STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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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. U-20147

At the August 20, 2020 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Daniel C. Scripps, Chair
Hon. Sally A. Talberg, Commissioner
Hon. Tremaine L. Phillips, Commissioner

ORDER

History of Proceedings

On September 11, 2019, the Commission issued an order in this case (September 11 order) directing the Commission Staff (Staff) to file a report of its findings from the distribution planning stakeholder sessions by April 1, 2020. For this report, the Commission specifically directed the Staff to summarize the workgroup process, including discussions on the value of resilience, and to provide recommendations for the Commission to include as guidance for the next round of distribution investment and maintenance plans (distribution plans).[1] September 11 order, p. 5. *See*

[1] The next round of distribution plans, currently applicable to DTE Electric Company (DTE Electric), Consumers Energy Company (Consumers), and Indiana Michigan Power Company (I&M), were set to be due by June 30, 2021 (*see*, Case Nos. U-17990, U-18014, and U-18370; September 11 order, p. 5) but are now, through this order, extended to September 30, 2021, with draft plans due to the Staff and stakeholders by August 1, 2021, as discussed in more detail below.

also, October 11, 2017 order in Case Nos. U-17990 and U-18014 (October 11 order), pp. 17-18, and April 12, 2018 order in Case No. U-20147.

On April 1, 2020, the Staff filed its final report (Staff's final report) in the instant docket.[2]

Workgroup Process, Stakeholder Input, and the Commission Staff's Reports

Presentations and Comments on the Commission Staff's February 19, 2020 Draft Report[3]

The Staff's final report built on the materials presented during a series of five stakeholder sessions held between June and November 2019. These sessions included presentations from representatives of DTE Electric, Consumers, and I&M on their experience with pilot projects and proposed pilots to explore non-wires alternatives (NWAs) and hosting capacity. In addition, participants heard from a number of state and national experts on a range of topics, including:

1. Frameworks for distribution planning, including presentations from Jeff Smith and Lindsey Rogers of the Electric Power Research Institute (EPRI); ICF Resources, L.L.C. (ICF) consultants Tom Mimnagh and Walter Rojowsky; Paul De Martini of Newport Consulting Group, LLC (Newport Consulting); and Curt Volkmann of GridLab;

2. Hosting capacity analysis (HCA), including a presentation from Yochi Zakai of the Interstate Renewable Energy Council; a discussion led by Mr. Smith; a discussion moderated by Dr. Laura Sherman of the Michigan Energy Innovation Business Council (EIBC); and a joint discussion on levels of detail and cost by representatives of DTE Electric, Consumers, and I&M;

3. Benefit-cost analysis (BCA), including a presentation from Tim Woolf of Synapse Energy Economics, Inc.; a presentation by Paul Alvarez and Dennis Stephens of the

[2] On April 1, 2020, the Staff filed two versions of its final report. This order details the corrected version. *See*, Case No. U-20147, filing #U-20147-0050.

[3] This summary of presentations that occurred during the stakeholder meetings and comments on the Staff's February 19, 2020 draft report (Staff's draft report) is not exhaustive but is rather intended to shed additional light on inputs that helped shape the Staff's final report filed on April 1, 2020. For additional details on these presentations, the Staff's draft report, and comments thereto, *see*, <https://www.michigan.gov/mpsc/0,9535,7-395-93307_93312_93593_95590_95596_95599-508710--,00.html> (accessed August 19, 2020).

Association of Businesses Advocating Tariff Equity (ABATE); a discussion led by Mr. Mimnagh; and presentations by representatives of DTE Electric, Consumers, and I&M;

4. NWAs, including presentations from Mr. De Martini and Professor Johann Mathieu of the University of Michigan; a discussion led by Mr. Rojowsky and Mr. Smith; and a joint discussion on qualified projects by representatives of DTE Electric, Consumers, and I&M;

5. Load and distributed energy resource (DER) forecasting, including a discussion led by Mr. Rojowsky;

6. Reliability metrics, including a presentation and evaluation of Michigan utility reliability reports from Joseph Eto of the Lawrence Berkeley National Laboratory; and

7. A presentation from Advanced Energy Economy Institute (AEE Institute) on regulatory innovations in the treatment of operating expenses.

In addition to these presentations and discussions from external stakeholders, the Staff provided numerous substantive overviews and facilitated discussions relating to how to define and properly evaluate hosting capacity and NWAs. The presentations and discussion from the five stakeholder sessions, as well as comments submitted during the stakeholder process, all informed the development of the Staff's draft report, which was circulated to stakeholders on February 19, 2020. Participants then had the opportunity to submit comments on the draft report, the following of which is a synopsis of those comments.[4]

ABATE supported numerous points in the Staff's draft report (e.g., on pilots and the Staff's apparent commitment to the extensive use of BCA in distribution planning) but asserted that certain elements merited higher priority (e.g., with regard to the least cost/best fit approach, the use of risk-informed decision support, and the inclusion of carrying charges in the definition of BCA costs). ABATE also opined that the Staff's draft report overlooked certain important context for distribution planning generally (e.g., on rate base growth pressure and lack of correlation to

[4] *See also*, Staff's final report, Appendix.

reliability improvements) and that certain assertions and implications within should be modified or removed, including on the topic of grid visions, which ABATE averred needs to be quantified with objective measures. Arguing the Staff's recommendations in its draft report are the status quo, with some augmentation through Commission guidance, but not going far enough to address fundamental challenges, ABATE ultimately recommended that the Commission establish a formal proceeding to develop a transparent, stakeholder-engaged distribution planning and capital budgeting process for distribution plans and capital budgets moving forward.

The American Council for an Energy-Efficient Economy (ACEEE) focused its comments on the topics of distribution planning objectives, HCA, NWAs, and the role of energy efficiency (EE) in distribution planning, the latter which ACEEE asserted should play a key role in this process. ACEEE endorsed the four primary objectives identified by the Commission[5] but asserted one objective is missing—environmental sustainability/environmental protection. ACEEE also recommended that any analysis of hosting capacity, along with NWAs, include an assessment of the potential for EE and demand response (DR), with the objectives of optimizing the amount of local renewables, not simply maximizing them, for hosting capacity and contributing to an NWA solution.

Consumers addressed distribution planning objectives, definitions, BCA, HCA, NWAs, and next steps in its comments. Consumers asserted that the Commission's four objectives continue to be appropriate for distribution planning, with safety as a top priority, followed by reliability and resiliency, but sought clarification around the Staff's use of resource diversity in the context of

[5] Discussed in more detail later on, but (1) safety, (2) reliability and resiliency, (3) cost effectiveness and affordability, and (4) accessibility. *See*, October 11 order, pp. 10-12.

distribution planning. Consumers disagreed that a BCA should be required for all utility distribution investments using ratepayer funds for several reasons and further addressed this topic as it relates to rate case filings and requirements. Consumers agreed with more limited pilots for HCAs but sought clarification on what the Staff anticipates with, along with implementation timelines for, a phase-in approach. Consumers generally agreed with the Staff on recommendations related to NWAs except with the Staff's inclusion of new business on this topic. And with next steps, Consumers opined great value in continuing to align distribution plans with integrated resource plan (IRP) filings, recommending a three-year cycle.

The Citizens Utility Board of Michigan (CUB) focused on concerns relevant to the interests of residential customers. In particular, CUB discussed the topic of reliability and how the BCA portion of the Staff's draft report may have the most potential impact on residential customers. CUB asserted that transparency in this process is critically important and echoed the call for reliability benefits to be expressed in terms of effects on system average interruption duration index (SAIDI), system average interruption frequency index (SAIFI), and customer average interruption duration index (CAIDI) metrics, with costs and benefits measured through a quantified versus qualified approach.

DTE Electric addressed the topics of distribution planning objectives, definitions, BCA, HCA, NWAs, alternative regulatory approaches, pilot programs, resiliency, standardized components for future utilities' distribution plans, the Michigan Infrastructure Council (MIC), the role of EE with distribution planning, the core functionality of the grid and the role of "vision" with grid planning, and next steps. Aside from clarifications at the end of its comments, these comments chiefly mirrored DTE Electric's comments filed in response to the Staff's final report on April 30, 2020.

The Environmental Law and Policy Center (ELPC) and Vote Solar (VS, collectively ELPC/VS) asserted that this distribution planning process has the potential to directly advance the overall objectives of MI Power Grid but that that potential will depend on Staff's report and the Commission's following order. Through that lens, ELPC/VS suggested modifications and clarifications to help strengthen and align the next set of distribution plans with the MI Power Grid initiative. In part, ELPC/VS recommended that distribution planning objectives be reset or added to align with MI Power Grid; that utilities be required to provide specified, explanatory information with their pilot proposals; that utilities initiate a phased, system-wide implementation of HCA; and that utilities incorporate NWA analysis into their broader distribution investment selection and prioritization processes. ELPC/VS also addressed resiliency, locational value, the role of EE with distribution planning, definitions, BCA, standardized components for future utilities' distribution plans, core functionality of the grid and the role of "vision" with grid planning, and conclusions and next steps.

The Energy Storage Association (ESA) commented on the benefits of energy storage and the role it can play not only with distribution planning but also with transmission. In this context, ESA also addressed BCA and policy options to address barriers to deployment of DERs, including storage.

GridLab commented on definitions, BCA, HCA, NWAs, core functionality of the grid and the role of "vision" with grid planning, next steps, and locational value. On the topic of vision, GridLab recommended that a long-term strategic vision and plan, featured as a component of every utility distribution plan going forward, include measurable goals and objectives.

I&M started with general comments on the process and the Staff's draft report, addressing topics such as regulatory and legal matters, a need for flexibility and adaptability with this process, and a potential cost recovery issue surrounding significant compliance expenses if new regulatory requirements are adopted. From there, I&M commented on, and suggested modifications to, proposed recommendations by the Staff regarding BCA; HCA; NWAs; alternative regulatory approaches; pilot programs; resiliency; standardized components for future utility distribution plans; the MIC; the role of EE with distribution planning; core functionality of the grid and the role of "vision" with grid planning, generally agreeing that a long-term strategic vision be included as a component of distribution plans but not that it be emphasized every step of the way; and next steps. In concluding remarks, I&M reiterated its support for a more flexible advisory approach to distribution planning at this time, rather than proposing requirements akin to administrative rules for this evolving and significant distribution plan process.

