For example, microgrids, and the technologies incorporated in them, give utility customers the ability to control their own reliability through islanding capabilities in the event of storms similar to those on August 10-12. However, given cost barriers and that current statute does not require utilities to allow for microgrids, these opportunities are limited. AEE/Michigan EIBC believe that encouraging microgrid development and ownership can provide residential and commercial customers with greater reliability and enhanced energy control benefits. Like other DERs, microgrids can also provide valuable grid services and support grid reliability under a range of operating conditions.

DTE Electric (DTEE)

AEE/Michigan EIBC submitted comments in response to DTEE's Draft DGP on August 30, 2021.[4] In the DGP, we observed that DTEE proposed a variety of measures that could improve distribution system reliability. However, we raised multiple concerns throughout the document. First, Section 3 of the Draft DGP outlines DTEE's 2035 Grid Modernization Scenarios (Exhibit 3.3.1, DGP p. 30) derived from the ICF and EnerNex 2021 report. The three scenarios highlighted in this section (electrification, increasing CAT storm, DG/DS) are practical groupings to anticipate conditions that could negatively impact grid infrastructure and operations if necessary changes are not implemented in a timely or effective manner. Despite AEE/Michigan EIBC's support for the general parameters of the three scenarios, we are concerned that the scenarios are currently presented as distinct from each other. While this structure simplifies analysis and helps distinguish appropriate signposts and impacts particular to each, it would be useful and reasonable to anticipate that the future will be characterized by

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[3] Including electric vehicles and the associated charging infrastructure.

[4] See AEE/Michigan EIBC Comments on DTEE Draft DGP. August 30, 2021. Case No. U-20147. Available at https://mi-psc.force.com/s/filing/a00t000000QiA6DAAV/u201470065.

elements of all three scenarios. For example, it is essential to understand how the Company plans to simultaneously navigate evolving load profiles and increased load flexibility due to electrification as well as infrastructure vulnerabilities from more severe weather. We welcome additional explanation about how DTEE plans to prioritize and distinguish future distribution system needs under the likely situation that all three (or some combination thereof) of these scenarios play out. The plausible scenario approach is indeed useful for the purposes of DTEE's DGP, but more information is needed for comprehensive grid modernization planning. We recommend that DTEE supplement its current approach with additional forecasts and/or models that can evaluate future impacts recognizing that elements of all three scenarios are likely to be relevant to planning and operations.

DTEE also details how it intends to perform significant grid hardening measures to upgrade the 4.8kV sections of its distribution network. As noted in our previous comments on the Draft DGP, AEE/Michigan EIBC recognize the need for traditional grid hardening programs. Measures such as these are necessary to improve grid reliability. Nonetheless, we have concerns that DTEE may not be pursuing every alternative option available to improve grid reliability. In its Draft DGP, DTEE demonstrates significant cost-savings from multiple non-wires alternatives (NWA) pilots in the form of solar plus storage, microgrids, and energy waste reduction/demand response.[5] These pilots demonstrate scalable options that DTEE could pursue more broadly to provide cost-effective, reliable service to its customers. These same technology solutions can also play an important role in improving resilience under extreme weather conditions.

Consumers Energy

Section VII of Consumers' EDIIP outlines its proposed five-year distribution plan with Section VII E focusing on reliability. As we wrote in our prior comments in response to Consumers' draft EDIIP,[6] we believe Consumers should consider how it can better incorporate DERs, including energy storage resources (ESRs) into its proposed $1.9 billion in investments to improve reliability and complement traditional grid reliability investments such as high voltage

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[5] DTEE DGP Section 12.7. Available at: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000RUqKjAAL.

[6] See AEE/Michigan EIBC Comments on Consumers Energy Draft EDIIP. June 1, 2021. Case No. U-20147. Available at https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000OpO56AAF.

and low voltage pole replacements, DSCADA, and line undergrounding. As DERs and ESRs can improve distribution system reliability, we also provided comments on Section VI of the EDIIP relating to Consumers' investments to develop initial hosting capacity analysis (HCA). We reiterate here our request for Consumers to reconsider the locational granularity of their proposed HCA to increase the opportunities for DERs and ESRs to connect to the grid.

2. **Are the metrics identified by the utilities to reduce the number and duration of outages and the number of customers experiencing multiple outages appropriate?**

General Comments

Both Consumers and DTE Electric use the System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI), and System Average Interruption Duration Index (SAIDI) to measure overall system reliability. AEE/Michigan EIBC believe that these are important metrics to report and track. Each company also tracks these metrics including and excluding major event days (MEDs) defined as a 24-hour period where at least 10% of customers are experiencing an outage. AEE/Michigan EIBC have concerns around the practices of simply analyzing these indices with and without MEDs, as it may not provide sufficient context regarding MEDs. Specifically, in the event of a storm, once fewer than 10% of customers are no longer experiencing an outage, the MED ends. However, the outages that remain are still attributable to the storm, and therefore may not be accurately accounted for under this paradigm. This gap in metrics raises concerns because it may result in an inability to identify areas of the distribution system that are particularly vulnerable to major storms. Given that DTE Electric and Consumers both have widespread AMI deployment, these utilities have the means to report the outage count and outage minutes to the day on which the outage started and thereby construct SAIDI, SAIFI, and CAIDI with and without major events (instead of using the MED construct). These more granular data would provide a better basis for understanding grid performance related to non-storm and storm-related events, allowing utilities to have a more detailed view of where the distribution system is underperforming.