The Michigan Electric & Gas Association (MEGA) expressed its concern that the approach for distribution planning seems to have become increasingly prescriptive. MEGA discussed how distribution planning is a continual process, with decision-making unique for each utility, and raised concerns about unintended and undesirable consequences with a strict plan and structure approach, asserting instead the need for flexibility to allow for best decision making. MEGA did, however, opine the approach to continue distribution plan requirements for larger utilities appropriate and, against that backdrop, addressed the topics of BCA; HCA; core functionality of the grid and the role of "vision" with grid planning, suggesting a more expansive discussion and description of what such a vision would look like; and next steps.

EIBC and AEE Institute commented that changes to the distribution planning process should line up with the overarching objectives of MI Power Grid and be more forward-looking; that the Commission should include concrete steps to increase transparency in distribution systems planning, specifically recommending HCA and dynamic system load forecasting as standard components in the next round of distribution plans; that the Commission should consider phased system-wide implementation for HCAs and NWAs versus pilots; and that the Commission should take the first steps in forming a customer-centric, bottom-up distribution planning process. From there, EIBC and AEE Institute addressed itemized topics in the Staff's draft report, including those mentioned directly above along with the topic of vision, which they assert should be driven by MI Power Grid and should define "long-term" in the context of long-term strategic vision and plan.

The Michigan Municipal Association for Utility Issues (MI-MAUI) indicated why local governments care about distribution planning and, in this regard, advocated for municipal governments to have specific and reserved representation in distribution plan processes and for utilities to have specific coordination responsibilities with municipal governments impacted by their distribution system projects. MI-MAUI also addressed the topics of resilience, reliability, and BCA.

Together, the information gathered during the stakeholder process, as well as the comments submitted in response to the Staff's draft report, all informed the Staff's final report filed on April 1, 2020.

The Commission Staff's Final Report

In the report's executive summary, the Staff discusses the launch of MI Power Grid on October 17, 2019, in Case No. U-20645, and the initiative's relevance and incorporation into this matter. The Staff notes that its report "does not contain consensus findings representing all the parties who participated with the process. The appendix references perspectives from utilities and stakeholders indicating disagreement with Staff recommendations." Staff's final report, Executive Summary, p. i. The report also clarifies that it "does not represent the Commissioners' individual or collective perspectives on distribution planning." *Id*.

Following further detailed introduction and background sections, the Staff more fully describes the stakeholder process throughout the evolution of this matter, including the five stakeholder meetings that took place on June 27, August 14, September 18, October 16, and November 19, 2019, which "featured substantial discussion and contributions from utility Staff, MPSC [Michigan Public Service Commission] Staff, national experts, and a variety of other stakeholders." *Id.*, p. 4. The Staff mentions stakeholder and utility comments submitted during this timeframe and thereafter and then details significant issues which subsequently flowed into its summary and recommendations on the following topics, discussed in further detail directly below: (1) distribution planning objectives, (2) definitions, (3) BCA, (4) HCA, (5) NWAs, (6) alternative regulatory approaches, (7) pilot programs, (8) resiliency, (9) standardized components for future utilities' distribution plans, (10) the MIC, (11) the role of EE (energy waste reduction (EWR))[6] with distribution planning, (12) core functionality of the grid and the role of "vision" with grid planning, and (13) next steps.

1. Distribution Planning Objectives

In its October 11 order, the Commission established four primary objectives for the distribution planning effort: (1) safety, (2) reliability and resiliency, (3) cost effectiveness and affordability, and (4) accessibility. The Staff revisited these objectives based on advice from national consultants during the stakeholder process. Specifically, the Staff's final report notes that, in Mr. De Martini's October 16, 2019 presentation, he frames the "scope of grid modernization" in various proceedings across the country as including objectives relating to "reliability and

[6] The Staff notes that EE is referred to as EWR in state statutes. *See*, 2008 PA 295, as amended. The Staff thus refers to EE as EWR after discussion of the same in its executive summary. Staff's final report, Executive Summary, p. vi.

resilience," "DER integration and utilization," and "safety and operational efficiency," all relating to a core objective of "customer needs" binding everything together. *Id.*, p. 18.

Considering the substantial distribution system investments currently being proposed by Michigan utilities and the correlation to sub-topics addressed during this stakeholder process, such as dynamic system load forecasting and BCA processes, the Staff underscores the importance of these stated objectives. The Staff also opines that resource diversity is another important consideration—a topic addressed by the Commission in its 2019 Statewide Energy Assessment (2019 SEA) in Case No. U-20464 (filing #U-20464-0063) and a topic also appearing to correlate to the stated objective of "accessibility" when considering the growing trend of DER integration at the distribution level. Staff's final report, p. 19.

The Staff recommends that the Commission reiterate, for clarity, the importance of the Commission's previously stated objectives, confirming safety (for customers and utility employees) as the first priority, followed by reliability and resiliency, and also confirming the correlation of resource diversity with accessibility.

The Staff notes, however, that multiple stakeholders commented on the need to include additional objectives in light of the introduction of MI Power Grid. As noted in the Staff's final report, these stakeholders state "that this distribution planning process should advance the objectives of MI Power Grid to be more forward looking and include customer engagement, connecting distribution planning with transmission planning, DER and renewable integration, [and] incorporation of emerging technologies." *Id.*

2. Definitions

The Staff asserts that definitions are important to ensure the same perspective by all for referenced terms. Following additional context, the Staff recommends that the Commission include the following definitions in this order for consistency across all Commission initiatives and for purposes of referencing distribution planning terms going forward:

- Distributed Energy Resource – A source of electric power and its associated facilities that is connected to a distribution system. DER includes both generators and energy storage technologies capable of exporting active power to a distribution system.

- Hosting Capacity Analysis – Amount of DER that can be accommodated without adversely impacting operational criteria, such as power quality, reliability, and safety, under existing grid control and operations and without requiring infrastructure upgrades.

- Non-Wires Alternatives – An electricity grid investment or project that uses distribution solutions such as distributed energy resources (DER), energy waste reduction (EWR), demand response (DR), and grid software and controls, to defer or replace the need for distribution system upgrades.

- Locational Value Assessment – Locational value assessment is intended to quantify the benefits and costs of DER, which are often locational in nature. (Note: Very little discussion around locational value occurred at the stakeholder meeting and perhaps is a subject that warrants future discussion with stakeholders.)

Id., p. 21 (footnote omitted).

3. Benefit-Cost Analysis

The Staff states that the purpose of a BCA is “to rank possible solutions based on the present value of each solution’s costs and benefits,” and quotes New York-based utility Consolidated Edison’s *Benefit Cost Analysis Handbook* in stating that the “main motivation of using a BCA is ‘to provide interested parties a consistent and transparent methodology to calculate the benefits and costs of potential projects and investments.’” *Id.* (footnote omitted). The Staff’s final report also considered variations of BCA tests; impacts depending on the selection of the BCA test and inputs, including the discount rate; the use of monetized metrics as proxies for non-energy and non-monetized impacts; and the conducting of sensitivities to demonstrate results where the BCA test and discount rates are varied. The Staff further discusses the disagreement among stakeholders and the Staff on distribution projects that should undergo this type of analysis, which the Staff avers should be further explored, along with the application of BCAs as applied to investments (individually or bundled).

The Staff identifies a need for BCA guidance in Michigan and states:

> Lack of Commission guidance on BCA has resulted in disparate benefit and cost methodologies at Michigan utilities, many developed in-house. In U-17990 and U-18014, the Commission ordered DTE [Electric] and Consumers to include BCAs considering benefits, capital costs, and O&M [operations and maintenance] costs in five-year distribution investment and maintenance plans but provided no further guidance. The current utility methods for analyzing benefits and costs have been critiqued as overly qualitative and opaque. To proceed with grid modernization absent clear Commission guidance on BCA allows each utility to develop its own benefit cost evaluation methods, none of which currently are true BCAs. Without the guidance of a cohesive regulatory perspective, Michigan's electric distribution utility system will develop in an ad hoc fashion.

Id., p. 23 (footnotes omitted). Given this need, the Staff recommends "a stakeholder process to explore and propose specific BCA criteria for Commission consideration and adoption," acknowledging likely evolution of this guidance over time like other leading states. *Id*.; *see also*, *id*., p. 24. The Staff recommends that the stakeholder process should also consider the following criteria:

> • One main BCA test and up to two sensitivities required for future distribution plans from the list of BCA tests below:
>
> o Ratepayer Impact Measure, Resource Value or Regulatory Test, Societal Cost, Total Resource Cost, and Utility Cost test
>
> • Non-energy and non-monetized costs and benefits to be included in BCAs, the recommended method of inclusion, and assumed values
>
> • Main discount rate and up to two sensitivities to use in BCAs
>
> • Utility investment criteria requiring BCAs (for all or some investments and why)

> • Required BCA reporting in future distribution maintenance and investments plans, for project spending approval in rate cases, and for post-implementation accountability, and
>
> • Specifics of a BCA pilot required of Consumers, DTE [Electric], and I&M
>
> Initially, Staff recommends two BCA stakeholder processes beginning immediately after the second distribution investment and maintenance plans are filed. Assuming Commission adoption of the BCA pilots resulting from the first BCA stakeholder process, Staff recommends the second stakeholder process be initiated when utilities have results to present, therefore continuing discussion about a broader implementation of BCA within future distribution planning processes. Lastly, Staff recommends the frequency of BCA stakeholder process thereafter be determined in the second stakeholder process to ensure BCA methodologies and assumptions are current.

Id., p. 24.

4. Hosting Capacity Analysis

Within the framework of the Commission's prior request for Consumers, DTE Electric, and I&M to conduct HCA pilots, the Staff relays a key stakeholder recommendation[7] to define the HCA use-case, with "'interconnection of DER'" and "the recognition that HCA inherently increases the utility's ability to map distribution assets" as specific use-case suggestions from stakeholders. *Id*., p. 24. However, the Staff also recognizes the inability for a universal recommendation at this time due to utility specific dynamics and challenges.

The Staff states that, while stakeholders acknowledged the high cost projections provided by utilities for conducting HCAs, they also noted that utilities in other states have conducted HCAs at far lower costs than estimated by Michigan utilities. For example, in response to DTE Electric and Consumers' joint presentation on the costs associated with HCAs at the November 19, 2019 stakeholder meeting, the Staff states that "stakeholders commented that they believe the estimates

[7] *See*, EIBC and AEE Institute's comments filed in the docket on October 4, 2019, Case No. U-20147, filing #U-20147-0042, p. 2.

of $0.5-1M [million] at the lowest end and $40M at the highest end are too expensive and beyond the costs utilities [have incurred] in other states, such as Dominion Energy in Virginia and Xcel Energy in Minnesota, have experienced." *Id.*, p. 9.[8] This led to further discussion, including additional information from utilities about various levels of potential HCAs.

The Staff agrees with the stakeholder suggestion[9] for the Commission to "identify 'integrating DER' as a use-case for hosting capacity analyses and also include the ability to map distribution assets." *Id.*, p. 25. Recognizing time and resource constraints and the need for balancing investments that enable greater levels of DER with the need to replace aging traditional infrastructure, the Staff recommends a phased implementation process for HCA pilots.

Rather than significant investment in a highly detailed, system-wide HCA, which the Staff does not believe to be prudent at this time, the Staff recommends that Consumers and DTE Electric "conduct a high level go/no-go analysis for their distribution systems combined with smaller pilots involving more detailed HCA analysis in selected locations where a higher penetration of DER already exists or is expected." *Id.*, pp. 25-26. The Staff does not recommend the same for I&M at this time, however, given I&M's low level of DER penetration and the lack of advanced meters on its system, but does propose that I&M continue to monitor the HCA activities of Consumers and DTE Electric and for this to be revisited after the next round of distribution plans are filed in 2021.

The Staff finds value in smaller scale, high-level HCAs from a transparency, benefit, and cost standpoint. The Staff states that "[w]hile each utility's distribution system has unique

[8] For more specifics, *see*, ELPC/VS's comments filed in the docket on December 16, 2019, Case No. U-20147, filing #U-20147-0047, pp. 2-3.

[9] *See*, EIBC and AEE Institute's comments filed in the docket on October 4, 2019, Case No. U-20147, filing #U-20147-0042, p. 5.

characteristics, Staff expects that there are enough similarities that it will be beneficial for utilities to explore HCA costs and methods in other jurisdictions and benchmark their pilot costs against HCA costs in other areas." *Id*., p. 26.

The Staff again discusses how a phased implementation process for HCAs may address constraints and also recommends that hosting capacity information involving interconnection studies for specific projects be made publicly available to increase information, albeit limited and location-specific, for customers at no additional cost. The Staff further recommends that the HCA activities it proposes be accomplished by utilities within the next two years, with resulting information made publicly available during that time, and for the utilities to provide a detailed status update in their distribution plans filed in 2021.

The Staff specifically recommends the following be adopted by utilities for HCA pilots under this framework:

> • Adopt streamlined interconnection of DER and improved utility distribution mapping capabilities as the use-case for HCA[.]
>
> • Adopt a phased implementation approach for HCA pilots to allow utilities to focus on providing cost-effectively obtained, basic system-level information and at the same time highlighting areas of their system that cannot safely accommodate an increase in DER penetration by doing the following:
>
> > o Perform base-level approach with a zonal go/no-go map.
> >
> > o Conduct specific, detailed analyses on areas of the distribution system with high DER penetration and incorporate this information into a more detailed map with feeder voltage level information as DER penetration continues to increase.
> >
> > o As interconnection studies are conducted and HCA data for a specific interconnection location is determined, make this information publicly available.
>
> • Staff proposes that I&M continue to monitor the HCA activities of Consumers and DTE [Electric] and not be required to undertake any HCA activities at this time.

• Examine HCA best practices and methods for cost reduction, as demonstrated by other jurisdictions nationally.

• Benchmark projected and actual HCA pilot costs against HCA costs nationally

• HCA information should be publicly available with a downloadable map and spreadsheet.

• The recommended HCA activities should be accomplished within the next two years, while resulting information is made available publicly throughout the two-year period. A detailed status update should be provided in the electric distribution plans filed in 2021.

Id., p. 27.

5. Non-Wires Alternatives

The Staff discusses the Commission's preference, set forth through prior orders, for an examination of NWAs regarding near-term distribution investments by utilities and the possibility of NWAs providing another path to resource diversity. The Staff mentions comments from stakeholders[10] as to the parameters of NWAs and contends an examination of what NWAs can solve is key to this topic. *Id*., p. 27.

The Staff specifically endorses the "questions presented in Paul DeMartini's October 16 stakeholder presentation" and notes that these questions "should be asked by the Commission and answered by the utilities prior to refining and implementing additional NWA pilots." *Id*., p. 28

[10] *See*, e.g., Consumers' comments filed in the docket on December 16, 2019, Case No. U-20147, filing #U-20147-0046, p. 5; *see also*, e.g., page 10 of DTE Electric's comments filed in response to the Staff's draft report, <https://www.michigan.gov/documents/mpsc_old/DTE_683248_7.pdf> (accessed August 19, 2020).

(footnote omitted).[11] Specifically, these questions focus on a "[c]ustomer-centric approach to NWA" and include the following:

- Why are NWAs being pursued?
    - What are the pressing issues?
- What are the desired outcomes?
    - Optimize utility T&D [transmission and distribution] expenditures?
    - Enable greater value for customer/developer DER investments?
    - Enable greater adoption of DER to meet renewable/customer choice goals?
- What are the range of potential solutions?
    - Pricing, Programs[,] & Procurements (3P's)
- What is the role of customers, DER developers, utilities, aggregators[,] and others?

Paul De Martini, Newport Consulting, *Non-Wires Alternatives Framework (Evaluation, Sourcing Options, and Relative Risks*) <https://www.michigan.gov/documents/mpsc/Full_Slides_-_ver_8_668920_7.pdf> (slide 86) (accessed August 19, 2020).

The Staff contends:

> Once these questions are answered, a focus on the parameters of non-wires alternative pilots is important. Staff agrees with the relevance of stakeholder recommendations requiring utilities to formulate a hypothesis of expected (improvement in) performance metrics, a methodology for measuring (improvement in) performance metrics, and a plan for reporting (improvements in) performance metrics. Utilities should also investigate the ability to obtain and incorporate customer or third-party resources in future NWA pilot proposals, an option presented by stakeholders several times during the stakeholder process.

Staff's final report, p. 28.

The Staff suggests that the Commission encourage the utilities to explore additional NWA opportunities relating to system expansion in their capital plans, as well as with regard to other opportunities that may exist, with a detailed description as to capital plans that are "avoidable or deferable by NWAs." *Id*. The Staff asserts synergy with the topic of NWAs and the process of

[11] In its Executive Summary, the Staff sets forth the following additional question it suggests also be asked by the Commission and answered by utilities prior to additional NWA pilots: "Are the benefits and costs of NWAs accruing to all customers on an equitable basis?" Staff's final report, Executive Summary, p. v.

refining utility pilot programs going forward, also referencing a MI Power Grid workgroup on this front.

6. Alternative Regulatory Approaches

In the context of an assumed changing electric distribution system planning process attributable to implied variables, the Staff discusses AEE Institute's August 14, 2019 presentation and a related publication[12] that explores emerging alternatives to cost of service regulation to address a more service-oriented world for utilities in the future.

Against this backdrop, the Staff recommends:

> As the MI Power Grid Financial Incentives/Disincentives workgroup develops a workplan with stakeholder participation, Staff suggests that the alternative regulatory approaches outlined in the AEE [Institute] August 14, 2019 stakeholder presentation along with AEE [Institute]'s corresponding comments in the U-20147 docket be explored by the workgroup. It is important to acknowledge that if the landscape is changing for electricity delivery, then part of that changing landscape includes alternative regulatory approaches that can address the possibility of a more service focused distribution model. Regulators have a responsibility to explore their role in this changing environment.

Staff's final report, p. 29.

7. Pilot Programs

The Staff mentions comments from, and discussions with, utilities seeking more detailed Commission guidance on pilot programs (specifically, what applications necessitate pilots and what problems need to be resolved by the pilots).

Considering the work being done with MI Power Grid, the Staff recommends that, "[i]n their on-going work, the Energy Programs and Technology Pilots workgroup should take into

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[12] *See*, AEE Institute, *Utility Earnings in a Service-Oriented World: Optimizing Incentives for Capital- and Service-Based Solutions*, <https://info.aee.net/hubfs/AEE%20Institute_Utility%20Earnings%20FINAL_Rpt_1.30.18.pdf> (accessed August 19, 2020).

consideration the important stakeholder comments that were included in the U-20147 docket and 2019 distribution planning stakeholder sessions." *Id*. (footnote omitted).

8. Resiliency

Here, the Staff references the 2019 SEA and recommendations therein that were accepted and adopted by the Commission. When broaching the topic of resiliency at stakeholder meetings, however, the Staff came across some issues, including often interchangeable and simultaneous use of the idea of reliability and resilience and differing viewpoints on addressing metrics and risks for resiliency itself.

In this context, the Staff states that "[m]any stakeholders and utilities agree that there is a need to define resiliency." *Id*., p. 30. But, according to the Staff, a clear definition may not be what matters most considering a huge variation with the interpretation of resiliency. In this regard, the Staff contends:

> Identifying the events that we want to assure our electrical system can handle as we talk about resiliency may be a more productive approach. Once we identify the events that we are most concerned about when we think about resiliency, then there is the potential for metrics to be identified. There has been work done to identify possible metrics to use in evaluating resilience that include both utility and non-utility costs. However, there has been no national standardization or established industry standard of resiliency metrics.
>
> Establishing an event-based approach to resiliency and how best to measure it will help utilities prepare their distribution plans. It will also help stakeholders, Staff and the Commission to assess the value of utility investments related to resiliency and aid in prioritizing resiliency investments within the multitude of other utility investments that address reliability, safety, and resource adequacy, to name a few.
>
> To some extent, resilience is addressed in current reliability planning, but there is a lack of clarity as to what degree. A working definition in conjunction with establishment of target objectives, specific factors that should be accounted for, and key components to consider when determining the benefits and costs of resilience would help delineate between reliability and resiliency investments. If it is assumed that resilience events can be measured by the time it takes to respond to any event, then one possible way to begin to measure resilience could be to use the IEEE [Institute of Electrical and Electronics Engineers] standard reliability metrics

> for SAIFI, SAIDI and CAIDI. Additionally, it would be important to include all events and associated outage duration to gain an understanding of how the duration of all events changes with reliability and resiliency investment. If it is determined that resilience events can be measured by the ability to respond to extraordinary events, then resiliency could be measured by comparing the SAIFI, SAIDI and CAIDI calculations including extraordinary events with those same calculations using the standard reliability data that excludes major event days. The difference between the two could be viewed as a measure of system resiliency.