Current practice in Michigan is for utilities to report the worst performing circuits to identify problem areas on the grid. However, AEE/Michigan EIBC argue that this is not the correct scope of analysis to determine system performance. Circuits can be miles long and have some segments that are reliable and others that are not. We recommend that the Commission change this metric so that utilities identify customers with poor reliability and incorporate these data spatially to better understand the nodal weak points that exist on the circuit. Similarly, circuit-level analyses do not provide a basis for equity analysis to ensure that low-moderate income customers are not disproportionately experiencing reliability issues. Tracking reliability through using individual customer data and superimposing that data over census tracts or zip codes within a utility's service territory would create a more granular view of those communities that are experiencing higher outage rates and reliability issues.

For the purposes of benefit cost analyses, AEE/ Michigan EIBC believe it would be helpful to decompose SAIDI, SAIFI, CAIDI by the cause of the outage and its location, cross-tabulated by customer type and location, where the location also includes topological data. Doing so would provide a clearer understanding of how different topographical features interact with different components of the grid and what customer classes are affected by these interactions.

3. **Do the financial incentives and penalties identified by the utilities align the respective utility's financial goals with the goals of this Commission in reducing outages and improving distribution performance?**

General Comments

Generally, AEE/Michigan EIBC support the development of financial incentives and disincentives with a critical caveat that any financial disincentives are not eligible for cost recovery. However, AEE/Michigan EIBC do not believe that either DTEE or Consumer's performance-based ratemaking (PBR) proposals in their current distribution system plans satisfy the Commission's request in its order in Case No. U-20697 to provide an "exploration of PBR initiatives" in their filings. Both companies did provide preliminary proposals and AEE/Michigan EIBC believe there is merit to developing those proposals as further outlined below. We encourage the Commission to require both utilities to provide more details and demonstrate a more complete PBR framework that could align utility financial incentives with the public policy goals of the Commission. While we recognize that this current inquiry is focused on reliability and resilience, we do not believe the exploration of PBR in Michigan should be limited to these issues.

We recommend that Michigan's utilities consider performance-based frameworks established in states such as Hawaii and New York, which are related to improving distribution system performance and minimizing customer outages. For example, recent Decision & Order 37787 from Hawaii approves comprehensive performance incentive mechanisms (PIMs) and metrics.[7] The portfolio includes several scorecards that provide a framework and evaluation criteria for utilization of AMI, low to moderate income customer affordability, and DER grid services. The Hawaii scorecard will report quarterly on the number and percent of customers participating in DER or demand response (DR) programs. In New York, ConEdison currently employs PBR to earn energy efficiency incentives and recover costs over a 10-year period. In 2019, ConEdison filed a petition[8] to increase revenues. A key feature of this petition was the integration of earnings adjustment mechanisms (EAMs), which act as PIMs to align rewards to the utility for achieving targets that create customer and system benefits. Incentive levels for utilities are developed in rate cases, which enables the rate of return and the total expected capital investment to be considered in concert. Given the general alignment of Michigan's policy goals with those in Hawaii and New York, we encourage the Commission to consider these examples as templates to enhance the state's distribution system planning efforts.

DTEE

In section 15.3 of the DGP, DTEE's proposed PBR framework focuses on the use of financial incentives and disincentives tied to reliability metrics. We support DTEE's incorporation of incentives and disincentives into their overall proposed PBR framework and believe that when incentive levels are set correctly, they can act as an effective tool to align utility financial goals with the goals of the Commission to reduce outages and improve distribution system performance. However, as stated in our previous comments, we recommend that when incentives are set, they should always result in net benefits for customers given a particular outcome,

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[7] Decision & Order 37787 Hawaii Public Service Commission. Docket 2018-0088. Available at: https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A21E17B53226E00118.
[8] New York DPS Docket 19-E-0065. Available at: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=58901&MNO=19-E-0065.

meaning that the total monetary benefit of achieving a particular outcome should be greater than the financial reward for the utility.

In its July 27, 2021 DGP stakeholder engagement presentation, DTEE outlined a deadband incentive and disincentive structure that we generally support and believe that when structured correctly can serve as an effective structure to align incentives, assuming that the disincentives and incentives are effectively structured.[9] Nevertheless, as noted in our prior comments, we seek further clarification on DTE's proposed PBR plan and information on what might be considered a suitable level of incentive and/or penalty, and how these levels would support the realization of net benefits for customers.