Id., pp. 30-31 (footnote omitted).

The Staff's final report notes that current reliability metrics sometimes mask extreme circumstances due to the use of aggregate data over a large region/territory and indicates a more granular approach (such as substation or circuit view) could be used if the Commission so desired.

The Staff discusses pilot activities by utilities to understand how different investments, specifically DERs, may impact and potentially improve resiliency. While the Staff believes information from these pilots can help quantify potential costs and benefits relating to reliability and resiliency, the Staff cautions that, "without having a clear definition to frame resiliency and how it differs from reliability, it becomes difficult to determine what resiliency events the pilot programs are designed to mitigate or accurately measure benefits." *Id*., p. 31.

The Staff recommends that:

> The Commission provide guidance to be used for the MI Power Grid Electric Distribution Planning workgroup about which methodologies to explore as a best fit for Michigan to enable Staff, stakeholders and utilities to further explore ways to improve the resiliency of the Michigan electric grid. Instead of providing a definition of resiliency, Staff recommends that the Commission identify the events that we want to assure our electrical system can handle as we talk about resiliency. Once we identify the events that we are most concerned about when we think about resiliency, then metrics should be identified.
>
> This report recommends the utilities distinguish between reliability and resilience in their plans, and report on system performance and planned investments with respect to each.

Id., pp. 31-32.

9. Standardized Components for Future Utilities' Distribution Plans

The Staff states that it supports a joint utility proposal to standardize components for upcoming distribution plans. According to the Staff, a general adherence to standardized components will make it easier for all to comprehend and compare plans.

As part of this recommendation, the Staff states:

> Regarding one category of standardized components entitled "Historical Performance", Staff recommends that the utilities should view SAIDI, SAIFI and CAIDI in total as outlined with quartiles, and by cause for the same period. Additionally, Staff recommends that utilities use the CEMI [customers experiencing multiple interruptions] and CELID [customers experiencing long interruption duration] metrics to directly measure the current unacceptable levels set by the Commission in the Service Quality and Reliability Standards for Electric Distribution Systems, [Mich Admin Code,] R 460.722. This will be further explored by the MI Power Grid Security and Reliability Standards Workgroup, where all the Service Quality and Reliability Standards for Electric Distribution Systems are being reviewed and proposed changes will be managed through the administrative rulemaking process. Staff's initial report for this workgroup will be filed April 30, 2020 followed by Staff's final report to be filed by September 1, 2020.

Staff's final report, p. 32 (footnotes omitted).[13]

10. Michigan Infrastructure Council

Given past Commission reference to the MIC, the Staff recommends that "utilities should coordinate distribution planning efforts with the MIC efforts in order to benefit all Michigan residents through more efficient and effective planning." *Id*.

[13] These deadlines were extended to July 31, 2020, for the initial report, and December 15, 2020, for the final report. *See*, April 15, 2020 order in Case No. U-20757, p. 16; April 15, 2020 order in Case Nos. U-20629 *et al*.

11. The Role of Energy Efficiency (Energy Waste Reduction) with Distribution Planning

The Staff discusses the relevancy of EWR with electric distribution, EWR being a key consideration for distribution planning because of its nexus with DERs and NWAs, and the value EWR brings to reducing load.

In this regard, the Staff recommends for the Commission to direct "the utilities to include an assessment of EWR options in their forthcoming electric distribution plans, including an evaluation of EWR in utilities' forecasts and NWA analyses." *Id*., p. 33.

12. Core Functionality of the Grid and the Role of "Vision" with Grid Planning

The Staff asserts "a holistic view of how enhanced technology and practices merge with a more traditional poles and wires system is imperative" and that the grid of the future needs to be advanced and highly efficient, requiring vision—from an engineering perspective when considering investments and also, as discussed by the utilities, thinking long-term for strategic purposes, which the Commission emphasized in its September 11 order. Staff's final report, p. 33.

With this background, the Staff suggests that:

> [T]he utilities' articulation of "vision" be emphasized every step of the way for future iterations of distribution plans. Such vision becomes the roadmap for results. As the utilities' proposed at the October 16 stakeholder session, a long-term strategic vision and plan should be a featured component of every utility distribution plan going forward.
>
> Several stakeholders and utilities such as ABATE, I&M, MEGA[,] Michigan EIBC[,] and AEE [Institute] commented on the definition and role of the utilities' "vision" in their response to the Staff's draft report that was circulated on February 19, 2020. Staff recommends the Commission direct its attention to these comments that are summarized in the appendix of this report when considering the role of the utility "vision" with future distribution plans.
>
> Various stakeholders would like the utility 10- and 15-year outlooks to focus on different things, making it difficult for utilities to analyze, address and incorporate everyone's preferences. Staff suggests that in a subsequent order in the U-20147 docket, the Commission provide additional clarification about what the utilities should include in the 10- and 15-year outlook portion of their subsequent

> distribution plans. Commission guidance on the longer-term utility projections could be very helpful.

Staff's final report, p. 34. In its executive summary, the Staff also recommends that utilities include measurable goals and objectives as part of their long-term strategic vision and plan. *Id*., Executive Summary, p. vii.

13. Next Steps

Following concluding remarks, the Staff discusses next steps, encouraging the Commission to provide additional direction and clarification on the important issues discussed above before utilities submit their next set of distribution plans in this docket. The Staff suggests that the Commission may also want to clarify the cadence of when subsequent distribution plans should be submitted by the utilities, with the Staff maintaining the alignment of distribution plans with IRP filings so that investments in both can be considered simultaneously.

In closing, the Staff anticipates a strong stakeholder process to continue with Commission-led dialogue on topics discussed in the report.

<u>Comments Subsequent to the Commission Staff's Final Report</u>

Following publication of the Staff's final report, three parties filed additional comments.[14] On April 30, May 29, and June 8, 2020, DTE Electric; ACEEE; and Natural Resources Defense Council, ELPC, VS, and the Ecology Center (collectively, the joint commenters), respectively, filed comments on the Staff's final report and/or in response to those comments filed.

[14] The September 11 order did not invite the submission of comments following the filing of the Staff's final report. Nevertheless, the Commission will take these voluntarily submitted comments into consideration in this instance, given the want and need for transparency in this matter.

1. DTE Electric Company

DTE Electric's comments include two sections: (1) the utility's responses to the Staff's recommendations and (2) clarification of some items discussed in the Staff's final report.

DTE Electric supports the four general objectives set forth by the Commission in the October 11 order but again stresses "that the utility must maintain discretion in interpreting what these objectives mean and how to pursue them." DTE Electric's comments, p. 2. DTE Electric unequivocally states that safety is the highest priority, agrees with reliability and resiliency being the second priority, and also agrees with the remaining objectives, along with resource diversity, being at the forefront of all forthcoming distribution plans. DTE Electric considers other stakeholder proposals as components of future distribution planning, rather than objectives, and further notes that MI Power Grid objectives should not be confused with those for distribution planning. DTE Electric recommends that the Commission uphold the four objectives from the October 11 order.

Regarding definitions, DTE Electric agrees with the Staff's proposed definition for DER. For HCA, the utility states that it "would like to rephrase the definition as '<u>analysis to assess the</u> amount of distributed energy resource (DER) that can be accommodated without adversely impacting operational criteria, such as power quality, reliability, and safety, under existing grid control and operations and without requiring infrastructure upgrades.'" DTE Electric's comments, p. 3. For NWAs, DTE Electric recommends changing the definition to "'an electricity grid investment or project that uses solutions such as distributed energy resources (DER), energy waste reduction (EWR), demand response (DR), and <u>grid software, communication and controls</u>, to defer or replace the need for distribution system upgrades.'" *Id.*, pp. 3-4. The utility does not, however, recommend the definition of locational value assessment at this time, due to little discussion on the topic during the collaborative workshops, no definition of the same generally accepted by the industry, and no proven successful cases on the topic by other jurisdictions. DTE Electric also does not consider this a near-term priority for distribution planning.

Concerning BCA, DTE Electric avers it is neither possible nor feasible for electric utilities to perform BCA on all of their distribution investments, stating that many distribution investments are mandatory in nature and should not be subject to BCA. DTE Electric asserts that it is ultimately its responsibility, as a managerial requirement, to prioritize and manage its distribution investments, which the utility does with the use of its own developed and refined global prioritization model (GPM). DTE Electric goes on to say:

> For selected high priority programs such as tree trimming and 4.8kV [kilovolt] Hardening where DTEE [DTE Electric Company] is able to track program impacts, system improvements have been observed. In contrast, the utility cost (UCT) and regulatory tests are both financially based analysis and rely on quantifying investment benefits into dollar values. Due to the non-monetized nature of safety, system planning, customer satisfaction, reliability and major event risk, it is not appropriate to use UCT or regulatory tests as the benefit cost analysis approach across all utility investments. DTEE also does not believe that it is beneficial or possible to meaningfully compare investments across different utilities. Each utility has its unique system condition, service territory and customer base. Any attempt to compare investments across utilities would not be meaningful or appropriate for the vast majority of the investments. At the same time, DTEE acknowledges that there may be some limited spend categories that may lend themselves to a financially based BCA. Some types of discretionary investments, such as utilizing energy efficiency or demand response as non-wire alternatives, could lend itself to a financially based BCA.
>
> DTEE would also like to point out the inherent differences between financial evaluations (e.g., utility cost tests and regulatory tests, etc.) and a weighting/scoring system that aggregates benefits in both energy/monetized and non-energy/non-monetized attributes. There is no single test that will achieve both financial evaluations and non-energy/non-monetized evaluations together.

DTE Electric's comments, pp. 4-5; *see also*, *id*., pp. 5-8. Despite its belief that its GPM is the optimal tool in this regard, the utility does indicate openness to an uncontested stakeholder process to discuss the BCA approach, to begin after the filing of its next distribution plan.

On the topic of HCA, DTE Electric agrees to adopt the "interconnection of DER" as the use-case for HCA but recommends removing the word "streamlined" as "HCA will not improve or streamline the interconnection process after an application is submitted. HCA may help developers better select sites and reduce the applications for non-viable areas; however, it will not change the steps and studies involved for utilities to evaluate the interconnection requests." *Id*., p. 9. The utility agrees with the Staff that a universal recommendation on how to specifically conduct HCA is not possible at this time. DTE Electric further agrees with a phased implementation approach for HCA pilots and discusses its plans in the next two years. Given uncertainties surrounding interconnection studies, the utility does not however recommend including updates of HCA data with interconnection study results as part of the pilot in the next two years. According to DTE Electric, "This will help define a fixed scope of the HCA pilots in the next two years for the utilities so that concerted efforts can be made for utilities on evaluating cost effectiveness of the pilots." *Id*. The utility supports the recommendation for I&M to just monitor its HCA activities, along with those of Consumers, at this time. DTE Electric further agrees that it would helpful and beneficial to benchmark with other national utilities and jurisdictions on HCA best practices and methods for cost reduction, which it states it has already engaged in doing and will continue to do, but also notes some issue with benchmarking on study costs. The utility also states that it:

> has reached out to other utilities highlighted by Staff and others on HCA costs and noted these costs are typically confidential and subject to non-disclosure agreements with vendors. In addition, it was difficult to ascertain the true cost due to legal and policy considerations for sharing such information from our peers and industry experts. With that said, DTEE will continue to conduct due diligence on HCA costs.

Id., p. 10. DTE Electric agrees to share results from the HCA pilots with a downloadable map and spreadsheet that can be publicly available, along with results from its own plans in the first quarter of 2022. DTE Electric additionally recommends that the Commission approve expenditures associated with HCA activities in the utility's future rate cases.

For NWAs, DTE Electric agrees that questions provided by Mr. DeMartini should be further explored before refining and implementing NWA pilots, and welcomes the opportunity for further dialogue on these questions. As to the Staff's added equitable question, the utility responds, "If an NWA solution provides system-level benefits and defer[s] traditional investments that would be rate-based, then that NWA project would be assumed to provide benefits and costs accruing to all customers on an equitable basis." *Id*., p. 12. The same would not be true however, according to DTE Electric, for an NWA installed at a specific customer site, which should not be rate-based but paid by that customer only. As far as parameters after these questions are answered, the utility states that its NWA pilots, with customer engagement and third-party support, are underway to help further understand a diverse set of parameters. DTE Electric agrees that NWAs are not a one-size fits all solution, expects continued learning of NWAs from current and future pilot projects, and welcomes the opportunity to engage in future discussions on the formulation, measurements, and reporting of performance metrics related to the NWA pilots. For collaborative NWA solutions to work effectively, however, the utility highlights a need to retain adequate oversight and control of the NWA resources, referencing challenges, the need for careful consideration, and the Commission's decision on the aggregation of bundled retail load in the August 8, 2019 order in Case No. U-20348, pp. 18-20. DTE Electric next recalls details from its November 19, 2019 presentation on its investment portfolio relative to NWA—specifically highlighting that total capital expenditure on load relief or system expansion is currently at 6% of total projected distribution expenditures and that not all projects within that 6% qualify for an NWA solution because of several noted considerations. DTE Electric's comments, pp. 13-14. As an important note, the utility states that new business projects are related to specific customer requests to connect to the grid and avers it highly unlikely that any new business-related investments could be replaced by NWAs. DTE Electric reiterates that specific customer load constraints do not accrue to customers on an equitable basis and should therefore not be rate-based. The utility further adds that the majority of its reliability and resiliency investments simply cannot be replaced by NWAs and cautions against the pursuit of NWAs for reliability and resiliency purposes at this time. DTE Electric also cautions against the consideration of NWAs for voltage and reactive power concerns, stating its belief "that installing capacitor banks and implementing Volt-Var Optimization (VVO) remain the most effective options to address voltage or reactive power issues." *Id*., p. 14. Summarizing:

> DTEE agrees that NWA can be explored as an alternative for some of the Company's investments. DTEE has several NWA pilots underway and is working with stakeholders to learn how we can improve our implementation of the NWA solutions to address geo-targeted loading issues. With that said, due to its unique characteristics and novelty, the NWA applications at this stage can be restricted and will need further study in the areas of "new business", "reliability and resilience", or "voltage and reactive power" before NWA can be considered as a useful, practical and safe application.

Id., pp. 14-15. DTE Electric welcomes the opportunity for continued discussion on this topic as part of the MI Power Grid initiative.

The utility similarly welcomes the opportunity to explore alternative regulatory approaches and developments and evaluations of pilot programs as part of the MI Power Grid initiative.

With resiliency, DTE Electric agrees that more clarity on events that have the potential to affect resiliency would assist utilities in developing methods to evaluate and measures to enhance system resiliency. The utility further agrees that this topic should be further explored as part of the MI Power Grid initiative. DTE Electric states that, without a definition of resiliency or the events that have the potential to affect resiliency, the utility finds it difficult to separate between reliability and resilience in its distribution plan. That said, DTE Electric offers the following interim solution for the next distribution plan filing:

- DTEE's definition of resiliency from the distribution perspective is the ability to recover quickly from a catastrophic storm that causes power interruptions to at least 5% of the Company's customer base. (e.g., the March 8, 2017 wind storm, the December 21, 2013 ice storm, etc.)
- Based on this definition, DTEE has provided SAIFI and SAIDI metrics related to catastrophic storms and plans to continue doing so in the next distribution plan. Both metrics are considered by DTEE today as the most relevant system performance metrics for resiliency as understood by the Company today.
- In addition, DTEE plans to discuss the updates of engineering standards to harden the system and the improvements of storm response processes to expedite customer outage restoration in the next distribution plan as key measures for improving resiliency.
- DTEE also believes [that the] majority of the strategic distribution investments in the Company's distribution plan contribute to both reliability and resiliency. Therefore, DTEE will not be able to differentiate and report on planned investments with respect to each.

DTE Electric's comments, p. 16.

With regard to standardized components for future utilities' distribution plans, DTE Electric agrees to provide SAIFI, SAIDI, and CAIDI by cause and industry quartile for the same period. The utility states that it is working with the Staff and stakeholders in the service quality and reliability standards collaborative but recommends that the Commission utilize orders and regulatory proceedings rather than rulemaking on the reporting of the reliability indices. DTE Electric mentions robust discussions on this topic and welcomes additional input from the Commission on what utilities should include in their 10- to 15-year outlooks in their distribution plans.

DTE Electric agrees that utilities should reference the MIC in their distribution plans and will continue engaging with the MIC "around the best way to share project data to allow improved project coordination with roads and other utility projects, such as water and sewer." *Id.*, p. 18.

On the role of EE/EWR with distribution planning, the utility states that it filed an assessment of EE resource options, including a potential study as an exhibit in its IRP, and thus avers a separate EE assessment for distribution planning would be redundant. DTE Electric goes on to say:

> In addition, EWR is a broad-based resource. As stated in [2016] PA 342, all customers pay into EWR programs, therefore all customers are eligible to participate. Specifically, Section 73 of PA 342 states the Commission must consider the extent to which EWR programs are available to all customers. Concentrated efforts of EWR for DO planning might conflict with the intent of the legislation. Therefore, a more appropriate solution would be to discuss EWR within the context of NWA solutions.
>
> Additionally, it is very difficult to capture broad scale baseload types of EWR in distribution planning due to lack of circuit level forecasting tools and methodology. The assessments of EWR lack the circuit level granularity necessary to make them useful in the distribution plan. Therefore, DTEE disagrees with Staff's recommendation for utilities to include an assessment of EWR options in their forthcoming electric distribution plans, including an evaluation of EWR in utilities' forecasts and NWA analyses.

DTE Electric's comments, p. 18.

On the topic of core functionality of the grid and the role of "vision" with grid planning, the utility agrees that a long-term strategic vision and plan should be a featured component of its distribution plan going forward but highlights that the detailed investment planning horizon will focus on a five-year outlook given prediction difficulties beyond that time frame. That said, DTE Electric states that it will be difficult to include measurable goals and objectives in its long-term strategic vision and plan, and thus not possible for every element within that vision and plan.

With next steps, the utility stands committed to submitting its next distribution plan on June 30, 2021, and suggests that distribution plans, given the increasing complexity of plan requirements and timing coordination between IRPs and distribution plans, be filed every three years.

Lastly, DTE Electric provides the following two clarifications and one errata:

> C-1
> Per page 25, the final report states "DTE has a mesh network in the thumb area which is sensitive to distribution system changes." DTEE would like to clarify that the mesh network of subtransmission lines spans our entire service territory not just the thumb area.
>
> C-2
> Per page 27, the final report states "Stakeholders have provided suggestions in the U-20147 docket as to the perimeters of NWA, with many of those comments summarized in the Significant Issues portion of this report." DTEE would seek clarification on whether it would be "parameters" rather than "perimeters" of NWA.
>
> E-1
> Per page 25, the final report states "The law allocates 0.5% to projects up to 20 kilowatts, 0.25% to projects up to 150 kilowatts, and 25% is reserved for methane digesters as large as 550 kilowatts." The correct percentage for methane digesters is 0.25%.

Id., pp. 19-20.

2. American Council for an Energy-Efficient Economy

ACEEE states that its comments respond to "one particularly concerning component" of DTE Electric's comments filed on April 30, 2020—namely about the role of EE/EWR with distribution planning. ACEEE's comments, p. 1.

ACEEE asserts that, contrary to DTE Electric, an IRP has a fundamentally different focus and level of analysis than a distribution plan and, thus, the consideration of EE/EWR in a distribution plan would not be redundant but "would be a necessary extension that would serve two important functions: (1) understanding how energy efficiency resource additions in the IRP will affect DRP [distribution plan] needs, and (2) examining additional practical applications of energy efficiency as a distributed resource (DER) to serve distribution system needs." *Id*., p. 2.

In further response, ACEEE states that EE/EWR is:

> widely utilized around the nation as a distribution system resource, as many of the references cited later in these comments will demonstrate. The fact that all customers pay into EWR programs is no different than the fact that all customers pay for all types of distribution system investments… even if they don't happen to reside in an area served by a particular distribution system investment. Including "concentrated efforts" of EWR where they are cost-effective for targeted distribution system objectives will benefit all ratepayers. The Commission should expect that DTEE will also maintain "broad-based" EWR programs available to all customers. [Multiple states have distribution planning processes where they include energy efficiency in addition to the use of energy efficiency as a broad based resource. New York's Brooklyn-Queens Demand Management (BQDM) program https://www.coned.com/en/business-partners/business-opportunities/brooklynqueens-demand-management-demand-response-program and California's local capacity procurement system for resource adequacy https://www.cpuc.ca.gov/RA/ are two prominent examples.]