Consumers Energy

On page 19 of its EDIIP, Consumers outlines two incentive/disincentive metrics based on a 5-year trailing SAIDI and 5-year trailing customers experiencing multiple interruptions (CEMI) index. We believe that these are useful indexes to consider in a proposed incentives/disincentives mechanism, but we believe that waiting until 2025 before they take effect is not necessary. Assuming these would be the first metrics to be implemented, this timeline will delay progress toward enabling PBR and limit potential benefits for Consumers' customers, particularly since we believe additional metrics beyond reliability can and should be considered in a timely manner. We therefore encourage the Company to consider whether additional performance metrics are appropriate at this time, such as peak load reduction or metrics related to beneficial electrification. Under a more comprehensive PBR framework, outcomes like peak load reduction would have both long-term cost containment benefits and reliability benefits.

4. **Do the distribution plans filed reflect the appropriate balance between needed investments and customer affordability? Are there alternatives that would better strike this balance?**

[9] DTE July 27, 2021 Stakeholder Presentation. Slide 26. Available at: https://drive.google.com/file/d/1L9i5jWIr2rJwHINlc7wZiKmMX-On3FyM/view?usp=sharing.

General Comments

AEE/Michigan EIBC have general concerns that neither Consumers nor DTEE's benefit cost analysis (BCA) frameworks strike a balance between necessary investments and customer affordability. Both company's frameworks do not reflect the full range of customer benefits from non-traditional grid investments and potentially limit cost-effective modernization solutions that could help keep costs lower for ratepayers. Currently in the MI Power Grid New Technologies and Business Models Draft Report, MPSC Staff recommends that "Benefit cost analysis, as detailed by the National Standard Practice Manual (NSPM) for Distributed Energy Resources, be required from the utilities when proposing and evaluating future pilots for new technologies and alternative business/ownership model pilots, and cost and benefits related to facets of "just" rates the Commission details be included in any benefit cost analysis."[10] We believe that requiring that the NSPM for DERs to be incorporated into utility planning processes would help ensure that utilities are considering all cost-effective options when pursuing grid modernization investments.

We also encourage the Commission to work with utilities and stakeholders to develop a standardized BCA framework for their distribution plans. We believe doing so will help improve the distribution planning process and lead to better, more cost-effective utility investments and programs that improve reliability and resilience. We recognize that the Commission is moving in this direction, with the upcoming BCA stakeholder session on November 3, 2021, and look forward to participating in that session and subsequent efforts by the Commission to improve benefit cost analysis to support it policy goals.

Consumers Energy

Section IV Subsection C and D of Consumers' EDIIP filing outlines a benefit cost analysis that the Company intends to use to pursue grid modernization investments and implement the Company's proposed Grid Modernization Roadmap. As our previous comments on the Draft EDIIP noted, we believe the proposed BCA should be expanded to more fully capture the range of costs and benefits that will be associated with grid modernization efforts. Specifically, in its customer perspective category in Figure 63: "Benefits Categories in BCA Framework Model,"

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[10]Michigan Public Service Commission Staff Report. Case No. U-20898. "MI Power Grid: New Technologies and Business Models Workgroup." p. vii. Available at: https://www.michigan.gov/documents/mpsc/MPG_New_Tech_Draft_Staff_Report_-_091521_735505_7.pdf.

the Company outlines six categories for the customer perspective (avoided outage costs, increased DER integration, increased power quality, increased customer satisfaction, increased customer flexibility and choice, and other benefits). These categories may not fully capture the benefits that residential and commercial customers could realize from DERs. The increased DER integration category is described as "improvements in operating efficiencies resulting in reduced costs." However, there are other direct monetary benefits that consumers could see from customer-owned DERs (e.g., energy arbitrage, demand charge avoidance, decreased bills) and direct resilience benefits seen from distributed resources such as battery storage and electric vehicles (EVs). These benefits categories should be expanded upon to effectively encapsulate all potential benefits from the customer's perspective into the BCA framework.

DTEE

Section 5 of DTEE's Draft DGP outlines the Company's proposed benefit cost analysis framework. In its current form, AEE/Michigan EIBC believe that the DGP only provides a high-level analysis of how the Company's proposed Global Prioritization Model (GPM) and BCA framework will operate in practice. In its stated goals for the GPM, DTEE has incorporated customer focus/equity in its stated goals but has not actually incorporated these goals into the criteria by which investments are ranked. In other words, "clean energy" and "community" appear to have received rhetorical support but may not actually impact DTEE's investment decisions and prioritization.

This lack of focus on customer benefits raises concerns that the Company's long-term investment strategy, in its current form, may not reflect an appropriate balance between critical investments and customer affordability. Before the Company pursues further investments in upcoming rate cases, we believe that it is necessary for the Commission to seek further clarification on what specific BCA methodologies were employed in DTEE's DGP and what types of cost tests were used. Additional detail on the types of tests employed, what benefits were included, and how they fit within the framework of the GPM would provide a clearer picture of how DTEE is assessing the importance of customer affordability in the BCA process.

Conclusion

AEE/Michigan EIBC thank the Commission for the opportunity to participate in this Docket and highlight opportunities for the Commission to work with utilities and stakeholders to improve distribution system reliability and better align utility financial goals with the public policy goals of the Commission. We view this Docket as a means to develop a more robust planning process that ensures utilities make prudent, cost-effective investments in the future.