ACEEE's comments, pp. 2-3 (bracketed material in original). ACEEE agrees that EWR should also be included in the framework of NWA solutions but notes NWA solutions are certainly within the scope of distribution plan analyses.

ACEEE argues that EE/EWR is not solely a broad scale baseload resource but is rather widely utilized as a targeted DER as well. According to ACEEE, "The fact that 'circuit level' forecasting and methodology is relatively new is clearly no excuse for not including an assessment of EWR where it can be a cost-effective resource. It is the responsibility of DTEE to develop that capability in order to better serve ratepayers." *Id*., p. 3.

ACEEE concludes with an overall summary, wherein it indicates strong support for the Staff's original recommendation on EE/EWR and avers DTE Electric's disagreement with the same is "clearly out of step with best utility practice around the nation . . . ." *Id*. ACEEE also includes examples of relevant resources in support of its comments. *Id*., pp. 3-4.

3. Natural Resources Defense Council, Environmental Law & Policy Center, Vote Solar, and the Ecology Center

The joint commenters focus on recommendations in the Staff's final report, along with DTE Electric's response to those recommendations, and are said to complement comments previously submitted.

While the joint commenters agree with the Staff that EWR should be considered as a key resource consideration in distribution planning, they strongly disagree with the Staff's definition of DER (which excludes EWR, as well as DR). The joint commenters argue that the Staff's "focus solely on generating resources is misplaced for the definition of DER" and recommend that the Commission consider and adopt the definition of DER as defined by the National Association of Regulatory Utility Commissioners' (NARUC's) DER Rate Design and Compensation manual, which includes reduction or shifting of demand. Joint commenters' comments, pp. 2-3. The joint commenters aver a lost opportunity for EWR and DR from being more broadly considered by not including them in the definition of DER. They further argue that "by limiting the definition of DER to 'active power' generation resources, this definition may limit the ability of inverter-based resources from providing reactive power solutions, such as VAR." *Id.*, p. 3. If the Commission does not adopt the NARUC definition of DER, the joint commenters recommend that "capable of exporting active power to a distribution system" be stricken from the Staff's proposed definition of DER.

On the role of EE/EWR in distribution planning, the joint commenters strongly support the Staff's recommendation and assert DTE Electric's arguments to the contrary to be flawed in several ways. First, and like ACEEE, the joint commenters argue that IRPs and distribution planning serve two different purposes (generation versus distribution needs) and thus an assessment of EE/EWR options in distribution planning is not redundant. Second, the joint commenters declare value in geographic targeting of EE/EWR programs to “meet or help meet distribution system needs at lower cost than traditional alternatives,” and to improve reliability in certain areas. *Id*., pp. 4-5. Further:

> Such geotargeting of efficiency programs need not be viewed as conflicting with statutory requirements for “broad-based” or system-wide EWR. For one thing, we see no reason why energy efficiency spending that is explicitly designed to address localized distribution needs could not be seen as “over and above” the statutorily-required, system-wide EWR programs and therefore not subject to the same requirements for equal access (and other requirements) as system-wide programs. Moreover, it may be appropriate to fund energy efficiency investments pursued as part of NWAs or for other distribution system needs through a different mechanism than the current surcharge used to fund system-wide efficiency programs (i.e. in the same way as other distribution system investments are recovered), which would clearly eliminate any concerns about violating statutory requirements for system-wide EWR programs. Indeed, Michigan utilities have acknowledged the value of geotargeted efficiency through pilot projects as part of workshops in the distribution planning stakeholder process; we recommend building on those early pilots going forward.

Id., p. 5. And third, the joint commenters argue that a lack of circuit level forecasting tools should not be a reason to exclude the role of EE/EWR in distribution planning, as DTE Electric’s forecasting can and must improve and the lack of such tools does not preclude the utility from assessing efficiency impacts in distribution planning in the interim. Here, the joint commenters suggest a simplified forecast adjustment, at a minimum, along with a more granular analysis of efficiency program impacts like that done by Consolidated Edison. *Id*., pp. 5-7.

The joint commenters assert DTE Electric’s argument on BCAs (being inappropriate to address, safety, reliability, and risk) is “fundamentally flawed,” as “[t]he reality is that the [utility] has made and continues to make implicit assumptions about the value of such attributes all the time.” *Id*., p. 7. The joint commenters declare that these attributes can be monetized and assert BCAs can help to make investment decisions better and more transparent. In this regard, the joint commenters:

> strongly suggest that the Commission consider the guidance on BCA that is in the *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (NSPM for DERs) that is due to be published next month. Until it is available, the original version of the manual, titled *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources* (NSPM for EE), should be referenced.

Id., p. 8 (footnote omitted). The joint commenters state that they strongly support most of the Staff's recommendation, just not with regard to its listing of the RIM test, which is not a cost-effectiveness test.

With HCA, the joint commenters recommend that the word "shall" replace "should" in the Staff's recommendation that "HCA information should be publicly available with a downloadable map and spreadsheet" and that any HCA map "should be provided via an interactive web page," like the map made publicly available by the Potomac Electric Power Company. *Id*.

And lastly, on NWAs and long-term vision, the joint commenters believe it important to contemplate the interconnected nature of the Staff's recommendations on these topics. They further state:

> In response to DTE, they are seeking to have it both ways. NWA's [sic] are future oriented, so any NWA project will have to focus on longer-term needs. Yet, DTE does not believe developing measurable goals and objectives are possible. In essence, if a measurable goal and objective for the utility was increasing the use of NWAs and have that track over time, DTE is saying in the short-term, there are no NWA's [sic] possible, and in the long-term, it is impossible to plan for NWAs. This is not a reasonable interpretation of Staff's recommendations. If DTE is doing a robust distribution planning process, such as one detailed in the DSPx [distribution planning] documents, then it would have an understanding of its reliability risks that, when aligned and integrated with interconnection requests, and demand and DER forecasting, would note areas of its system at risk. This is one of the roles of a distribution system plan- to address utility siloes to ensure all groups have access to information and can use and act on it. Staff's focus on NWAs is a good recommendation to provide visibility into whether or not the utility's distribution plan is progressing. Thus, we recommend the Commission maintain Staff's recommendations.

Id., p. 10.

Discussion

Before addressing the Staff's recommendations from its final report, albeit in a somewhat different order, the Commission would first like to express its appreciation and thanks to the utilities and other stakeholders for their participation and input in this ongoing and evolving process and to the Staff for its significant role and work on its report. Continued collaboration on this important process is key to success.

Distribution Planning Objectives, Core Functionality of the Grid, and the Role of "Vision" with Grid Planning

In the October 11 order, the Commission set forth the following overarching objectives for the electric distribution system:

> 1. Safety
>
> The electric distribution system and related utility operations to support this system have safety risks due to the inherently dangerous nature of electricity, equipment failures, damage due to third parties or inclement weather, older facilities designed without up-to-date safety protections, and potentially unsafe work practices while maintaining equipment. Safety is the Commission's top priority, and the Commission expects operational and investment strategies focus on this objective.
>
> 2. Reliability and Resiliency
>
> Electricity is essential in our modern society. Outages, particularly for prolonged periods of time, cause significant economic and societal costs. The Commission expects the electric distribution system to be designed and operated in a manner that is both reliable and resilient, including the ability to withstand and respond to major weather events and other disruptions. The Commission embraces Governor Snyder's 2013 reliability goals to reduce how often and how long customers experience outages (i.e., for the utilities to be operating in the first quartile among peers within the system average interruption frequency index (SAIFI) and top half among peers within the system average interruption duration index (SAIDI)). The Commission finds, however, that these outage outcomes should not be the sole focus, as the Commission recognizes the need to also address repetitive outages on particular circuits as well as overall performance during major outage events. Cybersecurity and physical security also play a key role in ensuring reliability and resiliency.

> 3. Cost Effectiveness and Affordability
>
> Processes for identifying and prioritizing cost-effective investments are essential to ensuring long-term affordability for customers. The Commission expects up-front analyses to ensure investment strategies are reasonable and prudent, alternatives are thoroughly considered, and longer-term operational savings from new investments can flow through to customers, thereby keeping rates affordable. A data-driven, value-based approach, as when to repair versus when to replace aging equipment, will also assist in investment decisions. Additionally, the ability to integrate new technologies in an optimal manner and provide planning tools and information to encourage efficient siting and operations of customer resources, such as DG [distributed generation] or energy storage, may also help displace or defer costly grid improvements, rather than exacerbate loading conditions and cause additional grid upgrades.
>
> 4. Accessibility
>
> The Commission expects the distribution system to be able to reasonably accommodate service to new or expanding customers without such additions causing major network upgrades due to an underlying infrastructure challenge. Planning to assess system conditions under different scenarios could also assist in providing guidance for siting new economic development projects or accommodating changing load patterns due to customer resources and consumption patterns. As technologies and customer preferences evolve, planning for the distribution system should optimize integration of customer and utility resources where possible.

October 11 order, pp. 10-12 (footnote omitted).

From there, the Commission discussed long-term considerations and near-term priorities, stating in pertinent part:

> The Commission remains dedicated to making decisions that ensure Michigan's ratepayers have access to safe and reliable service in both the short term and long term. Focusing the scope of the initial distribution plans to address near-term risks to customer safety and reliability will ensure customers continue to have access to safe and reliable electricity. This is an incredibly complex system, and the Commission believes that a focus on safety and reliability improvements in the near term will also provide a foundation for a stronger electric system that can adapt to changing technologies and customer patterns over time.
>
> For the longer term, the Commission recognizes that continuously evolving technology and customer expectations will require a more comprehensive approach to developing a "no regrets" distribution plan. The Commission therefore expects that future iterations of utility distribution plans will focus not only on ensuring

> short term safety and reliability but also leveraging new resources and approaches, such as energy efficiency, renewable energy, storage, line loss, volt/volt-[ampere] reactive [var] optimization, NWAs, and dynamic electric rate structures, to address looming system issues. The Commission envisions that future iterations of the five-year distribution plans will not only improve the efficiency of utility rate cases but will also play key roles in making informed decisions in other planning activities, such as the integrated resource planning under the state's new energy laws and local and regional transmission expansion planning processes.

Id., p. 17.

The Commission reiterates its support for the four objectives outlined above to guide this next iteration of distribution planning. Although some stakeholders suggested replacing these objectives with the MI Power Grid focus on customer engagement, integrating emerging technologies, and optimizing grid performance and investment, the Commission finds that this is unnecessary and prefers to retain the existing distribution planning objectives. The Commission points out that the descriptions of "accessibility" and "cost effectiveness and affordability" above explicitly address consideration of investment alternatives, engagement of customers, and the integration of emerging technologies, including DERs. These are all relevant considerations under MI Power Grid and reinforce the complementary nature of the distribution planning objectives to MI Power Grid. The MI Power Grid efforts geared at "optimizing grid performance and investments" are also central to this planning effort, including the need for more holistic energy system planning and improved utility incentives and grid performance from the standpoint of safety, reliability, resilience, cost, and accessibility. The Commission also acknowledges the Staff's suggestion that resource diversity considerations fall under the purview of accessibility. The Commission envisions the distribution grid of the future facilitating the interconnection and optimized operation of a diverse set of resources, whether they are owned by the utility, third parties, or directly by customers.

The Commission has previously stressed safety, reliability, and resilience as top priorities and reiterates the critical importance of these objectives. Aging infrastructure and less aggressive tree trimming have created safety and reliability challenges that must be addressed, and the Commission has authorized significant investments to meaningfully impact these issues, while acknowledging that systemwide changes will not materialize immediately. The Commission seeks to clarify that it does not view each objective in a serial, myopic fashion, such as only focusing initially on safety, reliability, and resilience, then, after those issues are resolved, turning to cost effectiveness/affordability and accessibility. The Commission views these objectives in an integrated fashion to maximize value for ratepayers. For example, solutions to an immediate or emerging safety or reliability problem should be cost effective over the short- and long-term recognizing the changing configuration of the grid as well as technologies and customer behavior that may affect system needs. Thus, the Commission expects these objectives to guide distribution planning in an integrated fashion to identify and prioritize system needs and to evaluate solutions. The Commission also embraces the "walk, jog, run" philosophy to tackling issues[15] as there are limits on utility, stakeholder, and Staff time and resources, and distribution planning can continue to evolve as we learn more.

With that said, the Commission agrees with the Staff and stakeholders that it is important to articulate the Commission's vision for the future of the grid, and specifically adopts

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[15] <https://www.michigan.gov/documents/mpsc/Full_Slides_-_ver_8_668920_7.pdf> (Slide 83), referencing <https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={E098D466-0000-C319-8EF6-08D47888D999}&documentTitle=201811-147534-01>, p. 179, Figure 55 (Staged Approach to Enhanced Planning Analyses) (both accessed August 19, 2020). *See also*, ICF White Paper, *The Value in Distributed Energy: It's all About Location, Location, Location* <https://www.icf.com/resources/white-papers/2015/value-in-distributedenergy> (accessed August 19, 2020).

Mr. De Martini's concept that the elements of distribution planning should all relate to a core objective of "customer needs" that binds everything together. Staff's final report, p. 18. As discussed in the Commission's initial MI Power Grid order issued in September 2019, the Commission expects the pace of technology change to accelerate with increased adoption of solar, storage, electric vehicles, and microgrids, and with customers becoming more engaged in producing and managing their energy. Accordingly, the Commission envisions a distribution grid of the future with increased DERs and active utility monitoring and controls to manage bidirectional energy flows and to detect and respond to reliability disturbances. The Commission is not in a position to drive this change from a technological or public policy standpoint, but it plays an important role in addressing regulatory barriers to new technologies, ensuring proper consideration of investment alternatives and ratepayer protection against potentially stranded investments due to technology obsolescence, and formulating fair and equitable rate designs as customers' use of the grid evolves. This transparent, holistic distribution planning effort is foundational to making informed decisions and spurring collaboration on these complex issues.

With respect to the 10- and 15-year horizons for this iteration of planning, the Commission recognizes that information on system needs and solutions will not be as detailed as the five-year horizon in terms of costs, design features, and prioritization of investments. Nonetheless, the Commission finds value in having the longer-term outlook as it can help provide important context for evaluating near-term investments and more transparency into the utility's vision and strategy, functionality, and the performance of the grid over time. *See*, September 11 order, pp. 4-5. As the Commission previously articulated in establishing the framework for these utility distribution plans, "[a] longer-term planning approach will help the Commission and stakeholders better understand the long-term goals and objectives underlying utility investment plans and how the execution of these plans can meet these goals and objectives in an affordable manner." October 11 order, pp. 14-15.

Definitions

The Commission agrees with the Staff's definitions of DER, HCA, NWAs, and locational value assessment. While the Staff's definition of DER does not include demand-side resources, EWR and DR are included in the Staff's definition of NWAs, and the Staff's DER definition is in-line with IEEE 1547-2018 and matches the Commission's proposed interconnection rules.[16]

Hosting Capacity Analysis

The Commission finds that increased visibility into distribution system capabilities and limitations is important to guide development of DERs in an efficient manner and inform planning decisions. Other jurisdictions have used HCAs and mapping to provide such visibility, while recognizing it is not a substitute for more detailed generation interconnection studies. This effort ties directly to the accessibility objective outlined by the Commission and will be of increasing importance as additional DERs seek to connect to the grid. The Commission agrees with the phased implementation approach outlined by the Staff to leverage and make publicly accessible existing information, and to build on this information over time as more detailed data are available through interconnection studies and system monitoring and analyses using distribution supervisory control and data acquisition, smart meters, and other sources. The Commission agrees with the timeframe outlined by the Staff with an initial base-level zonal go/no go map published and refined with updated analyses over a two-year period and DTE Electric and Consumers providing detailed updates in their distribution plans filed in 2021. The Commission also agrees with the

[16] *See*, <https://www.michigan.gov/mpsc/0,9535,7-395-93307_93312_93593_95590_95595_95689-508665--,00.html> (accessed August 19, 2020).

Staff that it is important to monitor hosting capacity best practices and implementation costs in other jurisdictions to leverage tools and learnings developed elsewhere. While the Commission agrees with the Staff for I&M to monitor HCA activities of Consumers and DTE Electric rather than produce its own map at this time, the Commission encourages I&M to leverage its planning expertise to contribute to this effort.

Non-Wires Alternatives

The Commission approaches NWAs from a fundamental tenet of utility regulation—that major utility investments (individual projects or groups of investments) should be examined for prudency through an open process and that this should necessarily include an examination of alternatives, whether they are "wires" or "non-wires" in nature, or a combination thereof. As recently noted in the May 8, 2020 order in Case No. U-20561 (May 8 order), the "consideration of alternatives – including NWAs – are an important element in demonstrating why [a utility's] proposed expenditures are preferable to other options." May 8 order, p. 112. There is an opportunity to build on existing NWA pilots (e.g., Consumers and its Swartz Creek Energy Savers Club (NWA) pilot project) as well as investments that have not necessarily been labeled as such but may have similar outcomes (e.g., DTE Energy Company's combined heat and power plant partnership with Ford Motor Company). In the distribution plans to be filed in 2021, the Commission expects further progress on articulation of decision criteria used by utilities to screen projects for NWA analysis, as well as additional pilots that could be considered.

While the Commission recognizes that NWAs may not always provide the appropriate technical solution when considering the entire topology of the distribution system, technologies and customer behavior continue to adapt and could present new opportunities going forward. That is, as behind-the-meter technologies such as DERs and energy efficient appliances evolve, the suite of grid solutions and services they are capable of providing to the distribution system will evolve as well. As utilities move to advanced distribution management systems to gain better transparency in the real-time operation of grid assets, the potential for ancillary services beyond load reduction, such as reliability improvement, volt/var reduction, and microgrids from DERs, will also expand. The Commission would like to see pilot studies focusing on these behind-the-meter technologies to better understand how these customer-sited resources can improve the reliability, efficiency, and productivity of the distribution system. The future distribution system will, as always, need to adapt to the changing demands of customers. Thoroughly understanding these technologies and their impact on distribution system operations is crucial to modernizing the electric grid. The Commission views NWAs not only as an opportunity for electric utilities to lower costs but also as an opportunity to engage, empower, and form partnerships with customers to meet carbon reduction goals economically. The Commission directs DTE Electric, Consumers, and I&M to work with the Staff to develop NWA pilots that expand beyond existing DR and EWR programs. With the publication of IEEE Standard 1547-2018, *IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces*, now is the time to understand how to best utilize both utility-owned and customer-owned DERs to maximize grid performance.

Regarding the distribution plans to be filed in 2021, the Commission agrees that, in the short-term, NWA projects should focus on capacity and substation projects. As the Staff and interested parties work to integrate NWAs into the utility planning process, limiting the number of capacity and substation projects considered for NWAs, as well as the scope of the eventual NWA pilots, in the next round of distribution plans is prudent. With this in mind, as noted in the May 8 order, p. 112, the Commission expects to be presented with "a robust suite of NWAs that may be evaluated for prudency as possible programs." Longer term, the Commission looks forward to continuing to refine the criteria under which NWAs would be considered, drawing on the experience of other jurisdictions from around the country, and directs the Staff to continue to work with utilities and other stakeholders in developing this criteria.

As a threshold matter, the Commission notes the Staff's endorsement of a series of questions that should be addressed by utilities "prior to refining and implementing additional NWA pilots." Staff's final report, p. 28 (footnote omitted). These questions, taken from Mr. De Martini's recommendations as well as the Staff's addition, focus on a "customer-centric approach to NWA" and include the following:

- Why are non-wires alternatives being pursued?
    - What are the pressing issues?
- What are the desired outcomes?
    - Optimize utility distribution expenditures?
    - Enable greater value for customer/developer DER investments?
    - Enable greater adoption of DER to meet renewable/customer choice goals?
- What are the range of potential solutions?
    - Pricing, programs and procurements (3P's)?
- What is the role of customers, DER developers, utilities, aggregators[,] and others?

* * *

- Are the benefits and costs of NWAs accruing to all customers on an equitable basis?

Staff's final report, Executive Summary, pp. iv-v.

Further, as part of the NWA analysis, the Commission would like greater transparency into the need for, costs, and timing of traditional solutions. For proposed NWAs, the Commission expects information regarding costs and savings, impact of the NWA in offsetting the need for traditional investment, customer consumption patterns with and without the NWA, implementation timing, and assumptions used in the analysis, including minimum customer participation levels. The Commission expects this to be an iterative process, with additional guidance on specifics relating to the affected project areas, substation characteristics, and details on both proposed wired and NWAs on a going-forward basis. Furthermore, while the Commission acknowledges the central role utilities play in determining appropriate investments in their distribution systems, the Commission also expects this process to be informed by options presented by other technologies and solutions providers. In another MI Power Grid order issued today in Case No. U-20633 launching a Staff-led stakeholder group on the integration of resource, distribution, and transmission planning, the Commission has also identified NWA evaluation frameworks as a topic for discussion. In that order the Commission is directing the Staff to file a summary of findings and recommendations relating to methodologies or frameworks for evaluating NWAs on or before May 27, 2021.

Finally, as noted below, the Commission is directing DTE Electric, Consumers, and I&M to file draft plans for comment by the Staff and stakeholders by August 1, 2021, in advance of final plans being filed with the Commission not later than September 30, 2021. The Commission specifically directs the utilities mentioned above to include in their draft plan responses to the questions posed by Mr. De Martini and the Staff, and invites comment from the Staff and stakeholders on these issues as well. While the Commission will not be approving the distribution plans, it continues to emphasize the role a robust consideration of alternatives will play in the consideration of alternatives–including NWAs–in specific proposed investments included in future rate cases. The cadence of future distribution plans will be determined later and may be informed by the stakeholder discussions in Case No. U-20633.

Benefit-Cost Analysis

While the Commission finds this an important topic to tackle in the near term, this is not a topic that can be resolved before the next round of distribution plans are due next year. The

Commission appreciates the Staff's recommendation to convene stakeholders on the BCA framework after the plans are filed next year, but the Commission refrains from making this commitment so that it can evaluate priorities in 2021 in light of other MI Power Grid activities. This decision does not, however, absolve the utilities from justifying their investments, including consideration and quantification of costs and benefits relative to alternatives. *See*, e.g., May 8 order, pp. 122-153. In addition, the Commission also notes that the Staff's final report outlines specific BCA criteria that warrant additional input from stakeholders. Further, the Commission is aware of a large amount of work nationally around BCA frameworks, including the *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*[17] that was recently published by the National Energy Screening Project and highlighted by the joint commenters to guide the Commission's evaluation of BCA. As with the criteria for considering NWAs, the Commission directs the Staff to continue to work with utilities and other stakeholders in continuing to explore the appropriate framework for evaluating BCA, including consideration of experiences from other jurisdictions and recommendations related to the issues highlighted in the Staff's final report. The Commission expects these additional details to inform and be integrated into future utility distribution plans.

Alternative Regulatory Approaches

The Commission generally agrees with the Staff's recommendation, with the belief that distribution plans can tie into a performance-based system. *See*, the Commission's *Report on the Study of Performance-Based Regulation* (April 20, 2018), the May 8 order, and MI Power Grid.

[17] The *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* and other materials can be accessed at <https://www.nationalenergyscreeningproject.org/> (accessed August 19, 2020).

Furthermore, in the May 8 order the Commission directed DTE Electric to include in its next distribution plan "proposed PBR [performance-based regulation] elements with reasonable metrics tied to utility financial performance, improvement targets, and timelines for achievement," and specified the following elements for consideration:

> 1. The utility's financial PBR system should include both incentives and disincentives based on performance; incentive structures should be holistically considered in terms of impacts on potential earnings;
>
> 2. The utility should consider the pros and cons of a comprehensive PBR system, which would avoid concurrent regular annual rate cases and separate PBR reconciliations;
>
> 3. Performance metrics should include outcome measures (e.g., customer average interruption duration index (CAIDI)) and not be limited to output metrics such as number of poles replaced;
>
> 4. Performance metrics should be linked to regional, national, and/or peer utility benchmarks, where possible;
>
> 5. Data and calculation methodologies should be well defined, transparent, and open for auditing/verification purposes;
>
> 6. Targets should be utility specific; and
>
> 7. Potential areas of performance focus are safety, customer service (end-use customers, builders, interconnecting generators, etc.), timeliness and quality, reliability and resiliency, long-term costs, and innovation.
>
> A final PBR plan and metrics shall be included with the company's distribution investment and maintenance plan . . . .

Id., pp. 106-107.

The Commission is also aware that issues involving distribution system performance and financial incentives and disincentives are contested issues in Consumers' electric rate case in Case No. U-20697. The requirements listed above apply only to DTE Electric; additional requirements for Consumers (if any) will be included in the Commission's order in Case

No. U-20697. At this point, the Commission is not expecting to require additional specific efforts for incorporating PBR frameworks or metrics for I&M.

Finally, the Commission expects additional focus on these alternative regulatory approaches as part of the Financial Incentives and Disincentives workstream to be included in Phase III of the MI Power Grid initiative, with additional details to follow next year.

Pilot Programs

The Commission agrees with the Staff that recommendations stemming from the MI Power Grid Energy Programs and Technology Pilots workgroup should inform the pilots proposed in the utility distribution plans. The Commission further notes that the Staff's draft report on Energy Programs and Technology Pilots was circulated to stakeholders on July 31, 2020, and the final report is scheduled to be filed on September 30, 2020. The Commission will provide additional guidance on structuring of pilots included in utility distribution plans following the filing of the Staff's final report on this issue, and encourages utilities to begin considering how to apply the recommendations from that stakeholder process as they begin to develop and refine the pilots to be included in their distribution plans next year.

Resilience

The Commission agrees with DTE Electric on the description of resilience, in terms of the ability to restore power following a major catastrophic event. The Commission also thinks about this term more broadly such as planning to mitigate more localized, high-impact outages caused by equipment issues, access limitations, or system configurations that inhibit timely restoration or backup capabilities, e.g., specialized equipment necessary to replace substation failure cannot be replaced in timely manner and the area cannot receive backup power through an alternative means or obstructions limit access to distribution equipment (e.g., closed in alleyways in Detroit).

Resilience in this context should also consider the vulnerability of loads that would affect public health, safety, or security under an extended outage, and related mitigation strategies to ensure continuity of service. With the potential for supply chain disruptions due the pandemic or other factors, as well as cyber or physical security threats, the Commission underscores the importance of robust, risk-based resilience evaluations and mitigation strategies as part of distribution planning efforts.

Standardized Components for Future Utilities' Distribution Plans

The Commission agrees with the Staff's recommendation as it relates to those components jointly agreed to by Consumers, DTE Electric, and I&M at the October 16, 2019 stakeholder meeting.[18] Without being too overly prescriptive, the Commission does find some consistency with components to be beneficial, particularly when comparing and aggregating data.

Michigan Infrastructure Council

Seeing continued relevance and importance with this matter, the Commission agrees with the Staff and finds that the utilities should continue to coordinate distribution planning efforts with those efforts made by the MIC in order to benefit all Michigan residents through more efficient and effective planning.

The Role of Energy Efficiency (Energy Waste Reduction) with Distribution Planning

The Commission agrees with the Staff's recommendation for the utilities to consider EWR in their upcoming distribution plans due next year. The Commission finds it important to run sensitivities in load forecasts for distribution planning and to start modeling locational impacts from customer behavior (whether through plug-in electric vehicles, EWR, storage, solar DG, DR,

[18] <https://www.michigan.gov/documents/mpsc/Full_Slides_-_ver_8_668920_7.pdf> (Slides 4-11) (accessed August 19, 2020).

etc.). The Commission recognizes that the purpose of distribution planning is not to design EWR programs or to conduct localized EWR/DR potential studies, but finds that a stronger linkage between EWR and DR efforts and distribution planning would facilitate the identification of potentially cost-effective NWAs that could defer to displace an expensive distribution upgrade. Indeed, in the 2019 SEA, Recommendation E-5 states that a framework should be developed "to evaluate non-wires alternatives such as targeted energy waste reduction and demand response in IRPs and distribution plans." 2019 SEA, p. 196. As such, the Commission is already on record recommending exactly the type of targeted demand-side programs supported by the joint commenters, ACEEE, and the Staff.

Moreover, the Commission agrees with joint commenters, ACEEE, and the Staff that geotargeting demand-side programs to impact distribution-level system needs is consistent with the statutory framework for delivering EWR and DR. The system-wide EWR requirements contained in statute, as well as the EWR and DR commitments approved as part of utility IRPs, represent a baseline for demand-side resources. However, as the joint commenters and ACEEE point out, demand-side investments may provide additional and situation-specific cost savings and other benefits for customers in specific distribution system contexts. While these situation-specific applications can certainly be included as part of utility compliance strategies with statutory mandates and IRP commitments, the fulfillment of those other obligations does not relieve utilities from considering–and ultimately implementing–demand-side options where doing so results in cost savings or other quantifiable benefits.

Next Steps

The Commission sees value in aligning distribution plans and IRP filings and is interested in such an alignment to the best extent possible. The Commission, however, recognizes that a perfect line up between the two may not be achievable given the statutory framework of MCL 460.6t and the utility-specific nature of each IRP case. *See,* e.g., Case Nos. U-20165 and U-20471. Moreover, given the pressing need to respond to the coronavirus pandemic during 2020 and the timing of this order, the Commission finds additional time is warranted to prepare the distribution plans and extends the previous deadline of June 30, 2021 to September 30, 2021. Given the importance of maintaining dialogue and openness with stakeholders, the Commission also finds that it is appropriate to have draft plans filed for stakeholder and Staff feedback prior to submission to the Commission in September, and directs DTE Electric, Consumers, and I&M to file draft plans with the Commission for comment by August 1, 2021.

THEREFORE, IT IS ORDERED that the next versions of distribution investment and maintenance plans shall be consistent with this order and shall be filed by DTE Electric Company, Consumers Energy Company, and Indiana Michigan Power Company by September 30, 2021, with draft plans shared with stakeholders and the Commission Staff by August 1, 2021. DTE Electric Company's distribution investment and maintenance plan shall also be consistent with the May 8, 2020 order in Case No. U-20561.

The Commission reserves jurisdiction and may issue further orders as necessary.

MICHIGAN PUBLIC SERVICE COMMISSION

Daniel C. Scripps, Chair

Sally A. Talberg, Commissioner

Tremaine L. Phillips, Commissioner

By its action of August 20, 2020.

Lisa Felice, Executive Secretary

P R O O F   O F   S E R V I C E

STATE OF MICHIGAN)

Case No. U-20147

County of Ingham)

Brianna Brown being duly sworn, deposes and says that on August 20, 2020 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Brianna Brown

Subscribed and sworn to before me
this 20th day of August 2020.

Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
As acting in Eaton County
My Commission Expires: May 21, 2024

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